VEDO EXHIBIT NO. 12.0

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc. for Approval of an Increase in Gas Rates	)))	Case No. 18-0298-GA-AIR
In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Approval of an Alternative Rate Plan	)))	Case No. 18-0299-GA-ALT

DIRECT TESTIMONY OF
RUSSELL A. FEINGOLD
ON BEHALF OF
VECTREN ENERGY DELIVERY OF OHIO, INC.

_____	Management policies, practices, and organization
_____	Operating income
_____	Rate base
_____	Allocations
_____	Rate of return
X	Rates and tariffs
X	Other: Cost of Service Study

TABLE OF CONTENTS

Direct Testimony of
Russell A. Feingold

I. BACKGROUND AND QUALIFICATIONS

Q1. Please state your name and business address.

A. My name is Russell A. Feingold. My business address is 2525 Lindenwood Drive, Wexford, Pennsylvania 15090.

Q2. By whom and in what capacity are you employed?

A. I am employed by Black & Veatch Management Consulting, LLC (Black & Veatch) as a Vice President and I lead its Rates & Regulatory Services Practice.

Q3. Please describe the firm of Black & Veatch.

A. Black & Veatch Corporation (the parent company of Black & Veatch) has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas. From an industry-wide perspective, Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas and electric distribution companies located in the U.S. and Canada.

Q4. Please describe your educational background.

A. I received a Bachelor of Science Degree in Electrical Engineering from Washington University in St. Louis and a Master of Science Degree in Financial Management from Polytechnic Institute of New York University.

Q5. Have you previously testified before the Public Utilities Commission of Ohio (Commission) or any other regulatory authority?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission (FERC), the National Energy Board of Canada, and numerous state and provincial regulatory commissions, including this Commission. My expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies.

In addition to traditional utility costing and rate design concepts and issues, my testimony addressed revenue decoupling concepts and other innovative ratemaking approaches, gas transportation rates, gas supply planning issues and activities, market-based rates, Performance-Based Regulation (PBR) concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates, and pipeline ratemaking issues related to the importation of gas into the United States.

Q6. What has been the nature of your work in the utility consulting field?

A. I have over forty-two (42) years of experience in the utility industry, the last thirty-nine (39) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. In addition to my presentation of expert testimony in utility regulatory proceedings that was just discussed, I have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A to my testimony.

Q7. Please summarize your specific experience in conducting class cost of service studies and designing rates for gas and electric utilities.

A. Over my utility consulting career, I have conducted numerous class cost of service studies for gas and electric utilities to provide guidelines for use in evaluating the utilities' class revenue levels and rate structures. In addition to these cost studies, which are based on a utility's embedded or historical costs, I have conducted long-run and short-run marginal cost, avoided cost, and unbundled service and cost studies. Finally, I have reviewed, evaluated, designed and implemented rate structures and other innovative pricing approaches for numerous gas and electric utilities operating in North America and abroad.

Q8. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Vectren Energy Delivery of Ohio, Inc. (VEDO or the Company).

II. SUMMARY

Q9. What is the purpose and scope of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor, present and explain the Cost of Service Study (COSS) submitted by VEDO in this rate proceeding. My testimony specifically addresses the structure, content and results of the Company's COSS, its underlying cost allocation methods, and how its results are used for ratemaking purposes.

Q10. Would you please identify the schedules you are sponsoring in this proceeding?

A. I am sponsoring the following schedules:

Schedule E-3.1 - Customer Charge/Minimum Bill Rationale

Schedule E-3.2 - Cost of Service Study

I am also sponsoring those portions of Schedule E-3 that are identified in that schedule and in the direct testimony of Mr. Scott E. Albertson.

Q11. What is the source of the information contained in the schedules you are sponsoring?

A. The source of the information generally is the books and operating budgets of VEDO. When data comes from another source, I will note that in my testimony if not made clear in the referenced schedules of the Application.

Q12. Has a COSS been submitted in this proceeding?

A. Yes. Schedule E-3.2 of the Company's filing contains its COSS based upon pro forma revenues and costs for the future test year ended September 30, 2018. The study was performed using Black & Veatch's proprietary, computer-based Gas Cost of Service Model.

Q13. Was this study prepared by you or under your supervision and direction?

A. Yes.

Q14. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

Q15. What rate classes were included in the Company's COSS?

A. All rate classes are included in VEDO's COSS, representing the following rate schedules: Residential Service (Rates 310, 311 and 315), General Service (Rates 320, 321 and 325), Large General Transportation Service (Rate 345) and Large Volume Transportation Service (Rate 360).

Q16. Please describe Schedule E-3.1.

A. Schedule E-3.1 - Customer Charge/Minimum Bill Rationale presents the components of the customer-classified costs for each of VEDO's rate classes. This information is extracted from the COSS which is presented in Schedule E-3.2.

Q17. Please describe in more detail the Company's COSS presented in Schedule E-3.2.

A. The Company's COSS presented in Schedule E-3.2 is organized as follows:

- Schedule E-3.2-1 presents a tabular summary of results for VEDO's COSS based on its future test year at present and proposed rates.
    - Schedule E-3.2-1A presents a unit cost analysis based on the functionalized and classified components of the Company's total revenue requirement.
    - Schedule E-3.2-1B presents the complete output detailing the results of the COSS by FERC or primary account.
- Schedule E-3.2-2 presents the complete output detailing the Functionalization phase.

- Schedule E-3.2-3 presents the complete output detailing the Classification phase for the Transmission and Distribution functions.
- Schedules E-3.2-4A through E-3.2-4D present the complete output for allocation to the rate classes of the Company's functionalized and classified revenue requirement for Transmission Demand, Distribution Demand, Distribution Commodity and Distribution Customer, respectively.
- Schedules E-3.2-5A through E-3.2-5C present a complete listing of the allocation factors used in the functionalization, classification and allocation phases of the COSS, respectively.
- Schedule E-3.2-6 lists the functionalization, classification and class allocation factor(s) assigned to each account in the Company's revenue requirement.

In addition, I am presenting the supporting work papers, designated as WPE-3.2-1 through WPE-3.2-13, which show how the cost allocators external to the COSS were developed. WPE-3.2-1 is the index work paper that lists the information contained on the other work papers.

