BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

Application of Enbridge Gas Utah to Increase Distribution Rates and Charges and Make Tariff Modifications.	**DOCKET NO. 25-057-06**

Errata to the Direct Testimony and Exhibits of

Matthew P. Smith

On behalf of

The Federal Executive Agencies

FEA Exhibit 2.0

September 16, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11901

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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Direct Testimony of Matthew P. Smith

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Matthew P. Smith. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA"). The FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Enbridge Gas - Utah ("EGU" or "Company"), such as Hill Air Force Base. The Department of Defense has been delegated authority by the General Services Administration to represent, through Department of the Air Force counsel, the consumer interest of the FEA in these proceedings under 40 U.S.C. §§ 501(c) and 121(d). Utility costs represent one of the largest variable expenses of operating federal offices, facilities, and installations, and all will be significantly affected by any action the Commission takes in these dockets. For these reasons, the FEA has a substantial interest in the above-captioned docket.

Q ARE YOU SPONSORING ANY ATTACHMENTS IN CONNECTION WITH YOUR TESTIMONY?

A Yes, FEA Exhibit 2.01 and FEA Exhibit 2.02.

II. SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will provide comments and recommendations on the Class Cost of Service ("CCOS"), specifically allocation methods used by EGU for distribution mains and other distribution equipment, the cost of which EGU has allocated to classes using its combined design day demand/throughput and distribution throughput allocators. My silence in regard to any issue should not be construed as tacit agreement or an endorsement of EGU's position.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A I recommend the Public Service Commission of Utah (the "Commission" or "PSCU"):

- Adopt my proposed CCOS study using Excess Design Day Demand and throughput to allocate the costs of large-diameter Intermediate High Pressure ("IHP") mains, as well as the costs of high-pressure feeder-line mains, compressor station equipment, and regulation station equipment to customer classes. Because my method better reflects class cost-causation, my CCOS study is appropriate to guide class revenue allocation.

- I recommend an allocation of the increase in this case based on my COSS, and a gradual movement to cost of service for all rate classes.

III. 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 below the utility's cost of service. In this instance, the class receives a subsidy from other rate classes. If, on the other hand, a class produces a rate of return above the average, then that class pays more revenues than needed to pay the utility its cost of service, and actually also pays for part of the utility's costs to service other rate classes that produce below-average rates of return – in this case the class would pay a subsidy to cover the cost of serving other rate classes.

The CCOS study therefore is an important tool, because it shows the revenue requirement, or cost of service, for each class under current and proposed rates, which gauges whether the class is paying cost of service or if it is paying or recovering a subsidy from other rate classes.

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, yes, 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, then the principle of gradualism can be applied to move each rate class gradually toward cost of service, therefore mitigating the impacts on customer classes and avoiding rate shock, while gradually moving each rate class to cost of service.

For example, the process of gradualism moves rate classes toward cost of service without excessive increases to any specific rate class. This includes limiting rate class increases/decreases to a certain multiple of the system average increase.

IV. EGU'S CLASS COST OF SERVICE

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

A Yes. I have reviewed the CCOS study prepared by Company witness Austin C. Summers in his direct testimony, EGU Exhibit 5.0.

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

A EGU proposes to divide its distribution main investments into three categories: small-diameter (6 inches or smaller) IHP mains, large-diameter (greater than 6 inches) IHP mains, and high-pressure feeder-line mains.[1] Distribution mains are typically the largest component of rate base 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 smaller 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

[1] Direct Testimony of Austin Summers at 2.

the Company's Distribution Throughput Study, which allocates costs to customer classes based on class throughput or commodity volumes.[2]

The costs of high-pressure feeder-line mains are allocated to classes by a weighted-average combination of Design Day Demand (60% weight) and annual usage or commodity throughput (40% weight).[3] The combination of these factors results in a composite allocation factor that is generally known as the Peak and Average ("P&A") allocation factor.

Q IS THE COMPANY'S PROPOSAL FOR ALLOCATING THE COST OF SMALL-DIAMETER IHP MAINS TO CUSTOMER CLASSES REASONABLE?

A Yes. 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 day demands but also must design the mains to connect customers to the delivery system. As a result, I do not oppose this allocation.

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[2] *Id.* at 2-6.

[3] *See* 23 Dec 22 Order Dkt. No. 22-057-03 at 36 (finding that the 60%/40% weighting is consistent with previous DEU case).

