- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications	DOCKET NO. 19-057-02 REPORT AND ORDER

ISSUED: February 25, 2020

SYNOPSIS

The Public Service Commission of Utah (PSC) approves a distribution non-gas rate (DNG) revenue requirement increase of $2,680,013 for Dominion Energy Utah (DEU). The revenue requirement is based on a test year ending December 31, 2020 ("Test Year"), an allowed rate of return on equity of 9.5%, and an overall rate of return of 7.178%.

The revenue increase is allocated to customer classes to improve alignment of revenue requirement with the cost of service for each customer class, resulting in non-uniform percentage changes to the rate schedules. The total increase will be implemented in a series of three steps: the first step will occur on March 1, 2020; the second and third steps will each occur in the early fall of 2020 and 2021, respectively.

We approve the continuation of the infrastructure tracker program (ITP). We also approve a Test Year ITP budget of $72.2 million, adjusted thereafter for each ITP plan year based on the GDP Deflator Index.

We approve DEU's proposed methods for allocating supplier non-gas (SNG) costs, including peak hour contract costs, and determining SNG rates. We also approve DEU's proposed administrative tariff modifications.

Table of Contents

APPEARANCES

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I. INTRODUCTION

This matter is before the PSC on DEU's July 1, 2019 application requesting authority to increase its DNG retail rates by $19,249,740, or 5 percent ("Application") and to implement new rates, effective March 1, 2020. The Application was filed pursuant to a commitment in an approved settlement stipulation in Docket No. 16-057-01.[1]

The Application is based on the forecast Test Year ending December 31, 2020, a 13-month average rate base with an historical base period, and a requested return on common equity ("ROE") of 10.5 percent. DEU proposes to bring all rate classes to full cost of service. DEU also proposes changes, both substantive and administrative, to its Utah Natural Gas Tariff PSCU 500 ("Tariff"). Additionally, DEU proposes to continue the ITP and increase the ITP's inflation-adjusted investment cap amount from the current $72.2 million to $80 million.

II. PROCEDURAL HISTORY

On July 1, 2019, DEU filed the Application, including supporting direct testimony and exhibits. On July 15, 2019, the Division of Public Utilities (DPU) filed a memorandum summarizing the results of its review of the Application pursuant to Utah Code Ann. § 54-7-12(2)(b)(ii). DPU's memorandum indicates the Application constitutes a complete filing as defined in Utah Administrative Code R746-700-10, -20, -21, and -22.

The following parties petitioned for and were granted intervention in this docket: Nucor Steel-Utah, a Division of Nucor Corporation ("Nucor"), the Utah Association of Energy Users

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[1] *In the Matter of the Joint Notice and Application of Questar Gas Company and Dominion Resources, Inc. of Proposed Merger of Questar Corporation and Dominion Resources, Inc.*, Docket No. 16-057-01 (Order Memorializing Bench Ruling Approving Settlement Stipulation, issued Sept. 14, 2016, Settlement Stipulation at ¶ 33).

(UAE), American Natural Gas Council, Inc. (ANGC), US Magnesium LLC ("US Mag"), and the Federal Executive Agencies (FEA).

On July 23, 2019, the PSC issued a scheduling order and notices of technical conferences, public witness hearings, and hearings, setting the procedural schedule for this docket ("Scheduling Order"). The Scheduling Order specified a bifurcated schedule: Phase I addressed DEU's revenue requirement; Phase II addressed cost of service for each customer class, rate design, and DEU's other proposed tariff changes.

Phase I – Revenue Requirement:

On October 17, 2019, DPU, OCS, ANGC, UAE, and FEA each filed Phase I direct testimony. On November 14, 2019, DEU filed Phase I rebuttal testimony. On December 5, 2019, DPU, OCS, UAE, ANGC, and FEA filed Phase I surrebuttal testimony. On December 17 and 18, 2019, the PSC conducted hearings on Phase I issues, including a public witness hearing on December 17, 2019.[2]

Phase II – Class Cost of Service, Rate Design:

On November 14, 2019, DPU, OCS, UAE, FEA, ANGC, and US Mag filed Phase II direct testimony. On December 13, 2019, DEU, OCS, UAE, and ANGC filed Phase II rebuttal testimony. On January 6, 2020, DEU, DPU, OCS, ANGC, UAE, and US Mag filed Phase II surrebuttal testimony. FEA filed Phase II surrebuttal testimony on January 15, 2020. On January 15 and 16, 2020, the PSC conducted hearings on Phase II issues, including a public witness hearing on January 15, 2020 during which seven individuals provided comments.[3]

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[2] No member of the public provided comments at this hearing.

[3] On January 28, 2020, in response to discussion during the Phase II hearing, DEU filed an updated Cost of Service Model. This model was not entered into evidence and is not a basis for any of the substantive decisions we have

III. DEU's UPDATED POSITIONS AT HEARING

In its Phase I rebuttal testimony, DEU either accepted certain adjustments or offered alternate proposals and proposed a revised revenue requirement deficiency of $17,523,375.[4] At hearing, DEU accepted other adjustments and offered alternate proposals.

A. Lead-Lag Study Adjustment – Cash Working Capital

DEU's Application included a Lead-Lag Study 2017 ("Study") proposing 7.358 net lag days used for the calculation of cash working capital (CWC). DPU recommended reducing DEU's net lag days to -0.828 days based on certain corrections and adjustments to the Study. DEU agreed with DPU's adjustment. This adjustment would reduce revenue requirement by $1,496,508.

B. Removal of the Audit Fee Accrual

OCS proposed an adjustment to remove audit fees that were charged in the base year that were reimbursed to DEU. In rebuttal, DEU proposed an alternate adjustment that partially removed certain audit fees. At hearing, DEU agreed with OCS's full removal of the audit fee accrual and identified a downward adjustment of $653,263.[5] This adjustment did not account for inflation. For consistency with our decisions in this order, we revised DEU's adjustment to account for inflation (2.5% in 2019 and 2.1% in 2020) and to use OCS's Utah allocation factor. Our revision of DEU's accrual adjustment would reduce revenue requirement by $682,076.

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made in this order. We take administrative notice of the model, though, to assist in our calculations related to our decision points.

[4] Rebuttal Test. of J. Stephenson filed Nov. 14, 2019 (hereafter, "J. Stephenson Rebuttal Test."), and Exhibit 3.9R.

[5] Dec. 17, 2019 Hr'g Tr. at 231:15-20.

C. Removal of Certain Fines from the Test Year

OCS proposed an adjustment related to fines assessed to DEU included in the base year. DEU agreed with this adjustment[6] that would reduce required revenues by $3,702.

D. Property Tax Expense Adjustment Update

OCS recommended an adjustment to property tax expense. In rebuttal, DEU proposed an updated property tax expense amount. After reviewing the updated expense level, OCS withdrew its recommended adjustment. DEU's updated property tax expense would reduce required revenues by $29,162.

E. Operations & Maintenance (O&M) Efficiency Reduction

In direct testimony, UAE proposed an O&M efficiency adjustment of $6.5 million. In rebuttal testimony, DEU updated the amount of savings related to DEU's cost reduction initiative, from $0.5 million to $1.1 million. In surrebuttal testimony, UAE agreed with this adjustment and OCS stated that "[i]f the [PSC] does not adopt my recommendation that the non-labor O&M inflation factors be removed from the rate case model in this case, then … an adjustment should be made to reflect the additional $600,000 reduction to Test Year O&M expense presented in DEU's rebuttal filing."[7] This adjustment would reduce revenue requirement by $601,333.

F. Excess Deferred Income Taxes (EDIT) Adjustments

In response to UAE's and OCS's direct testimony related to EDIT, DEU updated the 2020 plant-related amortization amount, corrected the rate base to reflect the 2018 EDIT

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[6] J. Stephenson Rebuttal Test. at 12:286-290.
[7] Surrebuttal Test. of D. Ramas filed Dec. 5, 2019 at 26:538-542 (hereafter, "D. Ramas Surrebuttal Test.").

amortization from January 2018 through June 2019, and modified its non-plant-related EDIT amortization proposal from 30 years to 12 years. These adjustments would increase revenue requirement by $713,966.

IV. PHASE I: REVENUE REQUIREMENT - DISCUSSION, FINDINGS, & CONCLUSIONS

A. Cost of Capital

For the reasons we discuss in this order, we approve a cost of capital for DEU that we find and conclude to be just and reasonable with a long-term debt ratio of 45%, a common equity ratio of 55%, a weighted average cost of long-term debt of 4.34%, and an allowed ROE of 9.50%. With all of these components, we find and conclude an overall rate of return on capital of 7.178% is just and reasonable.

1. Cost of Long-term Debt

As clarified in its rebuttal testimony, DEU proposes a test year embedded cost of long-term debt of 4.34%.[8] No party in this proceeding contested DEU's evidence supporting that cost of debt, and we find and conclude that the proposal is just and reasonable. We approve a cost of long-term debt for DEU of 4.34%.

2. Return on Equity

DEU testifies that an authorized ROE of 10.5%, within a range of 9.9% to 10.75%, is reasonable. Other parties provide testimony with recommendations between 9% and 9.5%, within ranges of 8.09% to 9.68%, although in some instances those recommendations are

[8] DEU's rebuttal testimony indicated evidentiary support for a 4.37% cost of long-term debt, and no parties in this proceeding contested that evidence. DEU nevertheless maintained its request for a 4.34% cost of long-term debt.

contingent on a specific capital structure. We find and conclude that an authorized ROE of 9.5% is just and reasonable, and we approve that return.

