Phillip Russell
Gary A. Dodge, #0897
HATCH, JAMES & DODGE
10 West Broadway, Suite 400
Salt Lake City, UT 84101
Telephone: 801-363-6363
Facsimile: 801-363-6666
Email: gdodge@hjdlaw.com

Attorneys for Utah Association of Energy Users

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. 19-057-02**

REDACTED PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

The UAE Intervention Group ("UAE") hereby submits the Redacted Prefiled Direct Testimony of Kevin C. Higgins.

DATED this 17th day of October, 2019.

/s/ Phillip J Russell

Phillip J. Russell
HATCH, JAMES & DODGE, P.C.
Attorneys for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 17th day of October, 2019, on the following:

QUESTAR GAS COMPANY	
Jenniffer Nelson Clark	jenniffer.clark@questar.com
Cameron Sabin	cameron.sabin@stoel.com
DIVISION OF PUBLIC UTILITIES	
Chris Parker	chrisparker@utah.gov
William Powell	wpowell@utah.gov
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
OFFICE OF CONSUMER SERVICES	
Michele Beck	mbeck@utah.gov
Steven Snarr	stevensnarr@agutah.gov
Robert Moore	rmoore@agutah.gov
Alyson Anderson	akanderson@utah.gov
NUCOR STEEL-UTAH	
Damon E. Xenopoulos	dex@smxblaw.com
Jeremy R. Cook	jcook@cohnekinghorn.com
AMERICAN NATURAL GAS COUNCIL, INC.	
Stephen F. Mecham	sfmecham@gmail.com
Curtis Chisholm	cchisholm@ie-cos.com
US MAGNESIUM, LLC	
Roger Swenson	Roger.Swenson@prodigy.net
FEDERAL EXECUTIVE AGENCIES	
Maj. Scott L. Kirk	Scott.Kirk.2@us.af.mil

/s/ *Phillip J. Russell*

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

Redacted Phase I Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 19-057-02

October 17, 2019

TABLE OF CONTENTS

EXHIBITS

REDACTED DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Utah Association of Energy Users Intervention Group ("UAE").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. Since 1984, I have testified in forty dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in approximately 200 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your Phase I direct testimony in this proceeding?

A. My testimony addresses certain revenue requirement issues in this general rate case. As part of my testimony, I make recommendations to adjust the revenue requirement proposed by Dominion Energy Utah ("DEU").

Q. What revenue increase is DEU recommending?

A. In its direct filing, DEU is proposing a revenue increase of $19,249,740, or 4.95% on an annual basis.[1]

Q. Please summarize the revenue requirement adjustments you are recommending.

A. My recommended adjustments reduce DEU's revenue requirement by a total of [redacted] relative to DEU's proposed revenue requirement increase of $19,249,740. This reduction includes an illustrative reduction to DEU's requested return on equity ("ROE") from 10.50% to 9.70%, which is the median ROE approved by state regulators in the United States for natural gas distribution utilities as reported by S&P Global Market Intelligence for the 12-month period ending September 30, 2019. I included this adjustment as a placeholder because UAE anticipates that the Division of Public Utilities ("Division") and the Office of Consumer Services ("Office") will fully address cost of capital in their respective testimonies, and the recommendations of the Division and Office will be given significant weight by the Commission.

[1] See DEU Exhibit 4.06, p. 2.

My adjustments are presented in Table KCH-1 below. One of my adjustments concerns the test period expense associated with DEU's proposed liquefied natural gas ("LNG") project – information which DEU deems to be confidential. Excluding this confidential adjustment, my recommended adjustments reduce DEU's revenue requirement by a total of **$23,918,758.**

My recommended adjustments are as follows:

(1) The non-labor operations and maintenance ("O&M") expense projected by DEU for the test period contains a cost escalation component to reflect projected inflation for the period extending from January 2019 through December 2020. This approach to ratemaking guarantees inflation before it occurs and builds a "cost cushion" into the Company's revenue requirement that would constitute an unwarranted windfall from the use of a projected test period. It is not reasonable to simply gross up the Company's actual base period costs by an index factor and pass these inflated costs on to customers. I recommend adjusting DEU's non-labor O&M expense to remove projected inflation from the test period. This adjustment reduces the Utah revenue requirement by **$1,934,618**.