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

A They classify the small mains cost as both customer related and demand related. The customer allocation of small mains is typically measured using a minimum-system study. The minimum-system study approximates the amount of small-main investment that is incurred irrespective of the demands placed on the small mains. In effect, small mains must have adequate length to connect all customers to the system. The length of the small mains needed for this purpose is independent from the demands placed on the small mains.

A review of EGU's Distribution Plant Factor Study for the small mains shows it examines the main line directly connected to the service line within a thousand feet of a service-tap point to ascertain the amount of main line attributable to class meters.[4] 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

[4] Direct Testimony of Austin Summers at 3.

quantity of gas supply that these customers require. These customers are connected directly to larger mains. Therefore, these customers should not be allocated 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 few small-diameter IHP main costs to customer classes with larger gas demands. For example, the TSL class is allocated 0.017% of the costs of small-diameter mains, which is a logical result.[5]

Q DO YOU AGREE WITH EGU'S PROPOSED CCOS STUDY ALLOCATION METHOD FOR LARGE-DIAMETER AND FEEDER MAINS?

A No, I do not. EGU's proposal in its CCOS study to allocate some categories of distribution main costs on a P&A allocator does not reflect cost causation, and therefore, is not reasonable. 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 a P&A allocator does not reflect the load characteristics of the system that caused EGU to incur main capacity costs and therefore does not follow sound cost causation principles.

[5] EGU Ex. 5.03 at 6.

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. As stated by the National Association of Regulatory Utility Commissioners *Gas Distribution Rate Design Manual* ("NARUC Manual") in reference to the P&A method:

> This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and tempers the

> apportionment of costs between the high and low load factor customers.[6]

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. 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 PLEASE EXPLAIN HOW EGU DESIGNS ITS DISTRIBUTION SYSTEM.

A Gas local distribution companies design and size their distribution systems based on the peak demands of their customers, including the day of maximum demand. The design of EGU's distribution system is no different.

Q WHAT EVIDENCE HAS EGU PROVIDED TO CONFIRM IT DESIGNS ITS DISTRIBUTION MAINS TO MEET SYSTEM PEAK DEMAND?

A The Company has provided multiple discovery responses supporting the fact that distribution main capacity is designed to meet system-peak demand. The specific evidence is summarized below and included in EGU's discovery responses attached as FEA Exhibit 2.01:

[6] NARUC Gas Distribution Rate Design Manual, publish June 1989, pages 27 & 28.

1. EGU's natural gas facilities are designed to serve the aggregate peak demand for all customer loads to ensure reliable and uninterrupted natural gas service.[7]

2. Load factor is not one of the criteria considered by the Company in terms of facilities required to serve a customer class.[8]

3. The Company identifies and recommends system improvements to maintain reliability and meet customer needs during peak demand conditions.[9]

4. The Company agrees that total usage is not a factor of how the capacity of its distribution mains are designed, i.e., EGU's demand-related costs.[10]

5. Demand-related costs are primarily incurred to meet the Design Day Demand on the Company's system.[11]

Q THE COMPANY'S EVIDENCE INDICATES THAT THE PRIMARY PURPOSE OF DISTRIBUTION MAINS IS TO MEET ALL CUSTOMER DEMANDS FOR NATURAL GAS AT ALL TIMES. IF DISTRIBUTION MAINS WERE DESIGNED TO MEET AVERAGE DEMAND, WOULD THIS PRIMARY OBJECTIVE BE ACCOMPLISHED?

A No. If distribution main capacity was designed to meet Average Demand, then the Company would not be able to provide firm service on days when demand exceeds the average. In this scenario, the Company would fail to achieve its objective of meeting all customer demands for natural gas at all times.

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[7]EGU's Response to FEA Data Requests 2.03, 2.04, 2.05, & 2.09. Included as FEA Exhibit 2.01 at 1-3 and 6.
[8]EGU's Response to FEA Data Request 2.06. Included as FEA Exhibit 2.01 at 4.
[9]EGU's Response to FEA Data Request 2.03. Included as FEA Exhibit 2.01 at 1.
[10]EGU's Response to FEA Data Request 2.08. Included as FEA Exhibit 2.01 at 5.
[11]*Id.*

However, if mains are designed to serve Design Day Demand (which they are), then it follows that the Company can meet all customer demands at all other times when demand is less than the Design Day Demand. It is clear that Design Day Demand is the driver of distribution main capacity and provides the Company with the ability to achieve its purpose of meeting all customer demands for natural gas at all times.

