- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	DOCKET NO. 20-035-04 REDACTED ORDER

ISSUED: December 30, 2020

SYNOPSIS

The Public Service Commission of Utah approves an increase to Rocky Mountain Power's annual revenue requirement of $31.41 million, based on a forecasted test year ending December 31, 2021, an allowed rate of return on equity of 9.65%, and an overall rate of return of 7.34%. The revenue requirement change is effective January 1, 2021 and will be partially offset in 2021 and 2022 by the refund of income tax expense savings resulting from federal tax law changes.

The Public Service Commission approves an increase in the single-family residential customer charge from $6 to $8 on January 1, 2021 and from $8 to $10 on January 1, 2022. The multi-family residential customer charge will remain at $6. The single-family residential customer charge increases will be balanced in two ways. First, each increase will be accompanied by a commensurate adjustment in the residential energy charges from what those energy charges otherwise would be absent the increased customer charges. Second, the refunds associated with federal tax law changes will further offset residential energy charges during 2021 and 2022.

With those rates and offsets, a single-family residential customer using, on average, 700 kilowatt hours per month will experience a monthly bill increase of $1.45 or 1.92% in 2021 and a monthly bill increase of $1.33 or 1.73% in 2022, and an average multi-family residential customer using 700 kilowatt hours per month will experience a monthly bill decrease of $0.55 or 0.72% in 2021 and a monthly bill decrease of $0.67 or 0.89% in 2022.

APPEARANCES

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I. INTRODUCTION

This matter is before the Public Service Commission (PSC) on Rocky Mountain Power's (RMP) application to increase its retail rates by $95,786,460, or 4.8% ("Application") and to implement the new rates effective January 1, 2021.

The Application is based on RMP's forecast test year ending December 31, 2021 ("Test Year"),[1] a 13-month average rate base with a historical base period, and a requested rate of return on equity (ROE) of 10.20%. The Application also proposes administrative and substantive changes to its Tariff P.S.C.U. No. 50 ("Tariff").

II. PROCEDURAL HISTORY

On May 8, 2020, RMP filed its Application, including direct testimony, exhibits, and conforming Tariff schedules.

The following parties intervened: Nucor Steel-Utah, a Division of Nucor Corporation; the Utah Association of Energy Users (UAE); US Magnesium LLC ("US Mag"); University of Utah ("U of U"); Utah Clean Energy (UCE); Western Resource Advocates (WRA); Walmart, Inc. ("Walmart"); The Kroger Co. ("Kroger"); ChargePoint, Inc. ("ChargePoint"); Stadion LLC ("Stadion"); and Salt Lake City Corporation ("SLC Corp").

On June 9, 2020, the PSC issued a Scheduling Order, setting a schedule including technical conferences, a public witness hearing, and evidentiary hearings. The Scheduling Order established two phases. The first phase ("Phase I") would address RMP's cost of capital and revenue requirement. The second phase ("Phase II") would address the cost of service for each

[1] The PSC held a hearing to consider RMP's proposed Test Year and subsequently approved it in an order issued March 6, 2020.

customer class, revenue requirement spread, unbundling, and rate design, along with RMP's other proposed policy and tariff changes. The Scheduling Order established a staggered schedule for the parties to submit written testimony for each phase, including opportunities for written rebuttal and surrebuttal testimony.

Consistent with the Scheduling Order, the PSC held hearings as follows: (i) the PSC heard evidence pertaining to RMP's cost of capital on October 29 and 30, 2020; (ii) the PSC heard evidence pertaining to RMP's revenue requirement from November 3 through November 6, 2020. The PSC heard evidence on Phase II issues on November 17 and 18, 2020.

To allow any interested person an opportunity to speak on Phase I or Phase II issues, the PSC held a public witness hearing on November 3, 2020.

Finally, the PSC convened on December 4, 2020 to allow parties an opportunity to make closing arguments relating to either or both phases of the docket.

III. SUMMARY OF APPLICATION AND POSITIONS RMP LATER REVISED IN WRITTEN TESTIMONY

RMP's Application requests approval of its proposed increase in retail rates and revisions to its electric service schedules and regulations, effective January 1, 2021. The Application also requests approval of certain accounting treatments, rate mitigation proposals, and new or updated programs, as discussed below.

A. RMP's Initial Proposed Revenue Requirement Increase

RMP initially requested a revenue requirement increase of $95.8 million. Inherent in this request is an overall revenue requirement of $2.097 billion, an overall weighted cost of capital of 7.70%, and a 4.8% increase to current base rates.

B. Rate Mitigation

RMP's Application includes a rate mitigation proposal that it calculates will reduce its proposed revenue requirement by $66 million. Specifically, RMP asks to reduce depreciation expense for certain retired coal-fired generation units using the Sustainable Transportation and Energy Plan (STEP) regulatory liability balance, and to reduce ongoing depreciation expense using the federal Tax Cuts and Jobs Act (TCJA) deferred tax benefits. RMP proposes to use the remaining TCJA deferred tax benefits to offset a portion of its proposed rate increase in 2021 and 2022.

C. Additional Proposals

RMP's Application requests we approve a number of additional ratemaking proposals. Those proposals include new and modified programs, rate design proposals, and accounting treatments. New and modified programs include a Wildland Fire Mitigation Balancing Account and an updated version of the Subscriber Solar Program.[2] RMP's rate design proposals include updated customer charges and bill credits, changes to residential and nonresidential rate designs including unbundled rate features, and two pilot programs for large nonresidential customers. RMP's accounting proposals include requests to (i) approve the balance of its Energy Balancing Account (EBA), (ii) make Production Tax Credits (PTCs) a component of the EBA, and (iii) create regulatory assets for certain unrecovered plant costs.

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[2] At hearing, based on parties' rebuttal and surrebuttal testimony, RMP withdrew its proposal for a new program structure for the Subscriber Solar Program.

D. RMP's Revised Requests in Filed Rebuttal Testimony

After other parties filed their direct testimonies, RMP accepted certain of their proposed adjustments and offered alternative proposals to others. Consequently, RMP's filed rebuttal testimony proposes an increase to revenue requirement of $72,049,907, approximately $23.7 million less than the increase RMP initially sought. Additionally, RMP proposes to implement this increase in two steps, increasing revenue requirement by $49.5 million on January 1, 2021 ("Step 1 Increase") and by an additional $22.5 million on July 1, 2021 ("Step 2 Increase") to reflect the delayed in-service dates of portions of the Pryor Mountain and TB Flats projects.[3] Applying the tax savings associated with the TCJA, RMP proposes to return $62.7 million of the TCJA deferred tax balance over two years: $38.2 million in 2021 and $26.8 million in 2022 (including interest). Further, RMP would align the credit in 2021 with a two-step base rate change such that the credit would be increased in the latter half of the year to fully offset the second base rate increase.

The following summarizes the adjustments supporting RMP's proposed revenue requirement increase as revised in its rebuttal testimony.

1. Capital Cost – Cost of Debt

RMP updated its 30-day London Interbank Offer Rate (LIBOR) for certain variable rate securities with current forward 30-day LIBOR during the Test Year. RMP also updated the

[3] RMP argues this two-step increase is appropriate because the COVID-19 pandemic has caused delays in these projects that are beyond RMP's control.

historical relationship for these securities through June 2020. This adjustment reduces RMP's revenue requirement by $0.7 million.

2. Capital Cost – Authorized Return on Equity

RMP lowered its proposed authorized return on equity from 10.2% to 9.8%. This adjustment reduces RMP's revenue requirement by $22.3 million.

3. Operation & Maintenance (O&M) Escalation – Removal

Due to the overall uncertainty of escalation as a result of the COVID-19 pandemic, RMP removed all non-labor escalation from the revenue requirement. This adjustment reduces the revenue requirement by $3.6 million.

4. Wheeling Revenue Update

RMP's rebuttal testimony updated its wheeling revenues forecast to reflect the transmission formula rate that the Federal Energy Regulatory Commission (FERC) recently approved for PacifiCorp's Open Access Transmission Tariff. This update increases revenue requirement by $2.3 million.

5. Renewable Energy Certificates (REC) Revenue Update

This adjustment increases REC revenue in the Test Year to account for additional expected revenue that RMP's prior estimate failed to capture. This adjustment decreases revenue requirement by an amount that is confidential.

6. Navajo Tribal Utility Authority (NTUA) Revenue Correction

As OCS pointed out, RMP did not properly adjust approximately $78,000 of Utah situs revenues in the base period for collections from NTUA for the Utah STEP and Utah Home

Energy Lifeline Program. This adjustment accepts the OCS's proposal to remove the Utah situs revenues from the Test Year. This correction reduces the revenue requirement by $0.08 million.

7. Materials and Supplies (M&S) Revenue Correction

The OCS detected an accounting error involving RMP's failure to account for payments it received from customers for M&S RMP had provided to them. This incremental adjustment accepts OCS's proposal to offset the costs RMP incurred to provide the M&S with the revenue RMP received from customers. The adjustment includes a true up for any timing differences between the sales and cost of goods sold. This adjustment reduces the revenue requirement by $2.8 million.

8. Schedule 300 Fee Change

In its Application, RMP proposed to update a variety of Schedule 300 fees (*e.g.*, returned payment charge, pole cut disconnect/reconnect fees) and to implement a paperless bill credit program. The Application only included the revenue impact associated with the proposed paperless bill credit program. This incremental adjustment accepts the OCS's proposal to include all Schedule 300 fees in the revised revenue requirement. This adjustment decreases the revenue requirement by $0.75 million.

9. Reliability Coordinator Fees

This adjustment updates the reliability coordinator fees included in this case to reflect the expected level of fees during the Test Year driven by the recognition of the change from PEAK Reliability to the California Independent System Operator as the reliability coordinator. This adjustment reduces RMP's revenue requirement by $1.36 million.

10. Transmission Power Delivery Uncollectible Expense

In response to OCS's proposed adjustment to remove the transmission power delivery uncollectible expense, RMP replaced the base period transmission power delivery uncollectible expense with a three-year average. The result is a reduction to revenue requirement of $0.32 million.

11. Insurance Premium Update

RMP states it received updated information for the August 2020 premiums that more accurately reflects the level of insurance premiums that will be in place for the Test Year. This adjustment increases revenue requirement by $1.76 million.

12. Wildland Fire O&M Update

On June 1, 2020, after its initial rate case filing, RMP filed its Wildland Fire Mitigation Plan with the PSC in accordance with the Wildland Fire Planning and Cost Recovery Act,[4] to reflect the final costs of its Wildland Fire Mitigation Plan. This update increases revenue requirement by $1.51 million.

13. Wages and Employee Benefits Adjustment (WEBA) – Full-Time Equivalent (FTE)

UAE noted RMP has experienced a lower employee level by 35.2 average FTE from the base period, which it proposes RMP reflect in this case. This adjustment accepts UAE's proposed adjustment to reduce FTE count in the Test Year by 35.2. This adjustment reduces revenue requirement by $1.36.

[4] Utah Code Ann. § 54-24-101 *et seq.*

14. WEBA – United Mine Workers Association (UMWA) Correction

Initially, RMP mistakenly accounted for the UMWA transfer of retiree medical benefits obligation twice, on Page 4.2 Wages and Employee Benefits and on Page 8.14 Deer Creek Mine Adjustment. To correct this double count, RMP removed the UMWA transfer previously included in Wages and Employee Benefits in its revised revenue requirement. This adjustment reduces revenue requirement by approximately $0.71 million.

15. Wage Increase Calendar Year 2021 Annualization Adjustment

UAE recommended an adjustment to reflect the projected wage levels that will exist during the 12 months ended December 31, 2021, rather than the wage levels at year-end 2021. RMP accepted UAE's adjustment, which reduces revenue requirement by approximately $0.70 million.

16. Net Power Costs (NPC) Alignment

RMP updated its NPC estimate to reflect the delayed in-service dates of the Pryor Mountain and TB Flats II wind projects. RMP adds that its NPC revision excludes any of the standard price and contract updates associated with a typical full NPC update. This update increases revenue requirement by $3.37 million.

17. Nodal Pricing Model Cost Update

In responding to UAE Data Request 3.9, RMP determined its estimated in-service cost of Nodal Pricing Model capital addition increased from $4.0 million to $4.5 million. This adjustment increases revenue requirement by $0.02 million.

18. Other Decommissioning, Colstrip – Correction

Based on testimony from DPU, OCS, and UAE, RMP adjusted its Colstrip Decommissioning costs to correct for a formula error when it initially calculated the remaining life associated with the Colstrip plant. This adjustment decreases revenue requirement by an amount that is confidential.

19. Electric Plant Acquisition Adjustment – Craig and Hayden Plants

Because the Craig/Hayden Electric Plant Acquisition Adjustment will be fully recovered shortly after the end of the Test Year, OCS proposed RMP buy-down the remaining net book balance of this regulatory asset with TCJA dollars. RMP has accepted this adjustment that reduces revenue requirement by $2.24 million.

20. Property Tax Update

According to RMP, capitalization rates used by state assessment officials within the income approach decreased considerably from 2019 to 2020; therefore, the 2019 capitalization rates that were used to forecast RMP's $181.3 million estimated property tax expense are no longer valid. RMP's revised analysis using the updated (lower) 2020 capitalization rates estimates property tax expense for the Test Year of $191.4 million. This update increases revenue requirement by $4.43 million.

21. Pro Forma Plant Tax Update

This adjustment normalizes base period Schedule M, deferred tax expense, and accumulated deferred income tax balances to an estimated pro forma level for the Test Year. RMP's rebuttal filing includes an incremental change to reflect the impacts of an adjustment related to bonus depreciation on RMP's 2019 tax return[5] as well as changes to PTCs as a result of the delayed in-service dates for Pryor Mountain and TB Flats. This update increases revenue requirement by $6.58 million.

22. Removal of TCJA Balances – Correction

This adjustment corrects a mathematical error in the calculation of the balance used to remove the non-protected property EDIT regulatory liability. This correction increases revenue requirement by $0.33 million.

23. Pro Forma Plant Data Update

As UAE proposed and RMP agreed, this adjustment updates the forecasted plant-in-service balances for projects that have been delayed or canceled and are currently outside of the Test Year. Among other things, this update reflects the revised in-service dates for the TB Flats and Pryor Mountain wind projects, the Advanced Meter Infrastructure Project, transmission and distribution projects, the Wildland Fire Mitigation Plan capital additions, and associated impacts to depreciation expense, accumulated depreciation, and applicable deferred taxes. This adjustment reduces revenue requirement by $28.87 million.

24. Repowering Capital Additions

This adjustment reflects the final capital costs related to repowered wind plants as part of the revised revenue requirement. This adjustment increases revenue requirement by $0.35 million.

[5] *See* 26 U.S.C. § 481(a).

All of these adjustments result in a January 1, 2021 proposed revenue requirement increase of $49.5 million ("Step 1 Increase"). In rebuttal RMP proposes a second revenue requirement increase of $22.5 million on July 1, 2021 to reflect the completion of the Pryor Mountain and TB Flats wind projects ("Step 2 Increase"). Table 1 presents a summary of RMP's rebuttal position.

TABLE 1. RMP PROPOSED REVENUE REQUIREMENT AT REBUTTAL

Adjustment	Impact to Proposed Revenue Requirement Deficiency, $	$95,786,460
Capital Cost - Cost of Debt	-725,237	95,061,223
Capital Cost – Authorized Return on Equity	-22,291,405	72,769,818
O&M Escalation Removal	-3,567,245	69,202,573
Wheeling Revenue Update	2,266,267	71,468,839
REC Revenues Update	[redacted]	[redacted]
NTUA Revenue Correction	-77,614	71,007,724
M&S Inventory Sales Revenue Correction	-2,834,169	68,173,555
Schedule 300 Fees	-749,592	67,423,963
Reliability Coordinator Fees	-1,360,092	66,063,871
Transmission Power Delivery Uncollectible Expense	-316,205	65,747,666
Insurance Premium Update	1,761,187	67,508,853
Wildland Fire O&M Update	1,506,779	69,015,632
WEBA - Full-Time Equivalent	-1,360,027	67,655,605
WEBA - UMWA Correction	-708,975	66,946,630
WEBA - CY 2021 Annualization	-702,409	66,244,220
Rebuttal Net Power Cost Alignment	3,371,383	69,615,603
Nodal Pricing Model Update	23,962	69,639,565
Other Decommissioning Cost – Colstrip - Correction	[redacted]	[redacted]
Electric Plant Acquisition Adjustment	-2,238,716	66,693,505
Property Tax Update	4,432,354	71,125,860
Pro-Forma Tax Update	6,579,106	77,704,966
Removal of TCJA Deferred Balances - Correction	329,702	78,034,667
Pro-Forma Plant Data Update 10.20	-28,868,638	49,166,029

Repowering Capital Additions	345,624	49,511,653
Sum of Incremental Adjustments	*-46,274,807*	
January 1, 2021 Change in Required Revenues		***49,511,653***
Pryor Mountain and TB Flats - Phase 2		22,538,254
July 1, 2021 Cumulative Change in Required Revenues (RMP's Position after Rebuttal)		**$72,049,907**

In addition to these adjustments affecting revenue requirement, in rebuttal RMP adopted OCS's adjustment related to a carrying charge applied to the Deer Creek Mine Closure Cost category of RMP's Deer Creek Mine regulatory asset. This category includes $5.7 million in carrying charges that have been accruing monthly at RMP's cost of debt. However, starting in February 2016, the costs to which RMP applied the carrying charge included recovery royalties that have not been paid by RMP. OCS recommended removing the carrying charge on these as-yet undetermined and unpaid recovery royalties from the Deer Creek Mine Closure regulatory asset, and RMP agreed. This adjustment reduces the carrying costs in the Deer Creek regulatory asset by $418,333 with no direct impact to RMP's revenue requirement.

IV. REVENUE REQUIREMENT – DISCUSSION, FINDINGS, AND CONCLUSIONS

A. Cost of Capital

For the reasons we discuss in this order, we approve a cost of capital for RMP that we find and conclude to be just and reasonable with a long-term debt ratio of 47.5%, a common equity ratio of 52.5%,[6] a weighted average cost of long-term debt of 4.79%, and an allowed ROE of 9.65%. With all of these components, we find and conclude an overall rate of return on capital of 7.34% is just and reasonable.

[6] RMP proposed 0.01% preferred stock, an amount that does not impact the ultimate calculation of the overall rate of return on capital.

1. Cost of Long-term Debt

As adjusted in its rebuttal testimony, RMP proposes a Test Year embedded cost of long-term debt of 4.79%. No party in this proceeding contested RMP's evidence supporting that cost of debt, and we find and conclude that the proposal is just and reasonable. We approve a Test Year embedded cost of long-term debt for RMP of 4.79%.

