Witness OCS – 4D Daniel

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
Application of Dominion Energy Utah to	)	**Docket No. 22-057-03**
	)	
Increase Distribution Rates and Charges	)	**Phase II Direct Testimony of**
	)	**James W. Daniel**
and Make Tariff Modifications	)	**On behalf of the**
	)	**Office of Consumer Services**

September 15, 2022

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EXPERIENCE AND QUAILIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Daniel. My business address is 919 Congress Avenue, Suite 1110, Austin, Texas, 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received the degree of Bachelor of Science from Georgia Institute of Technology in 1973 with a major in economics.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am an Executive Consultant with the firm GDS Associates, Inc. ("GDS") and Manager of GDS's office in Austin, Texas.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

From July 1974 through September 1979 and from August 1983 through February 1986, I was employed by Southern Engineering Company. While employed by the Southern Engineering Company, I participated in the preparation of economic analyses regarding alternative power supply sources and generation and transmission feasibility studies for rural electric cooperatives. I also participated in wholesale and retail rate and contract negotiations with investor-owned and publicly owned utilities, prepared cost of service studies on investor-owned and publicly-owned utilities and prepared and submitted testimony and exhibits in utility rate and other regulatory proceedings on behalf of publicly-owned utilities, industrial customers, associations, and government agencies.

From October 1979 through July 1983, I was employed as a public utility consultant by R. W. Beck and Associates. During that time, I participated in rate studies for publicly owned electric, gas, water and wastewater utilities. My primary responsibility was the development of revenue requirements, cost of service, and rate design studies as well as the preparation and submittal of testimony and exhibits in utility rate proceedings on behalf of publicly owned utilities, industrial customers, and other customer groups.

In 1986, I became a Principal of GDS and Manager of GDS's office in Austin, Texas. In April 2000, I was elected as a member of the Board of Directors and as a Vice President of GDS. In 2019, I became an Executive Director. While at GDS, I have provided testimony in numerous regulatory proceedings involving electric, natural gas, and water utilities, I have participated in generic rulemaking proceedings, I have prepared retail rate studies on behalf of publicly-owned utilities, I have prepared utility valuation analyses, I have prepared economic feasibility studies, and I have procured and contracted for wholesale and retail energy supplies.

Q. WOULD YOU PLEASE DESCRIBE GDS?

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; Orlando Florida; Augusta, Maine; Washington; Redmond, Washington, and Camarillo, California. GDS has over 175 employees with diverse backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, storm, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, energy procurement and contracting, energy efficiency program development, financial analysis, load forecasting, and statistical services. Our clients are primarily privately-owned utilities, publicly-owned utilities, municipalities, customers of investor-owned utilities, groups or associations of customers, and government agencies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. I have testified many times before regulatory commissions including the Public Service Commission of Utah. A complete list of regulatory proceedings in which I have presented expert testimony is provided as Exhibit OCS 4.1D.

INTRODUCTION

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Utah Office of Consumer Services ("OCS").

Q. PLEASE DESCRIBE OCS.

A. OCS is Utah's utility consumer advocate. OCS represents residential and small commercial consumers in various electric, natural gas, and telephone utility proceedings before the Utah Public Service Commission ("PSC" or "Commission").

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. My assignment was to analyze Dominion Energy Utah's ("DEU" or "Company") proposed class cost of service study ("COSS") and rate design in this proceeding.

Q. PLEASE SUMMARIZE THE CONCLUSIONS AND RECOMMENDATIONS YOU HAVE REACHED BASED UPON YOUR REVIEW AND ANALYSIS OF DEU'S APPLICATION.

A. Based on my review and analysis, I have reached the following conclusions and recommendations:

(1) DEU's demand allocation factor should be based on test year actual peak-day demands instead of estimated design-day demands.

(2) DEU's combined peak-day demand and throughput allocation factor should be weighted 52% peak-day demand and 48% throughput.

(3) General plant depreciation expenses should be allocated based on allocated gross general plant.

(4) DEU's proposed allocation of LNG – related costs assigns too much costs to the GS customer class and should be rejected.

(5) DEU's Conservation Enabling Tariff should be reevaluated.

(6) Customer class revenue levels should be set equal to their cost of service except when doing so results in an exorbitant rate increase for a customer class. In that situation, gradualism should be applied to alleviate the large rate increase for that customer classes.

<u>CLASS COST OF SERVICE STUDY ISSUES</u>

Q. WOULD YOU BRIEFLY DESCRIBE THE PURPOSE OF A COSS?

A. The primary purpose of a class COSS is to determine the portion of the utility's total retail cost of service or revenue requirement that should be borne by each customer class, absent other factors that may be appropriate to consider. Each cost component of the utility's total cost of service is either directly assigned or allocated to the various customer classes. The results are then considered to determine the level of revenues needed to be recovered through rates from each customer class. The results of the COSS will also provide important information for designing rates.

Q. WHAT ARE THE BASIC STEPS FOR PREPARING A CLASS COSS?

A. A COSS is typically developed in three distinct steps. First, the various components of the utility's overall revenue requirement are assigned to their functional use, *e.g.,* transportation, distribution, metering, and billing and customer service. Next, the functionalized costs are classified based on cost causation factors to the cost categories of fixed or demand-related, variable or consumption-related, and customer-related. Finally, the classified costs are directly assigned or allocated to customer classes using allocation factors developed for each classified cost category. Various methodologies or approaches exist for conducting each step in the COSS process.

Q. IS DETERMINING THE CUSTOMER CLASSES AN IMPORTANT STEP IN DETERMINING THE COSS?

A. Yes. Determining the customer groups to be used as customer classes is an important step in ratemaking. For determining customer classes, it is critical that similar customers be grouped into classes. Criteria that are typically used to group customers into customer classes include usage and demand characteristics, end-uses, size, and/or location on the system.

Q. BASED UPON YOUR REVIEW AND ANALYSIS OF DEU'S PROPOSED COSS, HAVE YOU INDENTIFIED ANY ISSUES OR PROBLEMS WITH DEU'S STUDY?

