BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF DOMINION ENERGY UTAH TO INCREASE DISTRIBUTION RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	))))))))	**DOCKET NO. 22-057-03**

Direct Testimony of

Brian C. Collins

On behalf of

Federal Executive Agencies

September 15, 2022

FEA Exhibit 2.0

Brubaker & Associates, Inc.

Project 11327

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I. QUALIFICATIONS AND SUMMARY

I.A. Qualifications

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A My education and professional experience are detailed in my Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING?

A I am offering testimony on behalf of the Federal Executive Agencies ("FEA"), including Hill Air Force Base ("Hill AFB"), a customer in the Transportation Service ("TS") class.

<u>I.B. Summary</u>

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will provide comments and recommendations on the class cost of service ("CCOS"), the class revenue allocation, the TS class split, and certain rate design proposals of Dominion Energy Utah ("DEU" or "the Company"). My silence in regard to any issue should not be construed as tacit agreement or an endorsement of DEU's position.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A For the reasons outlined in this testimony, I recommend the following to the Public Service Commission of Utah (the "Commission"):

1. My proposed CCOS study uses Design Day Demand to allocate the costs of large-diameter intermediate high-pressure ("IHP") mains as

well as the costs of high-pressure feeder-line mains to customer classes. Because Design Day Demand reflects how the Company designs its system of mains and best reflects class cost causation, my CCOS study is appropriate to guide class revenue allocation.

2. The Company's CCOS study does not best reflect class cost of service because of its reliance on annual usage or commodity volumes to partially allocate the cost of distribution mains to customer classes. As a result, I recommend my proposed CCOS study be used as a guide for the Company's class revenue allocation.

3. I recommend that my proposed class revenue allocation be used to determine class revenue responsibility. This is appropriate because my proposed class revenue allocation is guided by my CCOS study, which better reflects class cost causation with respect to the allocation of distribution main costs as compared to the Company's CCOS study.

4. My proposed class revenue allocation is based on the Company's fully requested revenue requirement. To the extent a reduction to the Company's requested revenue requirement is approved, I recommend an equal percent reduction for each class be applied after my class revenue allocation at the Company's fully requested revenue requirement is implemented.

5. Unless the cost allocation of distribution mains is corrected in the DEU CCOS study, I recommend the Company's proposed split of the TS class into TS Small ("TSS"), TS Medium ("TSM") and TS Large ("TSL") subclasses be rejected. Unless the Company's CCOS study reflects appropriate cost-based allocations of all distribution main costs, the subsidy paid by the TSL class will be exacerbated. As a result, I recommend the Company's proposed TS class split be rejected if the Commission accepts the Company's Peak & Average ("P&A") allocation of mains costs in the CCOS study.

6. Regarding the Company's proposal for renewal of the Infrastructure Rate Adjustment Tracker ("IRAT") by the Commission, I propose that the tracker be modified to track changes in total net plant investment in high pressure mains and should not track only incremental investments. The tracker should account for not only incremental rate base resulting from investments made under the rider, but should also account for the change in legacy net rate base.

II. CLASS COST OF SERVICE

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A CCOS STUDY?

A After the utility's overall cost of service (or revenue requirement) is determined, a CCOS study is used to allocate the cost of service among the utility's customer classes. A CCOS study shows the extent to which each customer class contributes to the total cost of the system. For example, when a class produces the same rate of return as the total system, it returns to the utility just enough revenues to cover the costs incurred in serving that class (including a reasonable authorized return on investment). If a class produces a rate of return below the system average, the revenues it provides for the utility are insufficient to cover all relevant costs. If, on the other hand, a class produces a rate of return above the average, then that class pays revenues sufficient to cover the costs attributable to it, and it also pays for part of the costs attributable to other classes that produce below-average rates of return. The CCOS study therefore is an important tool, because it shows the revenue requirement or cost of service for each class along with the rate of return under current rates and any proposed rates.

Q SHOULD A CLASS'S RATES ALWAYS BE MOVED TO FULL COST OF SERVICE BASED ON THE RESULTS OF THE UTILITY'S CCOS STUDY?

A To the extent possible, a utility's rates for its classes should be based on each class's respective cost of service. However, in instances where a full movement to cost of service for a utility's rates would cause rate shock for a particular customer class or classes, gradualism can be used to mitigate the impacts on customer classes and avoid rate shock. For example, the increase in current rates for a particular class or classes could be limited to a certain multiple of the system average increase in order to avoid rate shock and recognize the principle of gradualism.

III. DEU'S CLASS COST OF SERVICE STUDY

Q HAVE YOU REVIEWED THE CCOS STUDY PREPARED BY DEU IN THIS PROCEEDING?

A Yes. I have reviewed the CCOS study prepared by Company witness Austin C. Summers in his direct testimony, DEU Exhibit 4.0.

Q IN ITS CCOS STUDY, HOW DOES THE COMPANY ALLOCATE THE COST OF DISTRIBUTION MAINS TO CLASSES?