2. Return on Equity (ROE)

Four parties provided testimony and evidence related to ROE: RMP, who proposed a 9.8% ROE; DPU, who proposed a 9.25% ROE; OCS, who provided a primary proposal of a 9.0% ROE and a secondary proposal of an 8.75% ROE depending on capital structure; and Walmart who provided testimony arguing that we should not increase RMP's currently authorized ROE.

All of the evidence presented on this issue is relevant to our task to determine a just and reasonable ROE. This task requires an evaluation of returns earned by investments of comparable risk and an ROE sufficient for RMP to attract necessary capital to provide safe, reliable, and adequate utility service in Utah. To some extent this task is a delegated legislative function that requires us to consider the evidence and ultimately make a decision exercising our judgment and discretion.

We start our evaluation with the most recently authorized (and stipulated) ROE for RMP, 9.8%, in 2014. We consider the extent to which financial conditions have changed since that decision, and the impacts those changed conditions might have on RMP's authorized ROE. There is no dispute that U.S. treasury rates have decreased significantly since 2014. There is a wide difference of opinion within the record about what impact those treasury rates should have on our decision, and how they should impact specific economic models. We find that the lower U.S. treasury rates, compared to 2014, provide at least a starting point to our analysis indicating that a reduction to the ROE approved for RMP in 2014 seems appropriate. While there is conflicting evidence about how we should view the future trajectory of interest rates, we find that the evidence related to potential short-term increases in interest rates is not sufficient to alter our finding that an ROE reduction is appropriate.

However, other evidence mitigates the significance of low treasury rates. It is universally recognized that the pandemic has made the 2020 economy and financial markets both unique and volatile. And the evidence in this proceeding demonstrates that the utility sector generally has not recovered during the second half of 2020 commensurate with other market recoveries. As we consider current market conditions and volatility in context of both customers and investors, we find that ROE adjustments in the current climate should be modest and conservative.

As we determine what level of ROE adjustment is appropriate in this economic climate, we evaluate the financial models presented in testimony. These models are relevant evidence, but relying too much on a single model type gives away an unacceptable level of our legislatively delegated authority. Each of the customary models can provide useful information in establishing the range of appropriate ROE outcomes. Each, however, also can be used to achieve remarkably different results depending on the input data selected and the underlying assumptions regarding future economic conditions and other pertinent factors. In fact, the evidence in this case dramatically illustrates this reality. Accordingly, we find that no single financial model or set of data inputs can conclusively calculate a specific utility's appropriate ROE.

Additionally, the financial models employ data from a proxy group of publicly traded companies selected for business and financial comparability to RMP which is not itself publicly traded. Moreover, as in previous cases, we consider returns that have been authorized nationally for other similar entities. While those data are relevant, they are not the beginning and end of an ROE decision. On one hand, every utility and jurisdiction is different in terms of regulatory climate, statutory and appellate structure, trackers and balancing accounts, and other factors that impact investor risks. On the other hand, authorized return levels for other utilities and jurisdictions are a concrete factor that informs the capital markets relative to the cost and value of regulated utility equity.

We find that substantial evidence exists in the record to demonstrate that the ROE ranges produced from the financial models utilized by the DPU and OCS[7] are unreasonably low. The evidence demonstrates that those ranges are generally not consistent with the currently authorized returns of other vertically integrated utilities and recent decisions from utility commissions in other jurisdictions. DPU and OCS at least implicitly acknowledged problems with their models by recommending ROEs outside of the range of the model results. RMP's financial models also were criticized in the record for being out of line with ROEs awarded in other jurisdictions in 2020, failing to use risk premiums from a recognized source, and using overstated growth rates.[8]

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[7] 7.24% to 9.17% for the DPU, and 7.60% to 8.95% for the OCS.
[8] Both RMP and Walmart provided models indicating a median range of 9.73%.

All the evidence around the financial models supports our finding that those models should inform, but not control, our ROE decision. Considering all the evidence and the unique volatile financial market conditions that currently exist, we conclude it appropriate to move RMP's allowed ROE down, but by a modest and conservative amount. Accordingly, we approve an allowed ROE for RMP of 9.65% and find that ROE to be just and reasonable.

3. Capital Structure

RMP proposes a capital structure of 53.67% common equity (an increase from RMP's currently authorized 51.43% common equity) and 46.32% long-term debt. OCS, the only party who contested RMP's proposed capital structure, recommends 50% common equity and 50% long-term debt.

We recognize that ROE and capital structure are symbiotic factors that contribute to an overall cost of capital and cannot be considered in isolation from each other. Equity simply demands a greater expected return than debt, which means it is more expensive for customers. Correspondingly, the level of equity impacts the risk and, therefore, cost of debt. Considering the downward adjustment we are making to RMP's ROE, we find that a modest increase to RMP's currently authorized common equity ratio, smaller than the increase RMP requests, is just and reasonable.

RMP and OCS criticize each other's modeling that leads to each of their capital structure recommendations. These criticisms demonstrate that like an ROE decision, a capital structure decision must be informed by, but not controlled by, modeling results. However, we find that the reliance on short-term debt in the OCS modeling is inconsistent with RMP operations and risks double counting rate base and construction work in progress. This deficiency in the OCS modeling detracts from the credibility of the capital structure proposed by the OCS.

Additionally, we find that an increase to RMP's currently approved common equity ratio is likely to prevent volatility in RMP's cost of debt, particularly in context of recent changes to federal tax law that have impacted the way credit agencies view the utility sector. RMP's anticipated unusually large capital spending requirements also support RMP's request to increase its currently approved common equity ratio; we find that a lower equity ratio could make it more difficult for RMP to maintain its credit rating and therefore increase RMP's cost of debt.

Nevertheless, customers pay for the common equity ratio because equity is more expensive than debt. We must balance the effort to keep RMP's cost of debt low with what customers will pay to fund that effort. Considering and balancing those interests, we find and conclude that it is just and reasonable to approve a capital structure with a long-term debt ratio of 47.5% and a common equity ratio of 52.5%. We approve those ratios.

B. Operations and Management (O&M) Expense

1. Property Tax Expense

RMP's Application includes a system[9] Test Year forecast property tax expense of $181.3 million. DPU provides an adjustment using the average increase in property taxes from 2011 – 2019 to estimate the Test Year property tax expense. DPU believes that basing the expected property tax expense on historical data provides a more reasonable estimate and proposes to reduce RMP's expense forecast.

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[9] System expenses include expenses for all of the states in which PacifiCorp operates. We later revise these numbers as appropriate to represent the accurate revenue impact in Utah for RMP.

In response, RMP provided an update that incorporates the capitalization rates used during the 2020 assessment season. These revised capitalization rates result in a system Test Year property tax expense of $191.4 million. RMP argues DPU's calculation "fails to consider the key factors that lead to increased assessed values" and, therefore, provides an understated estimate of Test Year property tax expense.[10] RMP also demonstrates the relationship between property tax charged and net investment in operating property, which results in a 1.2% increase in property tax expense for each dollar increase in net investment in operating property. On surrebuttal, OCS voiced objections over the lateness of RMP's property tax expense update, the magnitude of the adjustment, and the limited information provided with RMP's rebuttal update. As such, OCS excluded the updated property tax expense in its calculations for projected Test Year expenses.

While DPU's method to estimate Test Year property tax expense is reasonable in an average year, we find it fails to consider the additional assets RMP will place into service during 2019 and 2020. RMP predicts net investment in operating property will increase by $3.0 billion during 2019 and 2020, an average of $1.5 billion per year. This amount is substantially greater than the average increase in net operating property of roughly $379 million each year from 2011 through 2018. Because of these conditions, we find RMP's method for forecasting property tax expense to be reasonable, and we adopt RMP's expense forecast.

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[10] S. McDougal Rebuttal Test at 23:439-440.

2. Lobbying Expenses

DPU asserts RMP's FERC account 930 forecast includes expenses RMP paid to Edison Electric Institute (EEI) and the National Hydro Association, Inc. (NHAI) for lobbying activities and that these expenses are not properly recoverable from customers. RMP asserts that EEI and NHAI lobbying activity expenses are booked to FERC account 426.4, an account that is not recovered from customers. Thus, according to RMP, the expenses associated with lobbying that DPU proposes to remove are not included in RMP's forecast revenue requirement and no adjustment is necessary.

At hearing, after RMP pointed out that lobbying expenses associated with these entities are recorded in account 426, DPU withdrew its recommended adjustment for the EEI expense. DPU, however, did not withdraw its adjustment related to the NHAI expense. Based on RMP's testimony and cross-examination at hearing, we find there is no lobbying expense associated with NHAI included in RMP's proposed revenue requirement and no adjustment is necessary.

3. Civic Goodwill-Related Participation

DPU proposes an adjustment to remove the expenses in FERC accounts 930 and 921 related to memberships in civic-related organizations, such as various chambers of commerce, from RMP's revenue requirement. DPU claims RMP's participation in these organizations does not provide a quantifiable benefit to customers, is not necessary for the provision of safe and adequate electric service, and benefits shareholders.

RMP asserts that participating in organizations associated with civic goodwill is beneficial to customers because it provides "basic information which aids [RMP's] development of its load forecasts and planning to meet the utility service needs of the communities we serve."[11] Further, RMP testifies that chamber of commerce meetings are often a source for learning about new load planned in a community or other matters that might impact RMP's infrastructure or service protocols. RMP maintains participation in these organizations is critical to its efforts to remain informed, to build and maintain relationships with community leaders, and that such activities benefit customers.

For the reasons set forth by RMP, we find that costs associated with reasonable participation in civic goodwill-related organizations are prudently incurred because participation in these organizations supports timely and efficient planning and open dialogue with business and community leaders, to the benefit of RMP's customers.[12] Accordingly, we decline to adopt DPU's proposed adjustment.

4. Employee Appreciation and Conference Expenses

DPU proposes an adjustment of approximately $86,000 to the Utah revenue requirement to remove expenses in FERC account 921 related to employee appreciation events, business travel, and conference expenses. DPU asserts these items are discretionary and are not required to provide safe and adequate service to customers; therefore their recovery from customers should be disallowed.

RMP asserts attendance at leadership conferences, which account for a large portion of the expenses at issue, are not perks or incentives but rather provide training, education, and strategic opportunities for RMP's leadership team to improve their skills and build important

[11] Rebuttal Test. of S. McDougal 34:692-94.

[12] In addition, these meetings may result in RMP becoming informed of service quality-related issues.

relationships in furtherance of safe and reliable service for customers. RMP testifies its employee appreciation efforts support its ability to attract and retain talented employees, and recognizing employees for extraordinary contributions is a reasonable expense that RMP should be allowed to recover in rates. RMP also explains it had already removed from its Application some of the business travel charges that DPU contests. RMP represents that, overall, the forecast amounts for travel are a reasonable estimate of expected Test Year expenses.

We find that the level of expenses related to leadership training and business travel are reasonable, appropriate for inclusion in account 921, and provide training and opportunities to build skills and relationships that support safe and reliable electric service to customers. We also find that the level of expenses related to employee appreciation are reasonable and that these expenses contribute to retaining skilled employees, which benefits customers. For these reasons we do not adopt DPU's proposed adjustment.

5. Non-Labor O&M Expense Escalation Update

RMP applied the IHS Markit (IHS) indices, based on the IHS fourth quarter 2019 forecast released in February 2020, to the non-labor O&M expenses to develop its Test Year information. OCS recommends RMP should use the more recent IHS first quarter 2020 forecast issued in May 2020 to determine the non-labor O&M expense amount in the Test Year. DPU agrees with OCS and supports its adjustment. UAE advocates its long-standing position of removing all expense escalators.

OCS maintains the industry-specific escalation factor forecast has changed substantially since the 4th quarter of 2019 and is no longer reflective of projected circumstances. OCS states RMP has agreed to reflect the impact of the more recent IHS Markit study in its Oregon rate case proceeding. DPU represents that the "more recent … indices are more relevant to the case than the Last Quarter 2019 IHS Markit indices as filed by [RMP]."[13]

Due to the economic uncertainty surrounding the COVID-19 pandemic, in rebuttal RMP removed all escalators from non-labor O&M expenses. RMP claims that applying the updated escalator would be inappropriate given the "uncertainty and difficulty forecasting such an unprecedented event."[14] RMP believes that including the updated escalator without analyzing the "impact to all other costs and revenues does not accurately represent the total change of the COVID-19 pandemic."[15]

OCS disagrees with RMP's revised proposal, arguing RMP has regularly applied escalation factors to its non-labor O&M expense in prior rate cases and now asks the PSC to ignore this long-standing practice only because the result would be a reduction to the base year non-labor O&M expense. OCS contends application of the escalation factors should be consistent.

We find that the evidence supports the non-labor O&M escalators proposed by OCS, and we conclude that the adjustment is consistent with past precedent. Updating the escalation factors is consistent with RMP's proposed rebuttal updates in other expense categories based on more current information. We find it reasonable to apply an expense escalator to estimate expenses during the Test Year, as we have in previous rate cases, regardless of whether the factors are positive or negative. Accordingly, we find OCS's non-labor O&M escalators in this case are

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[13] Rebuttal Test. of B. Salter at 3:67-69.
[14] Rebuttal Test. of S. McDougal at 40:820-21.
[15] *Id.* at 40:814-17.

reasonable, and we order an adjustment to RMP's requested revenue requirement. TABLE 3 – CONFIDENTIAL. REVENUE REQUIREMENTS ADJUSTMENTS, *infra* ("Table 3"), provides the incremental impact of this adjustment to revenue requirement.[16]

6. Removing Certain Costs from Non-Labor O&M Expense Escalation

According to OCS, RMP included several costs in the base year non-labor O&M expenses that should not have been escalated. OCS proposes removing the Utah situs uncollectible expense booked in FERC account 904 and certain labor costs booked in FERC accounts 926 and 929. OCS testified RMP agrees with its proposal and that it would update its escalation adjustment in rebuttal testimony. In rebuttal, RMP removed all non-labor O&M escalators, so it did not directly address the specific expenses OCS suggests removing. Based on OCS's testimony and RMP's apparent agreement with this adjustment, and in light of our acceptance of using updated IHS indices, we adopt OCS's adjustment. Table 3 provides the incremental impact of this adjustment to revenue requirement.

7. Generation Overhaul Expense

RMP's Application includes an adjustment that normalizes generation overhaul expense using a four-year historical average for the 12-month periods ending December 2016 through 2019 ("RMP's Method"). Before averaging, RMP restated the annual expense amounts to December 2019 dollars using certain inflation factors. RMP maintains that the purpose of averaging is to adjust for uneven costs, and it believes that without restatement to constant

[16] Some of the adjustments we make to RMP's revenue requirement include confidential numbers. To avoid allowing calculation of any confidential components, we treat all incremental adjustments to RMP's revenue requirement as confidential. The total revenue requirement adjustment is not confidential.

dollars the overhaul expenses reflected in rates will be systematically understated. RMP's testimony does not identify the source of the inflation factors used to restate the annual amounts. RMP provides a hypothetical example in support of its proposal. Further, RMP maintains "[t]o ignore an adjustment accounting for the differing purchasing power of dollars in different years is to ignore inflation that has already occurred."[17]

DPU supports RMP's Method. DPU states economic and statistical theories suggest RMP's Method is on average more accurate. DPU maintains that efficiency improvements in RMP's procedures are not likely to be significant from one overhaul to the next. In addition, to the extent that there are cost saving improvements in RMP's overhaul procedures, these improvements are properly reflected in the choice of an appropriate inflation rate. At hearing, DPU stated it did not examine the inflation factors RMP used in its calculations.

OCS recommends the historical generation overhaul expenses should not be escalated for purposes of normalizing generation overhaul expense. OCS provides a history of the generation overhaul adjustment in prior cases and asserts that in this case RMP has provided no additional information or analysis in support of its adjustment. Further, OCS maintains RMP's hypothetical example neither factors in productivity offsets nor is specific to RMP's overhaul expenses.

Given the variation in the generation overhaul expense from year to year, we approved the use of a four-year historical average to normalize overhaul costs in Docket Nos. 07-035-93[18]

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[17] Rebuttal Test. of S. McDougal at 43:868-70.

[18] *In the Matter of the Application of RMP for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per*

and 09-035-23.[19] However, we did not accept RMP's proposal to restate the average expense for each year to constant dollars in these dockets.[20]

In this case, RMP relies on economic theory and generalized models. RMP provides no analysis of actual generation type (*i.e.*, coal, gas, wind, geothermal, etc.), unit specific historical cost and budget data, or forecast overhaul schedule to support its contention that rates will systematically understate generation overhaul expenses absent use of RMP's Method. In light of those deficiencies and DPU's failure to examine the specific inflation factors RMP used, we find the record is insufficient to support a deviation from our previous decisions on this issue. RMP is the gatekeeper of information and must provide supporting analysis based on actual historical information. We therefore approve the OCS's generation overhaul adjustment to RMP's forecast. Table 3 provides the incremental impact of this adjustment to revenue requirement.

8. Transmission Power Delivery Bad Debt Expense

RMP reports system uncollectible expenses related to transmission power delivery customers recorded in Account 904 of $981,923. OCS recommends that amount be excluded

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Year, and for Approval of a New Large Load Surcharge, Docket No. 07-035-93 (Report and Order on Revenue Requirement issued Aug. 11, 2008).

[19] *In the Matter of the Application of RMP for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 09-035-23 (Report and Order on Revenue Requirement, Cost of Service and Spread of Rates issued Feb. 18, 2010).

[20] In Docket No. 09-035-23, our February 18, 2010 Order stated: "In addition to those reasons enunciated in our prior order in Docket No. 07-035-93, [RMP] provides no analysis of how [its] approach when applied to historical data provides reasonable results over time. The evidence provided in this case, and in other recent cases, is not sufficient to support adoption of [RMP]'s method. For these reasons we do not accept [RMP]'s recommendation, rather we uphold our original decision in Docket No. 07-035-23 and therefore accept the [OCS's] adjustment." *Id.* at 97.

from the adjusted Test Year because the amount is a large increase in transmission power delivery bad debt expense over the $298 RMP reported in 2018, and because RMP has not provided any evidence showing that the base year level of those costs is an appropriate predictor of future expense levels.

RMP responds that a single customer accounted for the majority of the bad debt expense in 2019 and that, although RMP reported far lower bad debt expense in 2017 and 2018, it is not uncommon for RMP to report a bad debt expense near the magnitude of that reported in 2019. RMP proposes an adjustment to the base year bad debt expense to equal an average of that amount for the previous three years, reducing the revenue requirement by $312,475. OCS disagreed with RMP's counterproposal, arguing that RMP's allocated costs include interconnection studies that exceed transmission customer deposits and collections, and that, based on an OCS data request, RMP is still pursuing collection of the expense.