A. Yes. I have identified four problems with DEU's COSS. These are: (1) DEU should replace its design-day demand allocation factor with an actual peak-day demand allocation factor, (2) DEU should use a properly calculated system load factor for weighting its combined peak-day demand and throughput allocation factor, (3) DEU has incorrectly allocated general plant related depreciation expenses, (4) DEU's allocation of costs to the interruptible service customer class and (5) the allocation of LNG plant costs. I will further discuss each problem below.

USE OF PEAK-DAY DEMANDS FOR DEMAND ALLOCATION FACTOR

Q. IS DEU PROPOSING THE USE OF A DESIGN-DAY DEMAND ALLOCATION FACTOR?

A. Yes. As it has done in the past, DEU is proposing to use a design-day demand allocation factor.

Q. PLEASE DESCRIBE HOW DEU DETERMINES ITS DESIGN-DAY DEMAND ALLOCATION FACTOR.

A. The design-day demand is estimated for the maximum daily demand for gas on DEU's system during an extremely cold period. The Company then determines each customer class's gas demand during the design-day demand. This is done by conducting a Design-Day Factor Study, which assigns responsibility for the design-day demand to the various customer classes.

Q. IN DEU'S PRIOR RATE CASE, DID THE COMMISSION APPROVE DEU'S USE OF THE DESIGN-DAY DEMAND ALLOCATION FACTOR?

A. Yes. While the Commission did approve the use of the design-day demand allocation factor in the prior DEU case, it also ordered DEU to provide in this case the peak-day data necessary for parties to propose the use of a peak-day demand allocation factor.

Q. WAS THE USE OF A PEAK-DAY DEMAND ALLOCATION FACTOR DISCUSSED BY THE COST ALLOCATION AND RATE DESIGN TASK FORCE?

A. Yes, that is my understanding.

Q. IS THE USE OF A TEST YEAR PEAK-DAY DEMAND ALLOCATION FACTOR RELATIVELY COMMON IN NATURAL GAS LDC RATE CASES?

A. Yes. Based upon my experience, the use of a peak-day demand allocation factor is much more common that using a design-day demand allocation factor. In fact, DEU affiliate East Ohio Gas Company uses a peak-day demand for determining allocation factors.

Q. ARE THERE OTHER REASONS FOR USING A PEAK-DAY DEMAND ALLOCATION FACTOR AS OPPOSED TO A DESIGN-DAY DEMAND ALLOCATION FACTOR?

A. Yes. The primary reason is that the use of a test year peak-day demand is more current and is a better representation of how DEU's system is actually being used by ratepayers. The likelihood that the DEU customers will ever impose the design-day demand on DEU's system is remote.

Q. DEU CLAIMS THAT CLASS ALLOCATION FACTORS USING TEST YEAR PEAK-DAY INFORMATION WILL BE MORE VOLATILE THEN USING DESIGN-DAY INFORMATION, IS THAT CORRECT?

A. While I would expect some variation in the peak-day demand allocation factor from year-to-year, I do not consider that a significant problem. Other allocation factors, such as factors based on throughput and number of customers will also vary from year-to-year. I would also expect that some or most of the recent variation in class responsibility is due to customer migration among the customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DEU'S PROPOSED USE OF A DESIGN-DAY DEMAND ALLOCATION FACTOR?

A. I recommend that the Commission reject the use of a design-day demand allocation factor. Instead, the Commission should approve the use of a peak-day demand allocation factor. The allocation factor is provided in DEU Exhibit 4.06.

COMBINATION OF PEAK-DAY AND THROUGHPUT ALLOCATION FACTOR

Q. IN DEU'S COSS DOES THE COMPANY USE AN ALLOCATION FACTOR THAT IS A COMBINATION OF THE PEAK-DAY AND THROUGHPUT ALLOCATION FACTORS?

A. Yes. DEU allocation factor #230 is a weighted average of the peak-day (or design-day in DEU's COSS) and the throughput allocation factors. As described on DEU Exhibit 4.2, allocation factor #230 is used to allocate fixed costs related to compressor stations, feeder systems, and measurement and regulation station equipment.

Q. HOW DID DEU DETERMINE THE WEIGHTED AVERAGE FOR THE PEAK-DAY AND THROUGHPUT COMPONENTS OF ALLOCATION FACTOR #230?

A. DEU weighted the peak-day component 60% and the throughput component 40%.

Q. HOW DID DEU DETERMINE THE 60/40 WEIGHTING FACTORS?

A. Although the 60/40 weighting factors are not discussed or explained in the rate application, these are the same weighting factors that DEU has used in recent prior rate cases. It is my understanding that the 60/40 weighting factors are not based on any analysis but rather is the result of a compromise in a prior rate case that the Company has continued to use in its recent rate cases.

Q. WERE THE WEIGHTING FACTORS AN ISSUE IN DEU'S PRIOR RATE CASE?

A. Yes. In Docket No. 19-057-02, several parties proposed various weighting factors including 100/0, 68/32, 60/40, and 50/50.

Q. HOW DID THE COMMISSION DECIDE THIS ISSUE?

A. In its Order, the Commission decided to retain the 60/40 weighting factors.

Q. SHOULD THE 60/40 WEIGHTING FACTORS BE USED IN THIS CASE AS WELL?

A. While that would be acceptable, I believe it would be best to set the weighting factors based upon a specified approach or methodology. The 60/40 weighting factors are subjective.

Q. WHAT IS YOUR RECOMMENDED METHODOLOGY FOR DETERMINING THE WEIGHTING FACTORS?

A. In DEU's prior rate case, several parties proposed using the system load factor as the break point for the weighting factors. The parties calculated the system load factor as 32%, which was used as the weighting factor for the throughput component. Their weighting factor for the peak-day component was 68%, or 100% minus the 32% load factor.

This methodology is a reasonable approach for determining the weighting factors. The problem in DEU's last rate case is that the parties advocating this methodology incorrectly calculated the test year load factor.