III. CONCEPTUAL BASIS FOR CONDUCTING A UTILITY'S COSS

Q18. Would you please state the purpose of a COSS?

A. A COSS is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of the utility's total cost of service (i.e., the utility's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each customer or rate class and to help determine the individual class revenue requirements and rate levels.

Q19. Are there certain guiding principles which should be followed when performing a COSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question - 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 utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost allocation methodology for use in conducting a COSS is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand, and the costs incurred by the utility 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.

A gas utility's gas 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, coincident design day capacity requirements[1] of all customers entitled to firm service; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. The costs incurred by a utility satisfy one or more of these operational objectives. There is generally a direct link between the manner in which costs are defined and their subsequent allocation.

[1] VEDO's design day capacity requirements are based on the firm customer demands expected to occur on a single day defined by VEDO as having 78 Heating Degree-Days (HDDs), or an average daily temperature of -13 degrees Fahrenheit.

It is a generally accepted concept in the utility industry that customer-related costs are incurred by a gas utility 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 may 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 a plant which is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Commodity related costs are those costs which vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related since they vary with the amount of gas volumes utilized by the Company's default sales service customers.

Q20. Please describe the general nature of gas distribution costs.

A. The delivery service costs[2] of a gas distribution utility are primarily fixed costs. Gas utilities design and install a gas distribution system capable of meeting its customers' design day requirements at the time of initial installation. Placing these facilities in service permits the utility to serve the changes in load due to extreme weather (i.e., the design day load). Once facilities serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers.

[2] Delivery service costs are the non-gas costs incurred by the utility to move gas volumes from its city-gates to customers' premises.

Q21. Is the fixed nature of these costs widely recognized?

A. Yes. The evidence supporting the fixed nature of these costs is quite significant. For example, utilities routinely normalize for weather both the costs and revenues of a gas utility as part of its rate case. If the costs of distribution mains were in any way related to the volume of gas consumed, it would also be necessary to weather normalize the utility's rate base, but this is not the case. It is widely recognized that the costs of distribution mains are fixed and do not vary with gas volume. Additionally, the Gas Distribution Rate Design Manual, prepared by the NARUC Staff Subcommittee on Gas, defines demand or capacity costs as follows:

> Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to the customer costs, such as the costs associated with distribution mains in excess of the minimum size.[3]

Q22. Please discuss the factors which can influence the overall cost allocation framework utilized by a gas distribution utility.

A. Three standard steps or phases are followed when performing a COSS: cost functionalization, cost classification and cost allocation. The factors affecting these steps

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[3] Gas Distribution Rate Design Manual, Prepared by NARUC Staff Subcommittee on Gas, June 1989, pages 23-24.

can 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 gas utility.

The physical configuration of the utility's gas system refers to considerations such as: (1) the transmission and/or distribution system configuration; (2) the mainline pipeline functionality; (3) the system operating pressure configuration; and (4) the existence of any production-related facilities. These considerations include determining whether: (1) the distribution system is a centralized grid/single city-gate or a dispersed/multiple city-gate configuration; (2) the gas utility has an integrated transmission and distribution system or a distribution-only operation; (3) the system operates under a multiple-pressure based or a single-pressure based configuration; and (4) the production-related facilities are used to support the peak demand or seasonal/annual demand requirements of the gas utility's customers.

With regard to data availability, the structure of the gas utility's books and records can influence its COSS framework. This structure relates to attributes such as the level of detail, segregation of data by customer or rate class, operating unit or geographic region, and the types of load data available.

State regulatory policies and requirements refer to the particular approaches used to establish utility rates in the state jurisdiction. For example, any specific methodological preferences or guidelines for performing COSS or designing rates established by the state regulatory body can affect the particular cost allocation method presented by the gas utility.

Q23. How do these factors relate to the specific circumstances applicable to VEDO?

A. Regarding the physical configuration of the Company's gas system, it is a combination concentrated (in the greater Dayton area) and dispersed/multiple city-gate transmission and distribution system, with a multi-pressure based system.

With respect to data availability, VEDO has detailed plant accounting records. Where necessary, it is a customary and accepted practice in the utility industry to rely upon current operating cost experience to derive reasonable cost estimates of customer-related facilities (e.g., services, meters and regulators) by rate class for purposes of assigning the test period costs of those facilities to the utility's rate classes.

Finally, I am not aware of any particular methodological preferences or guidelines for performing a COSS established by the Commission.

Q24. What steps did you follow to perform the Company's COSS?

A. I followed three broad steps to perform the Company's COSS: (1) functionalization; (2) classification; and (3) allocation. The first step, the functionalization process, involves separating rate base (primarily plant in service) and expense items into operational components based on the various characteristics of utility operation. For VEDO, the functional cost categories associated with gas delivery service include transmission and distribution.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics of services rendered, as previously discussed: (1) customer; (2) demand or capacity; and (3) commodity.

The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated using customer, demand, and commodity allocation factors.

Q25. What objective are you seeking to achieve through this three-step process?

A. The functionalization and classification of the utility's total cost of service (i.e., its total revenue requirement), provides the cost analyst with groupings of costs that are fairly homogeneous, which enables the identification and application of cost allocation methods that have a closer relationship to the causation of the costs that are being assigned to the utility's rate classes.

Q26. How does the cost analyst establish the cost and utility service relationships you previously described?

A. To establish these relationships, the cost analyst must analyze the utility's gas system design and operations, its accounting records and its system-wide and customer specific load data. From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q27. Please explain what you mean by the term "direct assignment"?

A. The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups.

Direct assignment of plant and expenses to particular customers or classes of customers is made on the basis of special studies wherever the necessary data is available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records.

Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q28. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common use facilities. Where a utility provides gas delivery services to two or more rate classes wherein one class uses fungible capacity which could be utilized by the other rate class, common costs are involved. This situation is illustrated through the utility's use of its gas distribution mains to serve multiple rate classes and a wide range of customers within these classes. As a result, to the extent a utility's plant and expenses cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the costs to the customer classes. The types of analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q29. As part of your work, did you review and analyze the Company's gas system design and operations?

