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

REDACTED DIRECT TESTIMONY OF

JORDAN K. STEPHENSON

FOR

DOMINION ENERGY UTAH

May 2, 2022

DEU Redacted Exhibit 3.0

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. Jordan K. Stephenson, 333 South State Street, Salt Lake City, Utah 84111.

Q. By whom are you employed and in what capacity?

A. I am employed as a Manager of Regulation for Dominion Energy Utah (DEU). My qualifications are detailed in DEU Exhibit 3.01. I am filing testimony on behalf of DEU ("Dominion Energy," "DEU" or the "Company").

Q. Were the attached DEU Exhibits 3.01 – 3.34 prepared by you or under your direction?

A. The inflation factors shown in DEU Exhibit 3.08 were prepared by Global Insight. All other exhibits were prepared under my direction.

Q. What general areas does your testimony address?

A. My testimony explains how I measured DEU's revenue requirement for this case and why the Company requests to increase its distribution non-gas ("DNG") rates to collect an additional $70.5 million beginning on January 1, 2023. I explain why the proposed test period of the average 13 months ending December 2023 best reflects the conditions that will exist during the rate-effective period. I also address each component of the Company's revenue requirement and the methods used to measure the financial conditions that will exist during the average 2023 test period.

Q. Considering this analysis, what are the major drivers of the proposed rate increase?

A. There are three main factors behind the proposed rate increase. I summarize them here and discuss them in full detail later in my testimony:

1) **The New Liquefied Natural Gas ("LNG") Facility in Magna, Utah ("LNG Facility"):** This case includes the costs of the on-system liquefied natural gas

storage facility discussed in Mr. Mendenhall's testimony. Investment in this facility equates to $218.6 million that is in addition to the ongoing capital investment discussed below.

2) **Ongoing Capital Investment Requirements:** Ongoing capital investment is the lifeblood that sustains a safe, reliable, and growing natural gas distribution system. Each year, the Company must invest a significant amount of capital to address customer growth, replace aging infrastructure, and expand the distribution system to meet system requirements and needs. This investment includes replacement and installation programs for meters and service lines that connect to over a million customers in the state of Utah, intermediate high-pressure and high-pressure mains carrying gas to and through served communities, regulator station replacement and installation programs, vehicles, equipment, and more. Including 2022 and 2023 investment, the Company will have increased the 2023 average gross plant balance by approximately $705.2 million from the 2020 test period level in the last case to address these ongoing activities.

All of this investment ($923.8 million total) results in several types of costs that must be recovered in annual operating revenues. These include depreciation expense, property taxes, and the cost of capital that is made up of debt and equity costs. Holding all else constant, these items would result in approximately a $100 million increase in costs since the last general rate case.[1]

3) **Operating and Maintenance Expenses ("O&M"):** DNG rates currently in effect were designed in Docket No. 19-057-02 in part to recover the expected operating and maintenance expenses in the 2020 test period. Since that time, the Company has seen an increase in both labor and non-labor O&M. DNG rates should

1 This is calculated using the return on rate base (7.18%), average depreciation rates (2.5%), and property tax rates (1.2%) approved in the last general rate case. $923M (7.18% + 2.5% + 1.2%) = $100M. Incremental O&M related to this investment is not included for this high-level analysis but is addressed later in my testimony.

be adjusted to accurately reflect operating conditions during the rate-effective period.

Q. Please summarize the impact of increased operating and maintenance expenses on the 2023 test period.

A. Total adjusted O&M expenses included in rates in the 2020 test period of Docket No. 19-057-02 were $118 million compared to $136 million proposed in this docket for the 2023 test period, an $18 million overall increase over this three-year period. The following table summarizes the sources of this increase (rounding to the nearest million):

O&M for Magna LNG Facility:	$5 million
Labor and Wages–Net of 2019 Early Retirement Program Savings	$6 million
Pipeline Integrity Management Program Increases (Transmission Integrity Management ("TIMP") and Distribution Integrity Management ("DIMP"))	$4 million
Other General Inflation, net of known Savings/Adjustments	$3 million
Total Operating and Maintenance Expense Increase (2020 Test Period to 2023 Test Period)	**$18 million**

Approximately $5 million of the increase is related to the new LNG Facility. Later in my testimony I discuss the proposed treatment of variable electricity costs for liquefaction, but for purposes of this high-level comparison, I am including all LNG Facility costs.

Approximately $6 million of the increase is related to labor and labor overhead expense. In 2019 the Company offered a voluntary retirement incentive program which resulted in a $7 million reduction to labor expense in the 2020 test period. Due to labor market constraints during the COVID-19 pandemic, hiring of new employees slowed significantly from 2020 through the majority of 2021. The Company has since ramped up its rate of hiring and plans for total headcount to reach pre-pandemic levels by the end of 2022. I provide more detail of employee headcount and labor expense later in my testimony.

Approximately $4 million of the increase is related to proposed updates to the annual pipeline integrity management program (TIMP and DIMP) expense accruals. I discuss this item in more detail later in my testimony.

The remaining $3 million increase is caused by inflationary pressures the Company faces across its operations, net of known savings to be realized in 2023 and established regulatory adjustments.

Q. Has your analysis of the 2023 test period conditions also included factors that would reduce the Company's revenue requirement?

A. Yes. While I have highlighted some key upward pressures to the Company's revenue requirement, the 2023 test period also includes some offsetting items that help to mitigate the total required increase.

The Company anticipates a lower weighted average cost of debt in 2023 compared to the 2020 test period, falling from an average of 4.37% to 4.0%. The Company also anticipates the equity percentage of its capital structure to average 53.23% in 2023 compared to the hypothetical 55% used in the 2020 test period. These changes reduce the overall cost of capital and resulting revenue requirement calculation.

I have also included revenue growth in my analysis. Even without the rate increase proposed in this case the Company will collect more revenue through 2023 as new customers tie into the distribution system. While rate recovery from new customers is not designed to recover the full cost of ongoing investment or increasing O&M, the resulting incremental revenues do help to offset the required rate increase in this case.

In addition, increases to rate base will be offset by larger accumulated depreciation and deferred income tax balances that are included as reductions to rate base. I have accounted for growing balances in these accounts which reduce rate base and the revenue requirement in the average 2023 test period.

While this covers some of the highlights that impact the revenue requirement, there are many items that must be considered and included in the analysis of test period conditions. I walk through each item and the methods used to incorporate them into the 2023 test period through the remainder of my testimony. To conclude this high-level summary, after accounting for all the various elements that make up the average 2023 test period, the Company will be operating at a revenue deficiency of $70.5 million. DEU respectfully requests that rates be adjusted to collect this additional amount in this case.

II. BASE AND TEST PERIODS

Q. What base period is the Company proposing to use in this case?

A. The Company proposes to use as the base period the 13-month period ending December 31, 2021. This constitutes the Company's most recent full calendar year of actual revenues, expenses, and rate base balances that will serve as the foundational starting point for the revenue requirement calculation.

