DPU Errata Exhibit A

Revised Phase II Direct Testimony of Abdinasir M. Abdulle
(Exhibit 4.0 DIR in Docket No. 22-057-03)

Originally filed with the Commission on September 15, 2022
Revised November 7, 2022

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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** **Exhibit No. DPU 4.0 DIR** **Phase II – Revised Direct Testimony**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Revised
Direct Testimony of

Abdinasir M. Abdulle

September 15, 2022
November 7, 2022

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND EMPLOYMENT FOR THE RECORD.

A. My name is Abdinasir M. Abdulle. My business address is Heber Wells Building, 160 East 300 South, Salt Lake City, Utah 84114. I am employed by the Utah Division of Public Utilities (Division or DPU), Department of Commerce as a Utility Technical Consultant.

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

A. I am testifying on behalf of the Division.

Q. WOULD YOU SUMMARIZE YOUR EDUCATION BECKGROUND FOR THE RECORD?

A. I have a Ph.D. in Economics from Utah State University. I have been employed by the Division for about 22 years.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Division's analysis, findings, and recommendations to the class cost of service (CCOS) study and the proposed rate design filed by Dominion Energy of Utah (DEU). Specifically, my testimony addresses the Division's review of the Direct Testimonies and exhibits of DEU witnesses Austin C. Summers and Jessica L. Ipson. The absence of comments on my part concerning an issue should not be construed as an acceptance or rejection of the issue.

Q. BRIEFLY DESCRIBE THE MATERIALS THAT YOU RELIED UPON IN YOUR REVIEW AND ANALYSIS OF THIS CASE.

A. I have reviewed and analyzed DEU's application, the Direct Testimonies of DEU's witnesses Mr. Austin C. Summers and Ms. Jessica L. Ipson, the DEU's proposed tariffs, and DEU's responses to discovery. I also reviewed the presentation material for Phase II Technical Conference held on June 22, 2022.

CLASS COST OF SERVICE

Q. WHAT ARE THE MAIN CCOS ISSUES IN THIS PROCEEDING?

A. In my review of the Direct Testimony of DEU witness Mr. Austin C. Summers, I have identified several issues that I deem require further comments. These issues include but are not limited to,

- Dividing the TS class into three subclasses,
- Using design day versus peak day in the CCOS and the peak demand responsibility for interruptible customers,
- Hybrid allocation factor 230 of 60% design day and 40% throughput,
- Reducing the discount of the rates paid by the TBF customers.

SPLITTING THE TS CLASS INTO THREE SUBCLASSES

Q. DID DEU PROPOSE A CHANGE IN THE TS CLASS?

A. Yes. DEU proposed to split the Transportation Service (TS) class into three sub-classes. Transportation Service Small (TSS) for customers with annual usage less than 25,000 Dth, Transportation Service Medium (TSM) for customers with annual usage of between 25,000 Dth and 250,000 Dth, and Transportation Service Large (TSL) for customers with annual usage of more than 250,000 Dth.

Q. HOW DID DEU DETERMINE THE POINTS OF SEPERATION?

A. Using customer load factors and annual usages, DEU drew a scatter plot and visually determined the reasonable points of separation between customer groups.[1] This resulted in homogeneous groups in terms of load factors and annual usages to be grouped together into a subclass. DEU then compared these groups using the

[1] Dominion Energy Utah, Docket No. 22-057-03, May 2, 2022, Direct Testimony of Austin C. Summers, page 20, lines 519-520.

rate of return index and determined that the TSS customers are paying rates above full-cost rates (1.79), the TSM customers are paying rates close to full-cost rate (0.92), and TSL customers are paying rates that are much below full-cost rates (0.32). This shows that there is intra class subsidies with TSS customers subsidizing other customers in the TS- class, specifically the TSL customers.[2]

The separation points or usage levels for each group are like the usage levels used in the cost-of-service workgroup, Docket No. 20-057-11, to split the TS class into three sub-classes. While no consensus was reached in the workgroup on how to split the TS class, the results presented by DEU in this case are consistent with those from the workgroup.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE PROPOSED SPLIT OF THE TS CLASS?