We find to be reasonable RMP's proposal to adjust the base year bad debt expense to an average of that expense for the previous three years. In this instance, averaging acceptably accounts for costs with high variability from year-to-year, and RMP's accounting treatment of the large bad debt expense attributable to a single customer in 2019 appears to be correct. OCS does not contest RMP's accounting treatment but rather disagrees that expenses of this type should be included in Utah customer rates. We find no evidence that RMP improperly incurred or accounted for the contested expenses, and we find that a three-year average will effectively forecast RMP's ongoing transmission-related bad debt expense. We conclude that RMP may include in Test Year revenue requirement a transmission bad debt expense equal to the average of that expense for the previous three years.

9. Annual Incentive Compensation Plan Expense

RMP offers its employees an annual incentive compensation plan ("AIP") that provides cash awards to employees based on the company, department, and individual performance. UAE argues that RMP should not be allowed to recover in customer rates the portion of the plan cost associated with rewarding its employees for RMP financial performance rather than customer-serving performance goals such as improving customer satisfaction, operating efficiency, and safety. Based on an RMP response to a UAE data request, UAE estimates that a certain percentage of each employee's incentive compensation award is based on achieving RMP's allowed return on equity, and a greater percentage is based on PPW Holdings, an unrelated affiliate of RMP, achieving a particular net income. UAE recommends the PSC disallow cost recovery for the portion of plan expense attributed to achieving these goals.

UAE asserts the benefits of providing employees cash incentives based on RMP's financial performance accrue to shareholders and not customers, and that established PSC precedent dictates the cost of those incentives be disallowed. UAE cites an order we issued in 1995 disallowing then-telephone utility US West Corporation's (USWC) cost recovery of cash awards provided to USWC executives under its incentive compensation plan. [21] We reasoned then that USWC failed to provide a "quantitative demonstration . . . of benefit to ratepayers" for

[21] Direct Test. of K. Higgins at 28:613–42. UAE refers to *Re US West Comm., Inc.* Docket No. 95-049-05 (Order issued Nov. 6, 1995), which predates the database of documents available on the PSC's website but is available at 1995 UTAH PUC LEXIS 10.

amounts paid to executives based on USWC's long-term stock price.[22] RMP responds that its goal each year is for its employees, on an overall basis, to earn through base compensation and incentive awards combined, an amount of compensation commensurate with market rates, such that any incentive amount is more properly characterized as an at risk portion of market pay rather than as an additional or bonus award. And RMP further asserts that each of six core principles that determine incentive goals benefit customers as well as shareholders, including those principles associated with financial performance.

The RMP AIP at issue here is distinct from the US West plan at issue in the docket cited by UAE. The incentive goals in RMP's AIP predominantly benefit customers because they reward operational excellence, environmental respect, customer service, and other beneficial attributes of employee performance. We previously articulated this distinction in evaluating a predecessor PacifiCorp AIP similar to the one at issue here and allowed recovery of its costs in rates because the plan included "goals benefiting ratepayers" and "no expense [was] claimed to meet purely financial goals."[23] Consistent with that decision, we find the record in this docket establishes that the six incentive goal categories predominantly benefit customers. Regardless of RMP's internal incentive plan structure, we find that the evidence supports RMP's contention that aggregate employee base pay plus all available incentive awards generally reflect the average market rate. We conclude that it is prudent for RMP to pay its employees awards related

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[22] *Id.*

[23] *In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Co.*, Docket No. 97-035-01 (Report and Order issued March 4, 1999), available at 1999 Utah PUC LEXIS 16..

to the incentive components that were presented in evidence. This avoids potential harm to customers that could occur if total compensation less than the market rate resulted in RMP's employees lacking necessary and appropriate skills. Accordingly, we decline to make the requested adjustment to RMP's revenue requirement.

10. Pension Settlement Losses

RMP testified it has "approximately [$]420 million of unrecognized net actuarial losses recorded as a regulatory asset, which will generally be recognized as [a] pension expense over the average remaining life of planned [sic] participants, which is approximately 21 years."[24] However, RMP brought attention to circumstances that require RMP's financial accounting to deviate from this treatment in a 2018 proceeding ("2018 Docket").[25] When the aggregate lump sum cash distributions from RMP's pension plans exceed a defined threshold in a calendar year, the Financial Accounting Standards Board's rules, specifically Accounting Standards Codification Topic 715 ("FASB's Rule"), require RMP to immediately recognize a portion of the unrecognized actuarial gains or losses in earnings ("Pension Settlement Adjustments"). These lump sum cash distributions generally occur at the election of a plan participant who accepts the lump sum in full satisfaction of RMP's obligations to the participant under the applicable retirement plan.

In the 2018 Docket, RMP sought a deferred accounting order to defer these Pension Settlement Adjustments for recovery in a future general rate case by amortizing them as

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[24] Nov. 3 Hr'g Tr. at 209:10-16.
[25] *See generally Application of RMP for an Accounting Order for Settlement Charges Related to its Pension Plans*, Docket No. 18-035-48.

expenses using “the same period that is used to amortize” the underlying regulatory asset or liability.[26] Other stakeholders generally opposed RMP’s request, arguing the issue should be considered in the context of a general rate case. We found the request would violate the prohibition against single-issue ratemaking absent a showing the expenses were extraordinary or unforeseeable.

No party in the 2018 Docket or here has argued the Pension Settlement Adjustments are not recoverable in the context of a general rate case. To the extent controversy exists, it concerns the manner in which RMP should recover any such losses.

Here, RMP forecasts Test Year pension losses of $11.9 million, and RMP’s preference is to include this full amount as a component of pension expense. The expense would remain in rates until the next general rate case. RMP alternatively suggests establishing a balancing account that would annually true-up the difference between the actual and expected level of net periodic benefit cost of RMP’s pension and other post retirement plans.[27]

The OCS and UAE oppose RMP’s request to include its full pension settlement losses for the Test Year as a component of pension expense. They argue RMP should recover these pension expenses over the expected remaining life of the Pension Plans. This will facilitate RMP recovering its annual pension costs in the same manner in which it would have recognized them had lump sum distributions not exceeded FASB’s threshold.

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[26] Application for Approval of a Deferred Accounting Order at 10, filed December 31, 2018 in the 2018 Docket.
[27] For simplicity, we refer to RMP’s pension plan and other post-retirement plans cumulatively as “Pension Plans.”

We conclude that RMP's Test Year pension settlement losses are plainly recoverable. Additionally, we find it reasonable to recognize recovery of those pension losses consistent with the required financial accounting standard.

We recognize that financial accounting, income tax accounting, and regulatory accounting have different purposes. The required financial accounting treatment by RMP of these pension settlement losses is not dispositive of the issue presented to us. Here, substantial evidence supports the uncontested assertion that certain eligible employees have elected to take cash distributions to permanently settle the Pension Plans' obligations to them in an amount that, aggregately, triggers a required change in RMP's financial accounting. We conclude that the same facts that require a change in RMP's financial accounting also justify inclusion of those expenses in the Test Year. We find that requiring the settlement losses to be amortized as the OCS and UAE recommend would be ignoring the fact that the settlement losses occurred. We find no reason to remove those actual costs from the Test Year.

However, we find these pension settlement losses that RMP incurs in the Test Year are not sufficiently representative of the costs RMP is likely to incur in subsequent years owing to the contingent and binary nature of Pension Settlement Adjustments. Indeed, if FASB's threshold is not triggered, RMP will incur no such losses and this appears to have commonly been the case in prior years. Additionally, testimony suggests circumstances could arise where FASB's Rule required immediate recognition of previously unrecognized actuarial gains in earnings. The adjustments FASB's Rule requires are a uniquely unpredictable and volatile accounting phenomenon.

We conclude a balancing account with an annual true-up provides a just and reasonable mechanism to account for these sporadic but potentially significant events. In its post-hearing brief, RMP argues this balancing account should "true-up annually the difference between the actual and expected level of net periodic benefit cost of [RMP's] pension and other post retirement plans, including settlement losses and any other potential curtailment gains and losses."[28] We expressly decline to create such a broad account; our intention is not to fundamentally alter the existing rate treatment of expenses associated with the Pension Plans. Rather, we conclude the specific Pension Settlement Adjustments that RMP must make to comply with FASB's Rule pose a unique challenge for ratemaking such that tracking them in a balancing account is appropriate.

In sum, RMP may recover the $11.9 million in settlement losses it anticipates incurring during the Test Year in rates effective January 1, 2021. However, RMP will establish a balancing account and true-up, on an annual basis, the Pension Settlement Adjustments that it actually recognizes with the amount it recovered in rates. Our conclusions here are sufficient to resolve the issue as regards rates to be effective January 1, 2021. We direct RMP to initiate a proceeding before the PSC on or before March 1, 2021 to establish the balancing account.

11. Deer Creek Mine Closure Regulatory Asset

RMP seeks to buy down Utah's share of costs associated with the Deer Creek Mine Closure Regulatory Asset using RMP's non-protected EDIT balances. RMP has been accruing those costs in a regulatory asset since December of 2014 under a settlement stipulation that we

[28] RMP's Post-Hearing Br. at 16.

approved in April of 2015.[29] Included in the costs RMP seeks to buy down are estimated recovery costs RMP expects to owe to the Office of Natural Resources Revenue (ONRR), a unit of the U.S. Department of the Interior, and carrying charges authorized under the 2015 order. As explained previously, in rebuttal testimony, RMP adjusted the regulatory asset balance by $418,333 to remove carrying charges applied to costs that had not yet been paid. In addition, RMP increased the amount of recovery-based royalties it seeks to offset from $5,249,190 to $6,777,197.

OCS and UAE recommend we disallow RMP cost recovery of the yet-to-be-determined royalties because those amounts are not yet known and measurable, for a proposed reduction to the Deer Creek Mine Closure regulatory asset of $6,677,197. Further, according to OCS, there is the potential that RMP may receive overriding royalties on coal produced from the Fossil Rock coal reserves that would serve to reduce the regulatory asset associated with the amounts RMP ultimately is required to pay to ONRR for these royalties. UAE proposes the EDIT buy-down amounts associated with the recovery royalties plus a carrying charge be credited to customers through Schedule 197 in proportion to the two-year amounts proposed by RMP in its rate mitigation proposal.

RMP concedes that the recovery royalty amount is an estimate, but argues that the Deer Creek Mine Closure is long complete and that continuing to defer the recovery royalties for a future rate case would create intergenerational equity issues.

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[29] *See In the Matter of the Voluntary Request of RMP for Approval of Resource Decision and Request for Accounting Order*, Docket No. 14-035-147 (Report and Order Memorializing Bench Ruling issued April 29, 2015).

We conclude RMP should not recover the portion of Deer Creek Closure costs associated with the ONRR royalties that are not yet known or measurable and accept OCS's and UAE's proposed adjustment to RMP's proposed EDIT buy-down amount. RMP concedes that the recovery royalties associated with the Deer Creek Closure are still preliminary due to project delays. Moreover, RMP disclosed in response to an OCS data request that it has not yet received any correspondence from the ONRR related to the recovery royalties. Therefore, RMP does not have enough information about the final amount of recovery royalties it will eventually owe at this stage to reasonably estimate that amount. Based on RMP's limited information and the reasons identified by OCS and UAE, we find OCS's and UAE's proposed adjustment is reasonable.

In this current economic climate we find UAE's proposal to return the EDIT buy-down amounts through Schedule 197, adjusted by our decision related to RMP's rate mitigation proposal, timely refunds the deferred tax benefits due to customers and is therefore reasonable and appropriate. We agree with OCS that once the amounts of the recovery-based royalties are known and measurable and actually paid by RMP, they can be considered in an appropriate future proceeding at which time a prudence review can be conducted. Because this adjustment relates to RMP's EDIT Amortization Balance, there is no direct impact to revenue requirement.

12. Lake Side 2 Unit 3 Outage Costs

OCS recommends the PSC disallow RMP's proposed cost recovery related to an outage at Lake Side 2 Unit 3 including all repair costs and replacement power costs and proposes a confidential reduction to revenue requirement. OCS further proposes that the replacement power costs should be addressed in the appropriate EBA proceedings that cover the years 2019 and 2020. OCS maintains the outage was the result of either RMP, or its contractors, not conducting the work on the unit in a sufficiently careful manner. OCS asserts that customers should not be liable for RMP's failures to perform, or require, competent work. Further, OCS points out that this is the second outage of this type RMP has experienced at the Lake Side plant, with the first similar event occurring in 2009.

RMP disagrees with OCS's adjustment and requests the PSC allow full recovery of the costs associated with this outage including the replacement power costs. RMP asserts OCS overstates its conclusion as Siemens' root cause analysis (RCA) identified multiple other "Low Probability" causes that could have led to the failure. Emphasizing the importance of understanding the root cause, RMP represents it hired a third-party contractor to perform an additional RCA, which has not yet been completed. RMP maintains it has demonstrated that it operated, maintained, and acted prudently with respect to Lake Side 2 Unit 3 by: (i) operating the unit within design; (ii) following OEM recommendations; (iii) providing oversight and being engaged with Siemens during maintenance activities; (iv) using the OEM experts on this equipment to perform maintenance; and (v) following foreign material exclusion policies and procedures for both RMP and the OEM. All of these actions demonstrate a concerted effort on the part of RMP to operate and maintain the unit prudently.

We find RMP has provided substantial evidence it has operated and maintained Lake Side 2 Unit 3 prudently. Significantly, RMP followed prudent practices by performing an RCA. There is nothing in the completed RCA that identifies negligent or imprudent actions as a likely cause of this outage. Rather, we see evidence that RMP engaged qualified expert companies to develop, perform, and/or recommend procedures to operate this plant. Given that RMP continues work to uncover the root cause of this outage, and RMP has demonstrated concerted efforts to prudently contract for quality services in maintaining and operating this plant, we find the evidence does not support disallowance. Further, we do not want to provide a disincentive to RMP to engage in comprehensive RCAs for these types of events, and we particularly do not want to provide a disincentive for the second RCA that is currently in process. We find that RMP acted prudently by engaging a disinterested third party to perform a second RCA, and we will not penalize RMP for doing so because the results of that second RCA are not complete, especially in light of the results of the first RCA that support our finding of prudent operation and maintenance.

Accordingly, we accept RMP's proposal to recover its costs associated with the Lake Side outage, and we do not order any adjustment to RMP's requested revenue requirement based on this issue.

C. Rate Base Adjustments

1. Prepaid Pension and Other Post- Retirement Assets

RMP argues a misalignment exists because the federal Employee Retirement Income Security Act requires RMP to make plan contributions that RMP cannot immediately expense under applicable accounting rules. To resolve this issue, RMP requests it be allowed to include its entire "cumulative net prepaid pension and other post-retirement asset" (cumulatively, "Pension Assets"), presently $252.335 million, in rate base, earning a return equal to its weighted average cost of capital. The value of the Pension Assets has not previously been a component of rate base.

RMP contends it should earn a return on the Pension Assets because it must finance them. Yet, RMP has been recovering pension expense every year based on the stipulated cost in its last general rate case ($10.5 million), and its actual pension costs appear to have been negative in subsequent years. That is, customers have been paying for pension costs in rates even though RMP did not actually incur them. The evidence further suggests RMP's Pension Assets have grown largely because of these negative costs (*i.e.* customers paying for pension costs in rates in years for which RMP contributed zero to the plans) and robust returns on the Pension Plans' underlying assets.

RMP's Pension Assets have been in an accrued liability position during many years. At no such time did RMP seek a corresponding reduction in rate base owing to the accrued liability. RMP characterizes its failure to seek a reduction during such years as an oversight. We find that it would not be just and reasonable to allow RMP to change the treatment of these assets now that doing so would favor RMP, as opposed to customers.

Considering the intergenerational inequities that would occur if we included the Pension Assets in rate base now, without having included them during years in which they were in an accrued liability position, it is not necessary to consider whether substantial evidence supports RMP's assertion that it must finance the Pension Assets, and if it does, whether that financing justifies including the Pension Assets in rate base. Table 3 provides the incremental impact of this adjustment to revenue requirement.

2. RMP's Proposed Advanced Meter Infrastructure (AMI) Project

RMP seeks to implement a program it calls the "Utah Advanced Meter Infrastructure Project" ("AMI Project") that "consists of the construction of an AMI field area network to enable remote reading of 790,000 existing automatic meter reading (AMR) meters, and on-site replacement of approximately 175,000 existing meters to smart meters."[30]

RMP asserts that, upon completion, the AMI Project will "fully automate and retrieve hourly meter reading data on a daily basis, allow Utah customers to access their [hourly] usage data on [RMP's] website … and improve outage management."[31] RMP identifies additional benefits, including but not limited to the following: (i) enhanced customer service through better and faster access to customer information; (ii) remote connection and disconnection with smart meters that obviate the need to deploy an employee to the site; (iii) analytic information that can be used to assess system performance and improve service; (iv) reduced costs associated with meter reading; and (v) enhanced safety and reduced carbon dioxide emissions through the reduction of vehicles used for drive-by meter reading.

RMP contends the AMI Project commenced in 2018 when it executed a contract with an information technology vendor. However, "cybersecurity design changes required corrections, which resulted in a delay to the original schedule."[32] The revised schedule anticipates installation of the field area network starting in 2021 "and will provide the ability to begin reading the

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[30] Direct Test. of C. Mansfield at 1:22-2:25.
[31] *Id.* at 24:513-25:516.
[32] *Id.* at 27:579-80.

existing AMR meters shortly thereafter."[33] RMP will begin installation of AMI meters in late 2021 and will finish by the end of 2022.

RMP estimates its total AMI Project cost will be $77.9 million in capital costs and $4.3 million in operation and maintenance costs. The capital costs include $30.1 million for meters, $35.2 million for information technology and telecommunications, and $12.6 million for customer service and project management.

The DPU and OCS oppose RMP's recovery of any AMI Project costs in this Test Year, arguing the project will not yet be used and useful. The DPU urges "[t]he general principle that utility investors provide the capital and remain at risk at least until such time as the assets are actually used and actually useful for utility service provides a valuable tool in the decision of when customers begin to pay investors for the use of those assets."[34] Further, "[c]apital that is anticipated to be taken out of service beyond the end of the rate effective period is generally not removed from current rates" absent a general rate case or interim rate adjustment.[35] These arguments weigh against allowing RMP to recover for AMI Project costs in this Test Year during which it will remain largely unimplemented.

We recognize the potential benefits from the use of advanced metering infrastructure and we do not discourage RMP from pursuing it so long as it can be demonstrated to be cost effective. Nevertheless, RMP has been forthcoming that the AMI Project is not projected for completion until the end of 2022, a year after the Test Year (itself a future projection) has ended.