As we consider the various ROE recommendations, we conclude that all the evidence supporting those recommendations is relevant to our task to determine a just and reasonable ROE. To some extent, this task is a delegated legislative function that requires us to consider the evidence and make an ultimate decision exercising judgment and discretion. Our starting point for this evaluation is our most recently approved ROE for DEU.

In February 2014, we reduced DEU's[9] authorized ROE by 50 basis points, from 10.35% to 9.85%. We begin our evaluation by considering the extent to which financial conditions have changed since that decision, and the impact those changed conditions should have on DEU's authorized ROE. Issues that can be viewed as "credit negative" for DEU, potentially leading to an increase in its authorized ROE, include the federal tax reform enacted in late 2017 and the Federal Reserve's cessation of injecting capital into the market.

Conversely, declining U.S. treasury rates since February 2014 could indicate a need to reduce DEU's authorized ROE. DEU's 191 account recovery mechanism, infrastructure rate adjustment mechanism, and Integrity Management Deferred Account all existed prior to 2014, and continue to reduce DEU's financial risk. Our recent approval of DEU's request to construct a liquefied natural gas (LNG) facility also should provide positive financial impacts to DEU. While the facility's completion will not occur until after the test year and it is therefore not included in DEU's rate base, our approval of DEU's application should reduce specific operational risks and ultimately provide financially positive impacts to DEU. Finally, we

[9] For simplicity, this analysis will refer to "DEU" even though in 2014 the utility operated under a different name.

conclude that decarbonization risk is not yet a relevant factor in context of an authorized ROE because the evidence of that risk presented in this docket relates primarily to states with different decarbonization policies than Utah. It is impossible to predict whether decarbonization in Utah will have results including more electrification, or including increased natural gas generation of electricity as coal generating units retire.

As we consider the totality of these high-level issues, we find that a reduction in DEU's authorized ROE is appropriate. We turn next to determining an appropriate size of reduction, first considering the financial models presented in testimony. We find that no single financial model or set of data inputs can conclusively calculate a specific utility's appropriate ROE. Accordingly, there is no conclusive weighting that we can apply to the results of various financial models.

With that in mind, we first evaluate the ROE range of 9.9% to 10.75% in the evidence provided by DEU. We find the usefulness of that model is impeached by outlier inputs, including an input representing a 28.83% growth rate for one utility. While DEU testified to having adjusted the top end of its proposed ROE range to temper an overly high average and median, we find it difficult to rely on that kind of adjustment. The quality of any financial model results depends primarily on the quality of the inputs. Subsequent adjustments to correct for problematic inputs simply reduce the overall quality of the modeling results. Additionally and more intuitively, considering the other evidence related to ROE, it is difficult for us to give credibility to model results that suggest any ROE lower than 9.9% is unreasonable. Accordingly, we find that the ROE range recommended by DEU is not controlling on our authorized ROE.

DPU's and OCS's financial model results support an authorized ROE of 9.5%, although that result is near the top end of the ranges from those model results. The financial model results presented by FEA do not support an authorized ROE of 9.5%; neither do the results presented by ANGC in context of the capital structure ANGC connected to its recommendation.

Considering that range of financial model results, we look to the evidence regarding recently authorized ROE results for other utilities in other jurisdictions. We conclude that this is a relevant consideration, but with some limits in value. Public utilities across the country operate in distinctive regulatory environments, with unique cost recovery mechanisms and other components that make utility and regulatory commission comparisons difficult. Nevertheless, this evidence has some usefulness as we consider it in context of the financial model results. The primary value we see in those decisions from other jurisdictions is that they lead us to find that excessive adjustments to a utility's approved ROE are not positive for the regulatory environment or the utility's credit rating.

FEA provides evidence that regulatory commissions around the country are making gradual downward movements towards what, in FEA's view, is the current market cost of equity. While we have noted the limits of comparing authorized ROE results from other jurisdictions because of the specific differences between utilities and commissions, there is value in identifying trends and the reasons for those trends. We find that the "gradual movement" trend is useful and follows a positive policy objective. Adjustments to an authorized ROE require some element of caution; this caution should lessen the risk of over-recovery, under-recovery, and excessive one-time shifts. We recognize several years have passed since our February 2014 decision, but the reasons for that delay were supported by most parties to this docket, and opposed by none.

Considering all of these factors and exercising the discretion we are required to employ, we find that a 35 basis point reduction in DEU's authorized ROE at this time is just and reasonable. Accordingly, we approve a 9.5% authorized ROE.

3. Capital Structure

Capital structure is invariably tied to authorized ROE. It becomes more relevant as the size of the gap between the cost of long-term debt and the authorized ROE increases. At least one party to this docket plainly linked its authorized ROE and capital structure recommendations. Two concepts, while clichés, are still true in this case: equity is more expensive than debt, and the level of equity impacts the cost of debt.

In January 2019, we approved a stipulation authorizing an equity percentage of total capitalization for DEU up to 55%. DEU, DPU, OCS, and UAE support maintaining that same equity percentage in this docket. FEA and ANGC provide evidence that a lower equity percentage would provide more defensible credit metrics and reflect a more optimal use of capital.

We consider the objections of FEA and ANGC to the proposed capital structure in context of how recently the January 2019 stipulation occurred and the continued support of other parties for the outcome. Utah state policy encourages settlements in public utility regulation,[10] and an important reason for that policy is the durability of consensus decisions. It serves the public interest and the regulatory climate to avoid re-litigating issues unnecessarily. Therefore,

[10] Utah Code Ann. § 54-7-1.

we must consider whether the objections of FEA and ANGC warrant revising the recently stipulated capital structure for DEU.

We conclude that those objections do not warrant a change to DEU's capital structure primarily because of the link between authorized ROE and capital structure. ANGC, in particular, testified to the importance of that link. When we consider how recently we concluded that a capital structure with 55% equity was appropriate in connection with a 9.85% authorized ROE, we now reach the intuitive conclusion that it remains appropriate approximately one year later in connection with a 9.5% ROE. We find that the ROE reduction we have ordered will operate in connection with maintaining the capital structure we approved in January 2019 to produce just and reasonable rates while maintaining DEU's credit metrics at appropriate levels, enabling continued access to capital at reasonable costs. Accordingly, we approve the capital structure proposed by DEU, with a long-term debt ratio of 45% and a common equity ratio of 55%.

B. ITP[11]

Based on the comments from DEU, DPU, OCS, and UAE, we find and conclude that continuing the ITP is in the public interest because it facilitates the needed replacement of aging infrastructure in a manner that encourages a relatively constant amount of investment in between rate cases and allows for a transparent process regarding the work accomplished and the work remaining to be done. In this case, DEU proposes several modifications related to the ITP.

[11] We have previously referred to the ITP as a pilot program. The ITP, including its projected completion timeline, is reviewed regularly and requires approval in every general rate case. Those requirements are not impacted in any substantive way by designating the ITP as a pilot, and we therefore conclude no reason exists to continue that designation.

To the extent DEU incurs spending variance in the annual ITP budget, it proposes to adjust for the variance in the infrastructure replacement surcharge calculation. DEU proposes that in years when ITP spending exceeds the allowed cap, there would be a reduction to the Infrastructure Tracker investment used in the rate base calculation the next time DEU seeks to adjust the surcharge.[12] We find and conclude that DEU's proposal for the treatment of annual ITP budget variances balances the interests of ratepayers and shareholders and provides reporting transparency. Therefore, we approve the change. Additionally, we find and conclude resetting the required ITP reporting date for DEU's master lists[13] from April 30 to June 30 will not impact ratepayers and will improve the ability of regulators to evaluate the program; therefore, we approve DEU's proposal.

DEU has tracked all costs related to replacement infrastructure through the ITP since DEU's last general rate case (GRC) and includes them as part of the revenue requirement it seeks in this case. Therefore, DEU proposes that upon new base rates taking effect, the ITP surcharge will be reset to $0.00.[14] DPU testifies "the costs accounted for in the [ITP] were appropriate and reasonable" and recommends "they be included in general rates for the pending general rate case."[15] We therefore find and conclude that DEU's proposed rate base treatment of past ITP investment amounts is just and reasonable. We also conclude setting the ITP balance to zero is appropriate.

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[12] DEU Exhibit 1.11 provides an example of the treatment of hypothetical budget variances.
[13] DEU's Master Lists provide a snapshot of pipe in service by size, vintage year, and feeder line in the case of its high pressure system, or county in the case of its intermediate high pressure system.
[14] Direct Test. of J. Ipson filed July 1, 2019, Exhibit 5.02 Tariff Rate Schedules in 2.02, 2.03, 2.04, 4.02, 5.02, 5.03, and 5.04.
[15] Direct Test. of J. Einfeldt filed Oct. 17, 2019 at 3:53-59.

DEU proposes to increase the 2020 Test Year annual ITP spending cap to $80 million from the current cap of $72.2 million[16] with future years adjusted for inflation using the GDP Deflator. DPU and OCS both oppose DEU's proposal relating to the annual spending cap but agree that the annual spending cap should include an inflation adjustment.[17] UAE proposes to continue the ITP at a cap of $72.2 million with no provision for future inflation adjustments.[18]

In approving the stipulations that created, and later expanded, the ITP,[19] we adopted their terms as the parties jointly presented them. The stipulation in Docket No. 13-057-05 allowed for the annual spending cap to be reset in a GRC, and both stipulations allowed for inflationary adjustments.[20] In this docket there is no agreement among the parties on the just and reasonable level of spending.