A. Yes. The Division concurs with DEU's proposed splitting of the TS class into three sub-classes as identified herein and in the testimony of DEU witness, Mr. Summers, and recommends Commission approval. There are two reasons for the Division's support of DEU's proposal.

First, DEU's cost of service study demonstrates the existence of significant intra-class subsidies. It is likely that the smaller TS customers are subsidizing the larger customers. Splitting the class into smaller sub-classes allows for more refined allocations and rate design within the class, which better reflects cost causation and mitigates the subsidies.

Second, while the split points were chosen manually as described by Mr. Summers, there is some statistical support for the groupings. As previously explained, the three sub-classes were grouped based on annual usage and standard statistical tests indicate a statistically significant difference in the average usage between the groups. For example, a T-Test for the difference in the means for the sub-classes

[2] Dominion Energy Utah, Docket No. 22-057-03, May 2, 2022, Direct Testimony of Austin C. Summers, page 8, lines 497-499.

indicates that the average usage for the TSS class is significantly different from the average usage in the TSM class. Likewise, the average usage for the TSM class is statistically significantly different from the average usage of the TSL class. The results of the T-Tests are summarized in Table 1 below.

Table 1. Comparing Annual Usage

	STD	df	T-STAT	P-Val
TSS v. TSM	3,341	1054	18.10	0.0000
TSM v. TSL	174,744	254	4.17	0.0000

The T-Test or Student T-Test is implemented using the test statistic,

$$t = \frac{(\bar{x}_1 - \bar{x}_2)}{\sqrt{\frac{S_1^2}{n_1} + \frac{S_2^2}{n_2}}}$$

Where the numerator is the difference in the sample means and the denominator is the square root of the sum of the sample variances weighted by the respective sample sizes. The t-statistic will have a t-distribution with $n_1 + n_2 - 2$ degrees of freedom (df). The P-value for each test indicates that the compared average usage are indeed different at a significance level of .05. For example, the average usage for the TSS class is different from the average usage for the TSM and likewise for the TSM and TSL average usages. The P-value indicates the probability of finding a t-statistic greater than the one calculated from the sample data; the smaller the P-value the more likely the two means are different from one another.

Similarly, the Kruskal-Wallis One Way ANOVA by Ranks[3] indicates that at least one median load factor (LF) is significantly different from the others. The test statistic in this case is,

[3] Wayne W. Daniel, Applied Nonparametric Statistics, 2nd ed., PWS-Kent Publishing,1990, pp. 226-234.

$$H = \frac{12}{n(n+1)} \sum_{i=1}^{k} \frac{R_i^2}{n_i} - 3(n+1)$$

Where "n" is the total number of TS customers; "n_i" is the number of customers in group "i" (i = TSS, TSM, and TSL); and "R_i" is the sum of the Ranked LF values in group "i". The test statistic will have a Chi Square distribution with k – 1 df. The results for the test are summarized in Table 2.

Table 2. Kruskal-Wallis One-Way ANOVA by Ranks (Load Factor)

	TSS	**TSM**	**TSL**	**T-STAT**	**df**	**P-Val**
N	830	226	30	165.90	2	0.0000
Sum of Ranks	506,223	78,767	5,237			

Given the small P-value for the test, we conclude that at least one median LF for the three groups is statistically significantly different from the others. Thus, even though the usage levels used to divide the TS class into the three sub-classes were manually chosen, given the intraclass subsidy and the statistical analysis there is support for the three groupings.

DESIGN DAY VS. ACTUAL PEAK DAY USAGE IN CCOS

Q. WHAT IS DESIGN PEAK DAY?

A. The Design Peak Day, normally called Design Day by DEU, is used as "an estimate of how much gas will be used on the system during an extremely cold period."[4]

Q. WHAT IS ACTUAL PEAK DAY?

[4] Austin Summers Direct Testimony, lines 272-273. Also, the DEU IRP page 3-4, Firm Customer Design Day Gas Demand better explains how Design Day is calculated.