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[33] *Id.* at 27:577-28:583.
[34] DPU's Post-Hearing Br. at 8.
[35] *Id.*

While RMP testified that a limited amount of work will be done in the Test Year, we find the evidence simply does not support a finding that the AMI Project will yield meaningful benefits during the Test Year. Even if there were a showing of meaningful benefits, the record evidence simply does not provide enough detail to establish proper rate base accounting of the portions of the AMI Project that are expected to be operational each month within the Test Year. Therefore, we must conclude its costs cannot be included in rate base in this docket. Table 3 provides the incremental impact of this adjustment to revenue requirement.

3. Cholla Unit 4

RMP requests that the PSC establish a deferral account to defer and amortize certain costs associated with closing Cholla Unit 4, an RMP-owned unit of a four-unit coal-fired power plant that RMP determined is economic to close by the end of 2020. RMP's costs include incurred Construction Work In Progress (CWIP), the value of estimated obsolete materials and supplies (M&S), and liquidated damages, all of which RMP proposes to defer and amortize through the end of the plant's original depreciable life in April 2025. RMP also proposes using the account to true-up any differences in final closing costs and decommissioning costs from its estimates in this general rate case (GRC).

UAE recommends that the PSC disallow RMP's proposed cost recovery of the CWIP and M&S expenses associated with the Cholla Unit 4 closure, for a total reduction of $960,404 from RMP's proposed revenue requirement. UAE argues that the plant associated with the CWIP and M&S expenses was never placed into service and therefore never used to serve customers, making cost recovery from customers inappropriate. UAE further asserts RMP should bear the burden of any residual costs associated with the early retirement of a plant such as Cholla Unit 4, even if that closure was itself a prudent economic decision for RMP and customers.

RMP responds that the CWIP and M&S costs were incurred as part of its normal plant maintenance procedures, that the costs were incurred before RMP made the decision to close Cholla Unit 4, and that customers would have been harmed if RMP had pursued the projects associated with those costs. RMP further notes that the M&S inventory was used to support the ongoing operations of the plant, including providing necessary spare parts in the event of an outage.

We find and conclude that RMP should not be denied cost recovery for prudently-incurred CWIP and M&S expenses associated with the closure of Cholla Unit 4 solely because RMP made the economically sound decision to retire the unit before the end of its useful life. RMP testified that it will be required to close Cholla 4 for environmental compliance reasons by April 30, 2025 at the latest, and that instead retiring the unit by year-end 2020 produces net benefits for RMP customers. We find RMP properly incurred the M&S expenses because it needed those assets for the ordinary operation of Cholla Unit 4, and to make necessary repairs in the case of an outage. And we find that RMP reasonably incurred CWIP costs in pursuing upgrade projects that would have benefited customers had a shift in RMP's future projections not created the economic necessity to close the unit before the end of its useful life. RMP should not be required to bear the risk of prudently-incurred expenses for a reasonably-pursued project solely because its projected benefits did not come to fruition.

Based on the foregoing, we accept RMP's proposal to recover its costs associated with the Cholla Unit 4 closure in a deferral account and we decline to order any adjustment to RMP's requested revenue requirement based on this issue.

4. Allowed Rate of Return on Craig Unit 2 Selective Catalytic Reduction (SCR)

RMP requests to recover in customer rates costs related to a selective catalytic reduction (SCR) retrofit at Craig Unit 2, a three-unit coal-fired electricity generating facility located in Moffat County, Colorado. The facility, in which RMP owns a 19.28% interest, is now scheduled for closure. The management and operation of Craig Unit 2 is governed by the Craig Participation Agreement, which mandates the installation of capital improvements required by applicable law and generally requires majority ownership share to approve Craig's annual capital expenditure budget.

UAE recommends we allow RMP to recover less than a full rate of return on costs related to the Craig Unit 2 SCR project. UAE asserts that, though RMP attempted to act in the best interests of customers by conducting an economic analysis of the project and voting "no" on SCR installation, RMP nevertheless invested in a project that, by RMP's own assessment, was neither cost effective nor prudent, and that RMP management was responsible for negotiating the Craig Participation Agreement under which RMP was forced to incur the SCR project costs. UAE recommends that we allow RMP recovery of the costs associated with the SCR project at a rate equal to RMP's cost of long-term debt, plus a tax gross-up.

RMP concedes that the Craig Unit 2 SCR project was not economically viable, but argues that it should be allowed full cost recovery because it prudently voted against undertaking the project and was only forced to incur the project costs when overruled by Craig's majority owners. RMP further asserts that the costs were prudently incurred because the Craig Participation Agreement required installation of the SCR to comply with Clean Air Act Regional Haze Rules established by the United States Environmental Protection Agency, to comply with the Colorado Regional Haze State Implementation Plan, and to continue to safely, reliably, and cost-effectively manage Craig Unit 2.

We find RMP should be allowed recovery of the Craig Unit 2 SCR costs at the authorized rate of return on capital investments. RMP took every reasonable action to prevent the majority partners in the Craig Participation Agreement from undertaking the SCR project, including conducting an economic assessment of the SCR project compared to an early closure of Craig, and exploring the possibility of legal action to stop or withdraw from participation in the SCR project. Additionally, we may only evaluate RMP's negotiation of the Craig Participation Agreement based on what was known or knowable at the time the agreement was negotiated. UAE asks us to evaluate RMP's negotiation of that agreement based on what is known now; we decline to do so. We are hesitant to chill RMP's entering into future joint ventures that have the possibility of being economically beneficial for Utah customers by disallowing RMP the recovery of its costs, including the authorized rate of return on its investment, for the unsuccessful joint venture at issue. And we believe that imposing different rates of return for different classes of capital as UAE suggests would unnecessarily complicate future ratemaking.

5. Pryor Mountain and TB Flats II Projects

i. The law precludes RMP's proposal to utilize an extended test period for the delayed portions of these projects, but RMP may recover for them on an average-of-period basis.

RMP represents construction of portions of its Pryor Mountain and TB Flats II wind generation projects (collectively, "Delayed Plant") have been unavoidably delayed because of the COVID-19 pandemic. Consequently, only portions of each project will be in service prior to the start of the Test Year and others will be delayed until approximately July 1, 2021. RMP testified that approximately 309 MW of nameplate capacity of TB Flats is expected to be in service at the start of the 2021 Test Year and approximately 194 MW of nameplate capacity will be delayed until June 2021. Similarly, approximately 80 MW of the 240 MW nameplate capacity of Pryor Mountain will be delayed until July 2021.

To avoid the necessity of filing another docket to recover for the Delayed Plant, RMP has proposed a two-step rate increase with the first increase occurring on January 1, 2021 and the second to "be effective as of July 1, 2021, or 30 days after the final in-service dates for the projects."[36] RMP seeks "the traditional 13-month average calculation for rate base" and concedes that this requires consideration of months well into the middle of 2022 for the Delayed Plant, a period that extends well beyond the Test Year.[37] Still, RMP argues its two-step rate increase is an appropriate manner to address the issue because, otherwise, RMP "would be in for a major plan[t] addition" and attendant proceeding next year.[38]

[36] RMP's Post-Hr'g Br. at 14.
[37] Nov. 3 Hr'g Tr. at 41:21-42:18.
[38] Nov. 3 Hr'g Tr. at 42:2-3.

UAE argues Utah law flatly bars the PSC from approving RMP's proposal because "as RMP admits, it seeks a rate increase based on data that is more than 20 months from the date of RMP's application." [39] UAE further argues RMP's proposal would constitute improper single-issue ratemaking and violates PSC rules insofar as RMP has not filed required information concerning its proposed separate test period.

Because UAE's first argument is dispositive, we need not reach its others. While the PSC has the power to sometimes waive administrative rules, it has no authority to waive a statute. Here, Title 54 is unambiguous: "the [PSC] may use … a future test period that is determined on the basis of projected data not exceeding 20 months from the date a proposed rate increase or decrease is filed with the [PSC]."[40] RMP filed its Application on May 8, 2020, yet it asks the PSC to adopt a rate increase for the Delayed Plant based on data projections that extend into the third quarter of 2022 and potentially later. The law simply does not permit this.

Accordingly, we deny RMP's request to implement a two-step increase and to recover the Delayed Plant in reliance on projections beyond the approved Test Year.

UAE testified that the appropriate ratemaking treatment for the Delayed Plant is to incorporate it "into the calendar year 2021 test period on an average-of-period basis, with comparable pro rata treatment for expenses and benefits."[41] UAE represents this is consistent with conventional ratemaking practice and is how RMP would have recovered for this plant had the original construction schedule called for completion in the middle of the Test Year. UAE

[39] UAE's Post-Hr'g Br. at 2.
[40] Utah Code Ann. § 54-4-4(3)(b).
[41] Surrebuttal Test. of K. Higgins at 16:317-19.

presents a specific, confidential adjustment in its filed surrebuttal testimony that adjusts revenue requirement accordingly for the delayed portion of the TB Flats II project.[42]

We conclude UAE's proposed treatment of the Delayed Plant is just and reasonable. RMP may recover for the Delayed Plant on an average-of-period basis over the Test Year.

Applying RMP's assumptions, including those identified in RMP's rebuttal adjustment 10.22,[43] we adjust RMP's revenue requirement to reflect the inclusion of the delayed portions of these facilities in rate base at their average-of-period values in the Test Year. This adjustment also reflects a pro-rata reduction in expenses and depreciation and is consistent with the method endorsed by UAE in its proposed treatment of the TB Flats portion of the Delayed Plants.[44] Accordingly, we approve and adopt this approach. Table 3 provides the incremental impact of this adjustment to revenue requirement after accounting for attendant changes to rate base, O&M expenses, and impacts to taxes and depreciation.

ii. Substantial evidence supports our finding that RMP acted prudently in acquiring and developing the Pryor Mountain project.

Several parties argued against RMP's recovery of Pryor Mountain investment though their arguments were disparate and, in one instance, retracted.

As an initial matter, we address UAE's argument that RMP's recovery of Pryor Mountain "should be limited to applicable avoided cost rate[s] at the time RMP decided to invest in the

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[42] *Id.* at 17:333-37. UAE does not offer a corresponding adjustment with respect to Pryor Mountain, instead advocating for an adjustment that limits RMP's recovery to the avoided cost price RMP would have paid a qualified facility for each MWh it produces. As discussed *infra* at IV.C.5.ii, we do not adopt this recommendation.

[43] *See* Rebuttal Test. of S. McDougal at 10.22, "Pryor Mountain and TB Flats - Phase 2," – CONF.

[44] *See* Rebuttal Test. of K. Higgins at 16.

project."[45] UAE cites the Public Utilities Regulatory Policy Act of 1978 (PURPA) and discusses its requirement that utilities purchase energy and capacity from "qualified facilities" at the utilities' "avoided costs." UAE further argues PURPA requires utilities purchase at avoided costs to "keep customers economically indifferent to the source of a utility's energy and capacity by ensuring that the utility's cost of purchasing power from a [qualified facility] does not exceed the cost the utility would [otherwise] incur."[46]

We are aware of no authority, and UAE cites none, that would permit or require us to reduce RMP's recovery on a capital project such that rates include only a unit price for each MWh produced equal to the avoided cost price that a non-utility, qualified facility would receive by compelling the utility to purchase its power under PURPA. RMP is a vertically integrated utility that bears responsibility for meeting the load requirements of every customer in its service territory. Like other public utilities, its rates are determined through well-established cost of service principles that are designed to ensure it remains solvent and able to meet that essential public responsibility. The rates RMP must pay to independent producers under PURPA are not relevant to this analysis.[47]

The relevant question is whether RMP acted prudently, based on the information it possessed at the time, in choosing to develop Pryor Mountain. The OCS challenges RMP's recovery on that basis, arguing Pryor Mountain is more costly on a per MW basis than other

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[45] UAE's Post-Hr'g Br. at 3.
[46] *Id.*
[47] Perhaps an argument could be made that Pryor Mountain's greater per MW cost is relevant in assessing whether RMP's avoided cost pricing at the time was lower than its actual avoided cost, but that is not the issue before us in this docket.

recently acquired wind resources. The OCS further questions RMP's inclusion of certain components ("Affiliate Components") that RMP purchased from an affiliate to construct some of the turbines. The OCS speculates: "it appears that the sale [of the equipment] was an opportunity for an affiliate to offload wind turbine components that were simply sitting in storage at a time when their value was declining because PTCs were expiring."[48] The DPU also criticized RMP for failing to seek voluntary pre-approval for the acquisition though it concedes such approval was not required by law.

Like the OCS, the DPU initially recommended the PSC find RMP's development of Pryor Mountain to be imprudent, but it has advised it "is no longer recommending disallowance of the Pryor Mountain wind farm on the basis of imprudence."[49]

After hearing the parties' testimony and reviewing the evidence, we find substantial evidence supports a finding that RMP acted prudently.

RMP testified it sought to develop Pryor Mountain because it would contribute to meeting near-term energy and capacity needs and offered net economic benefits to customers. The economic benefits largely stem from unique and time-sensitive opportunities RMP identified that would allow the project to qualify for federal production tax credits (PTCs) at a level otherwise phased out after 2016 and to enter an agreement with one of Facebook's subsidiary companies to purchase all renewable energy credits (RECs) associated with the project under Oregon Schedule 272.

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[48] OCS's Post-Hr'g Br. at 10.
[49] DPU's Post-Hr'g Br. at 13-14.

With the benefit of these opportunities, RMP's economic modeling showed Pryor Mountain would provide net customer benefits even under conservative assumptions with respect to natural gas prices and potential carbon costs.[50] Using "medium case" assumptions for those variables, RMP's modeling showed significant customer benefits. These projected benefits assumed qualification for the full PTCs and closure on the agreement to sell the RECs.

Consequently, the opportunity evolved over a compressed timeline as the utility worked to secure the development rights, finalize the REC contract, and, as explained just below, qualify the project for the 2016 PTCs. With respect to the latter, federal tax law provides significant PTCs for certain renewable generation resources but those credits began phasing out for projects that commenced construction after 2016.

RMP identified an opportunity to qualify the entire Pryor Mountain Project for the 2016 PTCs by purchasing nacelles and hubs (components of wind turbines) from an affiliate that had purchased them before 2017. To qualify for the full PTCs, RMP had to invest at least 5% of the total project cost in this essentially safe-harbored equipment, which we have referred to as the Affiliate Components. Ultimately, RMP purchased sufficient Affiliate Components to satisfy those specific component requirements for 73 of Pryor Mountain's 114 wind turbine generators.

Significantly, RMP purchased the Affiliate Components at the latter's cost, the price it paid when it purchased them prior to 2017. RMP also testified there is no market for safe-

[50] Contingent on the assumptions and extrapolation period used, RMP's analysis projects net benefits for Pryor Mountain in three of four scenarios, including a scenario that assumes low natural gas prices and no carbon costs. The final scenario, based on a different extrapolation period and similarly conservative assumptions, projects a net cost of $1 million whereas the other three scenarios project net benefits ranging from $7 to $82 million.

harbored wind turbines because such equipment cannot be transferred from one consolidated taxpayer to another without losing its safe harbor status. Because no market price for the safe-harbored Affiliate Components existed, RMP purchased the equipment at the affiliate's cost.

In addition to qualifying the entire project for maximum PTCs, RMP testified the Affiliate Components reduced the overall project risk because they were already manufactured and stored in Colorado within reasonable proximity to the project site in Montana.

Importantly, RMP completed a competitive solicitation to construct Pryor Mountain and provide all remaining construction materials and turbine components. RMP "rolled" the Affiliate Components it had purchased into that contract so it would encompass construction of all the new turbines at the site. The record does not contain a breakdown of costs by component, but uncontroverted testimony affirmed that "on a per wind turbine basis" and over the entire contract, "the per turbine price was comparable to … market."[51]

We find ample and substantial evidence supports our finding that RMP acted reasonably at the time it made the decision to acquire Pryor Mountain, which offered a time-sensitive opportunity to obtain a resource that would help to alleviate an identified need for capacity and energy while capitalizing on opportunities to qualify the generation for an amount of PTCs phased out after 2016 and to generate revenue through a contract to sell all associated RECs to a third party.

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[51] Nov. 3 Hr'g Tr. at 89:16-21.

D. Summary of Decisions on Revenue Requirement

Table 2 presents the final capital structure, ROE, and overall rate of return we approve.

TABLE 2 – COST OF CAPITAL

	Capital Structure	Rate	Weight
Debt	47.49	4.79%	2.27%
Preferred Stock	0.01	6.75%	0.01%
Equity	52.50	9.65%	5.06%
Total	**100.0**		**7.34%**

Table 3 – Confidential. Revenue Requirement Adjustments presents the impacts of our decisions above on RMP's requested revenue requirement. These decisions result in a total revenue requirement increase of $31,409,802.

TABLE 3 – CONFIDENTIAL. REVENUE REQUIREMENT ADJUSTMENTS

Description	Amount, $
Change in Revenue Requirement in RMP Direct Testimony	**$95,786,460**
Cost of Capital	
Capital Cost – Authorized Cost of Debt, 4.79%	-725,237
Capital Cost – Authorized Return on Equity, 9.65%	-37,986,815
Total Cost of Capital Adjustments	-$38,712,052
Undisputed Adjustments – Adjusted for Cost of Capital	
Wheeling Revenue Update	2,266,414
REC Revenues Update	[redacted]
NTUA Revenue Correction	-77,619
M&S Inventory Sales Revenue Correction	-2,834,353
Schedule 300 Fees	-749,641
Reliability Coordinator Fees	-1,360,150
Transmission Power Delivery Uncollectible Expense	-316,118
Insurance Premium Update	1,761,262
Wildland Fire O&M Update	1,506,843
WEBA - Full-Time Equivalent	-1,360,085
WEBA - UMWA Correction	-709,005
WEBA - CY 2021 Annualization	-702,439
Rebuttal Net Power Cost Alignment	3,371,530

Nodal Pricing Model Update	23,604
Other Decommissioning Cost – Colstrip - Correction	[redacted]
Electric Plant Acquisition Adjustment	-2,235,408
Property Tax Update	4,432,544
Pro-Forma Tax Update	6,581,636
Removal of TCJA Deferred Balances - Correction	322,533
Pro-Forma Plant Data Update 10.20	-28,474,594
Repowering Capital Additions	340,914
Total Undisputed Adjustments	-$19,303,599
Disputed Adjustments – Adjusted for Cost of Capital	
Pryor Mountain	[redacted]
TB Flats	[redacted]
Generation Overhaul	[redacted]
Non-Labor O&M Escalation Update	[redacted]
Remove Certain Costs from Escalation	[redacted]
Remove AMI Project	[redacted]
Remove Pension/PBOP Net Asset	[redacted]
Total Disputed Adjustments	-$6,361,008
January 1, 2021 Resulting Revenue Requirement Impact	**$31,409,802**

For the reasons previously discussed, we find this amount is just and reasonable and will enable RMP to provide service to its customers consistent with its responsibilities under Utah law.