Q WHAT IS THE PRIMARY DRIVER OF EGU'S SYSTEM PEAK DEMAND?

A Weather, specifically outside air temperature, is the primary driver of natural gas demand. The Company states that it uses ambient temperature, specifically Heating Degree Days ("HDD"), along with customer-usage patterns to understand temperature-dependent demand, which is extrapolated to a Design Day HDD to represent a statistically derived coldest day.[12] The point is that EGU's system peak demand is driven by weather sensitive customers who use natural gas for space heating, and those customers are largely residential. EGU's system peak demand is not driven by higher load factor customers who use natural gas for process purposes. The allocation of capacity costs must reflect these load characteristics.

[12] EGU's Response to FEA Data Request 2.03. Included as FEA Exhibit 2.01 at 1.

Q ARE THERE OTHER FACTORS THAT CONFIRM THAT SYSTEM PEAK DEMAND IS THE CAUSE OF INVESTMENT IN DISTRIBUTION MAIN CAPACITY?

A Yes. Once this capacity is installed, the costs are fixed and do not change for any amount of gas flowing through the system – whether that is a peak day or any other day. Absent the addition of new customers or a change in system design day requirements, the cost of mains will not change, regardless of changes in annual throughput that result from weather and conservation.

Further, consider an example in which EGU serves two customers with the same Design Day Demand requirements from identical distribution mains (i.e., same material, diameter, installed cost). However, one customer's annual throughput is twice as much as the other's. Thus, the demand-related cost to serve each customer is the same. However, each customer would be allocated a different amount of those capacity costs if an annual throughput allocator is used. Specifically, the customer with greater annual throughput (i.e., the higher load factor customer) would be allocated a greater share of capacity costs than the other customer. The use of a throughput allocator effectively penalizes the higher load factor customer for its more efficient utilization of the installed distribution main capacity. This is contrary to the objective of setting rates based on sound cost causation principles.

Q WHAT IS YOUR ISSUE WITH THE COMPANY'S USE OF A P&A ALLOCATOR?

A The "Peak" component of the P&A allocator reflects each class's contribution to system peak day demand (i.e., Design Day Demand); however, as stated above, by using both peak day demand and annual throughput (i.e., average demand) a double counting of average demand occurs.

V. RECOMMENDED MODIFICATIONS TO EGU'S CCOS

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

A As shown in Table1 below, 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. Because the Company's CCOS study allocates main costs using a P&A allocator, which results in the double counting of demand described in my testimony above, larger high load factor customer classes are allocated a higher percentage of main costs.

TABLE 1

Class Cost of Service Study Comparison

	EGU Proposed[1]			FEA Proposed[2]		
Rate Class	**Present Non-Gas Revenues**	**Proposed Increase/ (Decrease)**	**Percent Increase/ Decrease**	**Present Non-Gas Revenues**	**Proposed Increase/ (Decrease)**	**Percent Increase/ Decrease**
	(1)	(2)	(3)	(4)	(5)	(6)
GS	$485,786,552	$83,777,557	17.25%	$486,002,362	$98,966,646	20.36%
FS	3,731,722	532,828	14.28%	3,723,921	(111,025)	-2.98%
IS	199,664	126,397	63.31%	199,458	101,567	50.92%
TSS	13,697,511	4,926,859	35.97%	13,699,771	4,992,201	36.44%
TSM	18,005,322	5,106,475	28.36%	17,946,455	650,138	3.62%
TSL	21,680,507	5,683,462	26.21%	21,556,498	(3,091,550)	-14.34%
TBF	9,703,971	13,680,054	140.97%	9,677,620	12,393,486	128.06%
NGV	1,673,992	836,117	49.95%	1,673,156	768,287	45.92%
Total	$554,479,240	$114,669,749	20.68%	$554,479,240	$114,669,749	20.68%

Sources:
[1]EGU Exhibit 5.14.
[2]FEA Recommended COS Workpaper.

Q PLEASE DESCRIBE YOUR RECOMMENDED CHANGE TO THE COMPANY'S P&A ALLOCATOR.

A I recommend replacing the Company's Peak Demand component with a calculation of excess demand. That is, each class's contribution to Design Day Demand in excess of its respective class's average demand would replace the Company's Peak Demand component.