A DEU proposes to divide its distribution main investments into three categories: small-diameter (6 inches or smaller) intermediate high-pressure ("IHP") mains, large-diameter (greater than 6 inches) IHP mains, and high-pressure feeder-line mains. Distribution mains are typically the largest cost rate base item for a local distribution gas utility.

The costs of small-diameter IHP mains are allocated to classes by the Company's Distribution Plant Factor study used to determine the amount of small mains necessary to provide service to customers.

The costs of large-diameter IHP mains connecting the small-diameter IHP mains to the high-pressure feeder-line mains are allocated to classes by the Company's Distribution Throughput Study which allocates cost to customer classes based on class throughput or commodity volumes.

The costs of high-pressure feeder-line mains are allocated to classes by a weighted-average combination of Design Day Demand (60%) and annual usage or commodity throughput (40%). The combination of these factors results in a composite allocation factor that is generally known as the P&A allocation factor.

Q DO YOU OPPOSE THE COMPANY'S PROPOSAL FOR ALLOCATING THE COST OF SMALL-DIAMETER IHP MAINS TO CUSTOMER CLASSES?

A No, I do not. The Company's proposal results in allocating small-diameter IHP main costs to the customer classes that actually utilize small-diameter IHP mains. This allocator also appears to recognize the cost to connect customers to the Company's system of mains. Utilities design their system of mains to not only meet system peak demands but also to connect customers to the system of mains. As a result, I do not oppose this allocation.

Q HOW DO UTILITIES TYPICALLY REFLECT THE COSTS OF CONNECTING CUSTOMERS TO THE SYSTEM?

A They either use a small mains adjustment or a minimum system study. A small mains adjustment essentially removes the costs of small mains from large high load factor classes. Based on my review, the Company's proposed allocation of small diameter IHP costs is essentially a small mains adjustment and results in very little small main costs allocated to large high load factor classes.

Q DO LARGE TRANSPORTATION CUSTOMERS TYPICALLY UTILIZE SMALL-DIAMETER DISTRIBUTION MAINS?

A No, they do not. Large, high load factor transportation customers typically do not utilize small-diameter mains because they are incapable of delivering the quantity of gas supply that these customers require. As a result, these customers are typically allocated a small amount of the costs of small-diameter mains.

A review of the Company's CCOS study shows that the Company's Distribution Plant Factor study does indeed allocate very little small-diameter IHP main costs to customer classes with larger gas demands. For example, the

TSL class is allocated 0.007% of the costs of small-diameter mains, which is a logical result.

Q THAT BEING SAID, DO YOU AGREE THAT DEU'S PROPOSED CCOS STUDY BEST REFLECTS CLASS COST OF SERVICE?

A No, I do not. I disagree with DEU's proposal in its CCOS study to allocate some categories of distribution main costs largely on annual usage or commodity throughput instead of on class contributions to the system peak day. As explained above, large-diameter IHP main costs are allocated on commodity throughput by the Company; high-pressure feeder-line main costs are allocated on the P&A method. Allocating a portion of main costs on annual usage or commodity throughput does not reflect sound cost of service principles.

Based on the results of the Company's CCOS study used to guide revenue allocation, the TSL class would see a proposed increase of 65.53%. It does not seem logical that this class would receive this large of an increase.

The large increase is driven by the Company's use of the P&A allocation for feeder mains costs. Feeder mains are the largest component of Account 376, distribution mains, accounting for approximately 55% of the total main plant cost.

Q DO THE RESULTS OF THE ALLOCATION OF THE FEEDER MAINS COSTS TO THE TSL CLASS SEEM LOGICAL?

A No. According to the testimony of Mr. Summers at page 22, there are 826 customers in the TSS class, compared to 30 customers in the TSL class. Both the TSL class and the TSS class have almost the same Design Day Demands, resulting in the same Design Day Demand allocator of 4.2% as shown in DEU Exhibit 4.20. However, in that same exhibit, the P&A allocator for the TSL class is 8.3% vs. 4.3% for the TSS class. It is not logical for two customer classes with essentially the same Design Day Demands being allocated such disparate percentage of main costs and resulting in much different increases in present rates. The reason is due to the use of volume in the allocation of mains costs.

Q IS THE P&A METHOD A LOGICAL METHOD OF COST ALLOCATION?

A No. The P&A method typically uses the annual system load factor to determine the percentage of fixed delivery system investment allocated on annual system throughput. As load factor, which is a measure of system efficiency, increases, the percentage of transmission plant cost allocated on system throughput increases. Large manufacturing customers use gas consistently throughout the year and increase system load factor. Therefore, the P&A method is illogical because it allocates even more costs to those customers that increase system load factor and punishes efficient usage.

Q IS THE P&A METHOD A TRUE COST ALLOCATION METHOD?

A No. The P&A method is not a true cost allocation method as it introduces load factor to temper costs between high load factor and low load factor customer classes. Essentially, the P&A method introduces customer class cost mitigation into the cost allocation process. This is inappropriate. Instead, costs should first be allocated on cost causation, as is done with the Design Day Demand method. After costs are properly allocated to customer classes, any necessary cost mitigation to prevent rate shock for particular customer classes should then be addressed through the class revenue allocation process.