E. Policy and Other Issues

1. Wildland Fire Mitigation Balancing Account

Consistent with the Utah Legislature's 2020 House Bill 66, Wildland Fire Planning and Cost Recovery Amendments ("HB 66"), RMP requests PSC approval of a Wildland Fire Mitigation Balancing Account (WBA). The WBA is a recovery mechanism for the costs RMP incurs, incremental to those included in the 2020 GRC, to implement its Wildland Fire Protection

Plan (WFPP).[52] RMP will report the WBA balance annually in the December Results of Operations Report and will include the balance in the next general rate case unless it reaches a material level, in which case RMP will request recovery earlier. RMP states "[a]ll prudent capital investment and expenses incremental to Base Amount will be eligible for recovery through the [WBA]"[53] and explains its method for calculating WBA's revenue requirement. RMP's Application includes proposed Electric Service Schedule No. 97, Wildfire Mitigation Balancing Account, which shows the percentage adjustment, currently set at 0%, to be applied to the monthly power charges and energy charges of a customer's applicable schedule. No party opposed RMP's WBA proposal.

HB 66[54] identifies the requirements for cost recovery for prudently incurred investments and expenditures made in the course of implementing an approved WFPP. The law directs us to "authorize the deferral and collection of the incremental revenue requirement for the capital investments and expenses: (a) to implement an approved wildland fire protection plan; and (b) not included in base rates."[55] Based on our review of RMP's proposal and in the absence of opposition, we find and conclude RMP's WBA is reasonable and consistent with HB 66. Therefore we approve it and set the Base Amount equal to $9,586,112 as identified in Exhibit SRM-7R, modified consistent with our decisions in this case. We also approve Electric Service Schedule No. 97 as proposed.

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[52] The PSC approved RMP's WFPP Plan on October 13, 2020 in Docket No. 20-035-28, *Rocky Mountain Power's Utah Wildland Fire Protection Plan.*
[53] Direct Test. of S. McDougal at 44:963-65.
[54] HB 66 is codified at Utah Code Ann. § 54-24-101, *et seq.*
[55] *Id.* at § 54-24-202(3).

2. Schedule 94 – Energy Balancing Account Base EBA Calculation

RMP requests the PSC approve a change to Schedule 94 – Energy Balancing Account (EBA) that going forward, Base EBA would be determined in each annual EBA filing as the actual average Variable Supply charges billed to customers during the deferral period. RMP explains that with price unbundling, this method of determining Base EBA would be possible and it would represent a more accurate measurement of the amount of revenue that had already been collected from customers to cover base power costs for a given year. RMP notes that the proposed Schedule 94 tariff incorporates this proposed change.

DPU objects to the proposed change because the controlling statute requires Base EBA be set only in a GRC. Therefore, DPU recommends the PSC reject RMP's request.

RMP responds that DPU misunderstands RMP's proposed change. RMP explains it does not propose changing the Base EBA rates in each annual EBA filing, and it agrees that Base EBA rates cannot be changed outside of a GRC. Therefore, RMP asserts its proposed change is consistent with the law. RMP clarifies it proposes to use the actual revenue collected through Base EBA rates (as established in the GRC) instead of the forecasted revenue collection set in the GRC. RMP asserts that using the actual amount of revenue collected through the Base EBA rates during the deferral period is more accurate and may reduce the volatility of the mechanism.

RMP's proposed change in method is dependent on having unbundled pricing. As discussed further below, we do not approve RMP's unbundling proposal. Consequently, the change RMP proposes to the EBA method cannot be implemented at this time, and we decline to approve the change.

3. Accounting for REC Revenues

RMP accounts for the difference between the actual annual REC revenues received and the REC revenues reflected in base rates via its REC Balancing Account (RBA). Because of the decrease in the amount and volatility of REC revenues, OCS recommends the PSC discontinue the RBA once the true-up associated with the 2020 calendar year is completed. OCS further recommends that we adopt a deferral approach to REC revenue accounting. Using this approach, RMP would defer the difference between the amount of REC revenues incorporated in base rates and the actual annual amount of REC revenues received as a regulatory asset/regulatory liability. The resulting balance in the deferral account would be addressed in a future GRC. OCS claims this approach would be more administratively efficient than the current RBA. OCS does not oppose continuing to allow RMP to retain 10% of the revenues it receives from the sales of RECs.

RMP is not opposed to OCS's proposed deferral accounting in lieu of the annual rate adjustment currently in place. However, RMP recommends that it be allowed to retain the ability to propose ratemaking treatment for any regulatory asset or liability balance outside of a GRC. For example, RMP could propose outside of a GRC to apply the regulatory liability balance against another cost that would otherwise increase rates or to initiate a credit to customer rates to offset some other cost, such as an EBA charge. Any application of the balance would be subject to review by parties and approval by the PSC.

DPU does not oppose OCS's recommendations but suggests the PSC consider certain items prior to discontinuance of the RBA. DPU acknowledges that the amounts involved are not currently volatile and are relatively immaterial. New REC contracts, however, are being executed that may require continued annual monitoring. Additionally, depending on when RMP files its next GRC, without the annual true-up and review, it could be several years before the deferral account is reviewed and including a multi-year accrual review in a GRC compounds the possibility of errors. Further, DPU points out deferred accounting has typically been reserved for unforeseeable or extraordinary events and its use could create intergenerational equity issues. DPU does not support deferred accounting when expenses/revenues are normal, ordinary, and foreseeable.

In response to DPU's concerns related to the possibility of errors and intergenerational inequity, RMP states it can provide an annual report to track the REC revenue deferral balances, and DPU can still conduct an annual audit of the deferral. RMP asserts past RBA filings demonstrate the accuracy of its calculations, so concerns that a multi-year review in a GRC or other proceeding would compound the risk of error are small and unlikely.

We are not inclined to establish yet another RMP deferral account. From our perspective, the RBA operates fairly seamlessly and does not appear to be an unreasonable regulatory burden. In addition, establishing a deferred account associated with RECs, as proposed by OCS, does not appear to satisfy the criteria we typically have used to determine if a deferred account is warranted, particularly since the volatility of REC revenues has decreased in recent years. Further, in light of the increase in wind resource generation anticipated due to RMP's recent investments, we find that continued annual evaluation of the RBA is reasonable to ensure either customers or RMP are timely compensated for any variance between actual REC revenues and those included in this GRC. Ultimately, we find that the regulatory burden associated with the issues that could be created by the proposed change could easily surpass the current regulatory burden associated with the RBA. For these reasons we decline to adopt OCS's proposal.

4. Production Tax Credits and the Energy Balancing Account

RMP requests a change to its EBA to include PTCs. While PTCs are not presently included in the EBA, RMP argues they should be included because the EBA tracks net power cost (NPC) and PTCs are directly tied to generation. RMP concludes PTCs should be treated in the same manner as other variables associated with generation.

Utah Code Ann. § 54-7-13.5(b) defines an electric utility's EBA as an "account for some or all components of the electrical [utility's] incurred actual power costs" and specifies this includes fuel, purchased power, and wheeling expenses. The statutory language does not suggest this list is exhaustive; rather, "all components" of actual, incurred power costs are eligible for inclusion, "including" these enumerated items. The statute contemplates the EBA will sum such power costs and subtract "wholesale revenues."[56]

DPU and OCS oppose RMP's request, arguing PTCs are not actual power costs and their inclusion in the EBA will unnecessarily expand its scope, "provid[ing] yet another true-up mechanism to insulate RMP from regulatory lag."[57]

Consistent with the statute, we understand the EBA exists for the general purpose of facilitating RMP's recovery of the actual, net variable costs RMP incurs to produce power. Which is to say, we conclude the EBA should primarily track NPC. This ensures customers do

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[56] Utah Code Ann. § 54-7-13.5(1)(b)(ii).
[57] Direct Test. of P. Hayet at 32:710-12.

not overpay for NPC and that the utility is not penalized for common but significant fluctuations in these variables.

In 2017, we issued an order that, among other things, denied DPU's request to remove wheeling revenues from the EBA for similar reasons that it offers here. We declined to do so, reasoning that "wheeling revenues have a relationship with NPC in that they form an offset to wheeling expenses in general rates."[58] Similarly, PTCs are a function of marginal power production and operate to offset other components of NPC. We see no reason to treat them differently from any other components of NPC that are tracked in the EBA.

We approve RMP's request to include PTCs in the EBA. We direct RMP to file contemporaneously with the updated Tariff sheets reflecting our decisions in this case, an updated spreadsheet identifying the Base EBA and its various components, including PTCs.

5. Cost Recovery for Non-Fire Reliability Condition Correction Outside of Fire High Consequence Areas (FHCA)

Beginning on January 1, 2021, RMP proposes to draw on the December 31, 2019 $8.1 million balance of the property insurance reserve account to address certain reliability-related conditions. In support of its proposal, RMP will annually report the number of conditions identified, the number of corrections completed, costs, and the remaining balance in the property reserve balancing account. RMP testifies it will increase the frequency of inspections and use the same fire threat conditions outside of Fire High Consequence Areas (FHCAs) as those identified for the FHCAs and that the fire threat conditions will be corrected on an accelerated schedule. In

[58] *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15 (Order issued Feb. 16, 2017 at 8).

addition, RMP states it will modify the condition correction schedule for any non-fire condition. No party commented on this proposal.

According to RMP new modeling tools enable it to review the location of reliability-impacting conditions and target corrections in a proactive manner to avoid the impact of storm events. RMP asserts that while storm-related damage varies, the damage is more severe in areas where deteriorated or damaged facilities exist.

While no party commented on this proposal, based on RMP's testimony, we find accelerating the correction of certain reliability-related conditions should have a positive impact on electric service reliability. In addition, the reporting RMP proposes will ensure transparency. To the extent circumstances related to uncorrected reliability-related conditions may impact the property insurance reserve account, we find RMP's proposal to pay for the necessary corrections using the balance of this account as of December 31, 2019 is reasonable. For these reasons, we find and conclude RMP's proposal supports electric service reliability and will ensure transparency, and we approve it.

6. TCJA Deferred Balances

On December 22, 2017, the TCJA was signed and soon thereafter RMP established, among other things, a regulatory liability to record the amortization of the protected property-related EDIT balance that is owed to customers. In direct testimony, OCS witness Ms. Ramas explained that the amortization of the protected property-related EDIT liability fluctuates annually under the Reverse South Georgia Method (RSGM) for amortizing this regulatory liability balance and recommended RMP be directed to defer the difference between the amount of protected property-related EDIT amortization incorporated in base rates and the amount of amortization that actually will have occurred during the rate effective period. RMP opposed the recommendation by OCS to track and defer this variance.

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

7. RMP's Rate Mitigation Proposal

In its Application, RMP identifies deferred tax savings associated with the TCJA of $118,697,113 as available to offset revenue requirement in this GRC. RMP proposes to apply a portion of this balance toward buying down various regulatory assets and to refund the remainder to customers via a bill sur-credit to mitigate RMP's proposed rate increase. Specifically, RMP proposes applying the following amounts toward various regulatory assets: $11,743,341 (2017 Protocol), $9,573,636 (EIM Benefit), $10,292,396 (Carbon Plant Closure), and $20,581,541 (Deer Creek Mine Closure), leaving a balance of $66,506,199. In its Application, RMP proposes refunding this balance to customers via Schedule 197, Federal Tax Act Adjustment ("Schedule 197") in two increments: $44.3 million during 2021, and the remaining $22.2 million during 2022.

In rebuttal, RMP updated the portion of the TCJA deferred tax balance proposed for refund to customers to be $62,665,067. As in its Application, RMP recommends refunding this new balance in two increments: $38.2 million during 2021 and $26.8 million during 2022 (including interest). RMP states the sur-credit would expire on January 1, 2023.

We find that RMP has proposed a reasonable allocation of the TCJA deferred tax balance. The various uses reduce both customer and utility risk and provide a meaningful offset to the revenue requirement increase associated with this order. Moreover, our decision related to the Deer Creek Mine Closure recovery royalties increases the TCJA balance that is available to offset customer rates. Accordingly, we order a refund via Schedule 197 of $46,294,843 during 2021 and $23,147,421 during 2022. The refund amounts applicable to the various Tariff schedules are identified in Exhibit B – Pricing.

V. COST OF SERVICE AND REVENUE REQUIREMENT SPREAD – DISCUSSION, FINDINGS, AND CONCLUSIONS

A. Cost of Service (COS)

RMP's COS study in this docket ("COS Study") makes several changes to historically approved methods. With the uncertainties stemming from current economic conditions and the impacts of those conditions on RMP's customers and system, coupled with a lack of consensus by parties, we find that now is not the ideal time to approve substantial changes to the cost-of-service methods we have historically approved. For example, as discussed more fully below, we find the evidence is insufficient to assuage the concerns several parties expressed with functional unbundling and to depart from our previously approved approach to how plant is functionalized, classified, and allocated. Similarly, below we find the evidence is insufficient to justify OCS's proposed modification to our currently approved allocation factor for the production and transmission functions.

Despite the absence of persuasive evidence regarding the above-mentioned changes to COS methodology and others presented in this docket, we recognize technological changes in RMP's system and data collection capability justify further evaluation of traditional COS approaches. We find wisdom in the recommendations of several parties to establish a collaborative process that will commence after the conclusion of this docket. The purpose of this collaboration is to facilitate the exploration of improvements to current methods for assigning cost responsibility to the various customer classes and designing commensurate rates, including the unbundling of rate elements. At the end of this order we present additional details regarding this collaborative process.

1. Variable and Fixed Sub-functions Related to Production and Transmission Functions

RMP's COS Study introduces new variable and fixed sub-functional categories, intending to provide a more detailed breakdown of costs according to the demand and energy components of RMP's production and transmission functions. RMP defines its variable costs as those that are EBA-related and all non-EBA-related costs as fixed. RMP applies the same subdivision to its functionalized transmission costs. This new sub-functionalization and consequent unbundling, RMP states, allow delivery costs in rates to be delineated from supply, and allow base EBA costs in rates to be identified so the accuracy of the EBA can be improved. RMP suggests these benefits are consistent, are beneficial, and support the transparency that allows parties to better assess the economic impact of charges on each category of customer. RMP further asserts unbundling is necessary to support programs that H.B. 411 envisions and that it changed the COS Study only minimally from past practice in order to allow unbundling.

OCS argues modifications to RMP's traditional COS study methods to incorporate sub-functionalization are uninformative, fail to achieve RMP's own methodological balance, are fatally flawed, inappropriately and without transparency result in cost shifts from energy to demand, and could have additional unintended consequences. Accordingly, OCS opposes RMP's proposed fixed and variable sub-functions in this case.

DPU concludes the issue requires more discussion, arguing in rebuttal that both RMP's and OCS's positions have merit. DPU suggests that RMP needs to clarify its fixed/variable classification method and connect each type of classified cost to the standard cost causation drivers of customer numbers, peak demand, and total consumption of energy.

We find that RMP's proposed variable and fixed sub-functionalization categories carry some intuitive benefits related to transparency of costs, but we find the proposal's uncertainties outweigh them. The evidence is insufficient to find (i) whether the proposal will lead to unintended consequences and cost shifts; and (ii) whether the proposed categories are sufficiently connected to cost causation drivers. We decline to adopt RMP's proposal, but this decision does not impact the overall allocation of costs to the main production and transmission functions.

2. Production and Transmission (P&T) Costs Classification

RMP proposes to continue allocating the P&T functions using a 75%-demand/25%-energy allocation split. DPU agrees RMP's method of classifying P&T costs is long-established and facilitates cost allocation uniformity and simplicity across jurisdictions, and that the 12-

coincident-peak allocator is well recognized. DPU advocates against changes to RMP's split in this docket but supports future review.

OCS asserts a 40%-demand/60%-energy split better balances the demand and energy related characteristics of RMP's current and future system, which RMP opposes for the present case. RMP also opposes Kroger's preference for a 100%-demand/0%-energy classification because "generation and transmission investments, while designed to meet [RMP's] peak load requirements, are often built to provide customers with lower cost energy resources."[59] RMP adds that comparing OCS's and Kroger's positions demonstrates RMP's longstanding 75%-demand/25%-energy allocation split is balanced, reasonable, and appropriate for this proceeding. RMP claims that deviating from its proposed approach would require rigorous analysis that has not been provided by any party. RMP proposes a collaborative review of RMP's COS methodology.

We find that the method we have historically approved allocating the P&T functions has promoted uniformity and simplicity. While a vast difference exists between Kroger's and OCS's proposals, the record lacks evidence to reliably demonstrate the potential impact either proposal may have on customers. We conclude that such an uncertain outcome is neither just nor reasonable, and we decline to modify RMP's proposed allocation of the P&T functions.

3. Distribution Costs Classification

RMP's COS Study classifies distribution functional costs as either demand or customer-related. RMP classifies meters and services costs under customer-related functions, with all other

[59] Surrebuttal Test. of R. Meredith at 6:113-15.

costs considered demand-related. RMP testifies that distribution plant is split into primary and secondary voltage sub-functions for FERC accounts 364-368. Distribution substations and primary lines are allocated using weighted monthly coincident distribution peaks, and distribution line transformers and secondary lines are allocated using the weighted non-coincidental peak method. RMP states the meter allocation factor was developed using the installation costs of new metering equipment for different types of customers. RMP represents this method more accurately reflects cost causation because the cost of a substation will be largely driven by its capacity and a simple count does not take into consideration the size of different substations as they peak throughout the year.

DPU states RMP does not use the common forms of distribution cost classification, but instead classifies each FERC distribution account as either entirely demand-related or customer-related. Common practice involves statistical analysis to split some of the FERC accounts 364-368 (large accounts) between the two cost causation factors. DPU recommends RMP investigate the common alternatives to its current methods. DPU recognizes there is a tradeoff between improved classification accuracy and computational complexity.

OCS argues RMP did not meet its burden of proof to demonstrate that its allocation of FERC accounts 364–368 to primary and secondary voltage costs is reasonable. OCS recommends the PSC require more in justification of this method, including more explanation regarding the sample data relied upon, a description of the data and how it is tracked, and the criteria RMP used to select costs from the original data set. OCS recommends RMP provide additional information on its methodology and data inputs for sub-functionalizing distribution costs into primary and secondary. In recognition of this recommendation, OCS applied a 10% adjustment to the sub-functionalization of primary and secondary voltage.

UAE supports RMP's sub-functionalization of distribution plant costs in FERC Accounts 364-368, including its adjustment to FERC Account 364. UAE opposes OCS's analysis, arguments, and alternative proposals due to inadequate explanation. UAE further argues that OCS's proposed 10% allocation adjustment to primary voltage in FERC Accounts 365-367 is arbitrary and lacks analytical support. RMP states further study could be conducted on alternatives to classifying and allocating distribution costs, including those recommended by the DPU and UAE, in the collaborative review of COS methodology RMP recommends. The data and computing power that are presently available to RMP are now much better than what was available in the 1980s, opening opportunities to explore new approaches.