DEU has presented testimony showing that the projected timeline for ITP completion has expanded from 2030 to 2036 under the current ITP cap.[21] DEU also claims steel pipe costs related to ITP construction have increased. DPU counters that steel pipe is only a small portion of the cost of replacing pipe and in support of its position refers to a DEU data request response indicating that materials and supplies are less than 10% of the total cost of ITP replacement.

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[16] Direct Test. of K. Mendenhall filed July 1, 2019 at 22:496 (hereafter, "K. Mendenhall Direct Test.").
[17] *See* Direct Test. of E. Orton filed Oct. 17, 2019 at 11:241-243 (hereafter, "E. Orton Direct Test."); Direct Test. of A. Anderson filed Oct. 17, 2019 at 13:253-264.
[18] UAE Exhibit 1.0, Redacted Direct Test. of K. Higgins filed Oct. 17, 2019 at 25:475-477 (hereafter, "K. Higgins Direct Test.").
[19] *In the Matter of the Application of Questar Gas Company to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 13-057-05 (Report and Order issued Feb. 21, 2014); and *In the Matter of the Application of Questar Gas Company to Increase Distribution Non-Gas Rates and Charges and Make Tariff Modifications*, Docket No. 09-057-16 (Report and Order issued June 3, 2010).
[20] *In the Matter of the Application of Questar Gas Company to Increase Distribution Non-Gas Rates and Charges and Make Tariff Modifications*, Docket No. 09-057-16 (Report and Order issued June 3, 2010 at 21); and *In the Matter of the Application of Questar Gas Company to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 13-057-05 (Report and Order issued Feb. 21, 2014 at 8).
[21] K. Mendenhall Direct Test. at 26:585-590.

Further, DPU and OCS assert that DEU has significant amounts of other funding built into rates to meet its infrastructure needs and that it has an obligation to provide safe service with or without an ITP being in place.

In the absence of the kind of consensus among the parties that has always previously accompanied our approvals of the ITP, we conclude that DEU has not met its burden to prove that we should adjust the 2020 forecasted $72.2 million spending cap amount to $80 million. The evidentiary burden DEU carries is fact dependent, and in this instance the increases in steel pipe costs, a small percentage of total ITP costs, and other cost increases identified by DEU are simply not sufficient evidence to overcome the objections of other parties.

We conclude a spending cap indexed for inflation (by the same GDP deflator index included in the most recent stipulation) balances customer and shareholder interests. Accordingly, we find that a spending cap of $72.2 million is just and reasonable in result and we approve a spending cap at that level. We conclude that indexing that spending cap for inflation (by the same GDP deflator index we approved in the most recent GRC) balances ratepayer interests with the objectives of the ITP. The GDP deflator will continue to be used as an annual index to adjust the cap on an ongoing basis. This decision will be carried forward in the Projected Plant in Service adjustment discussed *infra* at 18-19.

DEU also proposes "[b]ased on an average 2020 test [year], any investment above $82.6 million that is put into service on or after January 1, 2019, should be included in the [ITP]. . . . Additionally, the effective date of an incremental surcharge related to the [ITP] should be set on or after March 1, 2020."[22] DEU's calculation of the $82.6 million value is presented in DEU

[22] K. Mendenhall Direct Test. at 34:805-806.

Exhibit 1.15. No party commented on this issue. We find the date of January 1, 2019 is a typographical error in DEU's application and, consistent with DEU Exhibit 1.15, should be January 1, 2020, the start of the Test Year for this case.

In light of our decision not to increase the ITP spending cap (except for inflation), we have updated DEU's Exhibit 1.15 to reflect that ITP investment above $80.4 million (rather than $82.6 million)[23,24] that is put into service on or after January 1, 2020 should be included in the ITP. We also find that DEU's recommendation that it provide verification in an upcoming proceeding to ensure no ITP costs have been included twice is reasonable because it increases program transparency.[25]

OCS requests we clarify the intent and timing of the prudence review of ITP-related investments and monitor the size and scope of the ITP going forward. We find this request reasonable since the only guidance related to this subject was included in the Stipulation we approved in our June 3, 2010 order in Docket No. 09-057-16.[26] Accordingly, we will soon invite comments in this docket to help refine ITP prudence review procedures.

C. Lead Lag, Cash Working Capital

In accepting DPU's adjustment to its 2017 Lead-Lag Study mentioned above, DEU stated "I believe this factor also addresses the concerns raised by [OCS]."[27] OCS, however, does not agree with DEU's inclusion of depreciation and provision for deferred income tax in the Study because these items do not result in a day-to-day cash outflow, are not representative of DEU's

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[23] Based on a Test Year ITP budget of $72,224,543.
[24] K. Mendenhall Direct Test. Exhibit 1.06, column F, row 7.
[25] K. Mendenhall Direct Test. at 34:814-816.
[26] Stipulation paragraph 17 states: ". . . All items included in the [IT] are subject to regulatory audit consistent with the audit procedures in the "Gas Balancing Account," Tariff Section 2.07. . . ."
[27] J. Stephenson Rebuttal Test. at 5:116-117.

cash working capital needs, and including them in the Study is inconsistent with the PSC's long-standing policy. DEU does not rebut OCS's position.

The introductory paragraph of DEU's Lead-Lag Study states "[t]he purpose of this lead-lag study is to identify the lag days used in calculating the cash working capital component of working capital. Cash working capital is defined as the amount of cash needed on hand by a utility to pay its daily operating expenses for the period between the time it provides services to its customers and the time it receives payment for those services."[28] Considering both this definition and the concerns raised in OCS's testimony, we find depreciation and deferred income tax are not daily operating expenses that should be included in a Lead-Lag Study. Accordingly, we approve OCS's adjustment changing net lag days from -0.828 days to -0.905 days.

D. Transponder Retirements

DEU used certain system-wide average ratios to forecast transponder retirement activity in 2019 and 2020.[29] OCS claims DEU's approach overstates transponder proceeds and dismantlement costs and proposes an adjustment that reduces rate base by approximately $3.6 million. This adjustment is based, in part, on modified Proceeds and Dismantlement factors to account for transponders individually. DEU disagrees with this adjustment in rebuttal testimony. In surrebuttal testimony, OCS proposed a depreciation expense adjustment of $166,263 to further address what OCS considers to be DEU's incorrect booking of transponder dismantling costs as part of the cost of the replacement transponders.

[28] J. Stephenson Direct Test. Exhibit 3.27 at 1.0.1.

[29] These factors are: 1) an end of Test Year *Account 107 – Construction-Work-in-Progress Amount Remaining* ("CWIP") factor; 2) a *Proceeds-to-Retirements* ("Proceeds") factor, which increases the *Account 108 – Accumulated Provision for Depreciation – Gas Plant in Service* amount; and 3) a *Dismantling Costs-to-Retirements* ("Dismantlements") factor, which reduces the *Account 108* amount.

At hearing, DEU accepted the basis for OCS's two adjustments but with one modification. DEU asserted that since OCS's adjustment departs from the average system-wide total factors and accounts for transponders individually, then all three ratios, i.e., dismantlement, proceeds, and CWIP, should be updated in the adjustments, not just the dismantlement and proceeds factors. DEU presented Hearing Exhibit 8 that summarizes the changes. During the hearing, DEU identified inconsistencies in Hearing Exhibit 8 when compared to DEU's Exhibit 3.2R and testified that the forecast transponder spending level for 2020 in Hearing Exhibit 8 should be updated to $4 million.

OCS testified that due to the late filing of the information it did not have sufficient time to review it and asserts its original adjustment is a reasonable means to resolve the problem and to avoid double counting pertaining to dismantlement costs. OCS suggests that based on the new information provided by DEU at hearing it would likely have proposed an even bigger adjustment.

We find that DEU overstated its transponder proceeds and dismantlement costs. We find that regulatory consistency is better satisfied if the adjustment recommended by OCS is accompanied by an adjustment to CWIP. Accordingly, to the extent we have been able to verify the inputs to DEU's Hearing Exhibit 8, we have revised it to reflect DEU's hearing testimony and the full CWIP amount in DEU's model, not the rounded CWIP amount used by DEU. We find both OCS adjustments to accumulated depreciation and depreciation expense, modified to contemplate CWIP, are just and reasonable.

Considering the extent to which this issue involved testimony and a hearing exhibit that evolved during testimony and the hearing, we conclude that transponder accounting should be more transparent going forward. We direct DPU to conduct an audit of the transponder replacement program and file the results with the PSC within one year of completion of the program.

E. Non-Plant-Related EDIT Amortization Period

In rebuttal testimony, DEU revised its proposed non-plant EDIT amortization period from 30 years to 12 years. This adjustment is included in DEU's comprehensive EDIT adjustment presented at hearing and previously discussed in this order. OCS recommends a 5-year non-plant EDIT amortization period and would also support a 3- or 6-year amortization period in alignment with GRC cycles. UAE supports an amortization period of no greater than 10 years.