(2) DEU proposes to set pension expense to zero for ratemaking purposes, even though pension expense calculated pursuant to Financial Accounting Standard ("FAS") practice is actually projected to be -$5,448,127 in 2020, *i.e.*, a negative value or credit. I recommend against setting pension expense to zero for ratemaking purposes in this case. Instead, pension expense should be set using the projected FAS cost for 2020. This adjustment reduces the Utah revenue requirement by **$5,281,817**.

(3) DEU's 2020 O&M budget is lower than the O&M expense used as the basis for the Company's requested revenue requirement in this case. I propose an O&M efficiency adjustment that reasonably apportions the projected cost savings in the Company's 2020 budget between customers and DEU. This adjustment reduces the Utah revenue requirement by **$6,515,204**.

(4) I recommend an adjustment that amortizes non-plant excess accumulated deferred income tax ("EDIT") on a going-forward basis over ten years rather than 30 years as proposed by DEU. I have also reduced the 2020 ARAM[2] amortization for plant-related EDIT based on DEU's current best estimate.[3] As part of my EDIT adjustment, I also recommend restating EDIT in rate base to reflect amortization starting January 1, 2018, as 2018 ARAM amortization is being credited to customers through the Tax Reform Surcredit 3. The net effect of these changes is an increase in the base Utah revenue requirement of **$478,027**. However, I recommend that these changes be packaged with a new Tax Reform Surcredit 4 in the amount of approximately **$3,647,685** that credits customers with the January 1, 2019 to February 29, 2020 ARAM amortization over one year.

(5) I present an illustrative revenue requirement adjustment that incorporates an ROE of 9.70% rather than the 10.50% ROE requested by DEU. My illustrative ROE uses the median ROE for natural gas distribution utilities approved by state regulators in the United States in the past year as reported by S&P Global Market

[2] ARAM stands for average rate assumption method and is discussed later in my testimony.
[3] According to DEU, the current best estimate for 2020 ARAM amortization is the actual 2018 ARAM amortization. See DEU response to UAE Data Request No. 4.03, included in UAE Exhibit 1.7.

Intelligence. The Utah revenue requirement reduction from such an adjustment is **$10,665,143** relative to the Company's filed case.

(6) DEU's expense related to DEU's proposed LNG project should be removed from the revenue requirement as it is unrelated to the Distribution Non-Gas ("DNG") service. This adjustment reduces the Utah revenue requirement by [redacted]

(7) I recommend that annual expenditures for the Infrastructure Tracker program be capped at $72.2 million for 2020 *without* future adjustments for inflation in order to provide reasonable cost containment.

Table KCH-1
UAE Revenue Requirement Adjustments

Adjustment Description	UT Jurisdiction Adjustment Impact	UT Jurisdiction Deficiency
DEU Requested Increase		$19,249,740
Remove Non-Labor Inflation Adjustment	($1,934,618)	$17,315,121
Pension Expense Adjustment	($5,281,817)	$12,033,304
O&M Efficiency Adjustment	($6,515,204)	$5,518,100
EDIT Adjustment	$478,027	$5,996,127
Return on Equity Adjustment *	($10,665,143)	($4,669,016)
Total UAE Adjustments (Non-Conf.)	($23,918,756)	
UAE Recommended Decrease		($4,669,016)
LNG Expense Adjustment	[redacted]	[redacted]
Total UAE Adjustments w/LNG Adj.	[redacted]	

* Includes illustrative ROE adjustment

REVENUE REQUIREMENT

O&M Cost Escalation

Q. What adjustment are you proposing with respect to non-labor O&M expense?

A. I am proposing an adjustment to remove the inflation escalator applied by DEU to its test period non-labor O&M expense.

Q. Please explain the basis for your adjustment.

A. The non-labor O&M expense projected by DEU for the test period contains a cost escalation component to reflect projected inflation for the period extending from January 2019 through December 2020.

To apply this cost escalator, DEU starts with its actual non-labor O&M expense for the base period, January to December 2018. DEU then applies a series of escalation factors to its base period cost for its materials and services using indices from the Global Insight Power Planner Report.

From a ratemaking perspective, I have two serious concerns with this approach.