Q. What test period is the Company proposing to use in this case?

A. The Company proposes to use as the test period the average 13-month period ending December 31, 2023, supported by a mix of historical activity and 2023 forecasted data. As I discuss later, this test period coincides with and best reflects the conditions that will exist during the rate-effective period beginning in January 2023.

Q. Is the proposed test period consistent with the Utah Public Service Commission's ("Commission") test period requirements found in Section 54-4-4 (3) (a) of the Utah Public Utility Code?

A. Yes. Section 54-4-4(3)(a) provides that, "the Commission shall select a test period that, on the basis of evidence, the Commission finds best reflects conditions that a public utility will encounter during the period when the rates determined by the Commission will be in effect." The Commission may use a future test period based on projected data not exceeding 20 months from the date a proposed rate change is filed. The Company's proposed test period fully complies with this requirement in that it is based on 20 months of projected data from the May 2, 2022 filing date.

Q. How does the 2023 test period compare with the rate-effective period?

A. The test period and the rate-effective period would each take effect on January 1, 2023. While the test period would end on December 31, 2023, the rate-effective period would continue into future years. It is unknown when the rate-effective period will end, but if history is any indication, the rate-effective period could extend to 2026.

During 2023, the two periods will overlap, resulting in a synchronization of utility costs and revenues required to cover those costs. Beyond 2023, the Company would operate at a gradually increasing deficiency for incremental capital investment or expenses not included in revenues from approved rates.[2]

As such, the Company's proposed future test period, using average-year data, is the best possible reflection of the conditions DEU will encounter during the rate-effective period. By contrast, annual data prior to 2023 would not reflect conditions expected to occur during the rate-effective period, let alone thereafter.

Q. Do you think the synchronization of investment, revenues and expenses is an important factor to consider?

A. Yes. Synchronization is an essential part of creating an accurate forecast. There is a direct link between the number of customers served by the system, the revenues generated by the system, and the investment needed to provide service to the Company's customers. As the number of customers rises, the investment needed for the system and the corresponding revenue from those customers also increase. Depreciation expense, property taxes and

2 "Rates" here refers to base DNG rates approved in this case as well as any incremental rate increases from other programs collected in separate rate proceedings, such as the Company's infrastructure tracker programs.

deferred income taxes are also linked to investment. The Company has considered all of these items together to develop a test period that best reflects the conditions that will occur during the rate-effective period.

Q. How have you synchronized the rate base, expenses and revenues?

A. Beginning with December 2021 rate base balances, I projected net plant and other rate base accounts for 2022 and 2023. Rate base changes are largely driven by capital expenditures required to serve new customers in 2022 and 2023 and to maintain the distribution system to continue to safely serve existing customers. This investment in turn enables incremental revenue from new customers and ongoing revenues from existing customers, which have been incorporated into the revenue forecasts for 2022 and 2023. In addition to revenues, this investment also results in incremental and ongoing depreciation expense, property taxes and deferred income taxes. I have incorporated these items into the expense forecasts in 2022 and 2023.

Q. How did you develop the 2023 test period and revenue requirement?

A. In simplified terms, the Company's revenue requirement is calculated by summing up each of the following:

O&M Expenses

Other Operating Expenses (Depreciation, Other Taxes, Income Taxes)

Return on Rate Base (Weighted Average Cost of Capital)

The deficiency, or amount by which revenues should be increased in the test period, is equal to the total revenue requirement less the amount of revenues the utility will collect absent a rate adjustment in this case, adjusted for the income tax and bad debt related to increased revenues.

I have attached a one-page summary of the 2023 test period as DEU Exhibit 3.02. The exhibit is vertically organized into two sections. The top section includes income statement items of revenues and expenses, ending with a net operating income on row 27. The lower section is comprised of rate base balances, with the total rate base shown on row 51.

DEU Exhibit 3.02 is also horizontally organized into several columns. Column B provides unadjusted 2021 base period amounts from the Company's historical financial records. These amounts serve as the foundation for the 2023 test period. Column C shows total adjustments to 2021 revenues, expenses, and rate base to arrive at the anticipated 2023 level. Column D presents the imputed income tax adjustment. Columns B, C and D are added together to calculate the adjusted system total in column E. Finally, I apportioned the amounts to the Utah or Wyoming jurisdiction by direct assignment or by allocation using one of three allocation factors: gross plant, rate base, or gas sales (throughput). The Utah jurisdictional amounts are shown in column F.

Throughout the remainder of my testimony, I explain each component of the revenue requirement shown in DEU Exhibit 3.02 and how the amounts were derived.

III. TEST PERIOD REVENUES

A. Distribution Non-Gas ("DNG") Revenues

Q. Please explain how you have calculated the DNG revenues to arrive at the 2023 test period values.

A. DEU Exhibit 3.02, column B, Row 3 provides historical system DNG revenues booked in the 2021 base period, or $434.4 million. I projected anticipated revenue increases in 2022 and 2023 absent rate relief in this proceeding. I excluded special program revenues (like Energy Efficiency or Sustainable Transportation Energy Plan) from my projection as these are handled through balancing accounts and surcharges in separate rate proceedings.

Revenue increases for the GS class were based on projected customer numbers and the currently allowed revenue-per-customer under the Conservation Enabling Tariff ("CET"). Although the GS revenue amounts are based on the allowed revenue-per-customer under the CET program, I have also forecasted billing determinants for the GS class based on

2022 and 2023 annual usage-per-customer estimates. All other rate class revenues were projected based on anticipated customer numbers and expected volumetric annual usage. DEU Exhibit 3.03 shows the complete revenue detail for 2023.

The increase in revenues through 2023, net of excluded Energy Efficiency and Sustainable Transportation and Energy Plan ("STEP") revenues, is shown in column C, row 3 of DEU Exhibit 3.02. This is added to historical revenues to arrive at the system total revenue amount of $446.9 million (column E), of which $433.4 million is Utah related (column F).

Q. What is the usage-per-customer you used for the test period?

A. The long-term trend of usage-per-customer has been declining over the last few decades. DEU Exhibit 3.04 shows the historical and forecasted use per customer for the GS class in Utah. The table below shows the projected usage-per-customer for 2022 and 2023.

	Usage Per Customer (Dth)	**Change From Prior Year (Dth)**
Historical 12 Months Ended December 2021	98.54	
Projected 12 Months Ended December 2022	98.35	-0.19
Projected 12 Months Ended December 2023	97.11	-1.24

The projected usage-per-customer is 98.35 Dth in 2022 and 97.11 in 2023. These figures are derived from forecasted demand and customer levels within the GS class. Mr. Summers has based his cost allocation and rate design in this docket upon the same forecast. It should be noted that these usage-per-customer numbers for the GS class are higher than the 70 Dths per customer that Mr. Summers uses in his typical residential bill calculation because they include all general service customers, both residential and commercial.