The error in the load factor calculation is that these parties used DEU's design-day demand rather than the test year actual peak-day demand. Load factor is a common utility statistic that measures how facilities or systems are being utilized. For a gas utility, it is the ratio of average consumption to peak consumption. The American Gas Association's ("AGA") "Glossary for the Gas Industry" defines load factor as:

> The ratio of the average requirement to the maximum requirements for the same time period, as one day, one hour, etc.

The key part of this definition as it relates to this case is that the numerator (average consumption) and denominator (peak consumption) in the calculation must be "for the same time period." The time period that should be used to determine DEU's system load factor is the test year.

Q. WILL USE OF THE DESIGN-DAY PEAK DEMAND TO CALCULATE DEU'S LOAD FACTOR PRODUCE DISTORTED RESULTS?

A. Yes, it does. The distorted load factor results are also another reason as to why DEU's use of a design-day demand allocation factor should not be approved. In my opinion, the system load factor based on using the design-day demand in the denominator is a meaningless percentage. For the test year in this case, that calculation produces a load factor of 32.4%. If the test year peak-day demand is used for the denominator, the correct load factor is 48.0%, which is significantly different.

The load factor problems from using design-day demands are even more apparent from the customer class load factor calculations. This can be seen on DEU Exhibit 4.14, which shows that the load factor for the Transmission Service-Large customer class is 125.23%. Based on the definition of load factor, this is an impossible result. This is caused by the use of contract demands, rather than actual demands for some customer classes.

Q. WHAT IS THE CORRECT SYSTEM LOAD FACTOR USING THE TEST YEAR PEAK-DAY DEMAND?

A. Using the data on DEU Exhibit 4.06, I calculated the system load factor of 48.2%. This load factor was calculated by adding the commodity volumes on lines 3 and 7 to determine the total commodity volumes of 172,905,622 Dths and then dividing the total commodity volumes of 172,905,622 Dths by 365 days to determine the average usage per day. I then divided that average usage by the peak-day demand amount of 986,622 Dths on line 5, Column (f).

Q. WHAT ARE YOUR RECOMMENDED WEIGHTING FACTORS FOR DETERMINING ALLOCATION FACTOR #230?

A. I recommend weighting factors of 52/48.

ALLOCATION OF GENERAL PLANT DEPRECIATION EXPENSES

Q. PLEASE EXPLAIN HOW DEU IS ALLOCATING GENERAL PLANT RELATED DEPRECIATION EXPENSES TO CUSTOMER CLASSES.

A. In addition to specifically developed allocation factors, COSS models typically develop internally generated allocation factors within the model. Examples of internally generated allocation factors include total operations and maintenance (“O&M”) expenses, gross plant, net plant, rate base, or total revenue. In its COSS, DEU uses an internally generated total gross plant allocator for allocating general plant depreciation expenses.

The problem with using the total gross plant allocation factor is that general plant, and therefore, general plant depreciation expenses, has no relationship to total gross plant. By far the largest component of DEU’s total gross plant is distribution plant. Therefore, using the gross plant allocation factor to allocate general plant depreciation expenses will allocate most of this expense on the basis of gross distribution plant. General plant depreciation expenses are caused by general plant, not distribution plant.

Q. HOW DOES DEU ALLOCATE GROSS GENERAL PLANT?

A. General plant consists of test year gross plant amounts booked in FERC Account Nos. 389 through 399. In DEU's COSS, most of these gross plant accounts are allocated using the gross plant allocation factor #620, which is an internally generated allocation factor that is based on the sum of allocated gross production and distribution plant. However, two accounts are allocated using allocation factor #605, which is based on the investment in tools, shop, and garage equipment assigned and allocated to the Customer classes. A significant portion of the investment is directly assigned to the NGV Customer class. Allocation factor #605 is very different from allocation factor #620. Therefore, allocation factor #620 should not be used to allocate all general plant depreciation expenses to the customer classes.

Q. WHAT IS THE APPROPRIATE ALLOCATION FACTOR TO ALLOCATE GENERAL PLANT DEPRECIATION EXPENSES?

A. Since general plant depreciation expenses are based on general plant, then an internally generated allocation factor based on allocated gross general plant should be used. This gross general plant allocation factor will be a weighted combination of allocation factors #620 and #605. This is consistent with DEU's allocation of distribution plant depreciation expenses, which are allocated using a gross distribution plant allocation factor.

ALLOCATION OF COSTS TO INTERRUPTABLE SERVICE CUSTOMERS

Q. IS DEU PROPOSING TO ALLOCATE DISTRIBUTION FIXED COSTS TO THE INTERRUPTIBLE SERVICE ("IS") CLASS?

A. Yes. Although DEU's proposed design-day demand allocation factor methodology does not assign any design-day demand to the IS customer class, DEU's combined design-day/throughput allocation factor #230 will allocate some distribution fixed costs to the IS customer class.

Q. HOW DOES DEU'S PROPOSED IS RATE COMPARE TO ITS PROPOSED FS RATE FOR FIRM SERVICE?

A. The two rate schedules have identical monthly BSF fixed charges. For the volumetric charges, both rate structures have declining three block rate structures but with differing block sizes and rates. Based on DEU Exhibit 4.17, which provides the rate design calculations for both rate schedules, the IS volumetric rates would be $1.18822 per dekatherm (Dth), or 56.3%, less than the FS winter rate for the first 200 Dth used, and would be $0.66662 per Dth, or 42.0%, less than the FS winter rate for the next 1,800 Dths used, and $0.93028 per Dth or 89.5%, less than the FS winter rate for all Dth used above 2,000 Dth. I would note that most of the Dths used by the IS customer class are in the under 2,000 Dth blocks.

Q. IF THE PEAK-DAY DEMAND ALLOCATION FACTOR IS APPLIED RATHER THEN THE DESIGN-DAY ALLOCATION FACTOR, HOW WOULD THAT IMPACT THE PROPOSED IS RATES?