First, at a broad policy level, I have concerns about regulatory pricing formulations that cause or reinforce inflation. This occurs when *projections* of inflation are built into formulas that are used to set administratively-determined prices, such as utility rates. Such pricing mechanisms help to make inflation a self-fulfilling prophecy. As a matter of public policy, this is a serious concern. It is one thing to adjust for inflation after the fact; it is another to help guarantee it. For this reason, I believe that regulators should use extreme caution before approving prices that guarantee inflation before it occurs.

Q. What is your second major concern?

A. A related, but distinct, concern involves the building of this "cost cushion" into the Company's test period costs. Allowing this type of systemic uplift in rates goes well beyond the basic rationale advanced by advocates for using a projected test period, which is to ameliorate the effect of regulatory lag on the recovery of investment in new plant.

Q. Please explain.

A. Prior to 2008, the Commission had a longstanding practice of requiring utilities to use historical test periods in setting rates, preferring the certainty of information that comes with using actual expenses, revenue, and investment as the basis for setting rates. Starting in 2008,[4] the Commission started to allow utilities to use projected test periods in setting rates. The primary justification for this practice is to allow a utility with expanding rate base the ability to avoid regulatory lag; that is, the use of a projected test period is intended to provide a utility a better opportunity to recover its investment cost than might occur with an historical test period. Since first allowing projected test periods in 2008, utility test periods in Utah have reached increasingly further into the future; in the instant case, DEU's projected test period extends 18 months beyond the Company's filing date.

[4] The Commission departed from its previous practice of requiring historical test periods in Docket No. 07-035-93, in which the Commission approved a projected test period extending approximately 12½ months beyond the utility's filing date.

In this case, DEU is attempting to go well beyond simply aligning the test period with its projected 2020 investment to mitigate regulatory lag; the Company is also attempting to gain an additional benefit by inflating its baseline costs by applying an indexed inflation factor through the end of 2020. Yet the use of a projected test period is the Company's *choice*: it is not required to do so. DEU should not be rewarded with a windfall mark-up of its baseline costs through an inflation adjustment simply by virtue of its test period selection. The Commission should not allow the use of a future test period to become a vehicle for utility recovery of such synthetic costs. Rather, DEU should be expected to strive to improve its O&M efficiency on a continuous basis, and thereby lessen the net impact of inflation on its O&M costs. It is not reasonable to simply gross up the Company's base period costs by an index factor and pass these inflated costs on to customers, thus virtually assuring utility rate inflation.

Q. Are there any indications that DEU is in fact striving to improve its O&M efficiency?

A. Yes. DEU's 2020 O&M budget provided in MDR_22 D.12 is actually lower than the Company's O&M expense used in developing its requested revenue requirement. As pointed out in OCS Data Request No. 4.05, the 2020 O&M budget provided in MDR_22 D.12 is $142.4 million.[5] In comparison, the 2020 O&M expenses used in developing the requested revenue requirement total $146.0 million.[6] In discovery, DEU explains that the "referenced budget amounts represent an

[5] See DEU Response to OCS Data Request No. 4.05, included in UAE Exhibit 1.7.
[6] DEU Exhibit 3.10, p. 1, line 53.

adjustment for efficiency goals across the broader corporation."[7] This response suggest that the Company anticipates that its actual 2020 O&M expenses will be less than the 2018 baseline amount plus inflation that DEU proposes to be included in its revenue requirement.

Notably, an update to the Company's 2020 O&M budget, which takes account of DEU's voluntary retirement program, is lower still, $131.7 million.[8] I will discuss the revenue requirement implications of the Company's declining O&M budget later in my testimony. But at this juncture, I simply note that the Company's declining 2020 O&M budget is strong evidence in support of my argument that inflation index factors should be removed from the projected test period.

Q. Are there ever situations in which inflation should be considered in a ratemaking context?

A. If inflation itself becomes a disruptive element in the U.S. economy, then perhaps it could properly be considered in the context of a future test period, but, even then, after accounting for a productivity offset. The United States experienced major inflation during the late 1970s. In that type of severe increasing-cost environment, some consideration for O&M inflation in a projected test period might be appropriate. However, we are very far from such a cost environment. Inflation in the United States has been at very low levels for many years and the prospects for core inflation, which excludes energy and food prices, remain subdued.