DEU supports its proposal because: 1) a major portion of the deferred income taxes account balance is tied to pension-related assets, the average remaining service life of which is estimated to be 12 years; 2) the 12-year period mitigates revenue requirement volatility for customers over time (i.e., the magnitude of the decrease in required revenues at the onset of the amortization period, followed by a significant increase in required revenues collected from customers in periods after the amortization amount is exhausted); and 3) the EDIT balance is currently included as a reduction to rate base, thereby fairly compensating customers during the proposed 12-year amortization period.[30] In contrast, both OCS's and UAE's proposals ensure customers are promptly credited with amounts customers have already paid to DEU for future income tax overpayments. OCS and UAE express concerns related to intergenerational equity associated with a lengthy amortization period.

[30] J. Stephenson Rebuttal Test. at 6:127-133.

We find that a 12-year EDIT amortization period balances: 1) promptly returning to customers the excess collected revenues associated with tax reform, 2) the increased volatility that would be associated with a shorter amortization period, and 3) the interest liability associated with the EDIT balance. Accordingly, we approve a non-plant-related EDIT amortization period of 12 years.

F. Projected Plant in Service

DEU's proposed revenue requirement includes a Test Year Capital Budget of approximately $277 million during the test year. DPU asserts the Test Year Capital Budget is excessive and should be reduced by $24,659,381 to accurately reflect the costs DEU is likely to incur for the rate effective period.[31] The $24.7 million reduction includes the $7.8 million reduction related to DEU's ITP budget request discussed above. Similarly, OCS recommends that Test Year capital expenditures be reduced, suggesting a $45.3 million reduction, to be consistent with DEU's 2019 capital expenditure budget level of $232 million.

DPU and OCS point to a disproportionately large Test Year increase when compared to the recent past capital expenditures and the disparity between the 2019 budgeted amounts versus proposed Test Year expenditures.[32] In addition, DPU[33] and OCS[34] assert DEU did not present evidence to justify a Test Year Capital Budget out of line with historic spending amounts.

We find that DEU has not met its evidentiary burden to prove the need for a Test Year Capital Budget of $277 million. This finding is supported by the information in DEU Exhibit

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[31] E. Orton Direct Test. at 17:395-18:405; Surrebuttal Test. of E. Orton filed Dec. 5, 2019 at 4:95-97.
[32] E. Orton Direct Test. at 12:277-13:285. Redacted Direct Test. of D. Ramas filed Oct. 17, 2019 at 8:153-161 (hereafter, "D. Ramas Direct Test.").
[33] E. Orton Direct Test. at 14:306-308.
[34] D. Ramas Direct Test. at 8:162-9:183.

3.1R showing that approximately one-third of DEU's proposed 2020 capital budget, or approximately $90 million, is for unspecified blanket/bucket-type expenditures. Having weighed the information provided in the Application and parties' testimony, we find DEU's capital budget as adjusted by DPU provides an amount sufficient to support DEU's justified capital spending needs. We therefore order and adopt a Test Year Capital Budget of $253,042,850 consistent with the level suggested by DPU.

G. Operations and Maintenance ("O&M") Non-Labor Inflators

DEU applies Global Insight inflation factors to the FERC O&M Expense account in the development of its Test Year information. OCS and UAE propose an adjustment to remove non-labor O&M inflation factors. OCS further proposed that if the PSC does not approve this adjustment "then . . . an adjustment should be made to reflect the additional $600,000 reduction to test year O&M expense presented in DEU's rebuttal filing."[35]

OCS maintains that inflation of base year expenses should be considered on a case by case basis and that it is not reasonable to inflate non-labor O&M expenses in this case "given DEU's history of reducing its O&M expenses coupled with [DEU's] forecast that O&M expenses will be lower in 2020 as compared to 2018 . . . ."[36] In rebuttal, DEU claims there is no reason to conclude that certain efficiency gains will repeat themselves in 2019 and 2020, and that its updated 2020 budget, prepared in the fourth quarter of 2019, is consistent with the amount included in the Test Year.

[35] D. Ramas Surrebuttal Test. at 26:538-542.
[36] D. Ramas Direct Test. at 32:704-706.

We find that DEU has provided sufficient evidence to support its non-labor O&M inflation factors.[37] We find it reasonable that efficiency gains achieved in previous years are not necessarily certain to be repeated in the Test Year, and we find that DEU's 2020 budget supports its proposed non-labor O&M inflation factors. Additionally, we find it a reasonable expectation that DEU will face inflationary risk during the Test Year. Based on the foregoing, we find DEU's non-labor O&M inflation factors in this case are reasonable and we do not order any adjustment to DEU's requested revenue requirement based on this issue.

H. Pension Expense

In its calculation of revenue requirement, DEU includes in the 2018 historical base year an entry of $112.5 million in Other Rate Base Accounts, Account 186-7 – Deferred Pension Asset. DEU then removed all pension-related rate base and expense items from the Test Year, effectively setting the pension expense to $0.[38] According to DEU, in 2017 Dominion Energy, Inc. contributed $75 million to the Questar Gas Company (now Dominion Energy Utah) pension fund. At least partially as a result of this contribution funded by Dominion Energy, Inc. shareholders, DEU has not contributed to the plan in 2017 and 2018, and does not anticipate making cash contributions in the Test Year.

OCS and UAE disagree with DEU's treatment of pension-related costs.[39] OCS proposes the PSC "continue to recognize pension costs in rates based on the long-standing accrual method

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[37] DEU argues these inflation adjustments have been present in Utah customer utility rates since the PSC Order in Docket No. 07-035-93 allowed Rocky Mountain Power the use of such inflators in its case, where the PSC determined non-labor expense inflation adjustments were appropriate in that case.

[38] DEU Exhibit 3.30, Column D lines 1-3 show the elimination of $27.8 million related to the pension portion of ADIT and $112.5 million related to the deferred pension asset, totaling $84.7 million in net rate base. Line 4 shows the elimination of $5.3 million in Utah pension expense credits.

[39] Because we are not ordering a reduction to DEU's pension expense, we do not need to consider DEU's alternate proposal to include the asset in rate base.

of accounting," by reducing Utah's pension expense by $5.4 million.[40] UAE proposes an alternative: adjusting pension expense to $0, as proposed by DEU in this case, on the condition that DEU agrees to exclude any positive or negative pension expense permanently from revenue requirement going forward.

We find that with or without the adjustment proposed by OCS, DEU ratepayers will benefit from the $75 million pension contribution through a lower cost of service.[41] We further find that DEU's proposal to exclude the prepaid pension asset and cancel the Test Year pension expense by setting it to $0 benefits ratepayers by reducing annual costs.

We typically support accrual accounting for pensions, and these findings do not modify that precedent. In this instance, however, given that ratepayers are benefitting from Dominion Energy, Inc.'s $75 million pension contribution, we find DEU's pension adjustment to result in just and reasonable rates. We decline to order the adjustments recommended by OCS and UAE.

I. Professional Services Expenses

DEU's 2018 Base Year Account 193 – Outside Services Expense includes the costs of professional services for assistance in seeking approval of a voluntary resource decision to construct a LNG facility. The Base Year amounts were then escalated to determine Test Year expenses. OCS argues these costs are not reflective of ongoing regulatory costs that would be incurred by DEU on an annual basis. UAE asserts the LNG project relates to supply service, and therefore it is unreasonable to include these LNG project expenses in the DNG revenue requirement.

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[40] D. Ramas Direct Test. at 35:751-44:964. *See also* D. Ramas Surrebuttal Test. at 37:792-797.

[41] This finding is supported by the testimony of DEU. Rebuttal Test. of A. Felsenthal filed Nov. 14, 2019 at 7:169-184.

DEU argues that it will have several large projects during the Test Year that will rely on outside professional services. DEU claims the costs for those professional services are similar to the professional services costs associated with the LNG facility, and that these projects are part of its ongoing distribution operations. When asked at the hearing to identify some specific projects, DEU provided examples including: a project to extend natural gas service to Eureka, Utah; a filing to implement legislatively authorized clean air projects; a new gate station to serve the northern region; and a loop of additional pipeline to serve Southern Utah. DEU clarified that the legal costs associated with the LNG application were expected to be repeated during the Test Year for professional services related to those projects. DEU testified those professional services would include legal work, engineering analysis, and preparation of requests for proposals.

We find that the professional services expenses associated with the LNG facility are a reasonable basis on which to anticipate Test Year professional services costs for the projects anticipated to be in the Test Year. While the LNG facility involved non-typical issues, we find that the estimated professional services are reasonable for the types of projects DEU expects to undertake within the Test Year. Additionally, we find that UAE's concern about the LNG facility not being related to the DNG revenue requirement is not controlling; what is at issue is not the LNG facility itself, but whether the professional services associated with that facility are a reasonable proxy for the DNG-related projects DEU anticipates during the Test Year. While one of the specific projects DEU identified at the hearing, the clean air project, is not a DNG project, we find that DEU has provided sufficient evidence to anticipate DNG-related professional services in the Test Year comparable to the professional services associated with the LNG facility. Accordingly, we decline to order an adjustment based on those professional services costs.

J. Summary of Phase I Decisions on Revenue Requirement

TABLE 1 presents a summary of DEU's revenue requirement deficiency position at hearing, with the exception of any transponder-related adjustments.