A. The Actual Peak Day is a historical number that shows how much gas was used on the system during the highest sendout day of the year.[5]

Q. WHAT IS THE DIFFERENCE BETWEEN THE TWO PEAK DAYS?

A. In short, the Design Day is an estimated number for the future and the Actual Peak Day is an actual number from the past. While either method can be used to allocate costs related to the coincident peak demand of customers, using the Actual Peak Day better reflects cost causation and aligns with the benefits customers receive from the system.

Q. PLEASE EXPLAIN THE DIVISION'S PREFERENCE FOR USING THE ACTUAL PEAK DAY FOR ALLOCATIONS.

A. The Division prefers using Actual Peak Day over Design Day because the Actual Peak Day is based on the actual known usage of the customers on the system and is a better reflection of the benefits derived by those customers. Design Day is a theoretical worst-case scenario that rarely, if ever, happens. It is useful for designing the system but inadequate for allocating costs according to actual system usage and benefits.

For the duration or life of the pipe and system, much of the wear and tear comes from actual everyday use. It is more appropriate to allocate costs based on the actual usage of the system than on a theoretical basis. Design Day calculations also assume that interruptible customers will not be using the system during the extreme cold weather conditions, excluding them from the calculation. Actual usage shows that interruptible customers are rarely if ever interrupted and receive the benefit of using the system without the appropriate allocation of the cost. The pipe in the ground and supporting infrastructure has been designed to meet the system needs on Design Day, however, the costs should be allocated to the customers based on

[5] The Division is using the Actual Peak Day based on a calendar year. It can also be based on the heating season, i.e., the 2021/22 season.

how the system is being used. The pipe exists not to just meet design day demand but also to satisfy the daily use.

Q. WOULD ALLOCATING USING ACTUAL PEAK DAY INCLUDE INTERRUPTIBLE CUSTOMERS?

A. Yes. If Actual Peak Day is used, then interruptible customers should be included in the allocated costs. In the past 3 years, interruptible customers have not been interrupted but have been using the system on the highest sendout days. [6] It is fair to include them in the costs.

Q. DOES THE HISTORICAL DATA USED IN THE ACTUAL PEAK DAY INCLUDE ESTIMATES?

A. Yes. That's because not all data is available on a daily basis for each class. Many customers are billed on a monthly basis, so an estimate is made by DEU. Although a small issue, it seems more appropriate than Design Day which is wholly based on estimates and is not ever met.

Q. IT HAS BEEN BROUGHT UP THAT ACTUAL PEAK DAY VARIES TOO MUCH AND IS NOT STABLE. IS THAT AN ISSUE?

A. It can be. That is why the Division is proposing to use a 3-year average of Actual Peak Days of the most recent years using historical data provided by DEU.[7] This smooths the variability from year to year. Table 3 below shows this.

[6] DPU Exhibit 4.01 DIR – DEU Response to DPU Data Request 5.02
[7] DPU Exhibit 4.02 DIR – DEU Response to DPU Data Request 4.05U

Table 3: 3 Year Average Actual Peak Day, Dth/Year

Date	GS	FS	IS	TS	TBF	NGV	Total
1/2/2019	846,691	12,043	1,146	180,102	28,297	663	1,068,941
2/3/2020	807,611	12,254	1,144	175,902	30,164	633	1,027,708
12/28/2021	766,846	11,317	1,622	178,632	27,609	597	986,622
3 Year Average Actual	807,049	11,871	1,304	178,212	28,690	631	1,027,757
Actual Peak-Day Factor	78.53%	1.16%	0.13%	17.34%	2.79%	0.06%	100.00%
For comparison:							
Design Day	1,189,838	14,870	-	189,497	64,500	974	1,459,679
Design Day Factor	81.51%	1.02%	0.00%	12.98%	4.42%	0.07%	100.00%

HYBRID ALLOCATION FACTOR: 60% DESIGN DAY, 40% THROUGHPUT

Q. HAVE YOU REVIEWED THE DEU HYBRID ALLOCATION FACTOR?

A. Yes. DEU is using a hybrid factor to allocate costs associated with compressor stations, feeder systems, and measurement and regulation station equipment. This factor is a blend of design day and throughput.[8] DEU is proposing a weighting of 60% Design Day and 40% Throughput. DEU did not provide any empirical analysis to justify or support its proposed 60% / 40% weighting. This weighting came under criticism by the UAE in DEU's previous general rate case.