[7] See DEU Response to OCS Data Request No. 4.05, included in UAE Exhibit 1.7.
[8] See DEU Response to OCS Data Request No. 4.06, included in UAE Exhibit 1.7.

Q. What is your recommendation regarding the application of an inflation escalator to the non-labor O&M expense for the projected test year?

A. I recommend adjusting DEU's non-labor O&M expense to remove its projected cost escalation increase for the test period. The impact of this adjustment is shown in UAE Exhibit 1.1. This adjustment reduces the Utah revenue requirement by **$1,934,618**.

Pension Expense

Q. What has DEU proposed regarding the treatment of pension expense?

A. DEU proposes to set pension expense to zero for ratemaking purposes, even though 2020 pension expense is actually projected to be -$5,448,127, *i.e.*, a negative value or credit.[9] DEU witness Mr. Jordan K. Stephenson explains that Dominion Energy shareholders contributed $75 million to the DEU pension plan in 2017, and as a result, the Company did not contribute to the plan in 2017 and 2018 and does not anticipate making cash contributions in the test period. Mr. Stephenson attributes the negative pension expense in the test period to the cash contribution made by shareholders and asserts that it is appropriate to set the pension expense to zero rather than reflect a credit to customers in the revenue requirement.[10]

---

[9] This is the Total System amount. See DEU Exhibit 4.18-Summers-Rate Case Model 7-1-2019, Labor Forecast tab. The Utah-jurisdictional portion of DEU's projected 2020 pension expense is -$5,261,562.
[10] Direct Testimony of Jordan K. Stephenson, lines 522-544.

Q. What is your response to the Company's proposed treatment of pension expense?

A. In Utah, and most jurisdictions in my experience, pension expense for ratemaking is based on FAS net periodic pension cost (with some adjustments for capitalized labor). For example, DEU's current Utah rates include $7.9 million per year in pension expense based on projected FAS pension cost at the time rates were last set in 2014.[11] Because base rates are not adjusted between rate cases when individual cost components change, this level of expense remains in rates today even though FAS pension cost is currently negative.

DEU's proposal would be a significant departure from the current practice of setting pension expense in rates based on FAS pension cost. If DEU were proposing to eliminate pension expense from ratemaking on a permanent basis, I believe the Company's proposed treatment would be worth serious consideration. However, DEU indicates that the Company is not supportive of such a permanent change.[12] Rather, DEU appears to contemplate a long-term arrangement in which customers would pay for pension expense in rates when FAS pension costs are positive, but would go without a credit in rates when pension costs are negative. I do not believe such an asymmetrical long-term arrangement is reasonable. By definition, over the life of a pension plan, the cumulative sum of FAS pension cost (including negative pension cost) will equal the cumulative sum of the Company's funding contributions. This mean that setting customer pension cost responsibility in rates equal to FAS

[11] DEU Phase I Technical Conference presentation, p. 18, adjusted for Utah allocation.
[12] See DEU Response to UAE Data Request No. 3.02, which is included in UAE Exhibit 1.7.

pension cost (as is currently done) ensures that, by and large,[13] customer rates will fully fund the pension plan costs over the life of the plan. Selectively "zeroing out" pension expense in rates when FAS pension cost is negative as proposed by DEU will cause customers to overpay for pension cost over the life of the pension plan. Such a result would not be reasonable. Therefore, I recommend against setting pension expense to zero for ratemaking purposes in this case.

Q. Mr. Stephenson indicates that as part of its pension expense adjustment, DEU removed $84 million in net rate base related to a deferred pension asset. Do you wish to comment on this statement?

A. Yes. Mr. Stephenson is referring here to a prepaid pension asset. Prepaid pension assets represent the difference between a utility's cumulative contributions to its pension plan (since the inception of the plan) and the cumulative FAS pension cost since the inception of the plan. If the difference is positive, this amount is construed to be a prepaid pension asset. If the difference is negative, it is construed to be a prepaid pension liability. In some jurisdictions, utilities are permitted to include prepaid pension assets in rate base. In other jurisdictions, such as Oregon, they are not. To the best of knowledge, Utah has never approved the inclusion of a prepaid pension asset in rate base. For that reason, I do not believe it is correct to view DEU's adjustment as having "removed" the prepaid pension asset from rate base, since I do not believe we can consider the prepaid pension asset as having been included in rate base in the first place.