We find the evidence is insufficient to ameliorate concerns parties have raised about RMP's proposed distribution sub-functions. The evidence is insufficient to support findings about the way RMP's proposal was developed and whether it more accurately reflects cost causation. Accordingly, we decline to adopt any modifications to RMP's currently approved distribution costs classification. This decision does not impact the overall allocation of costs to the main P&T functions.

4. Spread of the General Revenue Change

RMP proposes the following rate spread for its revised $72 million revenue requirement increase for major customer classes, excluding special contracts.[60]

Customer Class		Proposed Rate Change
Residential		6.7%
General Service	Schedule 23	0.00%
	Schedule 6	1.7%
	Schedule 8	1.7%
	Schedule 9	3.7%
	Irrigation	3.7%
	Lighting	-22.1%

RMP testifies that its proposed rate spread is designed to reflect cost of service results while balancing the impact of the rate change across customer classes. RMP's method sets the proposed rate spread midpoint at 3.7% based on the revenue increase to the rate schedules to which the proposed increase is being applied. Walmart and Kroger recommend that greater movement towards COS be made for classes paying more than their COS. In response, and assuming the PSC reduces the revenue requirement RMP seeks in the Application, RMP proposes smaller base revenue increases for Schedules 6 and 8 than it did in its Application and no base revenue increase for Schedule 23 and Schedule 15 – Traffic and Other Signal Systems. While Schedule 32 was not included in the COS Study because one year of data was not

[60] For its Step 1 price change, RMP proposes a rate spread that is proportionately lower than the Step 2 increase for each class, except for Schedules 7, 11, 12, and Schedule 15 – Metered Outdoor Nighttime Lighting, which will have the same rates for both rate changes since these classes are receiving a base rate decrease.

available at the time it was conducted, RMP assigned Schedule 32 a 3.71% increase based on an evaluation using COS data from Schedules 6, 8, and 9.

Responding to the rate spread in RMP's Application, UAE states that, given RMP's COS results, RMP's proposed rate spread among customer classes is reasonable. Moreover, to the extent the revenue requirement approved by the PSC is less than that requested by RMP, UAE recommends that RMP's rate spread proposal be used as the starting point for spreading the approved revenue change. For the lighting schedules that RMP proposes to receive a cost-based decrease, UAE recommends that those rate classes receive the same proportion of the total final revenue requirement as that proposed by RMP. For the other customer classes that RMP proposes to receive a rate increase, UAE recommends that the percentage rate change relative to the rate spread midpoint be preserved at a lower revenue requirement.

Likewise, Walmart and Kroger do not oppose RMP's rate spread. However, Walmart recommends that if the PSC determines a revenue requirement increase lower than that proposed by RMP, the PSC should allocate 50% of the reduction to Schedules 6, 8, 23, and 15, subject to certain conditions. Kroger, on the other hand, recommends that the PSC use any reductions to the proposed revenue requirement increase to address the subsidies being paid by Schedule 6 customers.

DPU also recommends the PSC adopt RMP's rate spread approach. DPU asserts the proposed rate spread provides a reasonable balance that reflects the COS results while also employing the principle of gradualism.

In direct testimony, OCS did not recommend a specific rate spread but rather a set of principles to be considered, including equity, gradualism, level of reliance on the COS Study, economic impacts of the COVID-19 pandemic, data quality, and uncertainty.

In rebuttal testimony, OCS asserts RMP's revised rate spread is unreasonable and should not be approved. OCS claims RMP's spread proposal for its revised revenue requirement is more influenced by testimony from large-usage customers than COS results. OCS testifies that RMP reduced the relative cost recovery responsibility of Schedules 6 and 8 in its revised spread without any justification. It transferred that responsibility to the residential class despite the same relative class COS performance of these classes as in RMP's Application. OCS also argues RMP's rate spread would impose an extreme, as opposed to gradual, rate increase on the residential class and that doing so in this harsh economic climate is inequitable and unreasonable.

In Table 8 of its surrebuttal testimony shown below, OCS proposes a rate spread aligned with its proposed revenue requirement decrease and a rate spread reflecting the approximate midpoint between its proposal and RMP's revised revenue requirement. OCS represents its rate spread proposal promotes gradualism and equity. Because the midpoint rate spread is applying a revenue requirement increase, albeit a small one, OCS ensured no class received a revenue requirement allocation less than its allocation under current rates. OCS also assigned Schedule 9 the highest percentage increase because, in OCS's view, for the last 10 years it has been the worst performing class. Finally, if the PSC assigns a different rate increase or decrease, OCS recommends a proportionate scaling of its proposed rate spread.

OCS Table 8

	Rate Spread	
Description	OCS Revenue	MidPoint Revenue
Residential	-0.51%	1.25%
General Service - Large	-3.00%	0.40%
General Service - Over 1 MW	-1.40%	0.60%
Street & Area Lighting	-10.00%	0.00%
General Service - High Voltage*	-0.50%	1.53%
Irrigation	-0.50%	1.28%
Traffic Signals	-8.00%	0.25%
Outdoor Lighting	-10.00%	0.00%
General Service - Small	-9.50%	0.00%
Customer 1	-0.50%	0.92%
Customer 2	-0.50%	0.92%
Rate increase	-1.97%	0.92%
* includes Schedules 31 and 21		

According to OCS, the effects of the COVID-19 pandemic have likely made the results of RMP's COS Study unreliable, in part at least, because of changing usage patterns. OCS urges the PSC, in light of the COS Study limitations and current economic conditions, to apply gradualism in revenue apportionment and rate design. Further, during this period of uncertainty and, in light of the purportedly stale data used to support RMP's COS Study, OCS recommends the PSC prioritize equity by assigning all classes the same directional change in rates, while allowing the magnitude of the change to vary among customer classes. OCS asserts requiring all customer classes to share the burden of rate increases, or benefits of rate decreases, supports inter-class equity and reduces the potential for customer confusion.

We use the allocation of revenue requirement to the classes of service identified in various parties' COS studies to inform our judgment about a just and reasonable rate spread.

Additionally, our rate spread findings have been, and continue to be influenced by interrelated principles, including: (i) the desirability of a gradual pace of change toward improved alignment of costs of service and rates, and (ii) the equitable treatment of all customer classes when overall revenue requirement increases such that, in general, a given class does not suffer an unduly large, disproportionate increase.[61]

A key objective of rate spread is that each class recovers its properly allocated costs of service. Here, conflicting evidence regarding the reliability of aspects of RMP's COS Study obscures the path to that objective. Moreover, aspects of RMP's proposed rate spread inordinately transfer revenue responsibility to the residential class. Further, we recognize that the current economic climate, strongly influenced by the COVID-19 pandemic, has created hardships for Utah households and businesses alike. Finally, the availability of the TCJA refund that will soften the impacts of the approved revenue requirement increase in 2021 and 2022 affects our consideration of an equitable rate spread for each class.

Weighing the COS evidence and balancing the foregoing considerations, we find and conclude the general approach to rate spread advocated by OCS will best serve our objective to set just and reasonable rates. Because the revenue requirement we adopt is higher than the midpoint revenue in OCS's Table 8, we have scaled the percentages in that column appropriately, as OCS recommended. We have also made one adjustment. OCS proposes the largest percentage increase for the General Service – High Voltage class. While the undisputed

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[61] *See generally, In the Matter of the Investigation into the Reasonableness of Rates and Charges of PacifiCorp, dba Utah Power & Light Co.*, Docket No. 97-035-01 (Report and Order issued March 4, 1999), available at 1999 Utah PUC LEXIS 16.

COS evidence shows this class underperforms in recovering its cost of service, we find its performance is sufficiently similar to that of the Residential class that we have adjusted the percentage increases for those two classes to be equal. In addition, given certain lighting schedules' significant over-performance for many years and the relatively small magnitude of their revenue, we find bringing these lighting classes to full cost of service at this time is reasonable.

Our final spread decision is presented below in Table 4 and the final spread of the revenue requirement increase is provided in Exhibit A.

TABLE 4 – REVENUE SPREAD DECISION

Target increase ($000)	$ 31,409,802
overall avg	1.57%
avg w/o 34, C3	1.63%
avg w/o LT, AGA, 34, C3	1.64%
Res 1, 2, 2E, 3	2.65%
6, 6A, 6B	0.71%
8	1.07%
9, 9A, 21, 31, 32	2.65%
10	1.64%
23	0.00%
C1	1.57%
C2	1.57%
34, C3	0.00%
7	-44.58%
11	-8.38%
12	-26.02%
15M	-32.39%
15T	0.00%

B. Rate Mitigation Proposal (EDIT Balances)

Given our findings pertaining to the remaining EDIT regulatory liability balances and revenue spread in this case, Exhibit B – Pricing identifies the surcredit amount RMP is to implement through Schedule 197 in 2021 and 2022.

VI. RATE DESIGN

A. Unbundling of Rates

RMP proposes to design rates that are unbundled according to three functional categories (delivery, fixed supply, and variable supply) in its Tariff, but not yet on customer bills. RMP's Application explains the three-step process it used to accomplish unbundling and identifies underlying themes supporting its rate design proposals, including making energy more affordable, increasing simplicity and transparency, and adapting to a more sustainable future. RMP states well-designed prices should send a clear price signal to customers about the incremental cost of additional energy consumption and thus promote energy efficiency.

RMP represents it seeks to separate retail rates into fixed and variable supply to better track the collection of Base EBA costs, and therefore improve the EBA's accuracy. RMP testifies information from unbundled rates can be useful for developing new programs, such as the Community Renewable Energy Program under H.B. 411, and to aid in the design of potential new energy efficiency programs.

Walmart supports RMP's unbundling proposal. Walmart further states it supported unbundling in Docket No. 13-035-184 because "unbundling tariff rates by function allows customers to determine the costs of each of the generation, transmission, and distribution functions, compare those functional costs across utilities or jurisdictions where they have other facilities, and communicate cost drivers, such as environmental compliance for generation plants, to non-technical audiences. Additionally, it ensures that functions for which costs are fixed, such as generation capacity, distribution, and transmission can be appropriately and transparently collected through [RMP's] base tariff rates."[62]

OCS recommends the PSC reject RMP's rate unbundling proposal. Further, OCS proposes that in the next rate case, the PSC should require RMP to inform rates based on cost and not inform rates on its rate unbundling methodology. OCS asserts the implications of RMP's proposed unbundling method are that it: (i) allows RMP to deviate from embedded cost of service study results when designing rates; (ii) shifts energy charges to demand charges; and (iii) shifts energy charges to customer charges. OCS submits that using unbundling to design rates with the goal of influencing renewable energy programs is likely to lead to unintended consequences. OCS suggests that DPU and Walmart failed to analyze the way RMP's sub-functionalized fixed and variable costs flow through to its proposed unbundled rate design proposals.

UCE recommends the PSC reject RMP's proposed method for unbundling rates in this proceeding. UCE claims RMP has not sufficiently established why its largely untested proposal is superior to any other established method of unbundling rates. UCE asserts this issue would be best served if parties addressed it outside of the GRC, where stakeholders can work together to explore best practices regarding rate unbundling.

[62] Direct Test. of S. Chriss at 7:138-8:145.

SLC Corp recommends the PSC not adopt RMP's proposed retail rate unbundling at this time. Rather, SLC Corp recommends the PSC should establish a working group to consider an unbundling methodology applicable to future rate designs.

We find that insufficient evidence exists to demonstrate that RMP's unbundling proposal will achieve the intended transparency and accuracy goals. To the extent a possibility exists that RMP's proposal deviates from COS study results when designing rates; shifts energy charges to demand charges; and shifts energy charges to customer charges, we find that RMP's proposal does not achieve the transparency it seeks to provide. The record simply does not provide adequate evidence for us to conclusively evaluate those possibilities. Accordingly, we conclude it is not in the public interest to adopt RMP's proposal at this time.

B. Schedule 1: Residential

1. Monthly Customer Charge, Minimum Charge

RMP proposes to eliminate the minimum bill for residential customers, which no party opposes. For purposes of assessing the monthly customer charge, RMP also proposes to differentiate billing residences based on a threshold of dwelling units within the billing residence, which is supported by OCS and unopposed by intervenors. Buildings with three dwelling units or more would be deemed multi-family, and all others single-family. We find this proposal reasonable because it creates a designation under which it becomes possible to recognize the difference in fixed costs between serving single-family and multi-family residences.

The Application states it is appropriate for the customer charge to recover the full costs, including line transformer costs, under the distribution function. RMP asserts fixed costs are associated with customer service, billing, and the infrastructure located geographically close to the customer that is dedicated to serving one or a small number of customers. RMP provides evidence that including these cost categories would justify a $13.69 customer charge for a single-family residence and a $10.33 customer charge for a multi-family residence. RMP proposes to increase the customer charge to $10 per month for single-family and to maintain the multi-family charge at $6. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges.

RMP states the costs of line transformers appropriately reside in the customer charge because: (i) The cost of line transformers is unaffected by changes in customer energy usage; (ii) the total number of transformers deployed is a large factor in the overall cost of line transformers in RMP's system, given the fact that the cost of a transformer does not increase proportionately to overall customer size; and (iii) line transformers are inflexible and cannot be easily redeployed to other customers. RMP asserts line transformers should not be lumped together with generation, transmission, and upstream distribution costs that are often included in the energy charge for residential customers. According to RMP, generation, transmission, and upstream distribution facilities are used by many customers and are often far from customers' location while line transformers typically service a small number of customers and are geographically located near the customers they serve. The line transformer costs are the primary source of the difference between the single-family and the multi-family customer charge.

OCS recommends that the customer charge be set at $6 per month for multi-family customers and $7 per month for single-family customers. According to RMP, however, OCS concedes its analysis did not model the full annual impacts where the energy charge for customers who use under 400 kWh/month is lower after accounting for the conversion of May rates to lower cost winter billing.

We find that elimination of the minimum bill, with a single-family monthly customer charge of $10 and a multi-family monthly customer charge of $6 is just and reasonable. This change to the monthly customer charge will better reflect the difference in fixed costs, particularly the fixed costs associated with line transformers, between single-family and multi-family residences. We also find that this change will result in a more accurate and transparent divide between fixed charges and energy charges. Accordingly, we approve RMP's proposal. However, recognizing the impact of this change on the residential class, we will implement this change in two steps. On January 1, 2021, the residential single-family customer charge will be set at $8 with the difference being reflected in residential energy rates. On January 1, 2022, the residential single-family customer charge will be set at $10 with residential energy rates reduced proportionately.

2. Inclined-Tiered Pricing, Two-Block Seasonal Differential Pricing

RMP proposes to eliminate the third tier energy charge for summer months and shorten the summer period from five to four months by moving May to the winter season. RMP's Application proposes a winter season price of 8.4319 cents for the first 400 kWh, 10.8152 cents for all additional kWh (October – May), and a summer price of 9.5280 cents for the first 400 kWh, and 12.2211 cents for all additional kWh (June – September). RMP states this price differential is based on different costs to serve different seasons. RMP demonstrates the weighted average EIM price is the lowest in the month of May. The Application proposes moving May to the lower cost winter season for residential customers and for all other rate schedules to better align costs and to help customers focus their energy efficiency efforts on the higher cost summer months.

No party opposes RMP's proposal to set a seasonal differential rate and no party opposes shifting May to the lower cost winter season for residential customers and for all other rate schedules. We find these two proposals more reasonably reflect actual costs during those months and we approve them.

RMP explains that tiered rates can result in unintended consequences, particularly as the electric industry evolves. In addition, tiered rate structures can be a source of confusion for residential customers. Accordingly, RMP proposes eliminating the summer third tier energy charge for residential customers, which "is an acutely punishing price that also stands in the way of electric vehicle adoption."[63]

DPU does not oppose RMP's proposed removal of the residential third tier. Similarly, OCS does not object to RMP's proposal to move from three tiers to two under the expectation that RMP would amend the bill impacts for low-use customers. UCE states the residential third tier was implemented to encourage customers to conserve energy, and removing it without replacing it simply removes an energy efficiency measure and, therefore, is not in the public

[63] Nov. 17 Hr'g Tr. at 19:17–25.

interest. WRA supports RMP's proposal to eliminate the third energy block in Schedule 1 for the reasons set forth by RMP.

We find substantial evidence supports RMP's contention that the third tier energy charge does not accurately reflect incremental costs to provide that energy. We also conclude that it would be inappropriate to maintain an overpriced tier solely to encourage conservation, especially where we have approved RMP's demand side management program to pursue that goal. Accordingly, we approve RMP's proposal to remove the third energy block from Schedule 1.

3. Low Income Lifeline Credit Increase

RMP proposes to increase the Low Income Lifeline Credit on Schedule 3 by $0.87, from $13.14 per month to $14.01 per month. RMP calculated this increase by applying its proposed average residential increase of 6.9% (before Schedule 197 tax credits) to the base amount of the current Low Income Lifeline Credit, $12.60. The $12.60 base amount is the current amount of Low Income Lifeline Credit less the $0.54 added by net metering program participants. Because of the decisions we have approved in this order that impact average residential rates, we find it reasonable and appropriate to increase the Low Income Lifeline Credit proportional to the average residential rate increase we are approving in this order. Because we have modified RMP's proposed rate increases, we similarly modify RMP's proposed increase to the Low Income Lifeline Credit. Accordingly, we approve an increase to the Low Income Lifeline Credit of $0.33.

C. Schedules 6, 6A, and 6B

RMP proposes to adjust the customer charge, facilities charge, power charges, and energy charges of Schedule 6 by applying the average percentage change to the requested revenue requirement. RMP also proposes to move the May billing month from the summer period to the winter period. To reflect the seasonal differential in cost, RMP proposes setting summer prices equal to 1.13 times the winter prices.

Kroger asserts that RMP's proposed rate design for Schedule 6 should be rejected, and that the price increase for Schedule 6 all go into customer, facilities, and demand charges instead of energy charges, given Kroger's assertion that energy charges for Schedule 6 are already excessive.

In rebuttal, RMP states that while the COS Study is a useful tool when determining rate design, there are additional considerations that must be taken into account. RMP acknowledges that stability in rate structure is important for customers migrating between rate schedules as their loads increase or decrease; however, there will be other time-varying rate schedules that customers can switch to with the elimination of Schedule 6B. Further, RMP asserts that ideally energy costs should not be lower for customers with larger load sizes, but presently this condition exists for RMP with its Schedule 6 and Schedule 8 pricing.

RMP proposes to re-design Schedule 6A to recover kW-based charges in a new format. This re-design would result in declining kWh-per-kW energy charges for customers on Schedule 6A. This structure enables RMP to charge customers less per kW as their load factor increases, similar to demand charges. Due to this re-design of Schedule 6A, RMP anticipates that customers currently enrolled in Schedule 6 will transfer to Schedule 6A.