Q. WOULD YOU COMMENT ON DEU'S PROPOSED HYBRID ALLOCATION FACTOR?

Yes. There are several methods of allocating demand or capacity costs. In natural gas distribution companies, the most commonly used allocation methods are coincident demand method, non-coincident demand method, and the average and peak method. The coincident demand method allocates a greater percentage of demand costs to lower load factor heating customers. Similarly, the non-coincident demand method favors the low load factor heating customers by reducing the

[8] Dominion Energy Utah, Docket No. 22-057-03, May 2, 2022, Direct Testimony of Austin C. Summers Exhibit 4.02, page 1.

amount of costs assigned to them. The average and peak demand method is a compromise between the other two methods. It is a weighted blend of total volume or usage, such as annual throughput and a measure of maximum volume on a given day, such as Actual Peak Day or Design Day. Hence, it moderates the cost allocations between the high and low load factor customers.[9]

The 60% / 40% weighting employed by DEU has resulted in reasonable rates in the past and may still do so. However, the Division concludes that the use of the blended factor, the average and peak method, is appropriate if the proper combination of measures for annual throughput and maximum volume are employed.

Q. PLEASE EXPLAIN THESE MEASURES AND THEIR USE IN THIS CASE FOR CREATING A BLENDED ALLOCATION FIGURE.

A. Regarding the Average and Peak Demand Method, the NARUC Manual states that,

> 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.

This indicates that in calculating the capacity costs associated with the average use, the system load factor should be used. The value of the system load factor depends on what measures of annual volume and maximum volume are used. The load factor is calculated as

$$Load\ Factor = (Annual\ Volume\ \div\ 365) \div Maximum\ Volume\ in\ a\ Day$$

In this case, there are really two competing sets of measures for annual volume and maximum volume that might reasonably be used. For annual volume, DEU has used 172,905,622 Dth, representing total volumes minus those serving the Lake Side

[9] DPU Exhibit 4.03 DIR - NARUC Gas Distribution Rate Design Manual. June 1989. Pages 26-28.

power plants. If Lake Side volumes are included, the number is 216,309,144 Dth. While Lake Side volumes are generally excluded from various ratemaking elements because of the contract between DEU and PacifiCorp, they should not be excluded from a measure designed to assess the load factor of system components. This is particularly so if the measure of maximum daily volume is based on a design component instead of a usage-based one. In this case, those two numbers equal 1,459,679 Dth for the Design Day or 1,027,757 Dth for the average actual peak usage.

Based on this formula and the measures of the annual and maximum volumes, we have the following options for blending the measures.

A. Design Day 2023 and non-Lake Side Throughput 2023 (the method proposed by UAE in the previous general rate case),
B. 3-Year Average Actual Peak Day and non-Lake Side Throughput 2023,
C. Design Day 2023 and Utah Total Dth, and
D. 3-Year Average Actual Peak and Utah Total Dth.

The four possible combinations of these measures, the resulting load factors, and weighting for the hybrid allocation factor are reported in Table 4.

Table 4. Weights for the Hybrid Allocation Factor

Measure	A	B	C	D
Annual Volume	172,905,622	172,905,622	216,309,144	216,309,144
Days in a Year	365	365	365	365
Maximum Volume in a Day	1,459,679	1,027,757	1,459,679	1,027,757
Load Factor	32.45%	46.09%	40.60%	57.66%
Hybrid Factor	68% / 32%	54% / 46%	59%- / 41%	42% / 58%

Q. WHAT IS THE IMPACT OF USING THE BLENDING OPTIONS LISTED ABOVE?

A. Changing the weights of the blended hybrid factor and/or the factors to be blended would impact the allocation of costs and the allocation of the TBF subsidy between the different customer classes. Tables 5 through 9 show the changes in the required increase or decrease in revenues, including TBF subsidies, resulting from the implementation of the DEU's proposed 60% design day / 40% throughput option and the other four options in CCOS. From these tables, you can see that there is a considerable variation in the allocation of costs and TBF subsidies between the different customer classes. These tables use the CCOS as filed by DEU before the DPU adjustments were included.