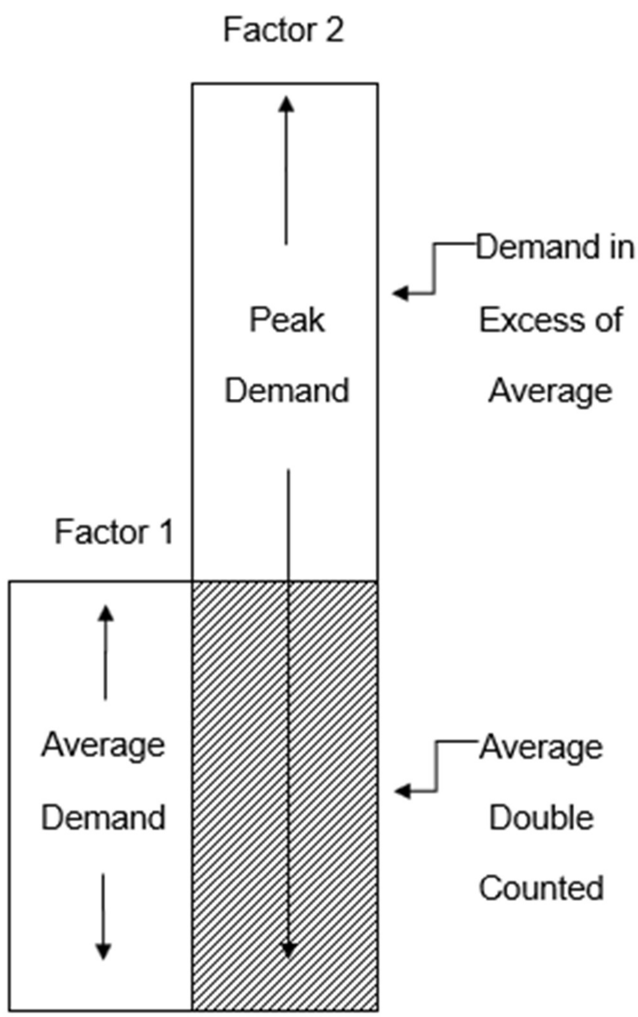
Q YOU STATED EARLIER IN YOUR TESTIMONY THAT THE CCOS SHOULD FOLLOW COST CAUSATION. HOW WOULD REPLACING THE COMPANY'S PEAK DEMAND COMPONENT WITH EXCESS DEMAND ACCOMPLISH THIS GOAL?

A My proposed change more closely aligns the Company's CCOS with cost causation in two critical ways: first, it removes the inherent flaw of double counting average demand which exists in the Company's P&A method; second, it allows for a greater assignment of cost to classes with weather-sensitive demands by capturing the excess demand in the distribution allocator. As stated above, the primary cause of Design Day Demand is outside temperatures. Capturing classes' contributions to the excess capacity held in reserve to meet the demand of weather-sensitive loads which spike on the system peak day better reflects cost causation.

Q YOU MENTIONED THAT THE P&A METHOD DOUBLE COUNTS AVERAGE DEMAND. CAN YOU PLEASE ILLUSTRATE THIS?

A Yes. Average Demand is counted twice in the cost allocation: once in the Average Demand component and again in the Peak Demand component. The impact of using the P&A method to allocate distribution main and regulator station equipment costs is the over-allocation of capacity costs to high-load factor customers. This is represented graphically, below, in Diagram 1. The Average Demand (Factor 1) is weighted by the system Load Factor ("LF"). Peak Demand (Factor 2) is weighted by (1 – LF). The two weighted demands are added together to arrive at the P&A allocation factor. As a result, arithmetically, Average Demand receives a full weight of 1, while demand in excess of the average is weighted less than 1 (i.e., by (1 – LF)).

Peak and Average Method



Peak and Average =

(LF x Factor 1) + (1 – LF) x Factor 2

Diagram 1

Diagram 1 illustrates the two steps in the process of calculating the P&A factors, the first of which is to determine the Average Demand component. The double counting of Average Demand occurs in the next step of the process, where each class's contribution to the system's Peak Demand is determined. In this second step, the P&A method considers the entire Peak Demand, including the Average Demand.

Q DOES YOUR RECOMMENDED METHOD ASSIGN CAPACITY COSTS TO CUSTOMERS IN A MANNER THAT REFLECTS HOW THE SYSTEM OPERATES TO PROVIDE SAFE, RELIABLE DELIVERY OF NATURAL GAS EVERY DAY OF THE YEAR?