TABLE 1. DEU PROPOSED REVENUE REQUIREMENT AT HEARING

Adjustment	**Impact to Proposed Revenue Requirement Deficiency**	**$19,249,740**
Lead-Lag Study Adjustment/Cash Working Capital	($1,496,508)	$17,753,232
Remove Audit Fee Accrual	($682,076)	$17,071,156
Fines Removal	($3,702)	$17,067,454
Property Tax Expense Update	($29,162)	$17,038,292
O&M Eff Update	($601,333)	$16,436,959
EDIT-Related Adjustments	$713,966	$17,150,926
DEU's Position At Hearing		**$17,150,926**

Based on our decisions above, **TABLE 2** presents the effects of our decisions on DEU's requested Utah revenue requirement, as modified. These decisions result in a total revenue requirement increase of $2,680,013. Based on our decisions above, we find this amount is just and reasonable and will enable DEU to provide service to its customers consistent with its responsibilities under Utah Code Ann. § 54-3-1.

TABLE 2. REVENUE REQUIREMENT ADJUSTMENTS

Adjustment	Impact to Proposed Revenue Requirement Deficiency	$17,150,926
ROE = 9.5	($13,218,801)	$3,932,125
CWC adjust to -0.905	($12,989)	$3,919,136
Capital Budget Reduction	($788,962)	$3,130,174
Transponder Accum. Depreciation	($322,280)	$2,807,894
Transponder Depreciation Expense	($127,881)	$2,680,013
Final Revenue Requirement Deficiency		**$2,680,013**

TABLE 3 presents the final capital structure, ROE, and overall rate of return we approve.

TABLE 3. CAPITAL STRUCTURE

	Weight	Cost	Weighted Cost
Long-Term Debt	45.00%	4.34%	1.95%
Short-Term Debt	0.00%	0.00%	0.00%
Common Equity	55.00%	9.50%	5.23%
	100.00%		7.18%

K. Other Issues

1. Tax Reform Surcredit 3

UAE and OCS propose adjustments related to the Tax Reform Surcredit 3 to address amortization of the plant-related EDIT for the period January 1, 2019 through the rate effective date of this case and to correct for the overstatement of the 2018 average rate assumption method (ARAM) amortization. In rebuttal, DEU proposes to extend Surcredit 3 for twelve months, through May 2021, at a level of approximately $3.6 million beginning on June 1, 2020. In surrebuttal, UAE and OCS support DEU's Surcredit 3 proposal. Based on the testimony presented and the parties' agreement to this outcome, we find DEU's Tax Surcredit 3 proposal reasonable and in the public interest. We approve DEU's Tax Surcredit 3 proposal as described in DEU's rebuttal testimony, and order DEU to file a tariff change by May 1, 2020 to implement this change.

2. Plant-Related EDIT Amortization

OCS recommends that DEU defer in a regulatory liability account the difference between the annual amortization of plant-related EDIT included in base rates in this case and the actual annual amortization under the ARAM to ensure ratepayers receive the full amount of EDIT owed to them. OCS asserts DEU's rebuttal testimony was silent on this recommendation. In surrebuttal testimony, OCS recommended the PSC explicitly include this requirement.

We find OCS's recommendation is reasonable to ensure neither DEU nor ratepayers unduly benefit from estimating plant-related EDIT in base rates. We direct DEU to track the difference between the annual amortization of plant-related EDIT included in base rates in this case and the actual annual amortization under the ARAM, and provide this information in the next GRC. However, without comment or support from other parties we decline to approve a regulatory liability at this time.

V. PHASE II: COST ALLOCATION AND RATE DESIGN - DISCUSSION, FINDINGS, & CONCLUSIONS

A. Cost Allocation

1. F230 Allocation Factor

The F230 allocation factor is used to allocate to the customer classes various revenue, expense, and rate base accounts, and is based on a combination of the design day and throughput factors. DEU, UAE, and ANGC propose an F230 allocation factor based on a weighting of 68%

design-day and 32% throughput.[42] OCS proposes a 50% design-day and 50% throughput weighting and FEA proposes a 100% design-day weighting. DPU proposes a 60% design-day and 40% throughput weighting consistent with DEU's original proposal and our historical practice. Modification to the weightings associated with F230 will result in a transfer of cost responsibility between classes.

Among other things, parties testify to the subjective nature of the design-day and throughput weightings for the F230 allocation factor and the resulting reassignment of costs, the lack of empirical analysis supporting a specific distribution of these components, and the likelihood of the occurrence of a design day. Parties also dispute the application of, and inputs used for, the NARUC Gas Distribution Rate Design Manual Average and Peak Demand Method, and the design basis of DEU's system.

We find the 60% / 40% weighting is consistent with past DEU GRC applications and addresses the need for facilities subject to the F230 factor to fulfill two functions: (1) to meet design day requirements, and (2) to move gas to all customers 365 days per year. We find this ratio also recognizes the diversity of use of the system by all customer groups. Recognizing the inherently subjective nature of this factor, we find it reasonable to continue the use of the 60% / 40% ratio.

2. Allocation of General Plant Depreciation

DEU allocates General Plant depreciation expense, Account 403, using its Gross Plant allocation factor. In support of its objective for consistent cost allocation, OCS proposes to allocate General Plant depreciation expense based on the gross plant allocated to classes in the

[42] According to UAE and ANGC, the 32% throughput level is based on DEU's system load factor.

General Plant category, Account Nos. 389-399, matching the depreciation expense with the plant giving rise to the depreciation expense.

While OCS focuses its adjustment on Account 403, we find the same mismatch can be said to exist for the allocation of General Plant-related costs in expense account 408 - Taxes other than Income Taxes and the General Plant components of rate base accounts 108 - Accumulated Provision for Depreciation, 111 - Accumulated Provision for Amortization and Depletion, and 254 - Other Regulatory Liabilities, all of which are allocated on DEU's Gross Plant allocation factor. Without a more comprehensive analysis of the allocation of all General Plant-related accounts, we find it would not be reasonable in this docket to change the allocation of Account 403.

3. Issues Pertaining to Design Day Factor

DEU's Application uses a design day allocation factor that was developed using firm contract demand of its TS and TBF rate classes and the average usage per work day for the NGV class, and assigns the balance to the GS and FS customers. DEU does not include the volumes attributable to interruptible sales (IS) and interruptible transportation ("TSI") customers in its development of the design day allocation factor.

UAE, ANGC, and FEA either agree with or do not oppose DEU's method. DPU and OCS believe the design day factor should be based on actual usage data (i.e., the highest day of natural gas SENDOUT for a year), and that DEU should include interruptible volumes in the development of the peak day allocation factor. Due to the lack of actual peak day data in this case, DPU recommends that DEU use actual peak day data to develop the design day allocation factor in the next GRC. Alternatively, DPU recommends the PSC require DEU to develop and include these data in its next GRC for consideration by parties. OCS recommends revising the design day factor in this case to include volumes from IS customers.

We have considered the variable treatment of the customer classes in DEU's method, the DPU-identified material difference in design day and actual peak day demand, and DPU's testimony that the general industry practice is to rely on actual or weather-adjusted usage in employing a peak allocation factor in class cost of service (CCOS) studies. We find DPU's request for DEU to develop and include actual peak day data, reflecting all rate schedules, in its next GRC filing is reasonable. Daily data is available for certain classes. To address DEU's concern that peak-day data for certain customer classes cannot be measured directly, DEU should develop and apply a method, as it has done in this case, to determine the allocation of the unmeasured volumes based on billing data or measurement studies.[43] To the extent there is disagreement on this issue, we also find it is a reasonable topic for discussion in the cost-of-service and rate design docket we establish in this order.

In this case, DEU does not include interruptible volumes in its calculation of the design day factor. According to DPU, including both IS and TSI volumes in the calculation of this factor in this case would result in an increase in the TS peak-demand allocation factor by approximately 2.5%. We do not find it reasonable in this case to modify the design day factor in a way that will allocate even more costs to classes that will already receive material rate increases. In addition, given the decreasing number of IS customers in the last several years we do not find it reasonable to allocate additional costs to these customers at this time absent further analysis of the value interruptible customers provide DEU's system.

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[43] Direct Test. of A. Summers filed July 1, 2019 at 9 (hereafter, "A. Summers Direct Test.").

If the decisions in this case result in the transfer of a material amount of firm TS contract quantity to interruptible status, we direct DEU through the cost-of-service and rate design docket we establish in this order to develop a cost-based evaluation of the optimum level of interruptible service for DEU's system.

4. Administrative and General (A&G) Expense Allocation

ANGC recommends the PSC require DEU to perform a more detailed assessment of the components of the A&G costs in its next GRC. ANGC argues that, based on the types and magnitude of the costs covered under the A&G category, many of the activities and associated costs covered under Account 923 – Outside Services have no cost-causative relationship to DEU's gross plant investment, and that the Gross Plant factor base data includes not only distribution plant but also production and gathering plant and intangible plant. We find that this issue warrants further evaluation in the cost-of-service and rate design docket we establish in this order, and we direct parties to address it in that docket.

5. Final Revenue Allocation

Our decisions above result in the following revenue spread which we find just and reasonable and conclude it is in the public interest to adopt.