Q. How have you estimated the number of customers for the test period?

A. The estimated 2022 and 2023 customer totals used in this case are based on the Company's updated Integrated Resource Plan forecast that will be filed in June 2022. The updated forecast incorporates contemporaneous and projected economics at the beginning of 2022.

In 2021, the Company experienced total customer growth of 28,019, or 2.58%. The IRP projections show continued growth of 29,408, or 2.64%, customers in 2022 and 26,743, or 2.34%, in 2023. The tapered growth rate in 2023 reflects some slowing in the housing market as housing demand responds to a higher cost environment.

B. General Related Other Revenue

Q. Line 7 of DEU Exhibit 3.02 also is a line item for "General Related Other Revenue" ("Other Revenue"). How does this line item impact the revenue requirement in this case?

A. Other Revenue is made up of revenues the Company receives for activities not directly related to distributing natural gas. For example, these include interest on past due accounts, equipment lease revenues, and capacity release revenues. These revenues reduce the revenue requirement the Company must collect from customers in base distribution-non gas rates.

Q. How did you estimate Other Revenue for the 2023 test period?

A. Other Revenue tends to be consistent from year to year. Because the most recent historical year represents a reasonable expectation for annual revenues going forward, I used the 2021 base period revenue amounts for the 2023 test period revenue requirement calculation. That said, I also adjusted other revenue by $4.9 million to reduce the revenue requirement for the expected Excess Deferred Income Tax accrual during the test period.

C. Excess Deferred Income Tax Adjustment

Q. Please explain this Excess Deferred Income Taxes ("EDIT") adjustment in more detail.

A. The amortization of Excess Deferred Income Taxes impacts both income and rate base accounts each year. These EDIT amounts are the result of the changes in corporate tax rates enacted through H.R.1-An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018 ("2018 Tax Reconciliation

Act"). The income component is passed through to customers as a reduction to the revenue requirement, and I have reflected this benefit by increasing Other Revenue in the test period. As this annual amortization occurs, the EDIT balance included in the 254 account is also reduced accordingly. As approved in Docket No. 19-057-02, Plant-Related EDIT amortization is recognized using the ARAM method while Other Non-Plant Related EDIT is amortized over a 12-year period. Based on this methodology, the Company has included an annual pre-tax EDIT Amortization of $3.823 million, of which $3.709 million is Utah related, as follows:

Description	EDIT Pre-Tax Amortization	Tax Gross Up	Total
EDIT Amortiziation - Plant Protected and Unprotected (ARAM)	2,882,045	946,836	3,828,882
EDIT Amortization - Non-Plant Related (12 Year)	941,175	309,558	1,250,733
Total EDIT Amortization	3,823,220	1,256,394	5,079,614
Description	Utah Pre-Tax Amortization	Utah Gross Up	Utah Total
UT EDIT Amortiziation - Plant Protected and Unprotected (ARAM)	2,795,584	918,431	3,714,015
UT EDIT Amortization - Non-Plant Related (12 Year)	912,940	300,271	1,213,211
UT Total EDIT Amortization	3,708,523	1,218,702	4,927,226

This results in a revenue requirement reduction of $4.927 million in the 2023 test period after grossing up for taxes. Rate base is also adjusted for 2022 and 2023 based on the annual pre-tax amounts.

Q. Is this EDIT adjustment consistent with prior rate case EDIT treatment?

A. Yes. In Docket No. 19-057-02, the annual EDIT amortization benefit was passed to customers as an adjustment to Other Revenue, which resulted in a reduced revenue requirement. The rate base balance in the 254 account was also adjusted accordingly as I have described.

Q. How does the annual EDIT amount in this case compare to historical EDIT amounts and the level approved in Docket No. 19-057-02?

A. Actual pre-tax EDIT amounts for Utah in 2019, 2020, and 2021 were $3.436M, $2.829M, and $3.754M respectively. In Docket No. 19-057-02, the following amounts were approved:

	A	B	C	D	E
Description			EDIT Pre-Tax Amortization	Tax Gross Up	Total
EDIT Amortiziation - Plant Protected and Unprotected (ARAM)			3,124,225	1,027,574	4,151,799
EDIT Amortization - Non-Plant Related (12 Year)			941,175	309,558	1,250,733
Total EDIT Amortization			4,065,400	1,337,132	5,402,532
			Utah Pre-Tax Amortization	Utah Gross Up	Utah Total
EDIT Amortiziation - Plant Protected and Unprotected (ARAM)			3,030,498	996,747	4,027,245
EDIT Amortization - Non-Plant Related (12 Year)			912,940	300,271	1,213,211
Total EDIT Amortization			3,943,438	1,297,018	5,240,456

Q. Seeing that the Company passed more benefit to customers in the last rate case than it realized thereafter, does the Company propose deferring or truing-up any differences in the approved EDIT amortization and the actual EDIT amortization in between rate cases?

A. No. In Docket No. 19-057-02, the Commission ordered that the Company need not defer or true-up differences between the approved EDIT amortization included in the test period and actual EDIT amortization booked or recognized thereafter. Like all costs in a test period, actual activity will likely differ in some degree from what is approved in a general rate case. In the case of these EDIT amortizations, the Company expects differences to be minor. Due to the administrative burden of re-deferring this activity in between rate cases, the Company supports the approved practice of resetting the annual credit amount and corresponding rate base balances in general rate cases without a re-deferral or true-up in between.

IV. TEST PERIOD EXPENSES

Q. DEU Exhibit 3.02, Rows 9 – 13 show historical gas purchase expenses, but these expenses are not included in the test period column (column F). Why have these expenses been excluded?

A. These expenses are incurred to purchase natural gas supplies and transport those supplies to a Company receipt point. Because these types of costs are recovered through the Company's Gas Balancing Account Adjustment Provision detailed in Section 2.06 of the Company's Utah Natural Gas Tariff No. 500 ("Pass-Through Account"), I have excluded them from the test period calculation in this case.

A. Operating and Maintenance Expenses

Q. Please summarize what the Company is including in the test period for operating and maintenance ("O&M") expenses.

A. As shown in column B, line 20 of DEU Exhibit 3.02, the Company recognized a total of $144.6 million in O&M during the base period of 2021. This amount includes Energy Efficiency and STEP O&M expense. I have taken a series of steps to adjust historical O&M to a total of $136.4 million for the 2023 test period, as shown in Column F, as follows:

- I took the historical, unadjusted 2021 expenses and factored in the cost of inflation to reflect expected levels of expense by FERC account.
- I added new annual O&M expense for the LNG Facility.
- I removed non-applicable expenses that are handled in separate dockets – specifically Energy Efficiency and STEP program expenses.
- I made several other established regulatory adjustments from prior rate cases.