A. The impact would depend (1) on whether the IS class had gas demand during the system peak-day, and (2) on whether the Commission decides to include any IS class peak demand in the allocation factor calculation. If the IS customer class did not have any demand, at the time of the system peak-day demand or if the Commission decided not to include any IS class peak-day demand in the allocation factor calculation, then DEU’s proposed IS rates would not change. If the IS class did have gas demand during the system peak-day and the demand amount was included in the calculation of the peak-day demand allocation factor, then more distribution costs would be allocated to the class. This would result in higher IS rates and less of a discount from the FS rates for firm service.

Q. DURING THE TEST YEAR PEAK-DAY DEMAND, DID THE IS CUSTOMERS HAVE ANY DEMAND ON THE SYSTEM?

A. Yes. As shown on DEU Exhibit 4.06, which provides the calculation of the peak-day demand allocation factor, the IS class’ demand, or peak responsibility, was 1,622 Dths which resulted in an allocation factor to the IS class of 0.1644%.

Q. IF THE COMMISSION ADOPTS THE USE OF A PEAK-DAY DEMAND ALLOCATION METHODOLOGY AND YOUR RECOMMENDED WEIGHTING FACTORS FOR THE COMBINED PEAK-DAY/THROUGHPUT DEMAND ALLOCATION FACTOR, DO YOU RECOMMEND INCLUDING THE IS CLASS’

ENTIRE PEAK-DAY DEMAND IN THE CALCULATIONS OF THESE ALLOCATION FACTORS?

A, No. That could eliminate all, or most, of the rate discount for interruptible service. I recommend that 25% of the IS customer class' peak-day demand be included in the allocation factor calculation. This will result in a IS rate increase of 10.9%, instead of DEU's proposed IS rate decrease of 5.40%. It will also result in a reasonable discount from the FS firm service rates.

Q. HAVE THE INTERRUPTIBLE SERVICE CUSTOMERS BEEN REQUIRED TO INTERRUPT DURING PEAK DEMAND PERIODS?

A. Per DEU's response to OCS Data Request No. 6.17 as provided in Docket No. 19-057-02, during the period of October 2013 through August 2019, DEU only asked interruptible customers to reduce usage on three occasions. These are: (1) December 5, 2013, (2) December 31, 2014, and (3) January 6, 2017. I would note that on these same days, DEU also asked its firm Transportation Service ("TS") customers to reduce their usage to the lower of their firm contract demand or their scheduled quantities for the day. For calendar years 2015, 2016 and 2018, DEU did not require any interruptions. A copy of DEU's response to OCS Data Request No. 6.17 as provided in Docket No. 19-057-02 is provided as Exhibit OCS 4.2D.

Q. HAS ANYTHING CHANGED THAT WILL FURTHER REDUCE THE LIKELIHOOD OF INTERRUPTIONS OF INTERRUPTIBLE CUSTOMERS?

A. Yes, the Commission approved a liquefied natural gas ("LNG") facility for DEU in Docket No 19-057-13. The LNG facility can be used to avoid having to call on interruptible customers to interrupt.

ALLOCATION OF NEW LNG PLANT

Q. HOW IS DEU PROPOSING TO ALLOCATE ITS LNG-RELATED COSTS TO CUSTOMER CLASSES?

A. DEU is proposing to allocate LNG-related costs to the two firm sales classes, GS and FS, based on throughput. DEU claims that the new LNG plant will not be used for the transportation customers so it has not allocated any LNG-related costs to the transportation customer classes. The result of DEU's proposed allocation is that the GS customer class will pay for 97.7% of DEU's new LNG plant.

Q. DO YOU HAVE A PROBLEM WITH DEU'S PROPOSED ALLOCATION OF ITS LNG-RELATED COSTS?

A. Yes. My primary problem is that since DEU sought Commission approval to build an LNG plant, many firm sales customers have migrated to transportation service. More firm customers may also migrate to transportation service in the future. At the time the Commission approved the LNG plant, the decision was based on the LNG plant providing service to a larger customer base. The current GS customers should not be required to pay for LNG plant costs that were intended to serve firm customers that migrated to transportation service.

Q. WHAT IS YOUR RECOMMENDATION FOR ALLOCATING LNG-RELATED COSTS?

A. I believe some LNG costs should be allocated to the TS classes. The Company's rate increase application in Docket No. 16-057-03 used a test year ending December 31, 2017. From that test year until the test year in this case, the number of TS customers has doubled from 582 customers to 1,165 customers. For the same time period, delivered volumes have increased by 16,557,322 Dths, or 40.2%. My recommendation is to adjust DEU's proposed allocation factor for LNG plant related costs by including 25% of this increase in TS volumes in the allocation factor. This will allocate a reasonable share of LNG plant costs to the TS customer classes.

THE CONSERVATION ENABLING TARIFF SHOULD BE REEVALUATED.

Q. IS DEU PROPOSING TO CONTINUE ITS CONSERVATION ENABLING TARIFF ("CET") IN THIS CASE?

A. Yes. DEU witness Mr. Summers provides a discussion on pages 29 and 30 of his direct testimony that explains his calculation of the annual General Service ("GS") revenue per customer required for the CET.

Q. HOW DOES DEU SUPPORT ITS PROPOSAL TO CONTINUE THE CET?

A. While DEU's rate application includes the CET in its proposed tariff, I have not seen any support to continue the CET. I would note that DEU's presentation at the June 22, 2022, Technical Conference included a section titled "Need for CET." Slide 32 of the presentation included the following three reasons for retaining the CET. These are:

(1) The CET removes disincentive to encourage energy efficiency.

(2) The CET mitigates the impact of increases and decreases in usage per customer; and

(3) Forecasting is easier and more accurate because it is based on customers instead of volume used.