TABLE 4: REVENUE REQUIREMENT SPREAD, COS ALLOCATION

	Forecast Revenues	Full COS Change	Percent Change
GS	$352,657,453	($9,345,658)	-2.7%
FS	$2,730,771	$81,139	3.0%
IS	$188,890	($37,290)	-19.7%
TS	$28,937,712	$11,123,946	38.4%
TBF	$1,592,976	$775,427	48.7%
NGV	$2,649,155	$82,448	3.1%

B. Rate Design

1. GS Class-Related Issues

a. Normal Heating Degree-Day Determination

DEU proposes a 20-year time span used to calculate average Heating Degree Days (HDDs) and forecast volumes rather than its current use of a 30-year span. DEU also proposes to shift the time period used to calculate HDDs to extend through December 31, 2018 rather than the current December 31, 2010. According to DEU, "[u]sing 20 years of data accounts for any recent changes in the weather while also accounting for the possibility of colder weather."[44] DEU states that volumetric rates will be slightly higher using a 20-year period, rather than a 30-year period.[45] Given the size of the revenue requirement change, DPU recommends no changes to the current rate structure components. No party other than DEU offered an evaluation of the use of a 20-year Normalized HDD and the impact of this factor on elements of the Phase II rate design.

We find it is reasonable to select a time period that addresses both stability and the influence of variability in winter temperatures that have become more frequent since 2014.[46,47] We also find value in having a consistent HDD used for all aspects of DEU's ratemaking, planning, and forecasting, including DEU's Integrated Resource Planning and DSM Program. Therefore, we find DEU's request reasonable and approve it.

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[44] A. Summers Direct Test. at 32:851-852.

[45] If the 20-year period is used to calculate the forecasted volumes in this case, there are fewer volumes available to collect the revenue requirement. These volumes are the denominator in the calculation of the volumetric rates. Therefore, the volumetric rates will be slightly higher under the 20-year period than if they were based on the 30-year period.

[46] A. Summers Direct Test. at 32:841-852.

[47] *Id.* at 32:853-860.

b. GS Schedule Block Breaks/Rate Optimization

DEU proposes to decrease the demarcation between the GS rate schedule's first and second blocks from 45 dekatherms ("Dth") to 30 Dth. DPU proposes that DEU defer at this time any revision in usage levels in the GS rate structure for the next GRC. OCS and ANGC recommend the PSC reject DEU's proposed redesign of the GS blocks.

ANGC argues DEU's cost analysis fails to address the impact of variations in customers' peak load contributions and load factors. ANGC recommends the PSC not accept DEU's rate optimization analyses as the cost curves fail to address the impact of variations in customers' peak load contributions and load factors on DEU's costs of serving individual customers. According to ANGC, there is no consideration of the manner in which a customer's cost responsibilities change as the customer's load factor changes.[48]

DEU supports its GS block redesign on the basis that under the current rate structure large GS customers are subsidizing small GS customers, and that rates designed to minimize the squared mean difference between the GS customers' total class cost of service and the revenues designed to collect that total class cost is a reasonable and appropriate means to cure the intra-class subsidy suggested by DEU's analysis.[49]

We find DEU has not provided sufficient evidence to support its proposed GS block redesign. DEU's proposed rate redesign does not include an analysis of the relationship between usage levels and cost responsibility.

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[48] Phase II Direct Test. of B. Oliver filed Nov. 14, 2019 at 32:639-33:659 (hereafter, B. Oliver Phase II Direct Test.").

[49] A. Summers Direct Test. at 27:696-709.

Additionally, in this case, we find DEU has not adequately supported its rate optimization analysis underlying its proposed GS block redesign. For example, we find there is not adequate consideration of the manner in which a customer's cost responsibilities change at differing levels of that customer's load factor. Accordingly, we do not approve DEU's proposed GS block redesign.

c. Conservation Enabling Tariff (CET) Revenue per Customer

Based on our revenue requirement and revenue spread decisions in this order we approve a CET revenue per customer per year amount of $311.64 as follows:

TABLE 5: ALLOWED CET REVENUE PER GS CUSTOMER

MONTH	TOTAL REVENUE	Allowed Revenue Per GS Customer
JAN	$54,324,940	$51.33
FEB	$46,312,927	$43.70
MAR	$38,100,784	$35.86
APR	$22,426,198	$21.10
MAY	$16,736,368	$15.74
JUN	$12,995,718	$12.22
JUL	$11,955,930	$11.26
AUG	$11,853,935	$11.15
SEP	$12,345,791	$11.60
OCT	$18,161,718	$17.01
NOV	$35,142,965	$32.79
DEC	$51,536,753	$47.88
	$331,894,027	**$311.64**

2. Transportation Class-Related Issues

a. Administrative Fee/Customer Charge

DEU proposes reducing the TS customer charge to $3,000 per year ($250 a month).[50] ANGC asserts no administrative charges are needed, and that only a minority of gas utilities have

[50] A. Summers Direct Test. at 29:768-770.

administrative charges for gas transportation service. ANGC claims DEU's proposed (lower) charge is still the highest in the industry. Further, ANGC maintains elements of the costs on which DEU bases its customer charge are inappropriate, unjustified, and often charge customers for services they do not need or want.[51] ANGC proposes to establish separate rates for customers with different usage characteristics.[52]

We find it is reasonable to collect ongoing administrative costs with a monthly charge. We find that DEU's proposed administrative charge and customer charges will collect approximately the amount allocated to the "Customer Function" in DEU's unbundled CCOS Study presented in the "Classification" tab of its rate case model. Based on this evidence establishing the charge as having a cost causation basis, we approve the reduced charge as proposed by DEU.

b. Demand Charge

UAE expresses concerns with DEU's treatment of demand-related costs versus volumetric-related costs within the TS class. UAE maintains the proportion of demand-related costs incurred within the TS class is actually much smaller than the system-wide share. UAE suggests it may be useful to reapportion the demand and volumetric charges in a gradual manner over time in stepped rate increases.[53]

US Mag objects to DEU's proposed demand charge and states if such a charge were approved it would reduce its daily contract quantity with DEU. US Mag asserts other large TS

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[51] C. Chisholm Phase II Direct Test. at 4:88-5:97.
[52] B. Oliver Phase II Direct Test. at 34:697-35:705.
[53] Redacted Phase II Direct Test. of K. Higgins filed Nov. 14, 2019 at 15:279-16:286 (hereafter, "K. Higgins Phase II Direct Test.").

customers may do the same, which could result in significantly higher design day allocations to remaining TS class customers.[54]

ANGC states the demand charge currently employed within the TS rate schedule is not dependent on arbitrary assumptions regarding the relationship between a customer's annual gas use and the customer's load factor to assess the customer's demand cost responsibilities. Therefore, a demand charge is preferable to a minimum usage requirement for the recovery of demand-related costs.[55]

We find that DEU's proposed demand charge will collect the amount allocated to the "Demand Function" in DEU's unbundled CCOS study presented in the "Classification" tab of its rate case model. Accordingly, we find that DEU has provided sufficient evidentiary support for its proposed demand charge. Considering that evidence, we decline to consider alternate rate structures that are not based on the cost of service results. We find DEU's proposal has a cost basis and represents a reasonable cost recovery approach. Therefore, we approve DEU's proposed demand charge.

c. Minimum Use Requirement / Moratorium

In its application, DEU proposed a TS class minimum use requirement of 35,000 Dth per year going forward. In rebuttal, DEU accepted the idea of a time-limited moratorium for new customers set at a threshold of 35,000 Dth. DEU maintains this policy needs to be implemented to stabilize the TS class composition to enable adequate analysis for the next GRC.[56]

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[54] Surrebuttal Test. of R. Swenson filed Jan. 6, 2020 at 2:23-4:75 (hereafter, "R. Swenson Surrebuttal Test.").
[55] B. Oliver Phase II Direct Test. at 46:939-945.
[56] A. Summers Direct Test. at 24-25.

At hearing, DPU stated it could argue either for or against a moratorium.[57] In responding to the initial minimum use proposal, OCS suggests that instead of forcing small transportation service customers to move to a gas sales or bundled rate class, DEU should develop a new transportation rate for service to smaller customers and design it to recover the appropriate level of costs to serve these customers.[58]

US Mag proposes a separate proceeding to address class cost-of-service and rate design issues that will not be resolved in this docket, such as whether to split the TS class into separate classes. How large TS customers react to the proposed rate changes may affect the analysis regarding breaking up the TS class.[59] US Mag asserts making a small TS subclass would be more useful than a minimum use requirement or a moratorium.[60]

ANGC asserts the evidence demonstrates small TS customers are not the primary cause of DEU's claimed under recovery of costs from the TS class. UAE proposes to keep the current transportation class as it is, but offers potential support for a moratorium.[61]

We find the evidence in this docket indicates smaller TS customers are not the primary cause of the TS class's lack of cost recovery. We therefore decline to establish either a minimum usage threshold or impose a moratorium on entry into the TS class because there is an insufficient evidentiary basis for either outcome. Issues associated with the TS class may be further explored in the cost-of-service and rate design docket we establish in this order.

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[57] Jan. 15, 2020 Hr'g Tr. at 189:23-190:6.
[58] Redacted Phase II Direct Test. of J. Daniel filed Nov. 14, 2019 at 22:481-484 (hereafter, "J. Daniel Phase II Direct Test.").
[59] Phase II Direct Test. of R. Swenson filed Nov. 14, 2019 at 6:108-7:115 (hereafter, "R. Swenson Phase II Direct Test.").
[60] R. Swenson Phase II Direct Test. at 8:133-138.
[61] K. Higgins Phase II Direct Test. at 16:302-17:309.

d. TBF Customer Class

In response to information presented in this docket, OCS asserts one of the customers in the TBF customer class should no longer be considered a bypass threat and should take service under a non-discounted rate.[62]

We conclude that whether a given customer qualifies for discounted service at the expense of the rest of DEU's customers is governed by DEU's relevant tariff terms that must be enforced by DEU. If the referenced TBF customer satisfies the relevant conditions, it should be allowed to remain on the TBF rate schedule, otherwise it should be transferred to another appropriate schedule.