Q. What approach did you use to inflate historical, unadjusted O&M expenses to the appropriate test period O&M level?

A. I followed the same methodology used in the Company's prior general rate case. First, I separated base period O&M into labor and non-labor categories. I then forecasted labor and non-labor expenses separately to arrive at the unadjusted 2023 test period O&M amount. DEU Exhibit 3.05 page 1 provides total unadjusted O&M by Federal Energy Regulatory Commission ("FERC") account for the 2021 base period, 2022 forecast, and 2023 forecasted test period. DEU Exhibit 3.05 page 2 shows the 2023 test period O&M categorized by labor and non-labor expense for each FERC account. Labor and labor overhead make up a total of $77.7 million in unadjusted O&M expense (DEU Exhibit 3.05, page 2, column A, line 53), while non-labor O&M expenses make up the remaining $74.5 million.

Q. How did you forecast the labor and labor overhead O&M expenses?

A. Projected amounts for labor and labor overhead O&M expenses were based on the percentage increase the Company expects to pay for labor and labor overhead in 2022 and 2023 as calculated and shown in DEU Exhibit 3.06. Total forecasted labor expense is driven primarily by employee headcount. The Company is currently backfilling positions after offering an early retirement incentive in 2019 and experiencing hiring constraints in 2020-2021 during the COVID-19 pandemic. Overall labor expense in 2022 is expected to increase as the Company restores employee headcount to pre-pandemic levels. In 2023, the Company plans to maintain projected 2022 headcount with an approximate 3% increase in wages.

Q. Can you please provide more detail on the impact of the 2019 early retirement incentive and hiring constraints during the COVID-19 pandemic?

A. Yes. As shown in DEU Exhibit 3.07, from January 2019 to January 2020, total headcount fell by 95, from 935 to 840. This large decline was a direct result of the early retirement incentive announced in 2019. As a result of this retirement incentive, the Company reduced labor expenses by $7.2 million in the 2020 test period of Docket No. 19-057-02, passing on the savings to customers in base rates currently in effect.

Following this decrease, in 2020, the hiring slowed significantly due to challenges created by the COVID-19 pandemic. These challenges continued through most of 2021. Total employee count grew from 840 to just 842 by December 2020. The lag in backfilling positions lasted through the majority of 2021.

In Q4 of 2021, the Company was able to increase its rate of hiring and ended the year with an overall increase of 11 employees. This backfilling effort has continued into 2022, and through March 2022, the Company had reached a total employee count of 878. The Company plans to end the year at 927 total employees. This total is included in the labor forecast in this case through 2023.

While actual year-to-year labor expense has been volatile since the last rate case due to these circumstances, it can be helpful to compare the total change over three years from the 2020 test period currently in rates to the proposed 2023 test period amount. After accounting for the early retirement savings, LNG Facility labor, and the exclusions of the pension credit and employee financial incentives which are removed from total expense in separate adjustments, the difference between the 2023 and 2020 test period labor equates to $1.28 million, or a three-year average increase of 0.50% per year. This is summarized in the following table:

Test Period Labor Reconciliation			
	2020 Test Period		**2023 Test Period**
Unadjusted Expense	$88,275,734		$78,420,591
Retirement Savings	-$7,154,145		$0
LNG Facility Labor	$0		$1,081,013
Remove Pension Credit (Reg. Adj)	$5,448,127		$10,044,611
Financial Incentive Adjustment (Reg. Adj)	-$1,301,370		-$2,997,153
Labor Expense Included in Test Period	$85,268,346		$86,549,062
3-year Change			$1,280,716
Total 3-year % Increase			1.50%
Average Annual Increase (3 Years)			0.50%

Q. How did you forecast the non-labor O&M expenses, excluding the LNG Facility?

A. The basis for the forecasted non-labor O&M expenses was the historical O&M expenses from January 2021 through December 2021. I increased or decreased the historical expenses using the 2021 inflation factors from the Global Insight Power Planner report attached as DEU Exhibit 3.08. These inflation factors and the resulting non-labor expense are shown in DEU Exhibit 3.09. DEU Exhibit 3.09 Column C shows total projected expenses from January through December of 2022 after inflation. I then increased or decreased these 2022 expenses using the Global Insight inflation factors for 2023 (Column D) to calculate the total 2023 expenses (column E). As shown on row 59, I have reduced inflation adjusted expenses by $250,000 related to cost saving initiatives that have been identified by the Company. The 2023 non-labor O&M expense is shown in column E, row 60.

Q. Has the Company previously followed these steps to forecast future period O&M?

A. Yes. The approach I have outlined has been used in several of the Company's prior general rate cases, including the most recent rate case Docket No. 19-057-02. In addition, the Company uses this approach in forecasted results of operations models that are filed annually with the Public Service Commission. I have compiled forecasted O&M from these models over the past five years compared to the actual O&M for the same period in DEU

Exhibit 3.17. As shown, actual O&M has been within +/- 1% of forecasted amounts on average, showing that this is a reasonable methodology to estimate test period conditions.

Q. How did you treat non-labor O&M for the new LNG Facility?

A. I added a total of $3.83 million of non-labor O&M expense to the 2023 test period. This consists of several components that are summarized in DEU Exhibit 3.10 and includes variable electric costs as well as fixed O&M costs for rented vehicles and equipment, outside services, insurance, and other general and administrative costs.

Q. Does the Company believe that variable costs of electricity and natural gas used to inject and vaporize the LNG should be included in its Pass-Through Account?

A. Yes. As shown on lines 2-3 of DEU Exhibit 3.10, the variable O&M consists of electricity costs totaling $2.1 million and gas costs totaling $270,000 in 2023. These are costs that will fluctuate with the liquefaction and vaporization of natural gas for storage in the LNG tank.

The $270,000 gas portion of this cost will be handled the same as any natural gas that the Company uses or consumes in its own operations. The cost of the gas itself is included in all gas supply costs when the gas is procured. As such, it will automatically flow through the Pass-Through Account. When the gas is used by the Company and thus booked as an O&M expense, that expense must be removed, or credited, out of the test period. This credit is booked to the 810 and 812 FERC accounts. I have credited the $270,000 in gas costs to the 812 accounts, resulting in no O&M impact of the gas costs in the test period.

Related to the variable electricity costs totaling $2.1 million, the Company believes that this category of costs should be collected through the Pass-Through Account due to the nature of these costs being directly tied to storing gas supply and due to the fact that they will be highly variable from year to year. The Company will request that these costs be collected in its next Pass-Through Account filing in June, and, if approved, these costs will be removed from the test period in this case.

Q. Please summarize how much total O&M expense is included in the 2023 test period related to the LNG Facility.

A. Including the non-labor O&M items discussed above as well as the labor expense discussed previously, total LNG O&M expense included in the test period can be summarized as follows:

Labor Expense	$1,081,013
Variable Electric Costs	$2,131,234
Fixed O&M	$1,703,130
Total LNG O&M Included in 2023 Test Period	**$4,915,377**

If the Commission approves Pass-Through Account treatment of variable electric costs in a separate Pass-Through Account docket, the total amount included in the 2023 Test Period in this docket should be reduced to from $4,915,377 to $2,784,143.