Q. WHY DO YOU DISAGREE WITH DEU'S CLAIM THAT THE CET REMOVES THE DISINCENTIVE TO ENCOURAGE ENERGY EFFICIENCY?

A. I do not necessarily disagree that full revenue decoupling helps remove the disincentive of the utility to encourage energy efficiency. I just do not agree that full revenue decoupling is necessary for utilities to encourage energy efficiency. Most utilities do not have full revenue decoupling, yet most have energy efficiency programs. Also, I will demonstrate later in my direct testimony, it appears that DEU's energy efficiency programs since the CET was approved have not been effective in reducing GS customers' annual average gas consumption.

Q. WHY DO YOU DISAGREE THAT THE CET MITIGATES THE IMPACT OF INCREASES AND DECREASES IN USAGE PER CUSTOMER.

A. The CET certainly mitigates the impacts of decreases in usage per customer to the benefit of the Company. As will be shown on Graph 2 later in my direct testimony, the increases in average use per customer are rare and of shorter duration. Any customer benefit from these increases is not significant, and I doubt it was evident to the typical GS customer.

Q. WHY DO YOU DISAGREE WITH DEU'S THIRD REASON FOR RETAINING THE CET, I.E., FORECASTING IS EASIER AND MORE ACCURATE?

A. This claim is unclear, as it does not say what is easier to forecast. If it is forecasting revenues, then that would be easier since CET recovers a fixed amount of revenue per customer. If it is forecasting gas consumption, which is more critical for planning purposes, then CET would not be of much benefit. I would add that easier forecasting of revenues is of no benefit to customers.

Q. DO YOU AGREE WITH DEU'S CLAIMED BENEFITS OF CET?

A. No. DEU's presentation at the Technical Conference provides no support for the claimed benefits. In addition, some of the claimed benefits are purported to be beneficial for both the Company and for customers. I contend that the claimed customer benefit is of little consequence to typical utility customers and that the utility is the primary beneficiary of the CET. Based on my experience, customers, customer groups and customer advocates oppose revenue decoupling because it is a major benefit for the utility, but not a benefit for customers.

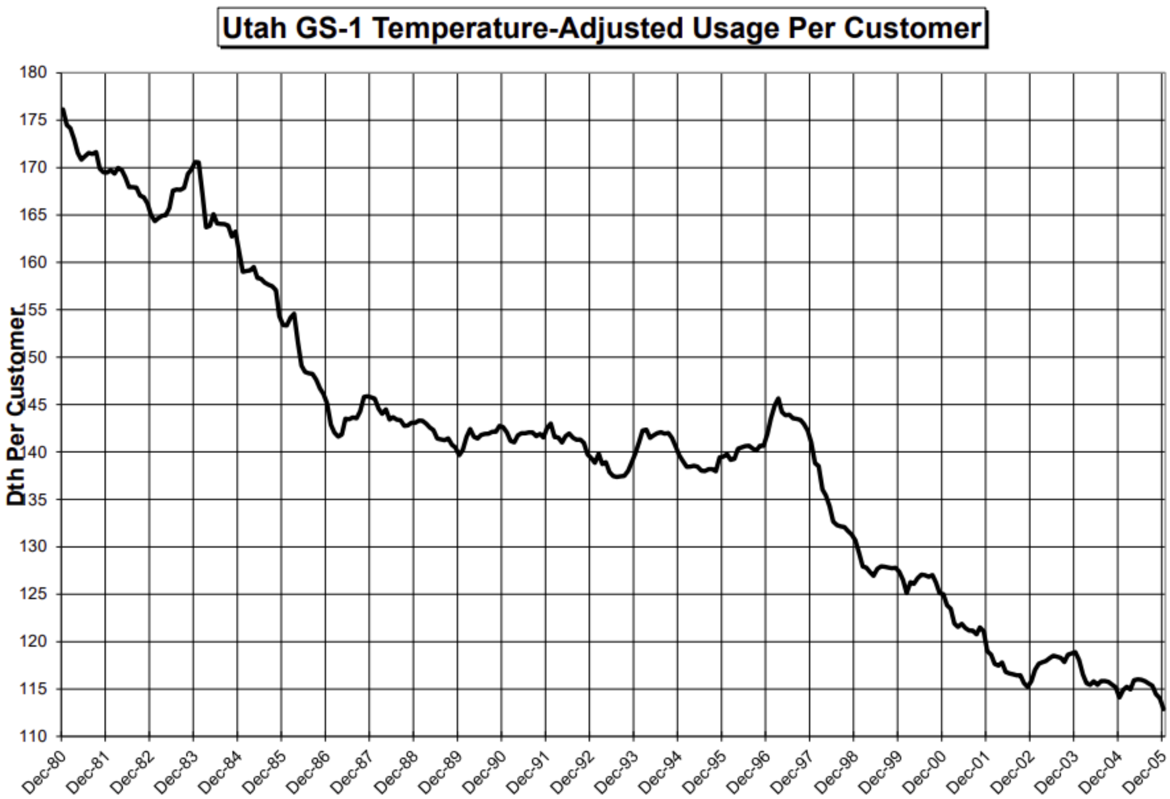
Q. WHY SHOULD THE CET BE REEVALUATED?

A. The primary reason for reevaluating the CET is that it may no longer be necessary. The problem the CET was intended to fix appears to have subsided. DEU also has many other automatic rate adjustment clauses that stabilize revenue collections.

Q. WHY WAS FULL REVENUE DECOUPLING APPROVED FOR DEU?

A. In 2006, the Commission initially approved the CET in DEU's revenue decoupling mechanism case Docket No. 05-057-T01. DEU witness Barrie McKay supported the need for full revenue decoupling by showing the rapid decline in average annual gas usage for GS customer from 1980 through 2005. On lines 141 through 144 of witness McKay's direct testimony it states that the average usage per GS customer declined 36% over that period. QGC Exhibit 1.4, which graphs the decline in GS-1 average, annual gas consumption for 1980 through 2005, is shown on Graph 1 below.