A Yes. The Company incurs the cost of mains to meet the aggregate demand of its customers on the expected day of its greatest system demand. The Company's calculation of Design Day Peak Demand is primarily driven by weather-sensitive customer loads on the statistically derived coldest day of the year. Through the use of the excess demand component of the allocator, my recommended method assigns greater cost responsibility to gas deliveries that are more variable due to weather sensitivity or other factors. Relative to the P&A method, my method is more reflective of cost causation on EGU's system, as the excess distribution main capacity is held in reserve to meet the demand of weather-sensitive loads that spike on a peak day.

Q DOES YOUR DISTRIBUTION ALLOCATION METHOD PRODUCE FAIR AND REASONABLE RESULTS?

A Yes. Relative to the P&A method, my method more closely reflects how the system is designed and used. Thus, the results are fair and reasonable, and more accurately reflect cost causation on EGU's gas system.

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

A Yes. For compressors and regulator facilities, reviewing the Company's CCOS study provided as EGU Exhibit 5.14, tab "COS Detail," 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 also be allocated across rate classes on the basis of my Excess Design Day Demand and throughput allocator.

The Company has allocated these costs on the basis of the P&A method. However, I propose to allocate them on the basis of Excess Design Day Demand and throughput. These costs are also incurred to meet system Design Day Demand and should be allocated to rate classes in a manner which best reflects 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 in 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 Excess Design Day Demand and throughput is also consistent with cost causation. The NARUC Manual identifies distribution costs to include distribution mains, compressors, and regulators.[13] As these sets of equipment fall into the same category of accounts, as well as design, as the distribution system, they should be allocated to classes on the same basis to maintain stable price signals to customers and achieve reasonable returns on investment to the Company.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO CAPACITY COST ALLOCATION IN THE COMPANY'S CCOS STUDY.

A The evidence provided by EGU makes clear that Design Day Demand, driven by outside temperatures, is the load characteristic that drives investment in distribution capacity to provide safe, reliable firm service to customers on the peak day and all other days throughout the year. However, the Company's use of a P&A allocator creates a double counting of the average demand, creating a mismatch between cost causation and allocation.

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

My recommended method, replacing the peak component of the distribution allocator with a calculation of excess Design Day Demand, removes this double counting of the average demand and is more accurate and reasonable than the P&A method for the reasons I have described. Therefore, I recommend the Commission adopt my CCOS using my revised allocation method for large-diameter IHP mains, feeder mains, compressor station equipment, and regulation station equipment, as represented in Table 1.

VI. CLASS REVENUE SPREAD

Q HOW IS THE CLASS COST OF SERVICE STUDY USED TO ALLOCATE THE REVENUE DEFICIENCY IN THIS CASE ACROSS RATE CLASSES?

A The CCOS study is used to measure the increase to each rate class needed to move rates to cost of service. The movement to CCOS should be limited so that it is gradual and ensures that no specific rate class is getting an excessive increase in this case.

Q HOW IS THE COMPANY PROPOSING TO SPREAD THE REVENUE DEFICIENCY ACROSS RATE CLASSES IN THIS CASE?

A The Company's proposed revenue spread allocates part of the distribution system, specifically large-diameter IHP mains and feeder mains, on a P&A allocator. Additionally, there are subsidies included in the CCOS for the TBF and NGV classes.[14] The TBF class subsidy is a long-standing subsidy in place to prevent harm to remaining classes if the TBF classes were to leave EGU's system.[15] The Company states that the NGV subsidy is necessary due to decreasing usage since the removal of the previous subsidy in 2013.[16] This subsidy is allowable given the subsidy is both in the public interest, and just and reasonable.[17] EGU also states that it is attempting to sell a portion of its Utah NGV stations at this time.[18] The FEA is not challenging the NGV subsidy for this case; however, if the NGV stations remain on EGU's system, the Commission should require EGU to produce evidence the subsidy is in fact in the best interest of the public, i.e., whether this subsidy needed to keep NGV customers on EGU's system in order to prevent a greater harm to the remaining rate payers on EGU's system which would result from the departure of customers from the NGV class.

Q IS THE COMPANY'S PROPOSED SPREAD REASONABLE?