Q DO ALL CUSTOMERS BENEFIT FROM A MORE EFFICIENT SYSTEM?

A Yes. More throughput without an increase in demand makes the system more efficient and reduces costs to all ratepayers. If the system load factor improves (increased throughput without an increase in peak demand), the system would be more efficient and fixed costs per unit would decrease. However, the P&A method's cost allocation formula would unfairly increase the allocation on throughput and punish the higher load factor classes that are responsible for increasing the efficiency of the system. The use of average throughput penalizes customers that exhibit efficient gas consumption (higher load factors). Under-utilization of the system should not be rewarded since it results in higher per unit prices for all customers.

Furthermore, the P&A method penalizes high load factor customer classes by ignoring economies of scale. Economies of scale are recognized when a gas utility sizes its distribution mains to satisfy the Design Day Demand requirements of its customer classes. The concept of economies of scale drives overall costs incurred by a gas utility for its gas distribution mains and these economies of scale are reflected in the Company's embedded costs of distribution mains. However, economies of scale affect the sizing of distribution mains, but not the allocation of their resulting costs. The economies of scale are created by the interaction of the capacity requirements of all its customer classes. A typical gas utility does not plan for the needs of its distribution system by examining the capacity requirements of any one customer class or by conducting capacity planning by disaggregating its capacity needs into average demand requirements and peak demand requirements. Instead, it examines its capacity needs in the aggregate based on the peak demands on its design day for all of its customer classes.

The flaw in the P&A allocation method becomes evident for a customer class that exhibits a high load factor. According to the P&A allocation method, this class should not receive any economies of scale benefits because the class's average demand is high relative to its peak demand. Yet, this class should receive economies of scale benefits just as any other class to the extent the capacity requirements of this class at the time these customers were connected to the gas utility's distribution system created economies of scale in the costs of expanding the system of mains to accommodate them.

From a purely cost causation perspective, transmission and distribution main investments are simply not a function of throughput. Instead, they are a function of the cumulative Design Day Demand of those customers served by those transmission and distribution main investments.

Q PLEASE EXPLAIN WHY DESIGNING THE DELIVERY CAPACITY OF THE UTILITY BASED ON DESIGN DAY DEMANDS ALLOWS THE UTILITY TO JUSTIFY ITS DELIVERY MAIN INVESTMENT BASED ON DEMANDS FOR A SINGLE DAY.

A Distribution mains are used to provide service every day of the year including the peak day, as well as the daily demand on non-peak days throughout the year. In order to achieve this year-round service objective, the capacity of the delivery mains must be able to meet the system coincident Design Day Demand and each rate class's daily demands. As a result, measures of utilization (e.g., average demand, or annual throughput), have no bearing on the delivery capacity cost that customers are causing the utility to incur.

A utility varies the pressure and amount of gas in the mains to meet the demands of all rate classes, and the system, every day of the year. However, the fixed cost of transmission and distribution main capacity designed to meet the system peak demand remains the same every day of the year, irrespective of operating pressure and capacity utilization of the mains. Therefore, there is no causal link between the cost of transmission and distribution main capacity and annual throughput.

Q ON A NON-PEAK DAY, IS THE EXCESS AVAILABLE MAIN CAPACITY USED TO MEET THE DEMAND OF HIGH LOAD FACTOR CUSTOMERS?

A No. Relative to lower load factor weather-sensitive customers, higher load factor customers more efficiently and consistently utilize the main capacity installed to meet their coincident peak Design Day Demand. The excess available main capacity on non-peak days exists due to weather-sensitive demand, and is held in reserve for weather-sensitive customers for when their demands spike on peak days. This excess capacity is not used to meet the demands of higher load factor, non-weather-sensitive customers throughout the year when it is not needed to serve weather-sensitive customers. Rather, as noted above, the capacity installed to serve all rate classes demands on the peak day, is also used to serve their daily demands, but at a lower operating pressure than what is required on a peak day.

Q WHY DOES ALLOCATING A PORTION OF DISTRIBUTION MAIN COSTS ON AN ANNUAL USAGE OR COMMODITY THROUGHPUT BASIS NOT REFLECT SOUND COST OF SERVICE PRINCIPLES?

A When a gas distribution utility is considering whether to engage in a particular expansion of its distribution mains capacity, it must first determine the proper size and cost of the expansion. In making this determination, the key consideration is the customer classes' expected usage of the mains on the system peak day. The expected usage on the system peak day dictates the need for an expansion as well as the proper size of the expanded mains, which, in turn, dictates the total cost of the project. The cost of the expansion is a function of the anticipated peak day usage – and that cost is *the same* regardless of when customers are expected to use gas. For example, the cost is the same regardless of whether customers are expected to use gas throughout the year or during only a part of the year (i.e., the winter months).

Q IS ANNUAL USAGE OR COMMODITY THROUGHPUT A DESIGN CRITERION FOR A TYPICAL GAS DISTRIBUTION COMPANY FACILITY?