GRAPH 1

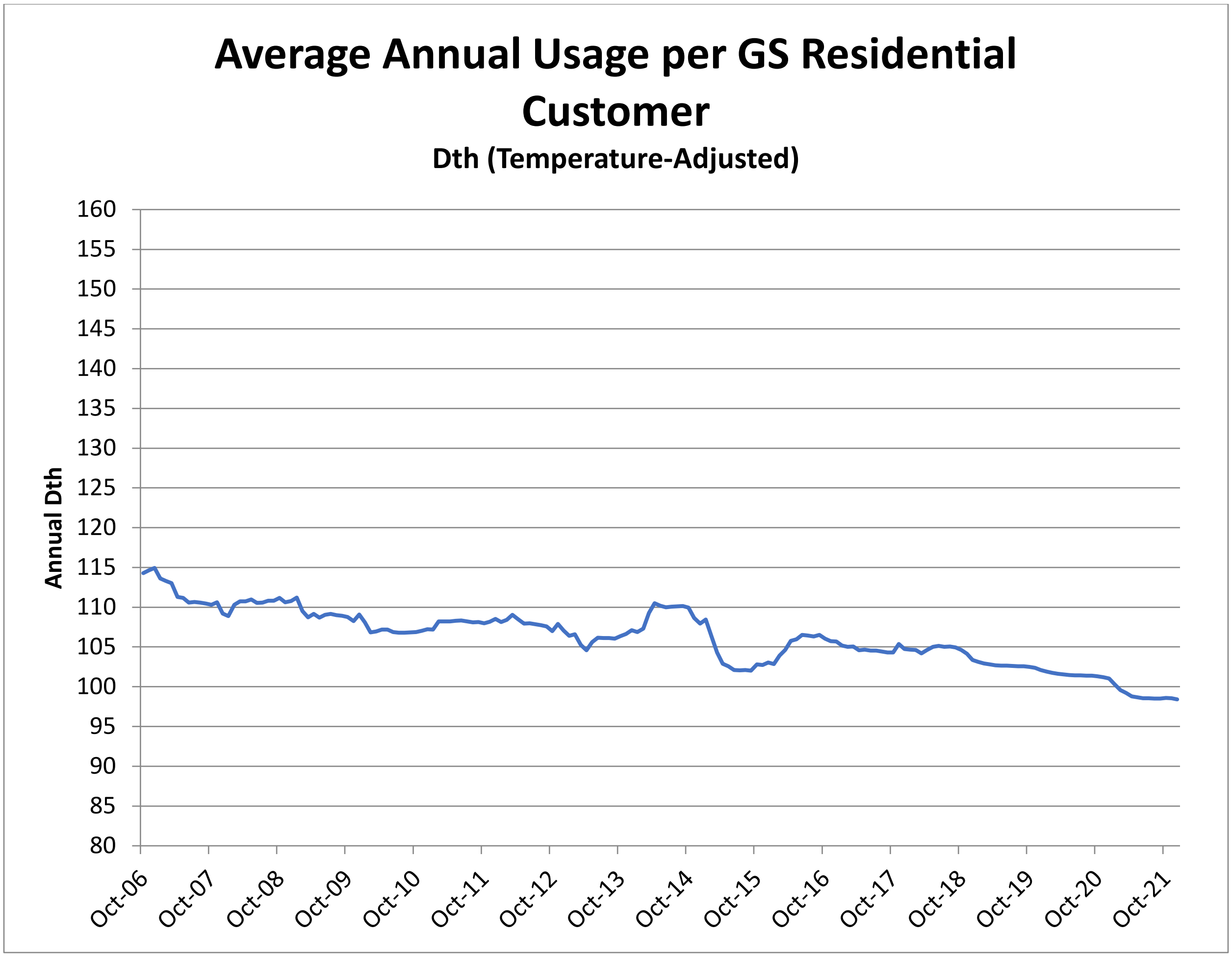


DEU's primary support for its proposed revenue decoupling mechanism in its decoupling case was the downward pressure on its earnings caused by the declining average annual GS gas usage.

Q. HAS THE WEATHER-NORMALIZED AVERAGE ANNUAL GS GAS USAGE CONTINUED TO DECLINE SINCE DEU'S FULL REVENUE DECOUPLING CASE?

A. Since the CET was implemented, the average annual GS gas usage has leveled off. The average annual GS usage in 2021 was 98.86 therms per year as compared to 114.29 therms in 2006. Over this is time period, the average annual percent decrease in average annual gas usage was only 0.9%. The following Graph 2 shows the average annual weather-normalized GS gas usage for every year since 2006, when DEU's full revenue decoupling was approved.

GRAPH 2



Based on this graph, it is obvious that the average annual gas usage of DEU's GS residential customers have leveled off and the primary basis for the CET has subsided.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS WITH THE COMPANY'S CALCULATION OF THE AVERAGE ANNUAL GS GAS USAGE AS IT APPLIES TO THE CET?

A. Yes. DEU filed a new Integrated Resource Plan ("IRP") with the Commission on June 15, 2022. On pages 3-2 and 3-3 of the IRP, the Company discusses expected impacts on the average annual GS gas usage. Contributing to the expected reduction for the 2022-2023 IRP year is that "smaller dwellings begin to occupy a greater share of the overall dwelling mix."

Q. WHY IS THAT A CONCERN?

A. The CET is intended to increase DEU's rates when the average annual GS gas usage declines due to energy efficiency programs and factors such as more efficient appliances and building standards. DEU should not be allowed to adjust rates through the CET because more customers are living in multi-family housing units or smaller single-family units. That is not related to enabling conservation.

Q. IN THE 2006 DECOUPLING CASE, DEU SAID IT NEEDED FULL REVENUE DECOUPLING TO ELIMINATE THE DISINCENTIVE TO PROMOTE ENERGY EFFICIENCY; HAS FULL REVENUE DECOUPLING ACCOMPLISHED THIS?

A. Based on my Graph 1 and Graph 2, since full revenue decoupling was implemented, the average annual gas usage per GS customer has leveled off rather than continue to decrease significantly. This would indicate that DEU's energy efficiency programs have not performed very well.