Given the testimony from DEU in Phase I of this docket that pipeline construction costs have increased significantly in recent years, we conclude it is reasonable that DEU should review and update its cost evaluation related to the TBF rate in the cost-of-service and rate design docket we establish in this order.

C. Rate Implementation

Due to the size of the TS and TBF rate increases, UAE proposes a set of stepped increases to move the TS and TBF rate classes to full cost of service over time.[63] DEU, DPU, OCS, US Mag, FEA, and ANGC all generally support UAE's asserted need for gradualism in moving the TS and TBF classes to full cost recovery. However, these parties differ with respect to the method of gradualism or the size of the steps and the length of time allowed to remove the inter-class subsidies enjoyed by the TS and TBF rate classes.

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[62] J. Daniel Phase II Direct Test. at 20:434-443.
[63] K. Higgins Phase II Direct Test. at 2:35-37 and 11:204-15:266.

DEU proposes a three-step phase-in of the TS and TBF rate increases, with 25% percent of the TS and TBF rate increases occurring at the effective date of the order, with the second and third steps of 25% and 50% respectively, occurring in connection with DEU's first annual IT applications in both 2020 and 2021.[64]

OCS recommends equal increases of one-third in each of the three steps;[65] DPU agrees with OCS's recommendation.[66] The FEA proposes to limit any class's rate increase to one and one-half times the overall revenue requirement increases yielding a 7.42% cap, with classes that were due to receive a decrease under the full cost standard being held to current rates.[67] US Mag proposes an initial 50% increase followed by a subsequent increase to be determined in another proceeding opened to examine the intra-class subsidy issues in the TS class, and that a final increase should not occur before the spring of 2022.[68] ANGC recommends that UAE's proposed three-step phase-in of the revenue increase should be limited to TBF and large TS customers.[69]

We affirm that moving each class to its full class cost-of-service recovery is in the public interest and the rates we adopt in this case will achieve that end, albeit over the next one and one-half years. It is intuitive that moving the TS and TBF classes to full cost recovery gradually requires other classes to continue to bear some share of the TS and TBF class cost responsibility in the interim. In light of the magnitude of the necessary TS and TBF rate changes, and given that, compared to current rates, the cost burden borne by other classes is small and of relatively

[64] Rebuttal Test. of A. Summers filed Dec. 13, 2019 at 9:212-221 (hereafter, "A. Summers Rebuttal Test.").
[65] Phase II Rebuttal Test. of J. Daniel filed Dec. 13, 2019 at 9:194-200.
[66] Phase II Surrebuttal Test. of H. Lubow filed Jan. 6, 2020 at 4:85-94.
[67] Direct Test. of B. Collins filed Nov. 14, 2019 at 23:7-11 and 24:1-4.
[68] R. Swenson Surrebuttal Test. at 6:116-123.
[69] Rebuttal Test. of B. Oliver filed Dec. 13, 2019 at 26:520-522.

short-term duration, we find that the gradual movement to full cost-of-service TS and TBF rates in this case will serve the public interest.

Given the absence of consensus on the preferred pace of transition to full cost-of-service rates for the TS and TBF classes, we exercise judgement in selecting both the schedule for and amount of the proposed step rate change. We find providing TS and TBF customers time to enter into or leave contracts before the transportation class's rates are set to full class cost-of-service reasonable and in the public interest. Therefore, we conclude a three-step process, over approximately one and one-half years, will reasonably achieve this objective. The first step increase will occur on the rate effective date of this order; the second step will occur at the time of DEU's Fall IT filing in 2020; and the third will occur at the time of DEU's Fall IT filing in 2021. To the extent DEU might not make an IT filing in 2020 based on our decisions in this order, the second step shall be implemented on January 1, 2021. The first step will implement 50% of the rate increase for the TS and TBF classes, with the remaining classes' rate changes adjusted to compensate for it. The second step will be an additional 25% of the TS and TBF rate differential. These first two steps will accomplish the removal of 75% of the rate subsidy within the first year of the rates being effective. The last step will be the removal of the remaining 25% of the intra-class subsidy at the time of DEU's Fall IT filing. We find and conclude that this method, the results of which are presented in Table 6 below, will result in just and reasonable rates, and is in the public interest. The rates and charges reflecting the decisions in this order are presented in Tables 7 and 8, below.

TABLE 6: SPREAD OF REVENUE CHANGE

Rate Schedule	Test Year Revenue	Step 1, March 1, 2020 $ Change	Step 1, March 1, 2020 % Change	Step 2, Fall 2020 $ Change	Step 2, Fall 2020 % Change	Step 3, Fall 2021 $ Change	Step 3, Fall 2021 % Change
GS	$352,657,453	($3,556,450)	-1.0%	($2,894,604)	-0.8%	($2,894,604)	-0.8%
FS	$2,730,771	$227,644	8.3%	($73,253)	-2.7%	($73,253)	-2.7%
IS	$188,890	($37,290)	-19.7%	-	0.0%	-	0.0%
TS	$28,937,712	$5,561,973	19.2%	$2,780,987	9.6%	$2,780,987	9.6%
TBF	$1,592,976	$387,714	24.3%	$193,857	12.2%	$193,857	12.2%
NGV	$2,649,155	$96,421	3.6%	($6,987)	-0.3%	($6,987)	-0.3%
Total	**$388,756,956**	**$2,680,013**					

TABLE 7: MONTHLY FIXED CHARGES

Description	Current Charges	Approved March 1, 2020 Charges	$ Change	% Change
Basic Service Fees:				
GS, FS, IS				
Category 1	$6.75	$6.75	$0	0%
Category 2	$18.25	$18.25	$0	0%
Category 3	$63.50	$63.50	$0	0%
Category 4	$420.25	$420.25	$0	0%
TS, TBF, MT				
Category 1	$6.75	$6.75	$0	0%
Category 2	$18.25	$18.25	$0	0%
Category 3	$63.50	$63.50	$0	0%
Category 4	$420.25	$420.25	$0	0%
Administrative Charges:				
Primary	$375.00	$250.00	-$125.00	-33.3%
Secondary	$187.50	$125.00	-$62.50	-33.3%

TABLE 8: BASE DNG RATES ($/Dth)

		Current Rates * (Eff. 12/2019)	Step 1, Mar 2020	$ Change	Step 2, Fall 2020	$ Change	Step 3, Fall 2021	$ Change
GS, General Service								
Winter								
1st block	0 – 45	$2.71594	$2.70165	($0.01429)	$2.67483	($0.02682)	$2.64801	($0.02682)
2nd block	over 45	$1.55421	$1.49925	($0.05496)	$1.47243	($0.02682)	$1.44561	($0.02682)
Summer								
1st block	0 – 45	$2.00577	$1.99981	($0.00596)	$1.97299	($0.02682)	$1.94617	($0.02682)
2nd block	over 45	$0.84404	$0.79741	($0.04663)	$0.77059	($0.02682)	$0.74377	($0.02682)
FS, Firm Sales								
Winter								
1st block	0 – 200	$1.53127	$1.62356	$0.09229	$1.59674	($0.02682)	$1.56992	($0.02682)
2nd block	201 – 2,000	$1.05655	$1.12611	$0.06956	$1.09929	($0.02682)	$1.07247	($0.02682)
3rd block	over 2,000	$0.55685	$0.60247	$0.04562	$0.57565	($0.02682)	$0.54883	($0.02682)
Summer								
1st block	0 – 200	$1.01054	$1.09175	$0.08121	$1.06493	($0.02682)	$1.03811	($0.02682)
2nd block	201 – 2,000	$0.53582	$0.59430	$0.05848	$0.56748	($0.02682)	$0.54067	($0.02682)
3rd block	over 2,000	$0.03611	$0.07067	$0.03456	$0.04385	($0.02682)	$0.01703	($0.02682)
NGV, Natural Gas Vehicles		$7.17500	$8.17277	$0.99777	$8.14595	($0.02682)	$8.11914	($0.02682)
IS, Interruptible Sales								
1st block	0 – 2,000	$1.46426	$0.91912	($0.54514)	$0.91912	$0.00000	$0.91912	$0.00000
2nd block	2,001 – 20,000	$0.19440	$0.13879	($0.05561)	$0.13879	$0.00000	$0.13879	$0.00000
3rd block	over 20,000	$0.14349	$0.08169	($0.06180)	$0.08169	$0.00000	$0.08169	$0.00000
TBF, Transportation Bypass Firm								
1st block	0 – 10,000	$0.40825	$0.44616	$0.03791	$0.49622	$0.05006	$0.54628	$0.05006
2nd block	10,001 – 122,500	$0.38184	$0.41813	$0.03629	$0.46505	$0.04691	$0.51196	$0.04691
3rd block	122,501 – 600,000	$0.26810	$0.29352	$0.02542	$0.32645	$0.03293	$0.35939	$0.03293
4th block	over 600,000	$0.05721	$0.06309	$0.00588	$0.07017	$0.00708	$0.07725	$0.00708
Demand Charge, monthly**	per Dth	$1.59249	$1.63333	$0.04085	$1.80875	$0.17542	$1.98417	$0.17542
MT, Municipal Transportation								
	per Dth	$0.83020	$0.81601	($0.01419)	$0.81601	$0.00000	$0.81601	$0.00000
TSF & TSI, Transportation Service, Firm & Interruptible								
1st block	0 – 200	$0.79411	$1.01063	$0.21652	$1.09127	$0.08064	$1.17191	$0.08064
2nd block	201 – 2,000	$0.51902	$0.66065	$0.14163	$0.71337	$0.05271	$0.76608	$0.05271
3rd block	2,001 – 100,000	$0.21211	$0.27017	$0.05806	$0.29173	$0.02156	$0.31328	$0.02156
4th block	over 100,000	$0.07861	$0.09999	$0.02138	$0.10797	$0.00798	$0.11595	$0.00798
Demand Charge, monthly**	per Dth TSF volumes	$2.32800	$3.05667	$0.72867	$3.51333	$0.45667	$3.97000	$0.45667