[13] Since FAS pension cost changes annually, and base rates are not reset every year, the cumulative pension cost *in rates* will likely not exactly match the cumulative sum of funding contributions over the life of the plan.

Q. Do you believe a prepaid pension asset should be recognized in DEU rate base in this case?

A. No. Recognition of a prepaid pension asset in rate base is an important policy decision with significant long-term ramifications. It should not be undertaken without a thorough examination of all the implications. The Public Utility Commission of Oregon, for example, devoted an entire docket to this question before determining that prepaid pension assets should not be included in rate base.[14]

Q. What is the revenue requirement impact of your pension adjustment?

A. The impact of my pension adjustment is shown in UAE Exhibit 1.2. It reduces the Utah revenue requirement by **$5,281,817**.

O&M Efficiency Adjustment

Q. Please explain your proposed O&M efficiency adjustment.

A. As I noted above, DEU's 2020 O&M budget is significantly lower than the Company's O&M expense used in developing its requested revenue requirement. After adjusting for DSM-related expenses, the updated 2020 O&M budget is around $14.3 million less than the O&M expense used as the basis for DEU's requested revenue requirement.[15] As explained by the Company in discovery, DEU's 2020 budget contains an adjustment for efficiency goals across the broader corporation. The underlying key question here is – why are these projected lower expenses from efficiency gains not reflected in the proposed revenue requirement? It seems to me

[14] Oregon Public Utility Commission, Docket No. UM 1633, Order No. 15-226, issued August 3, 2015.
[15] That is, $146.0 million - $131.7 million, as discussed earlier in my testimony.

that some effort must be made to capture the benefits of expense reduction in the rates customers pay. That is what I do in my proposed O&M efficiency adjustment.

Q. How did you calculate your proposed O&M efficiency adjustment?

A. I started by comparing DEU's updated 2020 O&M budget to the O&M expense in the Company's revenue requirement model *after* accounting for my inflation adjustment and my pension expense adjustment and after making an adjustment for DSM-related costs. I took account of my inflation adjustment and pension expense adjustment so as to not double-count these prior adjustments in computing my O&M efficiency adjustment.[16] I adjusted for DSM-related costs because DEU removes these expenses in calculating the DNG revenue requirement, but presumably keeps these expenses in its overall O&M budget. The calculation of my O&M efficiency adjustment is summarized in Table KCH-2, below.

[16] DEU's 2020 budget as presented in MDR_22 D.12 and the update provided in DEU's Response to OCS Data Request No. 4.06 do not show the details of the individual O&M cost components as provided in the Company's revenue requirement model. To be conservative in avoiding double counting, I am assuming at this time that the 2020 negative pension expense is included in DEU's updated 2020 budget.

Table KCH-2
UAE O&M Efficiency Adjustment Calculation

		System Total
1.	Adjusted Total O&M Expenses - DEU As-Filed [17]	$125,221,739
2.	O&M Expense Impact of UAE Inflation Adjustment [18]	($2,012,707)
3.	O&M Expense Impact of UAE Pension Expense Adjustment [19]	($5,448,127)
4.	Total O&M Expenses w/UAE Inflation and Pension Adjs.	$117,760,904
5.	Reverse DEU Energy Efficiency Adjustment[20]	$24,077,931
6.	O&M Expense in Revenue Req. Including EE Expense (Lines 4 + 6)	$141,838,835
7.	DEU Updated 2020 Budget [21]	$131,685,932
8.	O&M Efficiency Savings (Line 7 - Line 6)	($10,152,903)
9.	UAE Proposed Customer Share (Line 8 × [2/3])	($6,768,602)

As shown in Table KCH-2, I calculate that DEU's updated 2020 budget is $10.2 million lower than the Company's proposed revenue requirement in this case, after accounting for my inflation adjustment and pension expense adjustment and after adjusting for DSM-related costs. In my O&M efficiency adjustment, I propose to apportion two-thirds of the benefit of this $10.2 million difference to customers through a reduction in O&M expense that is included in the revenue requirement. I propose that the remining one-third of this difference be retained by the Company.