A No. As noted above, the Company's CCOS study is flawed by use of the P&A allocator. I recommend my revised CCOS be used to allocate the revenue deficiency across rate classes.

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[14] Direct Testimony of Austin Summers at 11.
[15] *Id.*
[16] Direct Testimony of Austin Summers at 10.
[17] *Id.*
[18] *Id.*

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 2 below:

TABLE 2

Class Revenue Allocation
(EGU vs FEA)

	EGU Proposed[1]				FEA Proposed[2]			
Rate Class	Present Non-Gas Revenues	Proposed Increase/ (Decrease)	Percent Increase/ Decrease	Increase Factor	Present Non-Gas Revenues	Proposed Increase/ (Decrease)	Percent Increase/ Decrease	Increase Factor
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GS	$485,786,552	$91,870,108	18.91%	0.9	$486,002,362	$106,430,248	21.90%	1.1
FS	3,731,722	630,331	16.89%	0.8	3,723,921	0	0.00%	0.0
IS	199,664	131,400	65.81%	3.2	199,458	61,874	31.02%	1.5
TSS	13,697,511	5,419,397	39.56%	1.9	13,699,771	4,249,796	31.02%	1.5
TSM	18,005,322	5,740,083	31.88%	1.5	17,946,455	925,745	5.16%	0.2
TSL	21,680,507	6,593,746	30.41%	1.5	21,556,498	0	0.00%	0.0
TBF	9,703,971	4,341,870	44.74%	2.2	9,677,620	3,002,088	31.02%	1.5
NGV	1,673,992	(57,185)	-3.42%	(0.2)	1,673,156	0	0.00%	0.0
Total	$554,479,240	$114,669,749	20.68%	1.0	$554,479,240	$114,669,751	20.68%	1.0

Sources:
[1]EGU Exhibit 5.14.
[2]FEA Recommended COS 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 31.02%. I then held classes that would get a rate decrease at full cost of service, to no change in current rates, and set the NGV class to no increase. This revenue difference was then allocated to the remaining classes, which either were not at the maximum increase of 1.5x system average, or set to no increase, by their proportion of Present Non-Gas Revenues.

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 FS classes should actually get a rate decrease as opposed to the Company's proposed 30.41% and 16.89% increases, respectively. My proposed revenue allocation set these classes at no increase. By mitigating the maximum increase for remaining classes to 1.5x the system average, customers are prevented from experiencing rate shock which could have negative consequences within the classes, and for the system as a whole. As a result, my class revenue allocation is more than fair.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Matthew P. Smith

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Matthew P. Smith. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A In 2017, I received a Bachelor of Science Degree in Economics from Southern Illinois University.

In May of 2018, I accepted an Analyst position with Brubaker & Associates, Inc. ("BAI"). I was promoted to Senior Analyst in 2021, and in 2023 I was promoted to Consultant. During my employment at BAI I have performed detailed analysis on a variety of subjects within the scope of electric, natural gas, and water regulatory proceedings. This analysis includes, but is not limited to, the following: Cost of Service Studies ("COSS"), Return on Equity ("ROE"), Rate Design, and Resource Adequacy issues. I have also been engaged in the evaluation of Request for Proposals ("RFP") responses, the creation of regional electric market price forecast models, and load forecast models for industrial energy users in the electric and natural gas fields. I have sponsored testimony on cost of service, and other issues, before the California State Regulatory Commission and the Florida Public Service Commission.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 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, state regulatory agencies, and some utilities. 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 negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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Docket No. 25-057-06
FEA Data Request No. 2.03
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.03: Please provide a narrative as to how the Company designs the capacity of its distribution main system to meet the peak natural gas demand of its customers.

Answer: The Company designs the capacity of its distribution main system to meet peak natural gas demand by leveraging a combination of historic customer usage data and ambient temperature metrics, specifically Heating Degree Days (HDD). Customer usage patterns are analyzed and correlated with HDD values to understand temperature-dependent demand. This data is then extrapolated to a Design Day HDD, which represents a statistically derived coldest day based on decades of historical temperature records.

In addition to temperature-driven demand, the Company incorporates firm contract demands from transportation customers into the Design Day forecast. These combined demand projections are used to model the distribution system using hydraulic modeling software, which evaluates system pressures, flows, and velocities across the entire network.