Q. You mentioned previously that you also removed non-applicable expenses that are handled in separate dockets – specifically Energy Efficiency and STEP program expenses. Can you summarize this adjustment?

A. Yes. The Energy Efficiency and STEP program revenues are collected from customers through the demand-side-management and STEP amortization rates. When revenues are collected, an offsetting expense is made to the 908007 expense account. *See* Dominion Energy Utah's Utah Natural Gas Tariff No. 500 ("Tariff") Sections 2.09 and 2.18. These revenues are not collected through DNG rates and are not included in the 2023 projected revenue calculation. Therefore, the 2023 Energy Efficiency and STEP expenses should be removed as well. DEU Exhibit 3.11, line 13, shows the removal of these expenses.

Q. You also mentioned a series of additional adjustments based on prior rate cases. Can you specify what those adjustments are?

A. Yes. Consistent with orders in prior rate cases, I have adjusted test period O&M expense in the following ways:

- Bad debt expense adjusted to a three-year average of DNG-related bad debt.
- Incentive Compensation adjusted to remove financial-related incentives tied to earnings targets.
- As part of a dues and donations adjustment, government relations expenses removed.
- Reserve accrual adjusted to a five-year average payout amount.
- Pipeline Integrity Management Expense adjusted.
- Pension related items removed.

Q. Please explain the adjustment for bad-debt expense.

A. Bad debt expense is broken out into three components: bad debt related to DNG revenue, bad debt related to supplier non-gas revenue, and bad debt related to commodity revenue. To adjust for bad debt expense, I annualized the DNG portion of bad-debt expense forecasted to occur for the 12 months ended December 2023 to the 3-year average level of bad-debt expense. The Division of Public Utilities originally proposed this methodology in the Company's 1995 general rate case[3], and it has been the approach used in each general rate case since, including the most recent in Docket No. 19-052-02.

The calculation of this adjustment is shown on DEU Exhibit 3.12, lines 11 through 38. I divided net charge-offs for each year (line 20) by booked system revenues (line 19) to calculate a bad-debt ratio (line 22). I then used the resulting ratios of 0.25%, 0.17% and 0.17% for 2019, 2020 and 2021, respectively, to calculate the three-year average of 0.20% in column H, line 24. I then calculated the allowed DNG related bad debt in column H, lines 26-38. After doing this, I multiplied Test-Period Utah DNG revenue of $459,479,386

3 Docket No. 95-057-02

(line 26) by the adjusted three-year average of 0.20% (line 28) to calculate an allowed Utah DNG bad debt of $908,323 (line 29). The base-period system Utah DNG bad-debt expense is -$187,116 (line 32). The base-period bad debt expense is based on booked 2021 bad debt. The resulting adjustment is an increase to Utah expenses of $1,095,439 (line 36).

In addition to adjusting the DNG portion of bad debt as described above, I also removed the bad debt related to supplier non-gas shown on line 7 and commodity revenue on line 8 because they are accounted for in the Pass-Through Account.

Q. Please explain the incentive compensation adjustment.

A. In accordance with previous Commission orders in Docket Nos. 93-057-01, 95-057-02, 99-057-20 and 02-057-02, Dominion Energy has removed, for ratemaking purposes, incentive-compensation expenses related to net-income, earnings-per-share, and return-on-equity goals either paid directly by Dominion Energy or allocated from Dominion Energy Services, Inc.[4] ("DES") for incentive payouts. In these dockets, the Commission allowed incentives paid based on operating goals. This adjustment involves three steps. First, the total 2021 incentive payout is allocated to Dominion Energy Utah. Next, the total income-related percentage of the incentive payout is calculated separately for officers, management, and non-management employees. This can be seen on page 1 of DEU Exhibit 3.13. The payout related to financial based goals was 85% for officers, 35% for DES and DEU management, and 25% for DES and DEU non-management employees (rows 11 and 12). The expense amounts allocated to Dominion Energy Utah were then multiplied by the percentages related to income goals to derive the total incentive payments to exclude from the revenue requirement calculation. Finally, as shown on page 2 of DEU Exhibit 3.13, the incentive amounts were adjusted for inflation to arrive at the total amount removed from the revenue requirement of $2.997 million (Column D, row 5). The Utah portion is shown in column D, row 6.

4 Dominion Energy Services, Inc. houses certain corporate services shared across all Dominion Energy affiliates. These shared services include accounting, finance, legal, HR, IT, and regulatory. Prior to the 2016 merger with Dominion Energy, many of these services were allocated to Questar Gas Company in similar fashion from Questar Corporation.

Q. Please explain the governmental affairs adjustment for dues and donation.

A. In the order in Docket No. 93-057-01, the Commission prescribed the types of donations and memberships that are recoverable in rates. In the 2021 base period, the Company was allocated a total expense of $176,631 from Dominion Energy Services for government relations labor, overhead, and administrative and general (A&G) expense. I updated this amount for inflation and removed it from 2023 expenses, as shown in DEU Exhibit 3.14, page 1, line 5.

Q. Please explain the insurance reserve accrual adjustment.

A. The reserve accrual includes legal liabilities associated with the Company's self-insurance program. In Docket No. 07-057-13, the Commission approved a stipulation of the parties that the allowed reserve accrual amount was to be based on the five-year average of actual payments made by the Company. Line 7 of DEU Exhibit 3.15 shows the five-year average, and line 8 reflects the actual accruals made, adjusted for inflation. The adjustment on line 9 increases expense by $338,560 for the 2023 test period amount.

Q. Please provide the background on the pipeline integrity expense.

A. On April 21, 2004, in Docket No. 04-057-03, Dominion Energy filed with the Commission an application for a deferral accounting order authorizing it to establish an account for costs the Company would incur to remain in compliance with the new federal requirements of the Pipeline Safety Improvement Act of 2002, and the Final Rule regarding "Pipeline Integrity Management in High Consequence Areas." On June 24, 2004, the Commission approved the application and authorized Dominion Energy to defer the incremental gas transmission line safety compliance costs incurred on or after January 1, 2004. On June 1, 2006 in Docket No. 05-057-T01, the Commission approved the Settlement Stipulation that allowed Dominion Energy to begin expensing a fixed amount of pipeline integrity costs. In Docket Nos. 07-057-13, 09-057-16, and 13-057-05, the Commission approved continued recovery of transmission integrity management costs.

Q. Please explain what the distribution integrity management program ("DIMP") costs are and how they are treated?

A. In Docket No. 09-057-16, the Commission approved a stipulation allowing for the deferral of the Company's DIMP costs.

The Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the Department of Transportation ("DOT") have published a rule establishing integrity management requirements for gas distribution pipeline systems. Like the Federal Pipeline Safety Regulations, this rule requires operators of gas distribution pipelines to develop and implement integrity management programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. The integrity management programs required by the rule are similar to those currently required for gas transmission pipelines, but tailored to reflect the differences in and among distribution systems. The final DIMP rule was published on December 4, 2009 and became effective February 12, 2010. Like the 2002 Pipeline Safety Act, the DIMP was federally mandated and has resulted in incremental costs.