A. Yes. Since it is widely recognized that a utility's plant-in-service components provide the most direct link to a utility's gas service requirements, I initially focused my efforts on better understanding the nature and operation of the Company's gas system. This effort included review of the design and operating characteristics of its gas transmission and distribution systems and the types and levels of costs incurred in connecting various sized customers to its gas distribution system.

Q30. Please explain the most important considerations you relied upon in determining the cost allocation methodologies which were used to conduct VEDO's COSS.

A. As stated above, it is important to recognize the cost causative characteristics of each of the cost elements which are to be directly assigned or allocated within any class cost of service study. Additionally, the cost analyst needs to structure data in the COSS in a format (e.g., by cost classification and function) which is supportive of the appropriate allocation of costs to the utility's customer or rate classes. Of further concern is the availability of data for use in developing alternative cost allocation factors. In evaluating any cost allocation methodology, consideration should be given to:

1. Recognition of <u>cost causality</u> as opposed to value of service;
2. Results which are <u>representative</u> of the true costs of serving different types of customers;
3. A sound <u>rationale</u> or <u>theoretical</u> basis;
4. <u>Stability</u> of results over time;
5. Logical consistency and completeness; and
6. Ease of implementation.

Q31. Please explain the overall approach and guidelines you used to conduct the Company's COSS.

A. Throughout the process of choosing cost allocation methods and deriving cost allocation factors for use in a utility's COSS, I always objectively determine cost causative factors that are grounded in the design and operating characteristics of the particular utility. This was also the case in conducting the COSS filed by VEDO in this proceeding. As a result, the Company's COSS reasonably reflects the appropriate cost causation characteristics across all of the Company's rate classes and derives results that objectively portray the true costs to serve each of the utility's rate classes and the customers within each rate class. These results can be used with confidence as a guide to establish the Company's class revenues and rates in this proceeding.

Q32. Please describe the key issues related to the allocation of demand-related costs within a gas utility's COSS.

A. An important and complex part of the allocation process is the allocation of demand-related costs. These costs represent a relatively largely portion of the utility's revenue requirements, and the nature of the plant facilities and expenses are joint in nature, meaning that "common" allocation methods must be used instead of direct assignments. A number of methodologies have been used to develop allocation factors for the demand components of costs. It is fair to say that three basic methodologies for allocating demand-related costs are the most common. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the gas utility. Under this methodology, demand-related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group relative to the system peak. The Peak Demand Allocation process might focus on a single peak, such as the utility's design day which is based on the worst case temperature conditions under which the utility's gas distribution system must be designed. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day.

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand. The portion of these facilities is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand). A more simplistic version of this methodology is the Peak and Average methodology. This cost methodology gives equal weight to peak demands and average demands.[4] As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's demand-related costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, may be designed to serve local peaks which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's (rate class) maximum demand, irrespective of the time of the system peak.

Q33. How have demand-related costs been allocated in VEDO's COSS?

A. The Company's COSS uses a coincident peak demand (derived on a design day basis) to allocate demand-related costs to its rate classes. Demand-related costs for the Company consist of the capacity costs (plant-related and expenses) associated with its city-gate facilities and the capacity or demand-related portion of its gas distribution system.

[4] The Peak and Average demand cost allocation method sometimes is implemented by using the gas utility's annual system load factor to weight the "average demand" and "excess demand" portions of the composite allocation factor.

Q34. Why doesn't the Company use average demand (i.e., annual throughput volumes divided by 365 days) to allocate demand-related costs?

A. Using only average demand to allocate demand related costs is inappropriate because it does not reflect the cost causative characteristics of demand-related costs. If a gas utility's system was sized and installed to accommodate average gas demands, it would be unable to accommodate the design day demands upon which the system was built. That is, by sizing plant investment for design day demands, the gas utility is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, it is clear that a design day demand criteria is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system. As such, cost causation with respect to demand-related costs is unrelated to average demand characteristics.

Additionally, use of average demand characteristics for the allocation of demand-related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the gas utility's system by customers with low load factors. Clearly, under-utilization of a gas utility's system is a result that is not in the interest of the gas utility to encourage.

For the above-stated reasons, it is inappropriate to solely rely upon only a commodity-based allocation factor, as derived from annual gas throughput volumes, for purposes of allocating demand related costs to a gas utility.

Q35. Why did you choose to utilize VEDO's design day demands rather than its actual peak day demands as a demand allocation factor?

A. Use of a gas utility's design day demands is superior to using its actual peak day demands[5] (or an historical average of actual peak day demands over time) for purposes of deriving demand allocation factors for a number of reasons. These include:

1. A gas utility's system is designed, and consequently costs are incurred, to meet its design day demand. In contrast, costs are not incurred on the basis of an average of peak demands over time.
2. Design day demand is directly related to the level of change in customers' maximum daily demands for gas and to the associated change in fixed plant investment over time.
3. Design day demand provides more stable cost allocation results over time.

Q36. Please explain why the Company's design day demand best reflects the factors that actually cause costs to be incurred.

A. VEDO must consistently rely upon design day demand in the design of its own distribution facilities required to serve its firm service customers. This requirement will ensure that the utility has sufficient gas distribution system capacity to continue to provide reliable gas service during design day (worst case) conditions. And perhaps more importantly, design day demand directly measures the gas demand requirements of the Company's firm service customers which create the need for it to acquire resources, build facilities and incur hundreds of millions of dollars in fixed costs on an ongoing basis.

[5] A gas utility's design day demand is derived to represent the highest amount of gas that can be used by its customers on a day with extremely cold weather conditions and serves as a measure of the maximum distribution system capacity that the utility requires to serve all firm customers during design day weather conditions. Actual peak day demand represents, in each year, the single day in which the maximum amount of gas is used by the gas utility's customers, but this amount is unlikely to be as high as the utility's design day demand.

Based on my experience, there is no better way to capture the true cost causative factors of the Company's gas operations than to utilize its design day demand requirements within its COSS.

Q37. What level of firm demand requirements must VEDO consider in designing its gas distribution system to deliver under all conditions?

A. It is my understanding that VEDO designs its gas system, and has sufficient capacity, to serve the maximum delivery service requirements of all its firm sales and transportation service customers. I would consider this to be a reasonable approach, and one that is common across the gas utility industry. Therefore, the demands of all firm customers will be treated on an equivalent basis for purposes of cost allocation based on using the design day demands of the Company's rate classes.