The modeling process also includes gas supply inputs from upstream transmission partners to ensure a comprehensive analysis. Based on the results of this annual peak day design model, the Company identifies and recommends system improvements to maintain reliability and meet customer needs during peak demand conditions.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.04
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.04: Does the Company use the Design Day Demand of its customers to design the capacity of its distribution main system? Please explain your response.

Answer: Yes. Refer to the Company's response to FEA 2.03.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.05
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.05: Does the Company use the number of customers on its system to design its distribution main system? Please explain your response.

Answer: System design is based off temperature and contract-dependent demand on a design day. The number of customers is not an influential part of the design process.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.06
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.06: Does the Company use the system load factor and/or class load factors to design the capacity of its distribution main system? Please explain your response.

a. Please provide an estimate of the variation of capacity factor on the Company's transmission main, seasonally, throughout the year.

Answer: No. The Company does not use system load factor and/or class load factors to design the capacity of the distribution main system. The Company is not familiar with the term 'Capacity Factor' and does not use it to design the distribution main system.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.08
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.08: Does the Company use the total usage of its system to design the capacity of its distribution main system? Please explain your response.

Answer: No. The Company does not use the total actual usage to design the capacity of the distribution main system. See response to FEA 2.03 for how the Company designs the distribution main system.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Docket No. 25-057-06
FEA Data Request No. 2.09
Requested by the Federal Executive Agency
Date of EGU Response: September 2, 2025

FEA 2.09: Does the Company agree that the system of mains must have enough capacity to meet the expected Design Day Demand of its customers? Please explain your response.

Answer: Yes. Each year, the hydraulic model results are used to identify resultant modeled pressures in Design Day conditions and those results are used to report the adequacy of the system to meet expected Design Day demand. See FEA 2.03.

Prepared by: Jeff Roberts, Supervisor Gas Distribution Engineering
Jordan Parks, Regulatory Analyst

Enbridge Gas Utah
Utah - DEC 2026 Adjusted Avg Results CET
12 Months Ended : Dec-2026

COST OF SERVICE SUMMARY AND ALLOCATIONS TO RATE CLASSES

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		Utah Jurisdiction	Allocations to Rate Classes							
	Description	DNG Related	GS	FS	IS	TSS	TSM	TSL	TBF	NGV
	Current Revenue Analysis @ 4.94%									
1	Annual Revenue before Deficiency	554,479,240	486,002,362	3,723,921	199,458	13,699,771	17,946,455	21,556,498	9,677,620	1,673,156
2	Return on Rate Base	4.94%	4.98%	8.08%	1.93%	3.25%	7.04%	10.53%	-1.34%	4.54%
3	Increase (Decrease) to equal ROR	-	885,099	(651,600)	31,795	1,099,234	(3,303,184)	(7,851,557)	8,230,011	1,560,202
4	Revenue Neutral Spread	554,479,240	486,887,461	3,072,321	231,252	14,799,005	14,643,271	13,704,942	17,907,631	3,233,358
5	Percentage Change from Current Revenues	0.0%	0.2%	-17.5%	15.9%	8.0%	-18.4%	-36.4%	85.0%	93.2%
6	Rate of Return Index	1.00	1.01	1.64	0.39	0.66	1.43	2.13	(0.27)	0.92
	Proposed Revenue Analysis @ 7.61%									
7	Annual Revenue before Deficiency	554,479,240	486,002,362	3,723,921	199,458	13,699,771	17,946,455	21,556,498	9,677,620	1,673,156
8	Deficiency	114,669,749	98,966,646	(111,025)	101,567	4,992,201	650,138	(3,091,550)	12,393,486	768,287
9	COS Adjustment TBF	0	0	0	0	0	0	0	0	0
10	COS Adjustment NGV	0	0	0	0	0	0	0	0	0
11	General Related Revenue Class Allocation	(12,504,033)	(11,249,109)	(57,828)	(3,781)	(263,618)	(303,132)	(336,861)	(275,860)	(13,843)
12	Net Cost of Service Collected in Rates	656,644,957	573,719,899	3,555,068	297,244	18,428,354	18,293,461	18,128,087	21,795,245	2,427,600
13	Increase (Decrease) to equal allowed ROR	114,669,749	98,966,646	(111,025)	101,567	4,992,201	650,138	(3,091,550)	12,393,486	768,287
14	Percentage Change from Current Revenues	20.68%	20.36%	-2.98%	50.92%	36.44%	3.62%	-14.34%	128.06%	45.92%