Q. Please summarize the proposed pipeline integrity expenses going forward?

A. The following table summarizes the Company's proposal compared to the approved 2020 amounts:

		Previously Approved Docket No. 19-057-02	**Proposal**	**Change**
1	Pipeline Integrity Expense	$7,163,307	$9,431,582	$2,268,275
2	Amortization Amount	$899,499	$2,645,601	$1,746,102
3	Total	$8,062,806	$12,077,183	$4,014,377

The first row shows the amount related to ongoing annual pipeline integrity expense. The proposed amount is based on the actual pipeline integrity costs incurred in 2021. As shown in the far-right column, actual costs in 2021 were $2.268 million higher than the amount currently approved related to ongoing annual expenses. When actual costs exceed the allowed annual expense, the difference is added to total pipeline integrity costs deferred. As of December 2021, the deferred balance was $7,936,804. I am proposing that this balance be amortized over a three-year period, resulting in a $2,645,601 amortization per year, for an increase of $1,746,102, as shown on row 2. The net effect of this change results in a $4.01 million increase to pipeline integrity expense.

Q. What will be the accounting treatment if the Company does not incur the full amount of ongoing expenses in a given year?

A. To the extent actual ongoing expenses are less than $9.431 million per year, the difference will continue to be credited to the deferred account[5]. To the extent actual ongoing expenses are greater than $9.431 million, the difference will continue to be debited to the deferred account.

Q. Is the Company proposing changes to the way Pension related activity is treated in the revenue requirement?

A. No. In Docket No. 19-057-02, the Commission approved the exclusion of certain pension-related items from the Company's revenue requirement. This includes the pension asset in account 186, the pension-related deferred income tax amount in account 282, and the corresponding pension credit in O&M expense. I have removed these items from the 2023 test period. The total adjustments are shown in DEU Exhibit 3.16.

Q. Did you make any additional adjustments to test period expense that have not yet been discussed?

A. No. I would like to note that in prior cases the Company has adjusted expenses for sporting event tickets and advertising. I'd like to briefly explain each of these.

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5 In Docket No. 04-057-03, the Commission approved the application and authorized Dominion Energy to defer the incremental gas transmission line safety compliance costs incurred on or after January 1, 2004. In Docket No. 09-057-16, the Commission approved a stipulation allowing for the deferral of the Company's DIMP costs.

Pursuant to the Commission order in Docket No. 99-057-20, the Company has historically removed from its test period the portion of expense for sporting event tickets that are not used for employee recognition. In 2021, the Company did not incur any expense for sporting event tickets and as such no adjustment was necessary in this expense category. The Company has also not included any expenses for sporting events in the test period.

Related to advertising expenses, consistent with the Commission order in Docket No. 93-057-01, and in general rate cases since 1993, the Company has consistently decreased expenses in the test period by removing advertising expenses related to promotional and institutional advertising. In the 2021 base period, there was no promotional or institutional advertising expense incurred by DEU or allocated to DEU from its parent Company. As a result there were no promotional or institutional advertising expenses in the test period. no adjustment was necessary.

B. Other Operating Expenses

Q. Returning to DEU Exhibit 3.02, row 22 includes depreciation, depletion, and amortization expense. Is the Company recommending changes to the depreciation rates in this case?

A. No. In the Revenue Requirement Stipulation in Docket No. 07-057-13, the Company agreed to perform a new depreciation study every five years on a going-forward basis. The depreciation study approved in Docket No. 19-057-02 is within this five-year window and the Company is not proposing a change at this time. The Company has calculated the depreciation expense in this case using approved depreciation rates. The Company plans to perform its next depreciation study in 2023 based on 2022 data and include any necessary changes from that study in its following general rate case.

Q. How did you forecast depreciation expense in this docket?

A. I adjusted the base 2021 depreciation expense to the anticipated depreciation expense that will be incurred in 2023 based on changing plant in service. A summary of the depreciation calculation is shown in DEU Exhibit 3.18. Column A reflects the cost basis of each FERC account during 2023. I depreciated each account using current depreciation rates shown in column B. Column C reflects the resulting depreciation expense. This includes an increase in depreciation expense caused by the LNG plant using the depreciation rate included in Docket No. 19-057-13.

Q. DEU Exhibit 3.02 row 23 includes Taxes Other Than Income Taxes. How did the Company forecast Taxes Other Than Income Taxes?

A. The detail for this forecast is shown in DEU Exhibit 3.19. Total other taxes for 2023 are expected to be approximately $5.9 million higher than the 2020 period amounts due mainly to an increase in property taxes (line 1). Dominion Energy's assessed property valuation has increased due to increased capital additions. Other taxes in this category include gross receipts taxes, payroll taxes, and utility revenue franchise taxes, as shown on rows 2 through 4. In total, the 2023 test period includes $35.7M for taxes other than income taxes (row 6).

Q. DEU Exhibit 3.02 row 24 includes Income Taxes. How are test period income taxes calculated?

A. Consistent with prior rate case dockets, I have imputed the appropriate income tax amount based on current state and federal income tax rates. DEU Exhibit 3.20 shows three methods the Company has consistently utilized to calculate the appropriate income tax amount to collect in the revenue requirement. The three methods are the algebraic method, the rate base method, and the operating income method. Each of the three methods result in an imputed income tax of $28.6 million for the 2023 test period.

V. TEST PERIOD RATE BASE

A. Net Plant-in-Service

Q. DEU Exhibit 3.02, rows 29 – 36 provide net plant balances. Please explain how this portion of rate base was projected for the test period.

A. I calculated the projected Gas Plant in Service (Accounts 101/106) balances starting with actual December 2021 balances (DEU Exhibit 3.21, column A), as this is the most recently available actual annual data. I then added the net 2022 capital additions (column B) to calculate the projected December 2022 balance (column C). I then added the 2023 net additions (column D) to the December 2022 balance to calculate the December 2023 balance (column E).

DEU Exhibit 3.22 page 1 shows the calculation of the net additions for 2022. I took the $359 million capital budget by FERC account for 2022 (DEU Exhibit 3.22, page 1, column A), and I removed the retirements expected to occur during 2022 (column B). Last, I added the amounts in the Construction Work in Progress (Account 107) and Completed Construction Not Classified (Account 106) at the end of 2021 that will be closed in 2022 (column C) and removed the 2022 expenditures expected to be in Construction Work in Progress at the end of the year (column D). The sum of columns A through D is the 2022 net additions, shown in column E. After doing this, I added the 2022 net additions to the 2021 plant balances by FERC account to arrive at a December 2022 balance. I took the same steps in DEU Exhibit 3.22, page 2, columns A through E, to arrive at December 31, 2023 Gas Plant in Service balances.