Q. IS REVENUE DECOUPLING FOR NATURAL GAS LDCs WIDELY ACCEPTED BY OTHER STATE REGULATORY AGENCIES?

A. When the Commission approved DEU's CET, the Commission expected that revenue decoupling for LDCs would become common practice in the U.S. This expectation was based on DEU's testimony in the 2006 decoupling case where the company stated: "Many state and national energy-policy groups are discussing and implementing alternative rate designs or tariffs designed to promote energy efficiency and conservation. These tariffs and rate designs are being adopted to remove financial harm experienced by natural gas utilities when Demand-Side Management programs are implemented."[1] That assumption has not turned out to be correct. Instead, a relatively small percentage of LDCs have full decoupling similar to DEU. Of 147 gas utilities, only 41 have full decoupling.[2]

Q. DOES DEU HAVE OTHER AUTOMATIC RATE ADJUSTMENT CLAUSES OR RIDERS?

A. Yes. In addition, to the CET, DEU also adjusts rates within the following rate adjustment provisions:

(1) Weather Normalization Adjustment ("WNA")
(2) Gas Balancing Account Adjustment Provision,
(3) Infrastructure Rate Adjustment Factor or Infrastructure Tracker Program ("ITP"),
(4) Rural Expansion Rate Adjustment, and
(5) Sustainable Transportation and Energy Plan ("STEP") Surcharge.

Q. ISN'T THE WNA ALSO CONSIDERED A REVENUE DECOUPLING MECHANISM?

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[1] Joint Application of Questar Gas Company, the Division of Public Utilities and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Order, Docket No. 05-057-T01, Direct Testimony of Barrie L. McKay at 4 (Jan. 23, 2006).

[2] S&P Global Intelligence Report, Use of adjustment clauses as of June 2022.

A. Yes. The CET is considered a full revenue decoupling mechanism and the WNA is considered a partial decoupling mechanism.

Q. DOES FULL REVENUE DECOUPLING LOWER INVESTORS' RISK WITH UTILITIES?

A. Yes. Decoupling allows utilities to automatically adjust its rates if it does not collect its approved base revenue per customer. It is widely accepted that decoupling rate adjustment mechanisms reduce the utilities' risk to investors.

Q. HAS DEU REDUCED ITS PROPOSED RATE OF RETURN ON EQUITY ("ROE") TO REFLECT THIS LOWER RISK?

A. No.

Q. IN DEU'S PRIOR RATE CASE IN DOCKET NO. 19-057-02 WHAT WAS ITS CLAIMED RATIONALE FOR NOT REDUCING ITS ROE FOR THE LOWER RISK ATTRIBUTABLE TO REVENUE DECOUPLING?

A. DEU's claimed rationale for not making a downward adjustment to its proposed ROE is that the lower risk had already been considered in its ROE analysis and recommendation. The basis for this claim is that the proxy group of utilities that DEU used in its ROE analysis included mostly gas utilities with revenue decoupling.

Q. HAS DEU MADE A SIMILAR ARGUMENT IN THIS CASE FOR NOT REDUCING ITS ROE?

A. No. Further, I do not believe DEU can support making a similar argument in this case.

Q. PLEASE EXPLAIN.

A. In this case, DEU has a new witness for determining its proposed ROE. The new ROE witness’s proxy group mostly includes gas utilities that do not have full revenue decoupling. As shown on the fifth column of DEU Exhibit 2.07 of the direct testimony of DEU witness Jennifer Nelson, only three of the twenty-four LDC operating subsidiaries in her proxy group has full revenue decoupling. The other twenty-one LDCs have either partial revenue decoupling or no decoupling.

Q. ARE FULL DECOUPLING AND PARTIAL DECOUPLING SIMILAR?

A. No. Full decoupling separates the utility’s margins or revenues from its gas volumes. Partial decoupling does not do this. Instead, it either allows some rate adjustments for things such as weather normalization or it provides a rate design that recovers less fixed costs in commodity or volumetric rates.

Q. DOES DEU EXHIBIT NO. 2.07 ALSO IDENTIFY LDCs WITH “FORMULA BASED RATES/ANNUAL RATE REVIEW MECHANISMS?”

A. Yes. However, two of the LDCs used, Atmos Energy-Texas and Texas Gas Service, are somewhat misleading. Those two LDCs have several distinct rate areas in the state, i.e., they do not have system-wide or statewide rates. Only some of their rate areas have annual rate review mechanisms.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE CET?

A. I recommend the following:

(1) OCS rate of return witness Dan Lawton discusses the lower risk to DEU investors due to all of the rate adjustment and rate tracker provisions. Based on the above and Mr. Lawton’s testimony, the Commission should approve a ROE on the lower end of Mr. Lawton’s range,

(2) The CET calculation should be revised in this docket to exclude the impacts of smaller residential housing units on the average annual GS gas usage calculation, and

(3) The Commission should order DEU to present analyses and supporting testimony in its next rate case on whether the CET should be continued.

REVENUE DISTRIBUTION

Q. WHAT IS A CUSTOMER CLASS REVENUE DISTRIBUTION?

A. The customer class revenue distribution is the determination of how a utility's total revenue increase is to be distributed to the customer classes. If customer class revenue levels are to be set equal to the cost of serving each customer class, then the revenue increase (or decrease) for each customer class is based on the approved class cost of service study. In some instances, factors other than cost of service are considered, and the revenue distribution will vary from the class cost of service study results.

Q. IN DEU'S LAST RATE CASE, WAS THE CUSTOMER CLASS REVENUE DISTRIBUTION BASED ON THE RESULTS OF THE COSS?

A. Not initially. In Docket No. 19-057-02 the COSS resulted in some customer classes needing substantial rate increases. In order to mitigate the impacts on some customer classes by setting class revenue levels equal to their cost of service at one time, the Commission decided to gradually move revenue levels to their cost of service with three annual rate changes. After the third rate change, all customer class revenue levels were equal to their cost of service.