Table 5. Results of the CCOS using DEU's 60% design day and 40% throughput

Customer Class	DNG Revenue	DNG Revenue Change: $ Increase / Decrease	DNG Revenue Change: % Increase / Decrease
GS	383,478,856	57,919,580	15.10%
FS	2,822,850	1,172,987	41.55%
IS	264,831	(14,883)	-5.62%
TSS	14,266,930	(1,541,715)	-10.81%
TSM	13,984,843	3,163,249	22.62%
TSL	11,229,738	7,491,662	66.71%
TBF	4,748,718	1,771,143	37.30%
NGV	2,605,737	549,665	21.09%
Total	433,402,504	70,511,689	16.27%

Table 6. Results of the CCOS using 68% design day and 32% throughput (Option A)

Customer Class	DNG Revenue	DNG Revenue Change	
		$ Increase / Decrease	% Increase / Decrease
GS	383,508,813	60,563,626.6	15.79%
FS	2,821,992	1,094,322.1	38.78%
IS	264,550	(40,344.8)	-15.25%
TSS	14,266,489	(1,585,439.3)	-11.11%
TSM	13,977,080	2,455,518.1	17.57%
TSL	11,211,492	5,833,972.5	52.04%
TBF	4,746,532	1,656,812.5	34.91%
NGV	2,605,557	533,221.5	20.46%
Total	433,402,504	70,511,689	16.27%

Table 7. Results of the CCOS using 54% 3-year average actual peak and 46% Throughput. (Option B)

Customer Class	DNG Revenue	DNG Revenue Change	
		$ Increase / Decrease	% Increase / Decrease
GS	383,420,239	51,336,475	13.39%
FS	2,825,142	1,399,656	49.54%
IS	266,577	170,136	63.82%
TSS	14,264,758	(1,820,279)	-12.76%
TSM	14,003,223	4,997,540	35.69%
TSL	11,286,084	13,284,284	117.70%
TBF	4,730,674	589,904	12.47%
NGV	2,605,808	553,974	21.26%
Total	433,402,504	70,511,689	16.27%

Table 8. Results of the CCOS using 59% design day and 41% Utah Total Dth. (Option C)

Customer Class	DNG Revenue	DNG Revenue Change: $ Increase / Decrease	DNG Revenue Change: % Increase / Decrease
GS	383,355,695	50,659,387	13.21%
FS	2,820,197	981,461	34.80%
IS	264,577	(37,856)	-14.31%
TSS	14,258,738	(2,081,553)	-14.60%
TSM	13,969,473	1,988,119	14.23%
TSL	11,205,480	5,496,716	49.05%
TBF	4,922,892	12,978,482	263.64%
NGV	2,605,451	526,933	20.22%
Total	433,402,504	70,511,689	16.27%

Table 9. Results of the CCOS using 42% 3-year actual Peak day and 58% Utah total Dth. (Option D)

Customer Class	DNG Revenue	DNG Revenue Change: $ Increase / Decrease	DNG Revenue Change: % Increase / Decrease
GS	383,214,406	38,289,634	9.99%
FS	2,822,159	1,204,956	42.70%
IS	266,248	137,456	51.63%
TSS	14,254,310	(2,451,159)	-17.20%
TSM	13,988,963	4,065,970	29.07%
TSL	11,266,430	11,840,509	105.10%
TBF	4,984,332	16,877,020	338.60%
NGV	2,605,657	547,303	21.00%
Total	433,402,504	70,511,689	16.27%

Q. WHICH METHOD DOES DPU PREFER?

A. Method B is DPU’s preferred option because it best balances the actual use of the system and its benefits with measures intended to properly allocate the costs of items using this allocation factor. It does this without a significant shock to the allocations as they have been made in the past.