Q38. Why is the use of design day demands closely related to the change in the Company's fixed plant investment over time?

A. Changes in design day demands serve as the primary input into the Company's ongoing decisions to install distribution system facilities to meet firm customer demands for gas delivery service. Simply stated, when customers' design day demands increase to a certain point, the Company needs to consider additional fixed plant investments, as it needs to be able to meet its design day demands.

Q39. Please explain why the use of design day demand provides relatively stable cost allocation results over time.

A. A gas utility's design day demand is the primary determinant of its planned capacity requirements and utilization. As described earlier, the design day demand is a measure of firm customers' maximum daily gas usage under pre-defined worst case weather conditions. As such, design day demand will not vary to the same degree as the utility's actual peak day demands, because those demands can increase or decrease in any year compared to the peak day demands experienced in past years based on whether the particular day was relatively colder or warmer. Therefore, use of design day demand provides a more stable basis, and one more tied to the basis of investment decisions, than any of the other demand allocators available based on either actual peak day demand or the averaging of multiple peak day demands.

Q40. In addition to the allocation of demand-related costs, are there any other aspects of a gas utility's COSS worthy of focus?

A. Yes. For similar reasons, another critical element of a gas utility's COSS is the cost classification, allocation methods, and related allocation factors used to assign the plant and expenses associated with distribution mains to the utility's classes of service.

Q41. Please describe the system operating conditions that provide a foundation for the choice of classification and allocation methods for the costs of distribution mains.

A. Gas customers in a utility's residential and commercial service classes have exhibited declining use per customer due to the improved efficiency of capital stock replacement and improvements to the housing thermal envelope. This improved efficiency over time lowers the utility's design day requirements compared to the design day requirements at the time when the original plant was designed and installed to serve customer loads. As a result, the growth in transmission plant and distribution plant for gas customers primarily reflects the growth in number of customers using gas service. That is, a utility's system of distribution mains must be extended over time to permit new customers to receive gas service. Therefore, the primary driver of new distribution mains cost is the addition of new customers. Further, there are substantial economies of scale associated with the gas distribution infrastructure such that the unit cost of capacity for gas delivery declines with size at a relatively rapid rate.

Q42. Please discuss the economies of scale associated with gas distribution service.

A. Scale economies for a gas distribution utility reflect the relationship between the installed cost of pipe by size and type, coupled with the increased capacity from pressure and pipe diameter. For example, doubling the size of the gas main results in more than a doubling of the available capacity of the main, at a cost for VEDO that is less than double the cost of the smaller size main. For a lower pressure system, increasing pipe size from two-inch to four-inch allows almost six times the amount of gas to flow. The resulting cost causation results in larger customers imposing lower unit costs of design day capacity on the gas utility's distribution system than do smaller customers.

Q43. Can you please explain how the costs of gas distribution mains should be classified and allocated in a gas utility's COSS?

A. Yes. There are two cost factors that influence the level of distribution main facilities installed by a gas utility in expanding its gas distribution system. First, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid over time to connect new customers to the system. Secondly, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the coincident peak gas demand placed on the gas utility's system by its firm customers. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment and the related operation and maintenance (O&M) expenses based on both the number of customers served by the gas utility and its design day demands.

To further explain, the customer component of distribution mains is premised upon the concept of a "minimum system." The "minimum system" for a gas distribution utility is the smallest hypothetical system a gas utility would construct to connect its customers. The classification of the costs associated with the minimum system as customer-related, rather than capacity-related, recognizes the fact that the gas utility must install a network of distribution mains simply to have a physical connection with its customers, regardless of the level of demand a particular customer will actually impose on the gas system. A customer cannot be served at any level if the customer is not physically interconnected with the utility's gas distribution system.

Using the minimum system concept as a foundation, it is widely recognized that a large portion of a gas utility's total cost of distribution mains must be borne regardless of customers' peak day or annual use. To illustrate this point, it is useful to summarize a gas utility's process for physically connecting new customers. To extend gas service to a typical residential subdivision, the utility must first design the gas system. Based on this design, the utility determines the length and size of pipe needed to serve the area and procures the necessary material. A field crew is then dispatched to the site, together with the materials and equipment required to install the natural gas facilities. The activities necessary to install gas mains include digging a trench, installing the main into the trench, and backfilling the trench. Pipeline boring (i.e., a trenchless installation method) may be necessary to install some main segments if the utility is unable to open trench a portion of the line due to existing surface conditions along the route of the main. After the main is installed, it will be pressure tested, tied into the existing gas system, and purged and filled with natural gas. The main is then ready to provide utility service to the new customers. These steps are necessary regardless of how much gas the new customers are projected to use during the year or during a peak day. The design work must still be completed, the crews, materials, and equipment dispatched to the site, the trench dug, the main installed in the trench, the trench backfilled, testing performed, and the other activities performed.

The additional costs associated with any larger mains required are mostly the incremental costs of the larger mains themselves, the additional labor involved with digging a wider trench for very large mains, and possibly the need for additional equipment to handle larger diameter pipe. As a result, a large percentage of the costs of providing gas delivery service to a gas utility's customers are incurred before they ever use one unit of gas. These are the costs the gas utility must incur simply to extend its gas distribution system to customers, irrespective of whether they will demand a small or large volume of gas on a peak day. As a result, the costs of such a minimum system are fundamentally customer-related in nature.

Q44. What methods are used in the gas utility industry to determine the customer component of distribution mains?

A. Based on my experience, the two most commonly used methods in the gas utility industry for determining the customer cost component of distribution mains facilities consist of: (1) the zero-intercept method; and (2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept method, a customer cost component is developed through statistical regression analyses to determine the unit cost (i.e., cost per foot) associated with a zero-inch diameter distribution main. This concept can also be thought of as estimating the fixed costs per foot that the utility incurs to design and install a gas distribution main regardless of the main's diameter.

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

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies are *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 of these authorities describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. In its publication, "Gas Distribution Rate Design Manual," NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.[6] Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q45. Have you prepared an analysis which supports VEDO's classification and allocation of distribution mains costs?