Q. IS DEU PROPOSING TO SET CUSTOMER CLASS REVENUE LEVELS EQUAL TO THEIR ALLOCATED COST OF SERVICE IN THIS CASE?

A. Yes.[3]

Q. WHAT ARE THE RESULTS OF DEU'S SETTING PROPOSED CLASS REVENUE LEVELS EQUAL TO THEIR COST OF SERVICE?

A. The results are shown on Table 1. As shown on the table, there is a wide range in revenue changes among the customer classes. The range is from a rate decrease of 10.08% to a rate increase of 66.8%.

This result is somewhat surprising since the current rate revenues were based on cost of service and DEU says it has not made any significant changes in cost allocation methodologies.

Q. DOES THE COMPANY OFFER ANY EXPLANATION FOR THE CAUSE OF THIS DISPARITY IN CUSTOMER CLASS REVENUE CHANGES?

A. Not directly. DEU does mention there were significant customer migrations since the prior rate case.

Q. WHAT ARE THE RESULTS OF YOUR ADJUSTED COSS?

A. A comparison of the customer class revenue increases (or decreases) necessary to move each class to their cost of service under the Company's COSS and OCS's COSS is provided in Table 1 below:

[3] The one exception is the TBF class. As in prior rate cases, DEU sets the TBF revenues below the cost of service in order to prevent customers from bypassing the system.

TABLE 1

Line No.	Rate Class		Current Base Rate Revenues		Dominion Proposed Base Rate Increase $	Dominion Proposed Base Rate Increase %		OCS Cost-Based Rate Increase $	OCS Cost-Based Rate Increase %
1	General Service	$	383,478,856	$	57,912,061	15.1%	$	12,839,052	3.3%
2	Firm Sales		2,822,850		1,173,466	41.6%		1,002,586	35.5%
3	Interruptible Sales		264,831		(14,447)	-5.5%		28,960	10.9%
4	Transportation Service - Small		14,266,930		(1,542,357)	-10.8%		(2,639,979)	-18.5%
5	Transportation Service - Medium		13,984,843		3,166,882	22.6%		4,438,209	31.7%
6	Transportation Service - Large		11,229,738		7,500,844	66.8%		13,091,895	116.6%
7	Transportation Bypass Firm		4,748,718		1,765,593	37.2%		3,718,973	78.3%
8	Natural Gas Vehicle		2,605,737		549,647	21.1%		1,198,221	46.0%
9	**Total**		**433,402,504**		**70,511,689**	**16.3%**		**33,677,916**	**7.8%**

A copy of my adjusted COSS is provided as Daniel Workpaper 1.

Q. BASED ON YOUR ADJUSTED COSS, SHOULD THE COMMISSION SET THE APPROVED CLASS REVENUES EQUAL TO THEIR COST OF SERVICE?

A. Given the substantial percent increases shown on Table 1 above for the Transportation Service-Large ("TSL") customer class, I do not recommend moving all customer classes to cost of service at one time. In order to alleviate the revenue increase necessary to set the TSL revenue level equal to their cost of service, the gradualism principle should be applied.

Q. PLEASE EXPLAIN WHAT IS MEANT BY GRADUALISM?

A. Gradualism is a rate setting tool or methodology used by the Commission, and other regulatory agencies, to gradually move customer class revenue levels towards the class's cost of service in situations where the COSS shows an exorbitant rate increase would be required to set the class's revenue level equal to their cost of service. Using gradualism, the increase to the class is set below the cost of service minimize the impact. The revenue shortfall resulting from gradualism is spread to other customer classes.

Q. HAVE YOU DEVELOPED A PROPOSED CUSTOMER CLASS REVENIUE DISTRIBUTION THAT APPLIES GRADUALISM TO THE TRANSPORTATION SERVICE-LARGE CUSTOMER CLASS?

A. Yes. In order to alleviate the impact of moving the TSL class to cost of service, I recommend that the percent increase be capped at 46.13%, which is the next highest customer class percent increase under the revised class cost of service study.[4] The revenue shortfall resulting from applying the cap should be spread to the other transportation service customer classes. Table 2 below shows the results of my proposed revenue distribution:

TABLE 2

Customer Class	Current Rate Revenues	Recommended Revenue Distribution	Recommended Change	
			Amount	Percentage
GS	$ 383,478,856	$ 398,983,139	$ 15,504,283	4.04%
FS	2,822,850	3,868,542	1,045,693	37.04%
IS	264,831	296,024	31,193	11.78%
TSS	14,266,930	18,198,183	3,931,253	27.56%
TSM	13,984,843	20,436,094	6,451,251	46.13%
TSL	11,229,738	16,410,051	5,180,313	46.13%
TBF	4,748,718	5,080,615	331,896	6.99%
NGV	2,605,737	3,807,772	1,202,035	46.13%
Total	**433,402,504**	**467,080,420**	**33,677,916**	**7.77%**

SUMMARY AND CONCLUSIONS

Q. WHAT SUMMARY AND CONCLUSIONS HAVE YOU REACHED?

A. Based on my review and analysis, I have reached the following conclusions and recommendations:

[4] The percent increase shown on Graph 1 for the TBF customer class is prior to applying the 40% discount DEU offers the class in order to incentivize these customers to remain part of the system.

(1) DEU's demand allocation factor should be bases on test year actual peak-day demands instead of estimated design-day demands.

(2) DEU's combined peak-day demand and throughput allocation factor should be weighted 52% peak-day demand and 48% throughput.

(3) General plant depreciation expenses should be allocated based on allocated gross general plant.

(4) DEU's proposed allocation of LNG-related costs assigns too much costs to the GS customer class and should be rejected.

(5) DEU's Conservation Enabling Tariff should be reevaluated and certain changes to the calculation should be implemented in this docket.

(6) Customer class revenue levels should be set equal to their cost of service except when doing so results in an exorbitant rate increase for a customer class. In that situation, gradualism should be applied to alleviate the large rate increase for that customer classes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.