By using average actual throughput, rather than design day, this system is more likely to capture the benefits each class receives from the plant, which is historically used by all customer classes on all days of the year. As noted in our discussion above, we disfavor using Design Day because it represents a theoretical measure of hypothetical cost causation rather than an actual measure of usage of the actual system. It fails to account for things as they really are.

Q. PLEASE COMMENT ON THE OTHER THREE METHODS YOU DESCRIBE.

A. Method A suffers from a blending of the hypothetical Design Day measure while ignoring the full measure of throughput. As noted above, while DEU's throughput number excludes volumes of gas supplied to the Lake Side plants, those volumes should be included if a Design Day is used. The Design Day measure is a theoretical maximum and on that theoretical maximum day the full measure of volumes should be included. If the system is designed for those volumes, there is no reason to exclude them. While certain costs are excluded from other rate case components to account for the contract, load, and revenue of the Lake Side volumes, they should be included if the other component of the equation is Design Day. Ignoring 20% of annual volumes flowing through the system, including on system peak days, is not reasonable.

Method C can be a reasonable measure. Although DPU disfavors using Design Day measures in rate setting for the reasons mentioned above, this method is consistent in that it uses total system volumes to measure the intensity of usage. In short, it cures the most significant defect of Method A's skewed approach.

Method D could be a reasonable measure but it represents such a significant departure from the current approach that a shift to it should occur gradually. DPU is not convinced that Lake Side volumes should be excluded from the calculation of this allocation factor in any scenario. That would ordinarily lead DPU to the conclusion that this approach should be adopted, given its stance on using the peak day. However, as Table 7 shows, the effects of such a change would be quite large. Even accounting for the fact that DNG rate changes represent a proportionally smaller share of some customer classes' loads, it is likely not reasonable to adopt this approach in this case, depending on what other adjustments are made to DEU's request.

TBF CUSTOMERS PAYING LESS THAN COST OF SERVICE

Q. WHAT RATE ARE THE TBF CUSTOMERS CURRENTLY PAYING?

A. The rates paid by the TBF customers are currently discounted by 50% to mitigate the risk of bypassing the local distribution system.

Q. WHAT IS DEU PROPOSING IN THIS CASE?

A. DEU is proposing to reduce the discount rate from 50% to 40% in this case.

Q. WOULD YOU COMMENT ON DEU'S PROPOSED DISCOUNT RATE?

A. Though DEU neither explained the rationale behind the reduction in the discount rate nor provided any empirical explanation as to how the discount rate is determined, the Division believes the proposed reduction in the discount rate would alleviate the energy burden of the other ratepayers by paying less in subsidy toward TBF customers. On the other hand, TBF customers will pay some of the fixed costs, which would otherwise be paid by other ratepayers. Therefore, the Division does not oppose the proposed reduction. However, the Division recommends the Commission to direct DEU to provide an analysis, such as breakeven analysis, to support the proposed discount rate.

RATE SPREAD

Q. WHAT RATE SPREAD DOES DEU PROPOSE IN THIS CASE?

A. In addition to allocating costs to the new TS sub-classes, DEU proposes to move each class except TBF to pay its respective full cost of service which includes its share of the subsidies to the TBF customers. Specifically, DEU proposes the following spread.

Table 10. Dominion Energy Utah's proposed rate spread

Class	DEU Proposed Rate Spread
Utah	15.93%
GS	14.78%
FS	40.82%
IS	-5.40%
TS	22.76%
TSS	-10.68%
TSM	22.30%
TSL	65.50%
TBF	36.16
NGV	21.01

Q. ARE THESE NUMBERS AFFECTED BY DPU'S POSITION ON THE HYBRID ALLOCATION FACTOR?

A. Yes. Depending on other adjustments, they will shift. While I noted the relative shifts caused by these methods from DEU's filed revenue requirement in my tables above, the Commission will need to apply the modified allocation factor to DEU's filed model after making any revenue requirement adjustments in order to ascertain the rate spread.