* Base DNG + Infrastructure Rate Adjustment
** Base Demand + Infrastructure Adder

TABLE 9: CET ALLOWED GS DNG STEPWISE REVENUE PER CUSTOMER PER MONTH

Month	Current Rates	Step 1 Mar 2020	$ Change	% Change	Step 2 Fall 2020	$ Change	% Change	Step 3 Fall 2021	$ Change	% Change
January	$49.30	$52.33	$3.03	6.1%	$51.83	($0.50)	-1.0%	$51.33	($0.50)	-1.0%
February	$40.92	$44.51	$3.59	8.8%	$44.10	($0.41)	-0.9%	$43.70	($0.40)	-0.9%
March	$32.81	$36.50	$3.69	11.2%	$36.18	($0.32)	-0.9%	$35.86	($0.32)	-0.9%
April	$20.70	$21.53	$0.83	4.0%	$21.32	($0.21)	-1.0%	$21.10	($0.22)	-1.0%
May	$13.64	$16.00	$2.36	17.3%	$15.87	($0.13)	-0.8%	$15.74	($0.13)	-0.8%
June	$11.62	$12.36	$0.74	6.4%	$12.29	($0.07)	-0.6%	$12.22	($0.07)	-0.6%
July	$11.08	$11.38	$0.30	2.7%	$11.32	($0.06)	-0.5%	$11.26	($0.06)	-0.5%
August	$11.05	$11.26	$0.21	1.9%	$11.20	($0.06)	-0.5%	$11.15	($0.05)	-0.4%
September	$12.79	$11.73	($1.06)	-8.3%	$11.66	($0.07)	-0.6%	$11.60	($0.06)	-0.5%
October	$17.15	$17.31	$0.16	0.9%	$17.16	($0.15)	-0.9%	$17.01	($0.15)	-0.9%
November	$31.67	$33.36	$1.69	5.3%	$33.08	($0.28)	-0.8%	$32.79	($0.29)	-0.9%
December	$44.33	$48.79	$4.46	10.1%	$48.33	($0.46)	-0.9%	$47.88	($0.45)	-0.9%
Total	$297.06	$317.06	$20.00	6.7%	$314.34	($2.72)	-0.9%	$311.64	(2.70)	-0.9%

D. Tariff Issues

DEU proposes numerous changes to its Tariff, housekeeping and otherwise. We address two specific changes below. Other than those changes affected by our decisions in this order, and based on DPU's general concurrence with the changes, and in the absence of any opposition, we find the changes proposed by DEU, including the two discussed below, reasonable and approve them.

1. Allocation of Peak-Hour Costs to Transportation Customers

DEU proposes to charge a portion of the peak-hour SNG contracts to the TS and TBF customers based on the peak-day factor and to collect this charge through a monthly demand charge of $0.11858 per Dth of contracted monthly firm demand. ANGC opposes this charge.

We find that DEU has provided sufficient evidence supporting its proposal through testimony pertaining to uneven load profiles during the day, that transportation-related penalties and procedures are imposed for different reasons than the peak-hour charge, and that DEU has used a peak-hour contract every day this winter.[70] Based on this evidence, we find it is fair and reasonable to allocate a portion of the costs of the peak-hour contracts to the TS and TBF customers. Therefore, we approve the application of a peak-hour charge to the transportation customers as proposed by DEU. The question of whether to apply this charge to the MT and IS customers is an element to be evaluated in the cost-of-service and rate design docket we establish in this order.

[70] A. Summers Rebuttal Test. at 17:415-419.

2. SNG Rate Determination Proceedings

DEU proposes to remove language from the SNG Cost Rate Determination provisions of its Tariff Section 2.06 regarding: 1) a reference to a rate determination procedure established in Docket No. 84-057-07, and 2) obsolete CO2 cost recovery language. DEU proposes to add language to the same Tariff section allowing for SNG rate determinations to be made in proceedings other than a GRC.

In direct testimony, DPU stated it reviewed the Tariff changes and that they are reasonable.[71] At hearing, OCS's counsel stated that based on its review of the proposed SNG Tariff changes, OCS does not oppose the proposed Tariff changes.[72] No other party responded to these proposed changes in testimony or at hearing.

Having reviewed DEU's proposed Tariff changes and testimony, we find it useful and in the public interest to remove obsolete language. Further, allowing additional forums for rate determination does not alter the standards and requirements that would apply to those changes; therefore, there is no harm to the public interest. Accordingly, and given there is no opposition to DEU's proposed text addition providing for the determination of SNG cost rates to be set in both GRCs and other appropriate proceedings, we accept the proposed changes.

3. SNG Cost Allocation Method

DEU proposes a method for allocating SNG costs to be used in the first 191 Account pass-through application after the allocation method is approved. DEU's method addresses cost

[71] Phase II Direct Test. of H. Lubow filed Nov. 14, 2019 at 12:316-317.
[72] Jan. 16, 2020 Hr'g Tr. at 23:7-11.

causation associated with winter contracts and results in different rates for summer/winter use for the GS and FS classes. No party commented on this issue.

We find DEU's method is based on cost causation principles and fairly allocates the costs of seasonal SNG-related contracts to the various rate schedules. Therefore, we approve the method as proposed by DEU to be used in the first pass-through application filed subsequent to this order.

VI. NEW COST-OF-SERVICE AND RATE DESIGN DOCKET

Given parties' desires to bring the whole transportation class to full cost of service in this case and to withhold intra-class subsidy issues until after the rates are determined in this case, US Mag put forth that, in the event the PSC accepts DEU's proposal, that it "address the intra-class subsidy in a new docket."[73]

DEU states in surrebuttal "[t]he only certainty in the current record is that the current TS class is not covering its full cost. . . . There is not sufficient data in the record to show that any particular split of the TS class would be just and reasonable,"[74] that "[f]urther rate design analysis must occur before the [TS] class is split,"[75] and that "if [DEU]'s proposals are approved by the [PSC], the TS class will be moving toward full cost and its makeup will stabilize such that a more detailed analysis can be done."

Moreover, DEU "believes that, given the right guidelines, a collaborative group could effectively study these [TS rate design] issues before the next general rate case."[76] We find that

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[73] R. Swenson Phase II Direct Test. at 7:110-118.
[74] Surrebuttal Test. of A. Summers filed Jan. 6, 2020 at 2:30-33 (hereafter, "A. Summers Surrebuttal Test.").
[75] A. Summers Surrebuttal Test. at 4:81-82.
[76] *Id.* at 4:87-91.

the current posture regarding TS intra-class issues precludes us from making findings requisite to address these issues adequately in this case.

We also find that a separate proceeding following our final order on the rates in this case is an appropriate and reasonable means to evaluate the TS class composition and other cost allocation issues associated with rate classes. It will provide adequate time for study before DEU files its next GRC. Accordingly, we will establish an investigatory proceeding in a new docket shortly after the reconsideration period for this order concludes.

VII. ORDER

Pursuant to our discussion, findings and conclusions:

1. We approve a revenue requirement increase of $2,680,013 allocated to the various customer classes as shown in Table 4.
2. We set the ITP investment level at $72.2 million adjusted annually for inflation and approve DEU's other proposed changes related to the ITP as modified by this order.
3. We approve the extension and modification of the Tax Reform Surcredit 3 as proposed by DEU in rebuttal testimony.
4. We approve the use of HDD's based on a 20-year average as proposed by DEU.
5. We approve a CET revenue per customer amount of $311.64 apportioned as described in this order.
6. The approved revenue increase of $2,680,013 shall be implemented in three steps. The Step 1 increase shall be effective March 1, 2020. The Step

2 increase shall be implemented in 2020, consistent with DEU's Fall IT filing, but no later than December 31, 2020. The Step 3 increase will be in connection with Dominion's Fall IT filing in 2021.

7. We approve the allocation of DEU's peak-hour contracts to Transportation customers and DEU's SNG cost allocation method.

8. DEU shall file appropriate Tariff revisions reflecting the Step 1 through Step 3 rate changes and all other Tariff changes approved herein within 14 days after the date of this Report and Order. The Tariff revisions shall reflect the determinations and the decisions contained in this Report and Order. DPU shall promptly review the Tariff revisions for compliance with this Report and Order.

DATED at Salt Lake City, Utah, this 25th day of February, 2020.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Jordan A. White, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#312230

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this Order by filing a written request with the PSC within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC does not grant a request for review or rehearing within 20 days after the filing of the request, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on February 25, 2020, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Email:

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