A No, it is not. To be sure, annual usage or commodity throughput is certainly a factor that should be and is considered in identifying the variable cost of operating the gas system. However, annual usage does not determine the amount of system peak capacity that is necessary to provide firm (i.e., non-interruptible) service to every customer every day of the year. Rather, the actual physical size of the distribution mains, regulators, compressors, and related equipment is based on customers' contributions to the system Design Day Demand. The system's capacity must be sized for Design Day Demand, so that all customers can utilize that system capacity to receive a firm, uninterrupted supply of gas every day of the year, including the day of the system peak demand.

Q DOES THE COMPANY'S PROPOSAL TO ALLOCATE A PORTION OF THE COSTS OF DISTRIBUTION MAINS BASED ON ANNUAL USAGE OR COMMODITY THROUGHPUT BEST REFLECT CLASS COST CAUSATION?

A No, it does not. The Company's proposal fails to meet the cost of service principle of cost causation. As explained above, a typical gas utility (including DEU) does not use annual usage or commodity throughput to design its distribution facilities. Rather, it designs the distribution system based on its customers' contributions to the system's Design Day Demand and to connect customers to the system. Therefore, allocating the capacity-related costs associated with distribution mains (including both rate base and expenses) on the basis of annual usage or commodity throughput is inappropriate because it does not reflect how the costs are incurred by the Company.

Q IN ADDITION TO THE FACT THAT IT DOES NOT BEST REFLECT SOUND COST OF SERVICE PRINCIPLES, ARE THERE OTHER PROBLEMS WITH ALLOCATING DISTRIBUTION MAIN COSTS ON THE BASIS OF ANNUAL USAGE OR COMMODITY THROUGHPUT?

A Yes. In particular, allocating costs based on annual usage or commodity throughput is unfair to the customers that make more efficient use of the facilities. This can best be illustrated by reference to a simple generic example. Assume that utility Customer A uses 5 Dth each and every day of the year (an annual total of 1,825 Dth), and that utility Customer B, who is located directly across the street, uses 5 Dth for 180 days of the year, including the peak day, but nothing the rest of the year (an annual total of 900 Dth). Assume, further, that the annualized investment cost of the main needed to serve these two customers is $3,000. The total annual usage of the two customers is 2,725 Dth, of which approximately two-thirds is attributable to Customer A and approximately one-third to Customer B.

In order to serve these customers, the gas company must construct a main capable of delivering 10 Dth of Design Day capacity on the peak day (Customer A's 5 Dth plus Customer B's 5 Dth). Because each customer uses one-half of the firm main capacity on the peak day, it seems reasonable that they should share equally in the cost – both would pay $1,500. In fact, that is how the costs would be shared under a demand-based allocation.

The results would be quite different, however, if the distribution main costs were allocated based on annual usage. In that situation, Customer A would be allocated $2,000 (2/3 of the total $3,000 cost) while Customer B would be allocated just $1,000 (1/3 of the total $3,000 cost) because it does not use the facility's capacity for six months of the year. Thus, the fact that Customer A uses the facility efficiently every day of the year will cause Customer B to save money, but Customer B's less efficient use will cause Customer A to pay additional money. In fact, Customer A would likely be much better off if the gas company simply built a dedicated main with a capacity of 5 Dth solely to serve Customer A's load. Similarly, Customer B would likely be worse off if it had to pay for its own dedicated main.

With proper cost allocation, both customers should be better off sharing a facility because there would be economies of scale resulting from the larger capacity main.

Q DOES ALLOCATING THE DISTRIBUTION MAIN COSTS BASED ON ANNUAL USAGE OR COMMODITY THROUGHPUT CREATE AN UNBALANCED ALLOCATION OF SUCH COSTS AMONG CUSTOMER CLASSES?

A Yes. In the example above, even though both Customer A and Customer B have the same Design Day Demand, they effectively pay different costs of capacity per unit of Design Day Demand when costs are allocated based on annual usage or commodity throughput. The total capacity cost incurred by the gas distribution company is $300 per Dth of Design Day capacity ($3,000/10 Dth). However, the higher annual usage Customer A pays $400 per Dth of Design Day capacity ($2,000/5 Dth), while the lower annual usage Customer B pays $200 per Dth of Design Day capacity ($1,000/5 Dth). Thus, under an annual usage-based allocation, a customer that utilizes the distribution system more efficiently pays a premium for Design Day capacity ($400 per Dth - $200 per Dth = $200 per Dth) above what a customer that uses the system less efficiently must pay. This occurs despite the fact that the two customers have the same demands and have equal rights to Design Day capacity on the system peak day, and despite the fact that the average cost of Design Day capacity incurred by the utility is $300 per Dth.

This simple example illustrates why it is unreasonable to allocate distribution main costs on the basis of annual usage, when such costs are incurred to ensure adequate capacity on the system peak day for all customers that require firm service throughout the year.

Q DO YOU HAVE ADDITIONAL CONCERNS WITH THE COMPANY'S ALLOCATION OF HIGH-PRESSURE FEEDER-LINE MAIN COSTS ON THE P&A METHOD?

A Yes. A major problem with the P&A allocator is the fact that it double counts the average component of demand. Thus, total usage, or average demand, is counted twice in the allocation of main costs – once in the peak allocation and again in the average allocation. The impact of using the P&A method to allocate main costs is the over-allocation of capacity-related costs to high load factor customers who make efficient use of the Company's system of mains.