RATE DESIGN

RATE DESIGN FOR TRANSPORTATION SUB-CLASSES

Q. WHAT RATE DESIGN DID DEU PROPOSED FOR TSS, TSM, AND TSL?

A. DEU proposed to use a declining block rate for all transportation sub-classes. Regarding block breaks, DEU proposed the same block breaks in the FS class for the TSS sub-class (200 Dth, 201-2,000 Dth, and >2,000 Dth). DEU also proposes the same block breaks as the TBF class for the TSL sub-class (10,000 Dth, the next 112,500 Dth, the next 477,500 Dth, and all usage over 600,000 Dth). For the TSM sub-class, DEU proposed two blocks with a break at 2,000 Dth. Furthermore, all three sub-classes will continue paying a Basic Service Fee, Administrative Fee, and Firm Demand Charges.

Q. DO YOU HAVE ANY COMMENTS ON THE DEU PROPOSED RATE DESIGN FOR THE TSS, TSM, AND TSL SUB-CLASSES?

A. Yes, I concur with aspects of the proposal, including the use of declining block rates, the block breaks, and the continuation of the fees and other charges. DEU witness, Mr. Austin C. Summers provided a clear explanation justifying the proposed blocking structure for the three subclasses.[10] If the Commission wishes to take a gradual approach with changes within this class, it should implement that gradualism by adjusting the rates of the subclasses in a manner that does not affect rates for the other classes.

Q. WOULD YOU COMMENT ON THE DEU'S PROPOSED RATE DESIGN FOR THE OTHER CLASSES?

A. Yes. DEU did not propose any changes, including block breaks and block differentials, to the rate design of the other customers. The Cost of Service and Rate Design Task Force did not propose any changes to the rate classes. The Division does not oppose keeping the rate design of these classes unchanged except for the cost allocated to each class.

BILL IMPACT

Q. In Mr. Summer's testimony, lines 763-772, the Company proposes to change the typical GS residential customer bill calculation from 80 Dth/year to 70 Dth/year. Does the Division agree with this proposal?

A. The Division does not oppose this proposal but given the range of GS residential customers' usage, the Division recommends the Company provide more customer

[10] Dominion Energy Utah, Docket No. 22-057-03, May 2, 2022, Direct Testimony of Austin C. Summers, page 23-25.

usage levels to give residential customers a better indication of bill impacts. The Division has looked at various methods for the Company to provide a range but has no preference. Here are the methods that have been considered:

1. Arbitrary data points
   a. If the median is 70 Dth/year, simply choose volumes smaller and larger than the median to cover a wider range of customers.
2. Quantiles
   a. The median or 50% quantile is 70 Dth/year. Also include the 25% quantile and 75% quantile.
3. Home Size or Type
   a. The typical apartment uses about 45 Dth/year. DEU could also display the values for a small, medium, and large home.

Q, DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry.. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications. As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. Coincident Demand Method

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. Noncoincident Demand Method

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak; regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. Average and Peak Demand 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.

5. Use of Load Studies For Allocation of Demand Costs

a. Concepts

As previously mentioned, load data are necessary for a cost of service study. These data are the basis for any demand allocation and, if inaccurate, can give misleading results regardless of the case taken with the remainder of the analysis. The load characteristics of each utility's system and each customer class on a system are unique and must be separately surveyed in each case. The purpose of the survey is to determine for relatively homogenous customer groups such information as load pattern, amount and time of occurrence of maximum load, load factor, and diversity or coincidence factor.

Arriving at load patterns is not an easy task. Most of the necessary information is not readily available from the normal record keeping of a utility. To secure the information requires a systematic activity known as load research. It embraces a whole gamut of engineering, statistical, and mathematical methods and procedures, ranging from the simple application of judgments to available data to refined mathematical probes into the significance of sampling techniques. The gas industry generally has not devoted the same resources to this area in the past as the electric industry on the whole has, so in most cases more reliance will have to be placed on use of existing records than would be preferred. However, since system peaks in the gas industry are highly weather sensitive, a fairly reliable correlation between temperature versus gas consumption can be developed from utility records. By applying a least square fit to