A. Yes. WPE-3.2-4 provides the derivation of the customer component of distribution mains for VEDO using the minimum system method based on the Company's historical costs of a two-inch main, adjusted to current cost levels using the Handy Whitman index. A further adjustment was made to recognize that the minimum size distribution main of two inches has some level of capacity carrying capability. The resulting percentage of 54.5

[6] Gas Distribution Rate Design Manual, National Association of Regulatory Utility Commissioners, June 1989, pages 22-23.

percent represents the customer cost component of distribution mains and the remaining 45.5 percent represents the demand cost component.

The customer cost component is then allocated to the Company's rate classes based on the number of customers in each rate class for the test year, and the demand cost component is allocated to the rate classes based on the design day demand allocation factor.

Q46. Why was it necessary to make a further adjustment to the customer component of distribution mains to recognize the capacity carrying capability of the minimum size main?

A. If one simply uses the current cost of a two-inch main without an adjustment as the basis for the customer component of distribution mains, it would overstate the customer cost component because a two-inch main functions to connect customers to the utility's gas distribution system <u>and</u> to provide some minimum level of capacity to serve a portion of customers' gas demand requirements. As a result, this adjustment slightly lowers the customer cost component (stated on a percentage basis) to recognize this dual function of a minimum-sized, two-inch distribution main.

Q47. Can you please explain how you determined the capacity carrying capability of VEDO's minimum size distribution main?

A. WPE-3.2-4 provides the calculations that support the derivation of the capacity carrying capability of a two-inch main operating as part of the Company's gas distribution system. The Company's capacity analysis resulted in a capacity carrying capability for a two-inch distribution main equal to approximately 0.13 Dth per day per customer.

Q48. Earlier in your testimony you discussed the use of special studies to assign plant and expenses to a utility's rate classes. Please describe the special studies you conducted to assign the Company's other distribution plant investment to its rate classes.

A. Regarding VEDO's major plant accounts, a series of direct assignments were developed to allocate the following plant accounts: Services - Account No. 680, Meters - Account No. 681, Meter Installations - Account No. 682, House Regulators – Account No. 683, and Industrial Measuring & Regulating Station Equipment - Account No. 685. In particular, the special studies reflect the differences in the unit costs that particular customer groups cause the Company to incur.

Q49. How was intangible plant allocated in VEDO's COSS?

A. Intangible plant (Account No. 601) which is related to the incorporation and reorganizational activities of the Company was allocated to VEDO's rate classes using a composite allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs). Miscellaneous Intangible Plant (Account No. 602) includes a variety of computer software investments that support the Company's customer service and delivery functions and related tariff modifications. These investments were allocated to the Company's rate classes using a composite allocation factor based on an equal weighting of labor-related expenses and the number of customers.

Q50. Please describe the method used to allocate the Company's reserve for depreciation and depreciation expenses?

A. These items were allocated on the same basis as their associated plant accounts.

Q51. How were distribution-related O&M expenses allocated in VEDO's COSS?

A. In general, these expenses were allocated on the basis of the cost allocation methods used for VEDO's corresponding plant accounts. A utility's O&M expenses generally are considered to support the utility's corresponding plant-in-service accounts. That is, the existence of the particular plant facilities necessitates the incurrence of cost (i.e., expenses) by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Maintenance of Services - Account No. 892, is allocated on the same basis as its investment in Services - Account No. 680. With the Company's detailed analyses supporting its assignment of plant-in-service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q52. How were Customer Account Expenses allocated in VEDO's COSS?

A. VEDO's COSS allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Meter reading expense (Account No. 902) was allocated to the rate classes based on the number of customers in each rate class since it was determined that there is no difference in the unit cost of reading a meter for a Residential Service customer compared the unit cost for reading the meters of larger customers. Customer records and collection expense (Account No. 903) was allocated to the rate classes based on the number of customers in each rate class. Uncollectible accounts expense (Account No. 904) consists of the amounts included in VEDO's Percentage of Income Payment Plan (PIPP) and Uncollectible Expense (UEX) Riders. These amounts were directly assigned to each rate class based on the corresponding level of revenues by rate class collected through these two riders during the test period.

Q53. How were Customer Service and Informational Expenses allocated in VEDO's COSS?

A. VEDO's COSS allocated these expenses to each rate class based on the number of customers.

Q54. How were Sales Expenses allocated in VEDO's COSS?

A. For Account No. 912 – Demonstration and Selling Expenses, VEDO's COSS allocates these expenses to each rate class based on the results of a special study which evaluated the costs of the energy conservation programs included in Account No. 912. The cost of each program was directly assigned to customers in either the Residential or General Service rate class, and the related common costs of the programs (e.g., program outreach expenses) were allocated to both rate classes in proportion to their directly assigned program costs. Account No. 911 – Sales Expense Supervision, Account No. 913 – Advertising Expenses, and Account No. 916 – Miscellaneous Sales Expenses were allocated to each rate class based on the number of customers.

Q55. How were Administrative and General (A&G) expenses allocated in VEDO's COSS?

A. VEDO's COSS allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Specifically, the A&G expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant or rate base; and (3) O&M expenses. In the Company's COSS, each of its A&G accounts was related to one or more of these categories. These categories were then used as a basis to establish an appropriate allocation factor for each account. The allocation factors chosen were broad-based to specifically recognize the corporate-wide nature of A&G expenses.

Specifically, Administrative and General Salaries (Account No. 920), Office Supplies and Expenses (Account No. 921), Employee Pensions and Benefits (Account

No. 926), and Injuries and Damages (Account No. 925) were allocated using a labor-based allocation factor derived from the labor component of the Company's transmission and distribution O&M expenses. Similarly, the plant and O&M allocation factors discussed above were derived based on the Company's total plant investment and total O&M expenses, respectively. Property Insurance (Account No. 924) was allocated on transmission and distribution plant. Outside Services (Account No. 923) and Miscellaneous Expenses (Account No. 930.2) include support activities provided to VEDO directly by outside service providers and its corporate parent organization. These activities relate to various general business functions that support the Company's gas utility operations. Due to the general nature of these costs and their corporate-wide applicability, these costs were allocated to the Company's rate classes using a composite allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs). Finally, regulatory commission expense (Account No. 928) was allocated using a generalized cost allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs).

Q56. How were income taxes allocated in VEDO's COSS?