Q ARE THERE ANY AUTHORITIES THAT RECOGNIZE THE FACT THAT DISTRIBUTION MAIN COSTS ARE APPROPRIATELY ALLOCATED ON THE BASIS OF PEAK DEMANDS?

A Yes. The National Association of Regulatory Utility Commissioners ("NARUC") recognizes that distribution main costs should be allocated to customer classes based on: (1) Design Day Demands for the demand component of main costs; and (2) number of customers for the customer component of main costs. In this regard, the NARUC *Gas Distribution Rate Design Manual* ("NARUC Manual") states as follows:

> Demand or capacity costs vary with the 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 distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size*.**[1]

[1]NARUC *Gas Distribution Rate Design Manual* at 23-24 (June 1989) (emphasis added).

Thus, NARUC recognizes that distribution main cost is not related to or caused by annual usage (i.e., throughput or commodity), but rather by peak demands and the number of customers.

Q SHOULD A COST ALLOCATION METHOD REFLECT HOW COSTS ARE ACTUALLY INCURRED ON THE COMPANY'S DISTRIBUTION SYSTEM?

A Yes. A utility's selection of a particular cost allocation method should be based on whether that allocation method appropriately reflects class cost causation and results in rates that provide accurate price signals to its customers.

Because rates should reflect class cost causation, the costs used in setting rates should be allocated to classes based on how each class causes the costs to be incurred by the Company. Distribution mains are designed to meet the demands of customers, and not their annual gas usages. A utility incurs the cost to construct and operate distribution mains and related facilities to meet its customers' Design Day Demands. Therefore, Design Day Demand is an appropriate cost allocation method for allocating capacity-related capital costs and expenses, because it allocates costs based on how they are incurred.

Allocating costs based on how they are incurred is consistent with the NARUC *Gas Distribution Rate Design Manual*, which states that:

> *Historic or embedded cost of service studies attempt to apportion total costs to the various customer classes in a manner consistent with the incurrence of those costs.* This apportionment must be

> based on the fashion in which the utility's system, facilities and personnel operate to provide the service.[2]

Q BUT DOESN'T THE COMPANY'S DISTRIBUTION SYSTEM ALLOW CUSTOMERS TO RECEIVE VOLUMES OF GAS THROUGHOUT THE YEAR?

A I do not dispute that, after the distribution system is designed and constructed to meet Design Day Demand, customers use the system to receive volumes of gas throughout the year. However, if customers expect supply sufficient to meet their Design Day Demand, then they should pay for adequate distribution capacity to allow gas to be delivered every day to meet their expected demands, including days with above-average demands. Otherwise, they will not be allocated adequate capacity to deliver gas on days with above-average usage, which would be most cold days, and their service would be interrupted on all of those days.

It is the Design Day Demand which drives the capacity-related cost incurred in order to design, construct, implement and maintain a distribution system that is adequate to provide firm service throughout the year, including the system peak day, to all customers that want firm service. Distribution systems are sized based on Design Day Demands to ensure that firm gas supply can actually be delivered every single day of the year. Because cost

[2]NARUC *Gas Distribution Rate Design Manual* at 20 (emphasis added).

causation is driven by Design Day Demand, distribution-related costs should be allocated based on Design Day Demand.

If the distribution system can meet the Design Day Demand of its customers, it can meet the demand of its customers on every single day of the year. Daily needs must be met, but the only way to ensure that will happen is through a system that is designed to meet the Design Day Demand. Only when the distribution main system is designed to meet the peak day demand of its classes is the Company able to deliver gas each and every day of the year to meet its customers' demands.

Q ARE YOU AWARE OF ANY OTHER AUTHORITIES' POSITIONS ON THE CLASSIFICATION AND ALLOCATION OF GAS PIPELINE COSTS?

A Yes. In its landmark Order No. 636, the Federal Energy Regulatory Commission ("FERC") endorsed the straight fixed variable ("SFV") cost methodology, which allocates fixed pipeline costs 100% on a demand basis. In the order, FERC states that:

> The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equity principle.
>
> *   *   *
>
> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternative fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant

> natural gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[3]

The SFV allocation method endorsed by FERC appropriately treats fixed pipeline costs as demand-related. Similarly, distribution main costs on DEU's system should be treated as demand-related, except for those costs that are classified as customer-related. (Interstate pipelines do not normally use a customer component in allocating costs. Because they are designed to transport gas from the production area to local distribution companies, their costs are driven predominantly by demand, and not by the need to connect individual small customers to the interstate pipeline.)

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO CCOS?

A I recommend that the costs of large-diameter IHP mains and high-pressure feeder-line mains should be allocated on a Design Day Demand basis to accurately reflect cost causation.

[3] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636 at 127-29 (Apr. 8, 1992).

Q DO YOU RECOMMEND THAT THE TRANSPORTATION CLASS BE SPLIT INTO THE TSS, TSM, AND TSL CLASSES AS PROPOSED BY THE COMPANY?