[17] DEU Exhibit 4.18-Summers-Rate Case Model 7-1-2019, Report tab.
[18] See UAE Exhibit 1.1, p. 2.
[19] See UAE Exhibit 1.2, p. 2.
[20] Reverses DEU Energy Efficiency Services Adjustment (pre-inflation 2018 amount), since this expense is collected through the demand-side management amortization rate.
[21] OCS Data Request No. 4.06, OCS 4.06 Attach 1, included in UAE Exhibit 1.7.

Q. Why do you propose that one-third of this difference be retained by the Company?

A. It is apparent from its updated 2020 O&M budget that DEU is attempting to achieve cost-savings goals. Such efforts should be encouraged. To a certain extent, a portion of the budget savings may be aspirational. I believe it is reasonable to acknowledge the Company's efforts by apportioning a share of the potential savings to the Company.

Q. What is the revenue requirement impact of your O&M efficiency adjustment?

A. The impact of my O&M efficiency adjustment is shown in UAE Exhibit 1.3. It reduces the Utah revenue requirement by **$6,515,204.**

Excess Deferred Income Tax

Q. What is EDIT?

A. EDIT was created as a result of the reduction to the federal corporate income tax rate from 35% to 21% in the 2017 Tax Cuts and Jobs Act ("TCJA"). Deferred income taxes arise due to timing differences between when income taxes are recognized for book purposes and when income taxes are ultimately paid to the taxing authority. A deferred income tax liability represents book tax expenses that exceed the tax actually paid by a utility in a given year, whereas a deferred tax asset occurs when a utility pays taxes sooner than when they are recognized for book purposes.

The use of accelerated depreciation for tax purposes typically results in tax expense paid by customers (through inclusion in rate case revenue requirements) that exceeds actual taxes paid to taxing authorities in the early years of an asset's life. In turn, this gives rise to an accumulated deferred income tax liability balance, which is treated as an offset to rate base.

Conceptually, an EDIT liability represents income tax prepayments by customers that are now greater than the utility's expected future income tax obligations for the associated assets due to the lower tax rate. These past customer overpayments should properly be refunded to customers.

The TCJA requires that EDIT associated with the accelerated depreciation of public utility plant, or "protected" EDIT, must be normalized into customer rates gradually to avoid incurring a penalty, using an amortization period that generally corresponds to the depreciable lives of the underlying assets.[22] Under normalization rules, the protected EDIT balance cannot be reduced more rapidly than the amount determined using the average rate assumption method ("ARAM"). In contrast, non-protected EDIT is not subject to the ARAM amortization constraint, and the appropriate amortization period should be determined by the Commission.

Q. Is all plant-related EDIT protected?

A. No. The normalization requirements that impose the ARAM limitation apply only to the EDIT associated with accelerated depreciation of public utility plant. All non-plant EDIT is non-protected, but a portion of plant-related EDIT is non-protected as well.

---

[22] The normalization requirements are described in Section 13001(d) of the TCJA (H.R.1 – 115th Congress [2017-2018]: *An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018*).

Q. DEU is currently crediting customers with benefits arising from the TCJA through surcredits. How is EDIT being amortized in the current surcredit?

A. DEU's Tax Reform Surcredit 3 is crediting customers with the amortization of 2018 plant-related EDIT in accordance with ARAM. DEU has indicated in discovery, however, that the 2018 EDIT amortization included in the Tax Reform Surcredit 3 is overstated by around $826,000.[23] I will address this issue later in my testimony.

Non-plant EDIT is currently not being amortized, but the issue of determining the appropriate amortization period for non-plant EDIT was reserved for this rate case.[24] DEU proposes in this case to begin amortization of non-plant EDIT on March 1, 2020 over a 30-year period, even though non-plant EDIT can be amortized more rapidly.

Q. Have you made an adjustment to plant-related EDIT ARAM amortization in this case?

A. Yes. I have reduced the 2020 ARAM amortization by approximately $826,000 based on DEU's current best estimate. According to DEU, its current best estimate for 2020 ARAM amortization is the actual 2018 ARAM amortization.[25]

---

[23] DEU responses to UAE Data Request Nos. 4.01 and UAE 4.02, included in UAE Exhibit 1.7.
[24] See Docket No. 17-057-26, April 23, 2019 Settlement Stipulation. Paragraph 13.
[25] See DEU response to UAE Data Request No. 4.03, included in UAE Exhibit 1.7. The updated UT-allocated ARAM amortization is $826,050 less than the ARAM amortization included in DEU's filed case (pre-gross-up). After gross-up, the update is $1,097,743 less.