A. Income Taxes were allocated to each rate class based on each class' income before federal income taxes. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues, previously allocated expenses and the various adjustments made by the Company for tax computation purposes. Income Taxes for each rate class at revenues producing an equal rate of return, and at proposed revenues, were computed in a similar method taking into account class revenues and allocated expenses so that the amounts equaled the income taxes at proposed rates within the Company's revenue requirement.

Q57. How were taxes other than income taxes allocated in the Company's COSS?

A. These expenses were allocated in VEDO's COSS in a manner to reflect the specific cost causative factors associated with the Company's particular tax expense categories. Specifically, these taxes can be cost classified on the basis of the tax assessment method established for each tax category (i.e., property and payroll). As a result, taxes other than income taxes of a utility typically can be grouped into the two categories of plant and/or expenses. In the filed COSS, each of VEDO's taxes other than income taxes accounts was related to one of the above-stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each tax account. Real Estate and State Gross Income Taxes were allocated on total transmission and distribution plant. Excise Tax was allocated using a composite allocation factor based on an equal weighting of total plant in service and O&M expenses (excluding purchased gas costs).

IV. RESULTS OF THE COMPANY'S COST OF SERVICE STUDY

Q58. Please discuss the results of the Company's COSS.

A. Referring to <u>Schedule E-3.2-1</u>, line 19, VEDO's COSS indicates that at present rates during the test year, its rate classes are contributing to the recovery of the Company's revenue requirement as follows:

- Residential Service exhibits a lower than average rate of return on net rate base.
- General Service exhibits a higher than average rate of return on net rate base.
- Large General Transportation Service exhibits a higher than average rate of return on net rate base.
- Large Volume Transportation Service exhibits a higher than average rate of return on net rate base.

Q59. How can COSS results such as these provide guidelines for rate design?

A. Results of a COSS provide cost guidelines for use in evaluating class revenue levels and class rate structures. With regard to rate class revenue levels, the rate of return results show that certain rate classes are being charged rates that recover less than their indicated costs of service. Obviously, because this condition exists, rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. By adjusting rates in accordance with the cost study, rate class revenue levels can be brought closer in line with the indicated costs of service resulting in movement of rate class rates of return toward the system average rate of return and resulting in rates that are more in line with the cost of providing service. At the same time, though, it is recognized that there are non-cost factors such as customer impact considerations (e.g., avoiding rate shock through gradualism) and rate continuity that are often balanced with the cost to serve in apportioning the utility's proposed revenue increase among its rate classes.

Concerning cost justification of rates within each rate class, the classified costs, as allocated to each class of service in the cost study, provide cost information that can be of assistance in determining the need for changes in the relative levels of demand, customer and commodity rate block charges.

It should be noted, however, that the results produced by a class cost of service study are not always relevant to all classes of service. In particular, this exception applies to the Company's special contract service customers, where rates are based on competitive alternatives or value of service concepts. For these customers, the value of gas delivery service to the customer relative to available alternatives, as captured in class revenues, has much more influence on the relative profitability (i.e., rate of return) of that class than cost causation does, as measured by a gas utility's cost of service study. This view is shared by NARUC in its Gas Distribution Rate Design Manual where it states that, “Setting rates based on value of service bears little relationship to setting them based on cost of service. When using value of service principles, we normally look not to the cost of the utility providing the service, but rather to the cost of alternatives available to the customer.” Therefore, the guidelines I discussed above are most useful when evaluating the Company’s rate schedules that contain customers charged for gas service at VEDO’s standard rates (i.e., full rates).

Q60. Did VEDO’s COSS provide the cost basis for the establishment of the Monthly Charge proposed for General Service - Group 1 customers under VEDO’s Straight Fixed-Variable (SFV) rate design proposal presented in the Prepared Direct Testimony of Mr. Albertson?

A. Yes. The proposed Monthly Charge for Group 1 customers in VEDO’s General Service rate class was based on the unit demand and customer costs in the COSS derived for VEDO’s Residential rate class adjusted for the increased daily demand requirements and higher unit meter investment costs of the customers included in General Service – Group 1.

Q61. Why was the Monthly Charge proposed for VEDO’s General Service - Group 1 customers guided by the costs of serving its residential service customers?

A. This approach was used in recognition of the relatively similar load characteristics that exist between VEDO’s Residential and General Service – Group 1 customers. These load characteristics include the portion of customers’ annual gas usage that is heat sensitive and the annual load factor for each of these two customer groups. Similarities in load characteristics mean that the fixed unit cost characteristics of these two customer groups are likely also similar in nature. As a result, it is reasonable to conclude that the cost-based Monthly Charge for VEDO’s Residential rate class can be used as a cost of service basis to establish the Monthly Charge for its General Service – Group 1 customers.

V. CONCLUSION

Q62. Does that conclude your prepared direct testimony?

A. Yes, it does.

EDUCATIONAL BACKGROUND, WORK EXPERIENCE AND REGULATORY EXPERIENCE
RUSSELL A. FEINGOLD

EDUCATIONAL BACKGROUND

- Bachelor of Science degree in Electrical Engineering from Washington University in St. Louis
- Master of Science degree in Financial Management from Polytechnic Institute of New York University

WORK EXPERIENCE

2007 – Present	**Black & Veatch Management Consulting, LLC** Vice President and Rates & Regulatory Services Practice Lead
1996 – 2007	**Navigant Consulting, Inc.** Managing Director, Energy Practice - Litigation, Regulatory & Markets Group; Energy Delivery Practice Lead
1990 – 1996	**R.J. Rudden Associates, Inc**. Vice President and Director
1985 – 1990	**Price Waterhouse** Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	**Stone & Webster Management Consultants, Inc.** Executive Consultant Regulatory Services Division
1973 – 1978	**Port Authority of New York and New Jersey**

Staff Engineer and Utility Rate Specialist

Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- National Energy Board of Canada
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Kentucky Public Service Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Nebraska Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission

- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission
- New York Public Service Commission
- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Public Utilities Commission of Ohio
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Régie de l'Énergie Quebec (Canada)
- South Dakota Public Service Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of Wyoming

EDUCATIONAL AND TRAINING ACTIVITIES

- Past Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.

- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison and University of Chicago School of Business, 1985 – 2018.
- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park, 1987 –1992, and University of Chicago School of Business, 2012-2018.
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987 edition.
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress).
- Contributing Author of "Regulation of the Gas Industry," LexisNexis Matthew Bender, 2016.

PUBLICATIONS AND PRESENTATIONS

- "Properly Balancing the Costs and Benefits of DER When Designing Rates," PowerForward: Ratemaking and Regulation, Public Utilities Commission of Ohio, March 20-22, 2018.
- "Ratemaking for the Modern Utility: A Flawed Approach or Beyond Reproach?" S&P Global Market Intelligence, 2017 Utility Regulatory Conference, December 5-6, 2017.
- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 14-16, 2017.
- "Regulatory Update", American Gas Association, Risk Management Committee Meeting, July 17, 2017
- "State Regulatory Issues – Analysis & Trends," American Gas Association Financial Forum, May 20-23, 2017.

- "The Valuing and Pricing of Distributed Energy Resources: Some Inconvenient Truths," SNL Energy Utility Regulation Conference, December 14-15, 2016.

- "Pricing Concepts and Regulatory Issues for Distributed Energy Resources," American Gas Association, State Affairs Committee Meeting, October 9-12, 2016.

- "State Regulatory Update – Regulatory Responses to a Changing Utility Industry," American Gas Association Financial Forum, May 15-17, 2016.

- "State Regulatory Update: Regulatory Responses to a Changing Utility Industry" American Gas Association, Finance Committee Meeting, March 14-16, 2016.

- "Rate Restructuring Tiers and Other Pricing Twists", SNL 2015 Utility Regulation Conference, December 10, 2015.

- "Utility Ratemaking Solutions During a Time of Transition", American Gas Association, State Affairs Committee Meeting, October 4-7, 2015.

- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 17-19, 2015.

- "Utility Ratemaking Solutions for a Changing Energy Marketplace", SNL Online Course, July 15, 2015 and October 27, 2015.

- "State Regulatory and Legislative Issues", American Gas Association Financial Forum, May 17-19, 2015.

- "Rate Design and Cost Allocation Issues", SNL 2014 Utility Regulation Conference, December 8-9, 2014.

- "Current Regulatory and Ratemaking Issues", American Gas Association, Accounting Principles Committee Meeting, August 18-20, 2014.

- Regulatory Update", Southern Gas Association, 2014 Management Conference, Accounting & Financial Executives Roundtable, April 2-4, 2014.

- "Emerging Regulatory Issues for Gas Distribution Companies," American Gas Association, Finance Committee Meeting, March 17-19, 2014.

- "Balancing Rising Costs & Customer Expectations," co-authored with Will Williams and Jeff Evans, Western Energy Institute, WE Magazine, Winter 2013 issue.

- "Current Trends in Utility Rates and Economic Regulation," Western Energy Institute, WE Magazine, Fall 2013 issue.

- "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," American Gas Association State Affairs Committee Meeting, October 6-9, 2013

- "Utilities 2.0 Roundtable," 2013 National Town Meeting on Demand Response and Smart Grid, July 10-11, 2013

- "State Regulatory and Legislative Issues," American Gas Association Financial Forum, May 5-7, 2013

- "Providing Natural Gas to Unserved and Underserved Areas," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 28-31, 2012

- "State Regulatory Issues Affecting Gas Utilities," American Gas Association Accounting Principles Committee Meeting, August 13-15, 2012

- "State Regulatory Landscape and Future Trends Affecting Utilities," American Gas Association Financial Forum, May 6-8, 2012.

- "The Continuing Saga of Fixed Cost Recovery: Arguments in Utility Rate Proceedings," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 30 - November 2, 2011.

- "State Regulatory Issues Affecting Utilities," American Gas Association Accounting Principles Committee Meeting, August 15-17, 2011.

- "State Regulatory Issues Affecting Utilities," Edison Electric Institute/American Gas Association Accounting Leadership Conference, June 26-29, 2011.

- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 15-17, 2011.

- "2011 Forecast – Regulatory Issues and Risks for Utilities," American Gas Association Finance Committee Meeting, March 16-18, 2011.

- "State Regulatory Issues Affecting Utilities," Edison Electric Institute and American Gas Association Accounting Leadership Conference, June 27-30, 2010.

- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 17-19, 2010.

- "A Utility's Regulatory Compact: Where's the Right Balance? – RMEL Electric Energy Magazine, Issue 1 – Spring 2010.

- "Communicating Ratemaking and Regulatory Concepts to a Utility's Stakeholders," American Gas Association, Communications and Marketing Committee Meeting, March 16-17, 2010.

- "Managing Regulatory Risk Workshop", Rocky Mountain Electric League, October 8, 2009.

- "State Regulatory and Legislative Issues Affecting Utilities," American Gas Association, 2009 Financial Forum, May 3, 2009.

- "Financial Incentives for Energy Efficiency: Lessons Learned to Date," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 7, 2009.

- "Breaking the Link Between Sales and Profits: Current Status and Trends," Energy Bar Association, Electricity Regulation and Compliance Committee, February 17, 2009.

- "State Ratemaking Issues for Gas Distribution Utilities," Energy Law Journal, Volume 29, No. 2, 2008 (Report of the Natural Gas Regulation Committee).

- "Current Issues in Cost Allocation and Rate Design for Utilities," SNL Energy, Utility Rate Cases Today: The Issues and Innovations, November 6, 2008.

- "Current Issues in Revenue Decoupling for Gas Utilities," American Gas Association, Financial and Investor Relations Webcast, October 16, 2008.

- "Addressing Utility Business Challenges Through the State Regulatory Process," American Gas Association, 2008 Legal Forum, July 20-22, 2008.

- "Earning on Natural Gas Energy Efficiency Programs," American Gas Association Rate and Regulatory Issues Conference Webcast, May 23, 2008.

- "State Regulatory Directions: Utility Challenges and Solutions," American Gas Association Financial Forum, May 4, 2008.

- "Ratemaking and Financial Incentives to Facilitate Energy Efficiency and Conservation," The Institute for Regulatory Policy Studies, Illinois State University, May 1, 2008.

- "Update on Revenue Decoupling and Innovative Rates," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, March 10, 2008.