A If the allocation of distribution mains costs occurs on a Design Day Demand basis, I do not oppose the TS class split proposed by DEU. However, if the Company's use of the P&A method is accepted by the Commission, I recommend the split be rejected. The proposed TS class split combined with the use of the P&A method for the allocation of feeder main costs only further punishes the high load factor TSL class customers and increases the subsidy paid by these customers to other classes.

Q DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO THE CCOS?

A Yes. For compressors and regulator facilities, according to the Company's CCOS study provided as DEU Exhibit 4.20, the Company is also proposing to allocate these costs on the basis of the P&A method. Compressors and regulators are sized to accommodate the peak day demands of the customers on the distribution mains. Therefore, these facilities' costs should be allocated across rate classes on the basis of 100% demand.

The Company has allocated these costs on the basis of the P&A method. However, I propose to allocate them on the basis of Design Day Demand. These costs are also incurred to meet system Design Day Demand and should be allocated to rate classes using the Design Day Demand allocator. This would result in cost allocation following cost causation.

Compressor stations and regulators are sized based on the size of mains and the demands on the system. As such, this equipment is designed to meet the peak day demands of the customers on it. If customers' demands vary from peak day, the size of this equipment does not change throughout the year, but rather is held on reserve for each customer until they need the compressor or regulator capacity on the Company's peak day demands. For these reasons, this equipment is sized and engineered in order to support the peak day demands of the customers connected to the distribution system.

Allocating this equipment on the basis of Design Day Demand is also consistent with NARUC. The NARUC Manual identifies distribution costs to include distribution mains, compressors, and regulators.[4] NARUC notes an advantage of allocating and pricing fixed costs on demand charges as it allows for a pricing structure that more closely reflects the actual costs incurred by the utility for providing service.

[4] *Gas Distribution Rate Design Manual*, NARUC Staff Subcommittee on Gas, June 1989, at 21-24.

Q HAVE YOU PREPARED A CCOS STUDY THAT ALLOCATES LARGE-DIAMETER IHP MAIN COSTS AND HIGH-PRESSURE FEEDER-LINE MAIN COSTS ON A DESIGN DAY DEMAND BASIS?

A Yes. In addition, I have also allocated the Company's compressor and regulator fixed costs on a Design Day Demand basis in my proposed CCOS study. As explained earlier, this equipment must also be sized to meet system peak day demands.

Q DOES ALLOCATING DISTRIBUTION MAIN COSTS ON COINCIDENT DESIGN DAY DEMAND ALLOCATE A PORTION OF MAIN COSTS ON AVERAGE DEMANDS OR COMMODITY THROUGHPUT?

A Yes. Like the P&A method, it does allocate a portion of demand-related costs on the basis of annual usage or commodity throughput because average demand is a subset of Design Day Demand. However, unlike the P&A method, the coincident Design Day Demand counts average demand (annual usage or commodity throughput divided by 365 days) only once when developing the cost allocation factor.

Q HOW DO THE RESULTS OF YOUR PROPOSED CCOS STUDY COMPARE TO THE RESULTS OF DEU'S PROPOSED CCOS STUDY?

A This is shown in Table 1 below.

TABLE 1

Class Cost of Service Study Comparison

	DEU Proposed[1]			FEA Proposed[2]		
Rate Class	**Present Non-Gas Revenues**	**COSS Incr./Decr.**	**Percent Incr./Decr.**	**Present Non-Gas Revenues**	**COSS Incr./Decr.**	**Percent Incr./Decr.**
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
GS	$ 391,822,088	$ 54,421,565	13.89%	$ 392,104,074	$ 67,721,598	17.27%
FS	$ 2,874,843	$ 1,117,044	38.86%	$ 2,865,605	$ 618,773	21.59%
IS	$ 267,754	$ (17,371)	-6.49%	$ 264,806	$ (172,727)	-65.23%
TSS	$ 14,438,531	$ (1,744,116)	-12.08%	$ 14,432,342	$ (2,145,494)	-14.87%
TSM	$ 14,201,397	$ 2,874,678	20.24%	$ 14,123,545	$ (1,054,042)	-7.46%
TSL	$ 11,451,583	$ 7,117,238	62.15%	$ 11,282,946	$ (669,074)	-5.93%
TBF	$ 4,883,040	$ 6,197,995	126.93%	$ 4,867,847	$ 5,771,228	118.56%
NGV	$ 2,615,861	$ 544,656	20.82%	$ 2,613,932	$ 441,426	16.89%
Total	$ 442,555,098	$ 70,511,689	15.93%	$ 442,555,098	$ 70,511,689	15.93%

Sources:
[1]DEU Exhibit 4.20
[2]FEA Cost of Service Workpaper

As shown in the table, instead of the large increase for the TSL class as proposed by the Company, my CCOS study indicates that the TSL class should actually receive a rate decrease, along with other transportation classes. Because the Company's CCOS study allocates main costs using annual usage or commodity throughput, larger high load factor customer classes are allocated a higher percentage of main costs. As previously explained, because the Company does not use annual usage or commodity throughput to design the capacity of its main system, utilizing annual usage or commodity throughput to allocate the costs of mains to customer classes does not follow cost causation.