I have also projected that the Accumulated Depreciation/Amortization (Accounts 108 and 111) will increase by $150.4 million between December 2021 and December 2023 resulting in an ending balance of $1.06 billion for the test year (DEU Exhibit 3.23, column E, line 12). This increase is due primarily to annual depreciation expense, which increases each year as plant-in-service increases. I have also adjusted the 108 account balance for anticipated retirements, proceeds, and dismantling activity through 2023. Account 254 –

Other Regulatory Liabilities has amounts associated with depreciation expense of future removal costs and will also change as assets are depreciated. The total depreciation expense booked to the 254 account is shown on line 11 of DEU Exhibit 3.23.

Q. How did you estimate the impact of retirements, proceeds, and dismantling costs in the 108 account?

A. For retirements, I used the 2021 base period amounts as an estimate for ongoing annual retirements to occur in 2022 and 2023. Proceeds and dismantling, or net salvage, and are related to retirements. To estimate proceeds and dismantling amounts, I calculated a three-year average ratio over total retirement dollars from 2019 through 2021. I then applied that ratio to the anticipated 2022 and 2023 retirement dollars to derive estimated proceeds and dismantling costs.

Q. The Company recently completed the replacement of meter transponders across its service territory. Did you account for the completion of this program in your 2022 and 2023 projection for retirements, proceeds, and dismantling?

A. Yes. Because the transponder replacement program is complete, I have removed transponder retirements, proceeds, and dismantling from the calculation of future proceeds and dismantling costs. The following schedule summarizes this calculation:

2019 - 2021 Transponder Retirement Amount	46,395,000
2019 - 2021 Transponder Proceeds Amount	0
2019 - 2021 Transponder Dismantling Amount	4,435,543
2019 - 2021 Retirement Total (Excl. Transponder)	45,865,632.95
2019 - 2021 Proceeds Total (Excl. Transponder)	(999,561.20)
2019 - 2021 Dismantling Total (Excl. Transponder)	13,107,237.91
3 Year % Proceeds	-2.18%
3 Year % Dismantling	28.58%

The Company booked $12.6 million in retirements in 2021. This is the amount of retirements I am estimating for 2022 and 2023. For proceeds, I used the three-year average ratio of -2.18% of retirements calculated in the table above to estimate proceeds for 2022 and 2023, which equates to -$274,668 each year ($12.6M X -2.18%). I repeated this calculation for dismantling as well to derive $3,601,721 each year ($12.6M X 28.58%).

Q. You stated that you used the capital budget to forecast the plant for the year ended December 2023. How accurate have the Company's capital budget forecasts been in the past?

A. DEU Exhibit 3.24 shows the capital budget for the last five years compared to actual expenditures. As shown on line 6 of the exhibit, actual capital expenditures have been within +/- 1% of budget amounts on average, demonstrating that the Company's capital budget is very accurate.

Q. What type of activity makes up the capital budgets in 2022 and 2023?

A. DEU Exhibit 3.25 provides a high-level capital budget summary for 2022 and 2023. DEU Exhibit 3.26 provides a detailed schedule of capital projects. A large portion of the capital budgets is made up of ongoing required programs. These include items such as new or replaced mains, service lines, risers (the connection from a service line to a meter), valves and meters. With over one million customers and a sprawling network of mains and services spread across the state, many of these capital activities are not specified to individual projects or customers, but are rather tracked as a program with total costs in a year budgeted using historical data, expected customer growth, and consultation with procurement, construction managers, etc.

In the past rate case, some capital project schedules included the term "bucket" or "blanket". This may have caused some confusion because such terminology erroneously suggests that these were placeholder line-items in the budget without a specific purpose. This is not the case. These are ongoing annual capital budget programs that do not lend themselves to a specific project or location – but are more broadly undertaken across the Company's service territory as required to serve new customers and ensure a safe and reliable system.

The capital budgets also include larger individual projects which are included in DEU Exhibit 3.26. The 2023 budget is based on 2022 activity, with adjustments for known changes between 2022 and 2023. For example, the amount of 2023 spending on feeder line projects is reduced because a large southern system reinforcement project will be completed in 2022. The vehicle purchase program in 2023 is reduced from 2022 levels because 2022 includes a bulk purchase that will not be required in 2023. 2023 also includes a large reduction in capital spend due to the completion of the LNG Facility in 2022. Other categories and projects are largely consistent with the 2022 budget and reflect anticipated ongoing capital requirements. All told, the 2023 capital budget falls from $359.6M in 2022 to $295.4M in 2023 (see DEU Exhibit 3.25, row 23).

Q. In Docket No. 19-057-02, the Commission ordered that the 2020 capital budget of $272 million used in the proposed revenue requirement calculation should be reduced by $24.7 million to $253 million. Did the Company reduce its capital spend in 2020 to match the Commission approved cost recovery capital spend included in rates?

A. The requested capital spend in 2020 was necessary to meet the demands of customer growth on the system and to maintain a safe, reliable system. While the Company reduced the infrastructure replacement tracker program budget in 2020 as required by the Commission's order in the last rate case (the Company had requested to increase spending in that program to $80 million to account for expected capital projects, but this proposal was not adopted in the case), the Company spent $272 million in 2020 compared to an approved $253 million included in the revenue requirement calculation on necessary capital projects. The difference makes up a portion of unrecovered capital investment from 2020 that has carried forward into this case.

The Company had originally included a capital budget of $277 million in the 2020 test period revenue requirement calculation. In its order, the Commission observed that approximately $90 million was "for unspecified blanket/bucket-type expenditures" as support for the reduction. However, these items referred to as "bucket/blanket" items in fixed asset accounting terminology, relate to real and specific capital programs to install or replace meters, services, mains, or small regulator stations. Because these are small projects spread across the state, the Company budgets for these in a bundled, programmatic fashion rather than individual one-off projects. Again, these are not "unspecified expenditures" but are actual, necessary expenditures to maintain the Company's system.

The years of history I have provided showing capital spending budgets versus actual capital spending, as well as the detailed capital budgets I have included in DEU Exhibit 3.26, show that the Company's capital budgets are a very close representation of how much capital spending will occur in 2022 and 2023.

B. Other Rate Base Accounts

Q. DEU Exhibit 3.02, rows 37-50, provide various other rate base accounts. Please explain how these items were projected for the test period.

A. Several of the 2023 balances in this category are carried forward from historical base period 2021 amounts. This is the case for the 154, 190008, 190009, 235-1, and 252 account balances.

[redacted]

I calculated the deferred income taxes account balances (Account 282) for 2022 and 2023 by taking projected investment, depreciation, and tax amounts and projecting their impact on deferred income taxes, consistent with the Company's methodology in Docket No. 19-057-02 and with Commission precedent (see DEU Exhibit 3.28, line 5).

I removed all pension related rate base items from the test period as discussed previously in my testimony and consistent with the Commission order in Docket No. 19-057-02.

Finally, I included a rate base adjustment for cash working capital that reflects the amount of cash required by the Company to meet daily cash operating needs. The methodology of calculating this rate base item is consistent with prior rate cases and relies on a lead-lag factor supported by a detailed lead-lag study.