- "Update on Revenue Decoupling and Utility Based Energy Conservation Efforts," American Gas Association, Rate and Regulatory Issues Conference Webcast, May 30, 2007.

- "A Renewed Focus on Energy Efficiency by Utility Regulators," American Gas Association, Rate and Regulatory Issues Seminar and Committee Meetings, March 26, 2007.

- "The Continuing Ratemaking Challenge of Declining Use Per Customer," American Public Gas Association, Gas Utility Management Conference, October 31, 2006.

- "Understanding and Managing the New Reality of Utility Costs in the Natural Gas Industry," Financial Research Institute, Public Utility Symposium, University of Missouri – Columbia, September 27, 2006.

- "Ratemaking and Energy Efficiency Initiatives: Key Issues and Perspectives," American Gas Association, Ratemaking Webcast, September 14, 2006.

- "Ratemaking Solutions in an Era of Declining Gas Usage and Price Volatility," Northeast Gas Association, 2006 Executive Conference, September 10-12, 2006.

- "Rethinking Natural Gas Utility Rate Design," American Gas Foundation and The NARUC Foundation, Executive Forum, Ohio State University, May 2006.

- "Rate Design, Trackers, and Energy Efficiency – Has the Paradigm Shifted?" Energy Bar Assocation, Midwest Energy Conference, March 2006.

- "Key Regulatory Issues Affecting Energy Utilities," American Gas Association, Lunch 'n Learn Session, November 2005.

- "Decoupling, Conservation, and Margin Tracking Mechanisms," American Gas Association, Rate & Regulatory Issues – Audio Conference Series, October 2005.

- "In Search of Harmony, [Utilities and Regulators] Respondents Weigh in with Needed Actions", Public Utilities Fortnightly, November 2005

- "The Use of Trackers as a Regulatory Tool," Midwest Energy Association – Legal, Regulatory, and Government Relations Roundtable, October 9-11, 2005.

- “Rate Design and the Regulatory Environment,” American Gas Association Finance Committee Meeting, October 2005.

- “Creative Utility Regulatory Strategies in a High Price Environment,” American Gas Association Executive Conference, September 2005.

- “Revenue Decoupling Programs: Aligning Diverse Interests,” The Institute for Regulatory Policy Studies, Illinois State University, May 2005.

- “Key Regulatory Issues Affecting Energy Utilities” American Gas Association Financial Forum, May 2005.

- “Energy Efficiency and Revenue Decoupling: A True Alignment of Customer and Shareholder Interests,” American Gas Association Rate and Regulatory Issues Seminar and Committee Meetings, April 2005.

- “Rate Case Techniques: Strategies and Pitfalls” American Gas Association, Rate & Regulatory Issues – Audio Conference Series, March 2005.

- “Regulatory Uncertainty: The Ratemaking Challenge Continues” Public Utilities Fortnightly, Volume 142, No. 11, November 2004.

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- “State Regulatory Oversight of the Gas Procurement Function” Energy Bar Association, Natural Gas Regulation Committee, Energy Law Journal, Volume 25, No. 1, 2004.

- “Cost Allocation Across Corporate Divisions”, American Gas Association, Rate and Strategic Issues Committee Meeting, April 2003.

- “Unbundling Initiatives – How Far Can We Go?” American Gas Association Restructuring Seminar: Service and Revenue Enhancements for the Energy Distribution Business, December 2002.

- “Utility Regulation and Performance-Based Ratemaking (PBR),” PBR Briefing Session sponsored by BC Gas Utility Ltd., April 2002.

- “LDC Perspectives on Managing Price Volatility” American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.

- “Can a California Energy Crisis Occur Elsewhere?” American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.

- “Downstream Unbundling: Opportunities and Risks,” American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.

- “Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?” American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999

- “Total Energy Providers: Key Structural and Regulatory Issues,” American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.

- “The Gas Industry: A View of the Next Decade,” National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.

- “Regulatory Responses to the Changing Gas Industry,” Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998

- “Trends in Performance-Based Pricing,” American Gas Association Financial Analysts Conference, May 1998.

- “Unbundling – An Opportunity or Threat for Customer Care?” presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.

- “Experiences in Electric and Gas Unbundling,” presented at the 1997 Indiana Energy Conference, December 1997.

- “Asset and Resource Migration Strategies,” presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.

- “The Status of Unbundling in the Gas Industry,” presented at the American Gas Association Finance Committee, March 1997.

- Seminar organizer and co-moderator at the American Gas Association, “Workshop on Unbundling and LDC Restructuring,” July 1995.

- “State Regulatory Update,” presented at the American Gas Association - Financial Forum, May 1995.

- “Gas Pricing Strategies and Related Rate Considerations,” presented before the Rate Committee of the American Gas Association, April 1995.

- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.

- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.

- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.

- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.

- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.

- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.

- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.

- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.

- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.

- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.

- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.

- Seminar organizer and moderator at the American Gas Association seminar, “Integrated Resource Planning: A Primer,” December 1991.

- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.

- “Strategic Perspectives on the Rate Design Process,” presented before the Executive Enterprises, Inc. conference, “Natural Gas Pricing and Rate Design in the 1990s,” September 1990.

- “Distribution Company Transportation Rates,” presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.

- “Design of Distribution Company Gas Rates,” presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.

- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, “Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing,” 1988-1990.

- “Local Distribution Company Bypass - Issues and Industry Responses,” (Co-author) June 1989.

- “So You Think You Know Your Customers!,” presented before the American Gas Association–Annual Marketing Conference, April 1990.

- “Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey,” presented before the Rate Committee of the American Gas Association, April 1985-1991.

- “Market-Based Pricing Strategies - Targeted Rates to Meet Competition,” presented before the American Gas Association Annual Marketing Conference, March 1989.

- “Gas Rate Restructuring Issues - Targeted Prices to Meet Competition,” presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.

- “Gas Transportation Rates - An Integral Part of a Competitive Marketplace,” *American Gas Association, Financial Quarterly Review*, Summer 1987.

- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review,* October 1983.

- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.

- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.

- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, State Affairs Committee of the American Gas Association
- Member, Energy Bar Association
- Life Member, Institute of Electrical and Electronic Engineers
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(Current as of March 2018)