Q WHAT IS YOUR RECOMMENDATION REGARDING YOUR CCOS STUDY?

A I recommend that my CCOS study guide class revenue allocation and rate design in this proceeding. This is reasonable because my CCOS study best reflects class cost causation by allocating the cost of distribution mains based on how the Company designs its system and incurs the cost of installing the mains – to meet the coincident Design Day Demand of its customer classes.

IV. DISTRIBUTION OF GAS REVENUE INCREASE

Q HAVE YOU REVIEWED DEU'S PROPOSAL FOR DISTRIBUTING ITS REQUESTED REVENUE INCREASE TO THE VARIOUS RATE CLASSES?

A Yes. DEU proposes to move all classes to cost of service, except for the Transportation Bypass Firm ("TBF") class.

Q WHAT IS THE COMPANY'S PROPOSED REVENUE INCREASE FOR THE TSL CLASS?

A The Company's proposed increase for the TSL class is approximately 65.53%. The Company's CCOS study results indicate that the TSL class would need an approximate 62.15% increase in current rates to bring it to cost of service, plus it provides a subsidy to the TBF class under the Company's proposal for class revenue allocation.

Q IS THE COMPANY'S PROPOSED REVENUE INCREASE FOR THE TSL CLASS REASONABLE?

A No. For the reasons detailed above, the Company's CCOS study is flawed because it allocates large-diameter IHP main costs and high-pressure feeder-line main costs partially on annual usage or commodity throughput. Annual usage or commodity throughput is not a correct basis to measure class revenue responsibility.

Q HAVE YOU DEVELOPED YOUR OWN CLASS REVENUE ALLOCATION OF THE COMPANY'S REQUESTED RATE INCREASE BASED ON THE RESULTS OF YOUR CCOS STUDY?

A Yes. My proposed class revenue allocation is guided by my proposed CCOS study and is shown in the table below:

TABLE 2

Class Revenue Allocation Comparison

	DEU Proposed[1]			FEA Proposed[2]		
Rate Class	**Present Non-Gas Revenues**	**Proposd Incr./Decr.**	**Percent Incr./Decr.**	**Present Non-Gas Revenues**	**Proposed Incr./Decr.**	**Percent Incr./Decr.**
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
GS	$ 391,822,088	$ 57,909,354	14.78%	$ 392,104,074	$ 68,288,109	17.42%
FS	$ 2,874,843	$ 1,173,453	40.82%	$ 2,865,605	$ 618,773	21.59%
IS	$ 267,754	$ (14,449)	-5.40%	$ 264,806	$ -	0.00%
TSS	$ 14,438,531	$ (1,542,423)	-10.68%	$ 14,432,342	$ -	0.00%
TSM	$ 14,201,397	$ 3,166,800	22.30%	$ 14,123,545	$ -	0.00%
TSL	$ 11,451,583	$ 7,503,726	65.53%	$ 11,282,946	$ -	0.00%
TBF	$ 4,883,040	$ 1,765,581	36.16%	$ 4,867,847	$ 1,163,381	23.90%
NGV	$ 2,615,861	$ 549,647	21.01%	$ 2,613,932	$ 441,426	16.89%
Total	$ 442,555,098	$ 70,511,689	15.93%	$ 442,555,098	$ 70,511,689	15.93%

Sources:
[1]DEU Exhibit 4.20
[2]FEA Cost of Service Workpaper

My proposed class revenue allocation is based on the Company's fully requested revenue requirement. To the extent that the Commission reduces the Company's requested revenue requirement, I would propose that any decrease be spread to customer classes on an equal percent basis after my class revenue allocation is implemented at the Company's fully requested revenue requirement.

Q HOW DID YOU DEVELOP YOUR CLASS REVENUE ALLOCATION?

A First, I utilized the principle of gradualism and limited classes to no more than 1.5 times the system average increase of 15.93%. I then held classes that would get a rate decrease at full cost of service, to no change in current rates. This revenue difference was then used to offset the increase to the TBF class.

Q WHY DO YOU BELIEVE YOUR PROPOSED CLASS REVENUE ALLOCATION IS REASONABLE?

A Based on the results of my CCOS study, the TSL class and other transportation classes should actually get a rate decrease. As a result, my class revenue allocation is more than fair. My proposal is a compromise between setting rates at full cost of service based on a CCOS study that uses Design Day Demand to allocate the costs of mains, and a CCOS study that uses annual usage or commodity throughput (large-diameter IHP mains) plus the P&A method (high-pressure feeder-line mains) to allocate the costs of mains to customer classes.

Q TO THE EXTENT THE COMMISSION ACCEPTS THE COMPANY'S CCOS STUDY FOR GUIDING CLASS REVENUE ALLOCATION, WHAT IS YOUR RECOMMENDATION?

A I recommend that no class receive a rate increase greater than 1.5 times the system average increase approved by the Commission.

V. DEU'S PROPOSED RATE DESIGN

Q DOES THE COMPANY PROPOSE TO RETAIN ITS INFRASTRUCTURE RATE ADJUSTMENT TRACKER MECHANISM ("IRAT")?