DPU supports RMP's proposed re-design of Schedule 6A because the marginal cost to serve systematically declines as load factor increases. ChargePoint recommends the PSC accept RMP's re-design of Schedule 6A with one modification. ChargePoint proposes adjusting the on- and off-peak time periods in Schedule 6A to provide a stronger price incentive to customers, similar to Schedule 29 that Pacific Power adopted in Oregon. ChargePoint also references uncertainty around RMP's deployment of AMI as support for its proposal.

UCE suggests that the newly re-designed Schedule 6A be approved as a new Schedule 6C to preserve the current Schedule 6A. WRA proposes the PSC adopt RMP's re-designed Schedule 6A but rename it as Schedule 6C and keep the original Schedule 6A.

RMP disagrees that keeping both the original Schedule 6A and the re-designed Schedule 6A is in the public interest. According to RMP, the re-design of Schedule 6A will help with the adoption of electric vehicles. RMP states that re-programming all Schedule 6A's meters would be a significant expense and poor timing when AMI deployment is not far off. According to RMP, the next GRC will be a better time to consider such a change.

RMP proposes to eliminate Schedule 6B because it is structured similarly to Schedule 6 and move current customers that are enrolled in Schedule 6B to Schedule 6 and Schedule 6A. The customers transferred over to the re-designed Schedule 6A are expected to save on average 5.3%.

UCE proposes that customers who have made significant investments intending to stay on Schedule 6B should be allowed to do so. WRA would also like for special conditions to be included in Schedule 6 to prevent excessive switching between the schedules. Further, WRA proposes that RMP establish an EV-specific commercial rate with input from stakeholders by January 1, 2023.

RMP acknowledges that stability in rate structure is important for customers; however, there will be other time-varying rate schedules to which customers may switch with the elimination of Schedule 6B. On surrebuttal, RMP responds to UCE by stating that adopting multiple Schedule 6's is confusing for customers and hinders RMP from recovering its costs. RMP argues that it does not make sense to provide four nearly identical schedules.

We find that RMP's proposal provides stability between schedules and better reflects the actual costs associated with fixed, energy, and demand charges. Accordingly, we conclude RMP's Schedule 6 rate design proposal is just and reasonable, and we approve it.

We find that approving multiple nearly identical rate schedules adds unnecessary complexity to the rate schedules and may hinder RMP from recovering its costs. Considering that current customers on Schedule 6B will have another time-varying rate schedule to choose from, and are expected to save 5.3%, we find that it is reasonable to eliminate Schedule 6B.

We find that an insufficient record exists to mandate a date for implementation of an electric vehicle rate schedule, and we decline to do so.

D. Schedule 8 and Schedule 9 Modifications

For Schedules 8 and 9, RMP proposes to implement the proposed revenue requirement change by applying a uniform percentage change to the customer charge and facilities charge. RMP also proposes applying a larger increase to power charges, and for energy it proposes increases for on-peak charges and decreases for off-peak charges. RMP designed power charges so that summer prices were set at a level 1.13 times winter prices. Additionally, RMP proposes modifications to the time-of-use (TOU) periods to reflect a more contemporary view of on-peak.

Table 5. Summary of Present and Proposed Time of Use Periods for Schedule 8 and Schedule 9

	Current Schedule 8 and 9	Proposed Schedule 8	Proposed Schedule 9
Winter Season	October-April	October-May	October-May
Summer Season	May-September	June-September	June-September
On-Peak Days	Mon-Fri, excluding holidays	Mon-Fri, excluding holidays	Mon-Fri, excluding holidays
Winter On-Peak Hours	7am-11pm	6am-10am & 6pm-12am(midnight)	6 am-9am & 6pm-11pm
Summer On-Peak Hours	1pm-9pm	2pm-12am(midnight)	3pm-11pm

RMP explains the support for reshaping the on- and off-peak periods is based on an analysis of prices for the 15-minute PACE EIM LAP for the 36-month period ending October 2019. RMP used the top ten daily hours in both seasons as the on-peak period for Schedule 8. The relative differences between on- and off-peak pricing compared to the average were used to develop the proposed energy charges. RMP used the top eight daily hours from among both seasons to define the on-peak period for Schedule 9. RMP asserts Schedule 8 and Schedule 9 are both large and significant customer classes and staggering their on-peak periods can potentially help RMP better manage its loads.

Schedule 9A is closed to new service. RMP proposes gradual movement of Schedule 9A customers toward Schedule 9 pricing, with the initial movement to make up 33% of the difference between the Schedules. RMP proposes that Seasonal and TOU charges for Schedule 9A will match Schedule 9. Remaining Schedule 9A customers would pay power charges set at 33% of the level proposed for Schedule 9 charges. RMP proposes a gradual transition to mitigate rate impact.

DPU expresses concerns about the analysis used to reshape the (proposed) on- and off-peak periods for Schedules 8 and 9. Generally, such periods can be determined through ANOVA or other statistical clustering methods applied to hourly marginal costs for selected months. ChargePoint comments on the Schedule 8 on- and off-peak periods only to suggest that the same periods could be used for Schedule 6A.

UAE recommends RMP modify its TOU periods so that they allow for a full eight-hour nighttime off-peak shift. In rebuttal, RMP generally agreed with UAE's proposal with one minor change -- the off-peak period in the evenings begin at 10:00 p.m. for both the summer and winter seasons, as opposed to 10:00 p.m. during the winter and 11:00 p.m. during the summer as proposed by UAE. In surrebuttal, UAE agreed with RMP's modification.

Because there are only nine customers on Schedule 9A, which has been closed for many years, and in the absence of opposition, we find that gradually transitioning these customers to Schedule 9 is reasonable. Further, we find that RMP's proposed rates and rate treatment for Schedules 8, 9, and 9A, as adjusted through rebuttal and surrebuttal testimony, accomplish movement towards cost-based rates. We recognize that some concerns have been raised as to whether RMP's method to determine on- and off-peak periods is reasonable. While RMP chose to use a different method than DPU preferred, there is substantial evidence to find that RMP's method results in reasonable on- and off-peak periods. Therefore, in light of these findings, we conclude that RMP's proposed changes to the rates and on- and off-peak periods for Schedules 8, 9, and 9A are just and reasonable. We approve those proposed changes.

E. Elimination of Schedule 21

RMP proposes to eliminate its Electric Service Schedule No. 21. Under Schedule 21, customers can receive electricity service for electric furnaces, annealing ovens, or salt baths where RMP has facilities of adequate capacity through a single point of delivery. RMP reports that Schedule 21 is closed to new service, that only two customers remain on Schedule 21, and that characteristics of customers with electric furnace operations are no longer distinguishable from those of other general service customers. RMP testified that it will transition one customer to Schedule 6 and one to Schedule 9 based on load size. No party opposed RMP's proposal.

DPU supports RMP's proposed cancellation and the transition of the two remaining customers to existing schedules, but suggests RMP consider phasing in the customers' new rates to avoid sudden major changes in the amounts paid under Schedule 21. DPU argues that the two remaining Schedule 21 customers are "sizable" and could "realize significant windfalls and losses" because of the rate transition.[64] RMP disagrees that a transition period is necessary.

We find that the evidence demonstrates that RMP has closely examined the two remaining Schedule 21 customers' usage and that both existing Schedule 21 customers have very low load factors. We find that the major transition impact to the two customers is their exposure to demand charges, and that, under RMP's proposed changes to Schedule 6A and Schedule 9,

[64] Direct Test. of R. Camfield at 36:737-8.

both customers will have the ability to take advantage of time-varying rates to smooth transition-related rate impacts. We conclude that transferring the two customers on this schedule to other schedules serves the important interest of achieving uniformity among similarly situated customers. Accordingly, we approve RMP's request to eliminate Schedule 21.

F. Schedule 32

Because insufficient data existed to include Schedule 32 in its COS Study, RMP's Application includes a COS analysis for Schedule 32 ("Analysis"). In the Analysis, RMP calculated proposed Delivery Facilities Charges (DFC) for Schedule 32 based on the cost of fixed demand-related transmission, distribution substations, distribution poles and conductors, and distribution transformers allocated to full requirements customers. RMP then set the Daily Power Charges (DPC) at a level that, in combination with the DFC, would recover the same level of cost as facilities and power charges that are applicable to full requirements customers. RMP's proposed DPC charge reflects the movement of May to a winter month and the Supplemental Power and Energy charges were set consistent with the customer's applicable general service schedule (Schedule 6, 8, or 9).

RMP's Application proposes modest increases to Schedule 32's various customer charges and administrative fees, and its pricing model includes an energy charge consistent with applicable Renewable Energy Contracts associated with Schedule 32. No party opposes these elements of RMP's Application.

UAE and the U of U oppose RMP's proposed DFC and DPC. According to U of U, RMP's proposal to increase the DFC for Schedule 9 customers taking service under Schedule 32 from the current $3.85 to $5.32, or 38%, imposes unfair burdens on these customers. U of U asserts RMP's Analysis does not represent the cost to provide service to Schedule 32 customers. U of U claims RMP's approach is the same approach the PSC rejected in Docket No. 14-035-T02. U of U also asserts RMP's proposed design for the DPC is flawed because it is based on a DFC that is different from that applied to full service customers. U of U recommends the PSC reject RMP's proposal and alternatively: (i) set the Schedule 32 DFC at the same rate as the facilities charge for the applicable general service schedule; and (ii) set the Schedule 32 DPC by converting the Schedule 6/8/9 on-peak power charge per KW to a daily charge.

UAE recommends setting the Schedule 32 DFC charge equal to RMP's proposed facilities charges for the corresponding full requirements customers and adjusting the DPC accordingly to recover the same level of cost as the power charges applicable to full requirements customers. UAE asserts the Schedule 32 DFCs and DPCs must be aligned with the charges for the corresponding full requirements rate schedules for the Schedule 32 rates to be non-discriminatory.

In rebuttal, RMP modified the Schedule 32 rates consistent with its revised revenue requirement proposal. In addition, RMP corrected the billing units used in its Analysis as requested by UAE. RMP asserts its proposed prices are grounded in COS and only modestly increase the proportion of recovery achieved through the DFC. According to RMP, the main difference between rates proposed by RMP and those proposed by UAE and U of U is the level of recovery included in DFC that is more fixed in nature, compared with that for the DPC that is easier to avoid.

RMP proposes that if concerns exist regarding the lack of a detailed COS study, the PSC could maintain the present composition of demand-related charges in Schedule 32. At hearing, RMP stated it is not proposing increasing the DFC and DPC by the same percentage. Rather, in light of its unopposed proposal to move May to the winter TOU period (which adjusted the billing determinant distribution), RMP clarified the amount of money collected from the DFC and the DPC should maintain the same ratio.

In surrebuttal, U of U states that it believed RMP's alternative proposal was to treat Schedule 32 as it treats Schedule 31, to maintain the current composition of demand charges by increasing the Schedule 32 facilities charge by the same percentage as the increase to the facilities charge for the corresponding full requirements rate. Based on RMP's testimony at hearing, U of U asserts RMP's alternative position is no longer clear. Nonetheless, U of U and UAE both state that the alternative they believed RMP had proposed would help mitigate parties' concerns.

We find it would not be reasonable to maintain the status quo of Schedule 32 in light of the revenue requirement and spread decisions we approve in this case, including a 2.65%, or approximately $300,000 increase, to Schedule 32. Schedule 32's rates must cover its assigned revenue increase. Further, we find RMP's proposed increase of the DFC for transmission customers from $3.85 to $5.01 is not adequately supported by the evidence because of the absence of a full COS study. We also conclude the proposed DFC increase for transmission customers is not consistent with our decision in Docket No. 14-035-T02. For this reason, we reject RMP's proposal. On the other hand, we find the alternate proposals also suffer, in part, from not being based on a COS Study. Additionally, we find U of U's and UAE's proposals, or those they believe to be RMP's alternative proposal, will not fully cover the revenue increase assigned to Schedule 32 resulting from the spread decision we approve in this case.

RMP's proposed inclusion of May in the winter period, which no party opposed, resulted in an increase in billing determinants assigned to the winter months and an equal reduction in the summer months. At hearing, RMP clarified that, in light of this modification, it would be inappropriate to simply increase the different existing rate components by an equal percentage. RMP further clarified its proposal that the amount of revenue collected from the DFC and the DPC should maintain the same ratio. Given this clarification and the absence of a COS study for Schedule 32, we find RMP's proposal to maintain the same ratio of revenue collected from the DFCs and the DPCs attempts to preserve our decision in Docket No. 14-035-T02, avoids dramatic swings in the facilities charge, and results in a reasonable change to the DFC.

Using the information presented in RMP's pricing model, RMP Exhibit RMM-1SR, filed on November 12, 2020, at current rates and forecast billing units we identify a DFC forecast of $944,733. Similarly, for the DPC, we identify a total revenue of $757,979 (representing $428,347 in May through September and $329,632 in October through April). Using these numbers, we calculate a revenue ratio of 55/45 between the DFC and the DPC, respectively. Using this ratio, RMP's pricing model updated for our decisions in this case and with the target rate change for Schedule 32 approximately equal to the amount to be collected in rates, we calculate a DFC of $4.35 and DPCs of $0.71 and $0.61 for the summer and winter months, respectively. These amounts approximately preserve the 55/45 ratio proposed by RMP, result in a reasonable increase in the DFC, and maintain the summer/winter differential presented by RMP in RMM-1SR for transmission customers.

There are currently no Schedule 32 customers taking service at primary and secondary voltages, therefore RMP's Analysis relied on COS Study data from Schedules 6 and 8. Specifically, there are no forecast billing units assigned to DFC and DPC rate elements, and the changes RMP proposes to the DFC and DPC in surrebuttal are associated with the costs of serving related Schedules 6 and 8. Considering the lack of Schedule 32 data, we find the Schedule 6 and 8 data to be most relevant, and we find RMP's method for determining the Schedule 32 DFC and DPC charges reasonable.

G. Proposed Non-Residential Pilot Programs: Schedule 35 and Schedule 36

RMP proposes two pilot pricing programs for large non-residential customers designed to ease demand and corresponding price shocks by inducing those customers to adjust their load under high demand conditions. The first program, titled the Interruptible Service Pilot and detailed in RMP's proposed Schedule 35, would offer a large customer Interruptible Demand Credits and Interruptible Energy Credits in exchange for nominating the customer's own non-interruptible load level and then reducing its load to that level during RMP-called interruption events. The second program, titled the Real-Time Day Ahead Pilot and detailed in RMP's proposed Schedule 36, would allow a large customer to elect variable energy supply pricing "shaped" by California Independent System Operator's Open Access Same-time Information System prices before 2:00 p.m. from the previous day, theoretically inducing the electing customer to calibrate its consumption to those previous-day prices.

DPU indicated its support for dynamic pricing options for large customers in general but offered recommendations to improve both pilot programs. For the Interruptible Service Pilot, DPU suggested that RMP measure curtailment by counterfactual reference load levels and that RMP offer customers a menu of curtailment options differentiated by load and hours curtailed, noting that load curtailment can be extremely costly and difficult for certain customers. RMP generally agreed with this suggestion.

OCS responds that RMP's two pilot proposals are not likely to provide meaningful customer value, could be a rate increase in disguise, and that they lack important pilot program features, including testing a new technology or unproven rate design, evaluation metrics, and a clear plan to eventually transition pilot program customers to a standard offering. OCS argues that we should require RMP's future pilot proposals to provide a more clear description of the product or service it is offering and its potential benefits to customers. And OCS urges us to require RMP's pilot program proposals to provide clear objectives, evaluation criteria, performance targets, and future scaling plans before we consider their approval.

We recognize that these two proposed pilot programs would not be mandatory for any customer. Nevertheless, we find insufficient evidence to support approval at this time. RMP proposed both as pilot programs, and we conclude that designation generally implies timelines, reporting, and evaluation metrics. While we decline to here adopt rigid requirements for pilot programs, we find RMP simply has failed to provide evidence to demonstrate either of these proposals is just, reasonable, or in the public interest.

More specifically, we find that RMP has not provided evidence to show its proposed Interruptible Service and Real-Time Day Ahead Pricing will provide sufficient value to RMP and customers to justify their pursuit. RMP should pursue innovative and dynamic pricing models for large customers, but those models should create identifiable and meaningful resource deferral or replacement and be well-calibrated to capture the benefits of curtailment or load-shifting for RMP and for customers. The evidence does not establish whether RMP's proposal has the potential to create those benefits or will simply result in a rate decrease for large customers that elect to participate. Finally, our decision will not hamper RMP's ability to explore the proposed pricing models and update its proposal in the near future; RMP has the opportunity to work with interested stakeholders to improve both proposals and request their approval outside of a GRC. Accordingly, we decline to approve RMP's proposed Schedule 35 and Schedule 36 pilot programs at this time.

H. Schedule 11 Street Lighting

RMP proposes to amend its price methodology for RMP-owned streetlights under its Electric Service Schedule No. 11. RMP currently charges monthly rates based on the type of lamp RMP provides subject to certain adjustments for pole type, length, and installation date. RMP proposes to replace this pricing methodology with one based on the type of lighting (area or street) and the level of lighting it provides, with light level measured in LED equivalent lumens. RMP's proposal also includes lower rates in each pricing tier for customers that pay to convert an existing RMP-owned area or street light to LED. No party opposed RMP's proposed Schedule 11 pricing method.

UCE testified that it supports RMP's proposed Schedule 11 amendments, but requests that the PSC require RMP to include a mechanism that allows a Schedule 11 customer to initiate a regulatory proceeding to purchase its area or street lights from RMP. DPU comments that UCE's proposal has merit and warrants further study, but urges us to focus on the cost of service implications of UCE's proposal.

RMP argues that it has in the past sold RMP-owned area and street lights subject to Schedule 11 to municipalities, with the most recent occasion occurring in 2016, and that a formal regulatory proceeding is not necessary to accomplish this objective. RMP already publishes pricing for customer-owned area and street lights on Schedule 12, and the municipal customer that purchased its lights in 2016 was simply transferred from Schedule 11 to Schedule 12.

We conclude that no additional procedure or process is necessary to accomplish UCE's goal of offering Schedule 11 customers the opportunity to modernize their area or street lights and incorporate them into innovative lighting solutions. RMP testified that it has the ability to effect a sale of RMP-owned area or street lights to a Schedule 11 customer and has done so in the recent past. And RMP can transition a Schedule 11 customer to its existing Schedule 12 once a proposed sale is complete. To the extent a municipality does not believe the purchase price RMP proposes is just and reasonable, it can file a request for agency action with us or an informal complaint with DPU.

For these reasons we approve RMP's proposed Schedule 11 pricing method changes without imposing additional rules or procedures.