Q. In Docket No. 19-057-02, the Company used a Lead-Lag study based on 2017 data. Have you updated your Lead-Lag study in this case?

A. Yes. The Company is using an updated Lead-Lag study based on 2020 data. I have attached the updated study as DEU Exhibit 3.29. The Commission-approved stipulation in Docket No. 07-057-13, requires the Company to use a lead-lag study in which the end date of the period used for the study is not more than three years old at the time of the filing. The end date of the 2020 study will be less than three years old at the time of this filing.

Q. Did the Company make any changes to the Lead-Lag methodology between the 2017 study and the previous study?

A. The Company used the methodology approved by the Commission in its order in Docket No. 19-052-02. Most notably, the Company excluded depreciation and deferred income tax items from the study consistent with the Commission's directive in that final order. The remaining components of the study remain consistent with prior lead-lag studies.

Q. Please explain how the Lead-Lag study affects cash working capital.

A. 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. If, on average, the time to collect revenues for services exceeds the time to pay the expenses for those services, the utility is experiencing a positive "net revenue lag," which requires cash on hand. If, on the other hand, the lag to pay expenses is longer than the lag to collect revenues, it is experiencing a negative "net revenue lag."

Q. Please summarize the results of the 2020 lead lag study?

A. The study shows that revenue was collected 44.25 days from the time of recognition. Expenses were paid approximately 35.9 days following recognition, for an overall net lag calculation of 8.35 days. The use of this calculated lag results in a test-year cash working capital requirement of $20.78 million (DEU Exhibit 3.02, column F, line 49).

Q. Did you make any additional adjustments to rate base that have not yet been discussed?

A. Yes. Consistent with prior rate case orders, I have made adjustments related to gas stored underground and the Wexpro production plant balances.

Q. Please explain the adjustment for Gas Stored Underground.

A. Pursuant to the final order in Docket No. 93-057-01, Account 164, Gas Stored Underground - Current, is to be accounted for in the Company's Pass-Through Account cases and excluded from test-year rate base. This is accomplished in Pass-Through Account cases by allowing a return on the actual average balance in this account to be entered as a gas cost in the 191 Account. This adjustment removes the total balance of Account 164 from the rate-base calculation. DEU Exhibit 3.30 summarizes this adjustment.

Q. Please explain the adjustment for Wexpro investment.

A. In accordance with the Wexpro Agreement, Wexpro adds 6.3% of Dominion Energy's production plant to the Wexpro investment as a general plant allowance when calculating the Wexpro service fee charged to Dominion Energy. The Wexpro Agreement also provides that the production plant component in each Dominion Energy rate base plant account should be reduced by 6.3%. This adjustment will continue to decrease over time as this plant fully depreciates. DEU Exhibit 3.31 summarizes this adjustment.

Q. You have discussed numerous adjustments to 2021 historical revenue, expense, and rate base amounts to calculate 2023 test period conditions. Have you prepared a summary of adjustments?

A. Yes. Attached as DEU Exhibit 3.32 is a summary of each adjustment I have made to historical 2021 amounts to arrive at test period 2023 amounts. Each adjustment is shown in its own column, with the total of all adjustments shown in the last column. The total of all adjustments on this summary matches the adjustment amount shown in column C of DEU Exhibit 3.02.

VI. COST OF CAPTIAL

Q. What is the cost of debt included in the average 2023 test period?

A. The Company has included a cost of debt of 4.0% in the 2023 test period. This is a decrease from the 4.37% cost of debt included in the most recently approved general rate case test period, and a decrease from the actual cost of debt of 4.32% in 2021. The 2023 cost of debt is based on current rates of outstanding issuances of debt and a planned issuance in the fall of 2022. DEU Exhibit 3.33 provides a more detailed breakdown of the components of debt and the cost of debt for the last general rate case (column C), year-end 2021 (column D), and the average 2023 test period (column E).

Q. What is the cost of equity included in the average 2023 test period?

A. The Company has included a cost of equity of 10.3% in the 2023 test period. This is discussed more thoroughly in the Direct Testimony of Company witness Jennifer Nelson.

Q. Please provide the capital structure and total cost of capital DEU is proposing for the 2023 test period.

A. The Company is proposing an average capital structure for 2023 that consists of 53.21% equity and 46.79% debt. At a cost of equity of 10.3% and cost of debt at 4%, this results in a weighted average cost-of-capital of 7.35%, as shown in the following table:

	AVG CAP STR DEC 23		Weighted
	Weight	Cost	Cost
Long Term Debt	46.79%	4.00%	1.87%
Common Equity	53.21%	10.30%	5.48%
	100.00%		7.35%

This results in a slight increase (0.17%) over the 7.18% weighted average cost-of-capital approved in the Company's previous general rate case.

VII. PROJECTED DEFICIENCY AND REVENUE REQUIREMENT

Q. Have you calculated a total revenue requirement for this case?

A. Yes. Based on the projected capital structure and a 10.3% return on equity incorporated together with the forecasted data and regulatory adjustments, I calculated the total Utah revenue requirement to be $503.9 million. (DEU Exhibit 3.02, column H, line 3).

Q. Using the currently allowed revenue per customer, what is the projected revenue deficiency for the test period?

A. DEU Exhibit 3.02 shows that, for the proposed test period, the Utah operations of the Company would be expected to earn 6.41% return on equity. This results in a revenue deficiency of $70.5 million (column G, line 3).

Q. Have you made a similar calculation of the revenue deficiency using volumetric revenues for the GS class instead of the allowed revenue-per-customer?

A. Yes. DEU Exhibit 3.34 shows that, for the test year, the Utah operations of the Company would be expected to earn 5.93% return on equity during the rate-effective period, absent rate relief in this docket. This amounts to a revenue deficiency of $79.3 million.

Q. Does the difference cause the total revenue requirement to change?

A. No. The allowed revenue requirement does not change. A summary of the two calculations is shown in the following table:

	Current Revenue	Deficiency	Revenue Requirement
CET Allowed Revenue	$433.4 Million	$70.5 Million	$503.9 Million
Volumetric Revenue	$424.7 Million	$79.3 Million	$503.9 Million

Rates will be set on the total revenue requirement, not the deficiency, thus, the end results will be the same regardless of how one calculates revenue deficiency.

Q. Does that conclude your testimony?

A. Yes.

State of Utah)
) ss.
County of Salt Lake)

I, Jordan K. Stephenson, being first duly sworn on oath, state that the answers in the foregoing written testimony are true and correct to the best of my knowledge, information and belief. Except as stated in the testimony, the exhibits attached to the testimony were prepared by me or under my direction and supervision, and they are true and correct to the best of my knowledge, information and belief. Any exhibits not prepared by me or under my direction and supervision are true and correct copies of the documents they purport to be.

____
Jordan K. Stephenson

SUBSCRIBED AND SWORN TO this 2nd day of May, 2022.

____
Notary Public