Q. Do you have any recommendations concerning non-plant EDIT amortization in this case?

A. Yes. I recommend that non-plant EDIT be amortized over a ten-year period, rather than over the much longer 30-year period proposed by DEU. Doing so will increase the annual Utah amortization (grossed up) from approximately $485,284 per year to $1,455,852 per year. Such a change is reasonable because EDIT essentially represents past income tax payments made by customers in rates that, in hindsight, turned out to be excessive, because the deferred taxes that DEU will ultimately pay are subject to a lower tax rate than originally anticipated. Consequently, it is reasonable for EDIT to be returned to customers as expeditiously as possible, within the requirements of the law.

Q. Are there any other aspects of EDIT that you wish to address?

A. Yes. I recommend that the amount of EDIT recognized in rate base be realigned with the EDIT that is being amortized in rates through Tax Reform Surcredit 3. Specifically, DEU's (initial) Tax Reform Surcredit went into effect June 1, 2018. That surcredit is passing through to customers the benefits of the direct reduction in tax expense associated with the decrease in corporate income tax rates. Tax Reform Surcredit 3 went into effect June 1, 2019 and is providing a credit to customers for the ARAM amortization of plant-related EDIT that was projected to occur over the January 1 to December 31, 2018 period.[26] However, the Company's proposed rate base in this case shows EDIT amortization not starting until June 1,

[26] The effective date of the EDIT ARAM amortization is January 1, 2018, notwithstanding the fact that the actual credits did not appear on customer bills until later.

2019. This later amortization start date actually overstates the EDIT credit to customers in rate base because it does not reflect the fact that 2018 EDIT is being returned to customers. To rectify this mismatch, I recommend restating the starting date of EDIT amortization in rate base to January 1, 2018 to correspond to the commencement of EDIT amortization that is being credited to customers.

However, a companion part of my proposed EDIT adjustment is also to credit customers with 2019 EDIT amortization. Currently, there is no provision to do this in Tax Reform Surcredit 3. I recommend that upon its expiration, Tax Reform Surcredit 3 be replaced by a new Tax Reform Surcredit 4 to provide a credit for ARAM amortization over the January 1, 2019 to February 29, 2020 period, as well as correct for the overstatement of 2018 EDIT amortization noted above. Since DEU is using a 2020 test period, failure to offer a Surcredit 4 to credit 2019 EDIT amortization to customers would mean that customers potentially would never receive the benefit of the amortization credit for 2019.

Taken in combination, my proposal to recognize EDIT amortization in rate base effective January 1, 2018 and to credit customers with 2019 EDIT amortization through Surcredit 4 will synchronize the EDIT amortization reflected in rate base with the EDIT amortization credits actually received by customers.

Q. Will it be necessary in the future to have a Tax Reform Surcredit 5 to reflect 2020 EDIT amortization?

A. No. While the Commission may have an interest in doing a final true-up to Surcredit 4, it will not be necessary to continue using surcredits to address EDIT amortization for 2020 and years beyond, as 2020 EDIT amortization is incorporated into this rate case.

Q. What is the revenue requirement impact of your EDIT amortization adjustment?

A. My EDIT amortization adjustment is shown in UAE Exhibit 1.4. The net impact of (a) updating the 2020 ARAM amortization to DEU's latest estimate, (b) changing the going-forward amortization of non-plant EDIT to ten years, and (c) restating rate base to reflect EDIT amortization starting January 1, 2018 is to increase the Utah revenue requirement by **$478,027.** In addition, the adoption of Tax Reform Surcredit 4 will provide a credit of approximately **$3,647,685** for a 12-month period. This estimate is presented in UAE Exhibit 1.4, page 3.