A Yes. The Company is requesting that the program be allowed to continue as it has previously been approved by the Commission. The Company also refers to the program as the Infrastructure Tracker Program ("ITP"). The Company's proposal is described in the direct testimony of Kelly B. Mendenhall, DEU Exhibit 1.0.

Q IS THE COMPANY PROPOSING ANY CHANGES TO THE IRAT?

A No. According to Mr. Mendenhall, the Company is not proposing any substantive changes to the program.

Q WHAT TYPES OF INVESTMENTS ARE ELIGIBLE FOR THE IRAT?

A IRAT eligible investments include new high-pressure gas feeder lines and intermediate high pressure gas lines that replace aging high-pressure gas feeder lines and intermediate high pressure gas lines.

Q IN THE EVENT THE COMMISSION DOES APPROVE THE COMPANY'S PROPOSAL FOR THE IRAT, DO YOU HAVE ANY SUGGESTED CHANGES?

A Yes. DEU's capital investment costs from the replacement of IRAT eligible investments should be synchronized with the investment costs included in base rates. Currently, base rates include the recovery "of" and "on" investments classified as high-pressure gas feeder lines and intermediate high pressure gas lines. Much of this investment is not subject to replacement currently through the IRAT.

Specifically, the Commission should ensure that DEU's investment included in base rates is synchronized with the incremental eligible investment subject to the IRAT. Synchronizing a utility's total investments is fair to both the utility and its customers, and will ensure that a utility does not recover excessive charges from its customers.

Q WHAT IS YOUR SPECIFIC RECOMMENDATION?

A The level of depreciation expense included in base rates associated with high-pressure gas feeder lines and intermediate high pressure gas lines should be used to offset the IRAT eligible investment prior to the rate of return calculation for the IRAT surcharge. This will ensure that the utility properly recovers the incremental revenue requirement associated with eligible infrastructure replacement and that the utility is not allowed to charge excessive surcharges through the IRAT.

Once rates are set in a rate case, depreciation expense continues to add to accumulated depreciation, which further reduces net plant, and results in a reduced rate base, thus reducing the rate of return component customers should be required to pay. The proposed IRAT surcharge does not reflect the decline in rate base that has occurred since base rates were last set. Therefore, the utility is allowed a return on new plant under the surcharge, while not reflecting the decreased return on a reduced net plant balance from the other high pressure gas lines that are not subject to current IRAT replacement.

My proposal will synchronize the net plant balance for high pressure gas lines not currently subject to IRAT replacement with the increased net plant investment levels associated with the IRAT eligible investment. In this way, customers are not required to pay an increased return on IRAT investment.

Q WHY SHOULD DEPRECIATION EXPENSE IN BASE RATES BE REQUIRED AS AN OFFSET TO RATE BASE WHEN DETERMINING THE APPROPRIATE LEVEL OF SURCHARGE REVENUE?

A Depreciation expense that is already included in a utility's base rates can sometimes be sufficient to fund the capital investment necessary to replace a utility's aging or obsolete infrastructure. Using the depreciation expense in a utility's existing base rates to fund new infrastructure capital investment replaces depreciated utility rate base with new utility rate base. This can be illustrated with an example. Assume that a certain utility has annual rate case proceedings, and has $10 million in annual depreciation expense and $10 million in annual new capital investment. Utility customers should be held harmless for the rate of return calculation in the base rate case proceedings, since the utility's base rates would go down as rate base decreased by $10 million through depreciation, but that rate base is replaced by the new $10 million capital investment, causing the utility's rate base to go back up to the level where it started for purposes of calculating the rate of return component.

Now assume the utility implements a rider surcharge, without recognizing the declining value to existing rate base (depreciation offsets), instead of annual base rate proceedings. In the case of the utility recovering the incremental revenue requirement for new investment through a rider surcharge, customer rates would go up to account for the $10 million spent by the utility on eligible infrastructure, but the surcharge would not reflect the reduction for the $10 million of depreciated rate base. Customers would pay higher rates, but do not get the benefit of any offsetting rate base reductions provided by depreciation expense included in existing base rates. If offsetting rate base reductions (depreciation offsets) are not considered in determining the appropriate level of surcharge revenue, it could result in excessive utility charges to customers.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

<u>Qualifications of Brian C. Collins</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Guam Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Carolina Utilities Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation

Commission, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Washington Utilities and Transportation Commission, the Public Service Commission of Wisconsin, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiations. In addition to our main office in

St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky, and Phoenix, Arizona.

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BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF DOMINION ENERGY UTAH TO INCREASE DISTRIBUTION RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	))))))))	**DOCKET NO. 22-057-03**

State of Missouri)
) ss.
County of Saint Louis)

I, Brian C. Collins, being first duly sworn on oath, state that the answers in the foregoing written testimony are true and correct to the best of my knowledge, information and belief.

Brian C. Collins
Brian C. Collins

SUBSCRIBED AND SWORN TO this 15th day of September, 2022.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2023
Commission # 15024862

Tammy S Klossner
Notary Public