Return on Equity

Q. What ROE is DEU proposing?

A. DEU is proposing an ROE of 10.50%.[27] This return represents an increase of 65 basis points over the 9.85% ROE approved by the Commission in Docket No. 13-057-05 and 80 basis points above the median ROE for natural gas distribution utilities approved by state regulators in the United States in the past year as reported by S&P Global Market Intelligence.

[27] See Direct Testimony of Robert B. Hevert, lines 37-40.

Q. Does UAE support DEU's request?

A. No. Please refer to UAE Exhibit 1.5, page 2, which lists the ROEs for natural gas distribution utilities approved by state regulators in the United States as reported by S&P Global Market Intelligence for the 12-month period ending September 30, 2019. The median ROE approved over these past 12 months was 9.70%. If DEU's ROE in this case were to be set at a rate reflective of the national median, it would be in the vicinity of 9.70%.

Q. In offering this discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?

A. No. I fully expect that the Division and Office each will file cost-of-capital analyses for the Commission's consideration, along with that filed by DEU. My discussion of national trends is intended to supplement that analysis. Based on my experience in other proceedings, I would not be surprised if other parties present credible analysis indicating that DEU's ROE should be set lower than 9.70%.

Q. What would be the revenue requirement impact if DEU's ROE were set at the national median of 9.70%?

A. The revenue requirement impact of setting DEU's allowed ROE equal to 9.70% is presented in UAE Exhibit 1.5, page 1. It reduces the Utah revenue requirement by approximately **$10,665,143** relative to DEU's filed case. As I discussed previously, I incorporated an ROE of 9.70% into UAE's overall revenue requirement recommendations for illustrative purposes, pending further information being presented into the record by other parties.

LNG Project Expenses

Q. Please explain your adjustment for LNG project expenses.

A. DEU has included in its proposed revenue requirement certain expenses related to its proposed LNG project, including outside legal and consulting costs for Docket No. 18-057-03. As the Company's proposed LNG project is related to supply service, I do not believe it is reasonable to include these expenses in the DNG revenue requirement. Therefore, I propose an adjustment that removes these costs from the revenue requirement.

Q. What is the revenue requirement impact of your adjustment for LNG expenses?

A. The impact of my adjustment is shown in Confidential UAE Exhibit 1.6. It reduces the Utah revenue requirement by [redacted]. Because DEU considers the LNG case expenses to be confidential, I have placed this adjustment at the end of Table KCH-1 as a standalone item.

INFRASTRUCTURE TRACKER PILOT PROGRAM

Q. What is the Infrastructure Tracker Pilot Program?

A. The Infrastructure Tracker Pilot Program was approved in Docket No. 09-057-16 on a pilot basis. As initially adopted, the program allowed DEU to use a tracker to recover, between rate cases, the incremental cost of replacing high-pressure feeder lines and related facilities by levying a pro rata surcharge on customer classes. Annual expenditures on program-eligible infrastructure were initially limited to $55 million on an inflation-adjusted basis. In Docket No. 13-057-05 the cap was increased to $65 million plus an inflation adjustment and was expanded to include certain intermediate high-pressure belt mains. For 2020, the inflation adjustment results in a cap of $72.2 million.[28]

Q. What is DEU proposing regarding this program going forward?

A. As described in the Direct Testimony of Mr. Kelly B. Mendenhall, DEU proposes to increase spending in this program in 2020 to approximately $80 million per year and proposes that this amount continue to be adjusted in future years for inflation.

Q. What is your response to this proposal?

A. I recommend that the program cap remain at the $72.2 million level for 2020 using the calculus of the Settlement Agreement in Docket No. 13-057-05 that was approved by the Commission. Further, I recommend that annual expenditures continue to be capped at $72.2 million *without* future adjustments for inflation in order to provide reasonable cost containment for the tracker mechanism. The cap does not preclude DEU from making prudent investments in replacing high-pressure feeder lines if the investment costs are in excess of the cap – it merely restricts the amount of expenditures that are eligible for tracker recovery. An inflation adjustment is not needed because this program consists of a series of unique feeder replacement projects. The Commission should deny the request to continue to add automatic increases to the annual expenditure amount that is eligible for single-issue ratemaking treatment, as such mechanisms should be used sparingly, if at all.

[28] Direct Testimony of Kelly B. Mendenhall, lines 496-499.

Q. Does this conclude your direct testimony?

A. Yes, it does.