I. Rate Implementation

Based on and consistent with our decisions above we determine the rates presented in Exhibit B – Pricing are just and reasonable and conclude they are in the public interest, effective January 1, 2021.

J. Proposed Working Groups, Task Forces, and Collaborative Processes

Various parties have proposed formal working groups, task forces, or other collaborative processes in connection with certain issues, adjustments, and RMP proposals discussed in testimony in this case including the AMI Project, residential rates, a multi-site commercial rate, Schedule 32 rate design, Schedule 6A TOU rates, electric vehicle-specific rates, critical peak pricing, class cost of service allocation, and rate unbundling.

We find that a collaborative stakeholder process could evaluate avenues for consensus or clarification on some or all of these issues. However, we are mindful of time demands on parties, and we have no desire to remove any party from participation in a stakeholder process because the process becomes too burdensome.

Accordingly, we will accept comments in this docket on or before Tuesday, February 16, 2021, and reply comments on or before Tuesday, March 2, 2021, on the scope and format of a collaborative stakeholder process. These comments may address the potential scope of the process, whether the process should involve a PSC docket or be more informal, whether any reporting is appropriate, and who should take the lead in the process.

VII. ORDER

Pursuant to our discussion, findings, and conclusions:

1. We approve a revenue requirement increase of $31.41 million, allocated to the various customer classes at the prices shown in Exhibits A and B.
2. We approve a rate mitigation strategy to return $46.3 million to customers in 2021 and $23.1 million in 2022 through Schedule 197.
3. Our decision to increase the single-family residential customer charge shall take place in two steps, from $6 to $8 on January 1, 2021, and from $8 to $10 on January 1, 2022. The multi-family residential customer charge will remain at $6.
4. RMP shall file appropriate Tariff revisions reflecting rate changes and all other Tariff changes approved in this order as of January 1, 2021 within 14 days after the date of this order. RMP shall include in this filing an updated spreadsheet identifying the Base EBA and its various components, including PTCs.
5. RMP shall file appropriate Tariff revisions reflecting rate changes and all other Tariff changes approved in this order to take effect on January 1, 2022, no later than Monday, November 1, 2021.
6. We approve RMP's request to establish a deferral account associated with the costs of closing of Cholla Unit #4.

7. We approve RMP's request to draw on the December 31, 2019 balance of the property insurance reserve to address certain reliability-related conditions.
8. We approve RMP's proposed Wildland Fire Mitigation Balancing Account as proposed.
9. RMP shall initiate a proceeding by March 1, 2021 to establish a balancing account for pension settlement losses.
10. Any interested person may provide comments in this docket by **Tuesday, February 16, 2021**, and reply comments by **Tuesday, March 2, 2021**, on the scope and format of the collaborative stakeholder process described in this order.

DATED at Salt Lake City, Utah, December 30, 2020.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#316866

Notice of Opportunity for Agency Review or Rehearing

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

CERTIFICATE OF SERVICE

I CERTIFY that on December 30, 2020, a true and correct copy of the foregoing was delivered upon the following as indicated below:

By Email:

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____
Administrative Assistant

EXHIBIT A – SPREAD OF REVENUE REQUIREMENT INCREASE

Exhibit A
Estimated Effect of Proposed Changes
on Revenues from Electric Sales to Ultimate Consumers in Utah
Base Period 12 Months Ending December 2019
Forecast Period 12 Months Ending December 2021

Line No.	Description	Sch No.	No. of Customer Forecast	MWh Forecast	Present Base ($000)	Base ($000)	TAA ($000)	Net ($000)	Base Change ($000)	Base Change (%)	Net Change ($000)	Net Change (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
									(6)-(5)	(9)/(5)	(8)-(5)	(11)/(5)
	Residential											
1	Residential	1/3	857,245	6,776,607	$730,023	$749,388	($19,802)	$729,587	$19,365	2.7%	($436)	-0.1%
2	Res. Optional TOD	2/2E	623	6,392	$601	$618	($17)	$602	$17	2.9%	$1	0.1%
3	AGA/Revenue Credit				$7	$7	$0	$7	$0	0.0%	$0	0.0%
4	**Total Residential**		857,868	6,782,999	$730,631	$750,013	($19,818)	$730,195	$19,382	2.7%	($436)	-0.1%
	Commercial & Industrial											
5	Gen. Svc. Dist.	6	13,514	5,786,326	$473,635	$476,520	($10,620)	$465,900	$2,885	0.6%	($7,736)	-1.6%
6	Gen. Svc. Dist. Energy TOD	6A	2,806	404,018	$46,170	$47,049	($1,101)	$45,948	$879	1.9%	($222)	-0.5%
7	Gen. Svc. Dist. Demand TOD	6B	16	3,381	$331	$310	($7)	$304	($21)	-6.3%	($27)	-8.3%
8	*Subtotal Schedule 6*		*16,336*	*6,193,724*	*$520,137*	*$523,879*	*($11,728)*	*$512,151*	*$3,743*	*0.7%*	*($7,985)*	*-1.5%*
9	Gen. Svc. Dist. > 1,000 kW	8	249	2,020,703	$146,557	$148,125	($3,224)	$144,901	$1,568	1.1%	($1,656)	-1.1%
10	Gen. Svc. High Voltage	9	156	4,847,332	$265,710	$272,898	($6,132)	$266,765	$7,188	2.7%	$1,056	0.4%
11	Gen. Svc. H.V. Energy TOD	9A	9	41,940	$3,196	$2,994	($59)	$2,935	($202)	-6.3%	($261)	-8.2%
12	*Subtotal Schedule 9*		*165*	*4,889,272*	*$268,905*	*$275,891*	*($6,191)*	*$269,701*	*$6,986*	*2.6%*	*$795*	*0.3%*
13	Irrigation	10	3,339	206,134	$15,777	$16,043	($404)	$15,638	$266	1.7%	($139)	-0.9%
14	Irrigation TOD	10TOD	269	24,258	$1,923	$1,947	($50)	$1,898	$25	1.3%	($25)	-1.3%
15	*Subtotal Irrigation*		*3,608*	*230,392*	*$17,700*	*$17,990*	*($454)*	*$17,536*	*$291*	*1.6%*	*($164)*	*-0.9%*
16	Electric Furnace	21	3	1,837	$233	$504	($11)	$493	$271	116.1%	$260	111.5%
17	Gen. Svc. Dist. Small	23	96,230	1,404,452	$138,042	$138,042	($3,023)	$135,019	($0)	0.0%	($3,023)	-2.2%
18	Partial Req. Svc. >= 1,000 kW	31	7	189,259	$12,375	$12,591	($236)	$12,355	$216	1.7%	($20)	-0.2%
19	Svc. From Ren. Ene. Facilities	32	3	196,650	$13,008	$13,353	($33)	$13,320	$346	2.7%	$313	2.4%
20	Ren. Ene. Pur. for Qlf. Cust > 5,000 kW	34	1	242,230	$13,028	$13,028	$0	$13,028	$0	0.0%	$0	0.0%
21	Contract 1		1	617,100	$31,382	$31,874	($725)	$31,150	$492	1.6%	($232)	-0.7%
22	Contract 2		1	705,456	$31,485	$31,979	($729)	$31,250	$494	1.6%	($235)	-0.7%
23	Contract 3		1	1,288,626	$62,958	$62,958	$0	$62,958	$0	0.0%	$0	0.0%
24	AGA/Revenue Credit				$4,797	$4,797	$0	$4,797	$0	0.0%	$0	0.0%
25	**Total Commercial & Industrial**		116,605	17,979,703	$1,260,607	$1,275,012	($26,354)	$1,248,658	$14,406	1.1%	($11,948)	-0.9%
	Public Street Lighting											
26	Security Area Lighting	7	6,491	10,498	$2,496	$1,383	($24)	$1,359	($1,113)	-44.6%	($1,137)	-45.5%
27	Street Lighting - Company Owned	11	715	13,573	$4,103	$3,759	($66)	$3,694	($344)	-8.4%	($410)	-10.0%
28	Street Lighting - Customer Owned	12	1,229	26,869	$1,896	$1,403	($25)	$1,378	($493)	-26.0%	($518)	-27.3%
29	Metered Outdoor Lighting	15	637	15,963	$1,155	$781	($14)	$767	($374)	-32.4%	($389)	-33.6%
30	Traffic Signal Systems	15	2,734	7,776	$803	$803	($15)	$787	($0)	0.0%	($15)	-1.9%
31	*Subtotal Public Street Lighting*		11,806	74,679	$10,453	$8,129	($144)	$7,985	($2,324)	-22.2%	($2,468)	-23.6%
32	Security AR LG-Contracts (PTL)		4	7	$1	$1	$0	$1	$0	0.0%	$0	0.0%
33	AGA/Revenue Credit				$5	$5	$0	$5	$0	0.0%	$0	0.0%
34	**Total Public Street Lighting**		11,810	74,686	$10,458	$8,134	($144)	$7,990	($2,324)	-22.2%	($2,468)	-23.6%
35	**Total Sales to Ultimate Customers**		986,283	24,837,388	$2,001,696	$2,033,160	($46,316)	$1,986,843	$31,464	1.6%	($14,853)	-0.7%

EXHIBIT B – PRICING

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	January 1, 2022 Effective Delivery Price
Schedule No. 1- Residential Service				
Total Customer	9,344,849			
Customer Charge - 1 Phase	9,329,308			
Single Family	7,140,845		$8.00	$10.00
Multi Family	2,188,463		$6.00	$6.00
Customer Charge - 3 Phase	15,541			
Single Family	3,325		$16.00	$20.00
Multi Family	12,216		$12.00	$12.00
Aggregate Charge	0		$2.00	$2.00
Non-Standard Meter Reading Fee	253		$22.00	$22.00
Minimum 1 Phase	17,284			
Single Family	12,077			
Multi Family	5,207			
Minimum 3 Phase	29			
Single Family	7			
Multi Family	22			
Minimum Seasonal	4			
On-Peak kWh (Jun - Sept)	0		4.3560 ¢	4.3560 ¢
Off-Peak kWh (Jun - Sept)	0		(1.6334) ¢	(1.6334) ¢
First 400 kWh (Jun-Sept)	1,080,475,945		9.2802 ¢	9.0279 ¢
Next 600 kWh (Jun-Sept)	960,049,471		11.9733 ¢	11.7210 ¢
All add'l kWh (Jun-Sept)	527,790,900		11.9733 ¢	11.7210 ¢
First 400 kWh (Oct-May)	2,051,977,461		8.2126 ¢	7.9893 ¢
All add'l kWh (Oct-May)	1,671,527,763		10.5959 ¢	10.3725 ¢
On-Peak kWh (May - Sept)	0			
Off-Peak kWh (May - Sept)	0			
First 400 kWh (May-Sept)	1,356,162,147			
Next 600 kWh (May-Sept)	1,083,453,568			
All add'l kWh (May-Sept)	560,494,056			
First 400 kWh (Oct-Apr)	1,776,482,587			
All add'l kWh (Oct-Apr)	1,515,229,182			
Subscriber Solar kWh	15,864,580		12.2436 ¢	11.9126 ¢
Unbilled	0			
TAA		Tax Year 1	-3.02%	-3.02%
Subscriber Solar kWh Adj	(316,213)	Tax Year 2	-1.51%	-1.51%

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	January 1, 2022 Effective Delivery Price
Schedule No. 2 - Residential Service - Optional Time-of-Day				
Total Customer	4,350			
Customer Charge - 1 Phase	4,339			
Single Family	3,371		$8.00	$10.00
Multi Family	968		$6.00	$6.00
Customer Charge - 3 Phase	11			
Single Family	11		$16.00	$20.00
Multi Family	0		$12.00	$12.00
Aggregate Charge	0		$2.00	$2.00
Non-Standard Meter Reading Fee	0		$22.00	$22.00
Minimum 1 Phase	9			
Single Family	5			
Multi Family	4			
Minimum 3 Phase	0			
Single Family	0			
Multi Family	0			
Minimum Seasonal	0			
On-Peak kWh (Jun - Sept)	258,230		4.3560 ¢	4.3560 ¢
Off-Peak kWh (Jun - Sept)	825,288		(1.6334) ¢	(1.6334) ¢
First 400 kWh (Jun-Sept)	495,959		9.2802 ¢	9.0279 ¢
Next 600 kWh (Jun-Sept)	407,470		11.9733 ¢	11.7210 ¢
All add'l kWh (Jun-Sept)	186,496		11.9733 ¢	11.7210 ¢
First 400 kWh (Oct-May)	919,695		8.2126 ¢	7.9893 ¢
All add'l kWh (Oct-May)	734,416		10.5959 ¢	10.3725 ¢
On-Peak kWh (May - Sept)	302,460			
Off-Peak kWh (May - Sept)	954,246			
First 400 kWh (May-Sept)	617,449			
Next 600 kWh (May-Sept)	451,197			
All add'l kWh (May-Sept)	188,068			
First 400 kWh (Oct-Apr)	810,180			
All add'l kWh (Oct-Apr)	677,142			
Subscriber Solar kWh	0		12.2436 ¢	11.9126 ¢
Unbilled	0			
TAA		Tax Year 1	-3.02%	-3.02%
Subscriber Solar kWh Adj	0	Tax Year 2	-1.51%	-1.51%

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	January 1, 2022 Effective Delivery Price
Schedule No. 2E - Electric Vehicle Time-of-Use Pilot Option				
Total Customer	3,114			
Customer Charge - 1 Phase	3,114			
Single Family	2,923		$8.00	$10.00
Multi Family	191		$6.00	$6.00
Customer Charge - 3 Phase	0			
Single Family			$16.00	$20.00
Multi Family			$12.00	$12.00
Aggregate Charge	0		$2.00	$2.00
Non-Standard Meter Reading Fee	0		$22.00	$22.00
Minimum 1 Phase	0.0000			
Single Family	0			
Multi Family	0			
Minimum 3 Phase	0			
Single Family				
Multi Family				
Minimum Seasonal	0			
Rate Option 1				
On-Peak kWh	206,699		21.0339 ¢	21.0339 ¢
Off-Peak kWh	963,611		6.4097 ¢	6.4097 ¢
Rate Option 2				
On-Peak kWh	347,186		32.4592 ¢	32.4593 ¢
Off-Peak kWh	2,130,652		3.2108 ¢	3.2108 ¢
Subscriber Solar kWh	0		12.2436 ¢	11.9126 ¢
Unbilled	0			
TAA		Tax Year 1	-3.02%	-3.02%
Subscriber Solar kWh Adj	0	Tax Year 2	-1.51%	-1.51%

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	January 1, 2022 Effective Delivery Price
Schedule No. 3- Residential Service - Low Income Lifeline Program				
Total Customer	216,323			
Customer Charge - 1 Phase	216,152			
Single Family	113,309		$8.00	$10.00
Multi Family	102,843		$6.00	$6.00
Customer Charge - 3 Phase	171			
Single Family	27		$16.00	$20.00
Multi Family	144		$12.00	$12.00
Aggregate Charge	0		$2.00	$2.00
Non-Standard Meter Reading Fee	0		$22.00	$22.00
Minimum 1 Phase	44			
Single Family	26			
Multi Family	18			
Minimum 3 Phase	0			
Single Family				
Multi Family				
Minimum Seasonal	0			
On-Peak kWh (Jun - Sept)	5,354		4.3560 ¢	4.3560 ¢
Off-Peak kWh (Jun - Sept)	15,633		(1.6334) ¢	(1.6334) ¢
First 400 kWh (Jun-Sept)	26,384,768		9.2802 ¢	9.0279 ¢
Next 600 kWh (Jun-Sept)	17,765,859		11.9733 ¢	11.7210 ¢
All add'l kWh (Jun-Sept)	5,668,613		11.9733 ¢	11.7210 ¢
First 400 kWh (Oct-May)	51,185,664		8.2126 ¢	7.9893 ¢
All add'l kWh (Oct-May)	32,983,258		10.5959 ¢	10.3725 ¢
On-Peak kWh (May - Sept)	6,768			
Off-Peak kWh (May - Sept)	21,221			
First 400 kWh (May-Sept)	33,384,447			
Next 600 kWh (May-Sept)	20,215,888			
All add'l kWh (May-Sept)	5,928,185			
First 400 kWh (Oct-Apr)	44,288,230			
All add'l kWh (Oct-Apr)	30,171,412			
Subscriber Solar kWh	108,762		12.2436 ¢	11.9126 ¢
Unbilled	0			
TAA		Tax Year 1	-3.02%	-3.02%
Subscriber Solar kWh Adj	(3,852)	Tax Year 2	-1.51%	-1.51%

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price		January 1, 2022 Effective Delivery Price	
Schedule No. 135 - Residential Service - Net Metering						
Total Customer	418,416					
Customer Charge - 1 Phase	418,038					
Single Family	405,641		$8.00		$10.00	
Multi Family	12,397		$6.00		$6.00	
Customer Charge - 3 Phase	378					
Single Family	112		$16.00		$20.00	
Multi Family	266		$12.00		$12.00	
Aggregate Charge	0		$2.00		$2.00	
Non-Standard Meter Reading Fee	14		$22.00		$22.00	
Minimum 1 Phase	48,755					
Single Family	47,983					
Multi Family	772					
Minimum 3 Phase	11					
Single Family	8					
Multi Family	3					
Minimum Seasonal	0					
On-Peak kWh (Jun - Sept)	7,090		4.3560	¢	4.3560	¢
Off-Peak kWh (Jun - Sept)	44,469		(1.6334)	¢	(1.6334)	¢
First 400 kWh (Jun-Sept)	21,966,174		9.2802	¢	9.0279	¢
Next 600 kWh (Jun-Sept)	14,447,176		11.9733	¢	11.7210	¢
All add'l kWh (Jun-Sept)	7,916,923		11.9733	¢	11.7210	¢
First 400 kWh (Oct-May)	50,047,131		8.2126	¢	7.9893	¢
All add'l kWh (Oct-May)	47,956,842		10.5959	¢	10.3725	¢
On-Peak kWh (May - Sept)	7,604					
Off-Peak kWh (May - Sept)	52,839					
First 400 kWh (May-Sept)	24,008,564					
Next 600 kWh (May-Sept)	15,166,728					
All add'l kWh (May-Sept)	8,344,047					
First 400 kWh (Oct-Apr)	47,906,710					
All add'l kWh (Oct-Apr)	46,908,197					
Subscriber Solar kWh	0		12.2436	¢	11.9126	¢
Unbilled	0					
TAA		Tax Year 1	-3.02%		-3.02%	
Subscriber Solar kWh Adj	0	Tax Year 2	-1.51%		-1.51%	

Exhibit B

Pricing Residential Schedules

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	January 1, 2022 Effective Delivery Price
Schedule No. 136 - Residential Service - Net Metering				
Total Customer	307,354			
Customer Charge - 1 Phase	307,354			
Single Family	303,609		$8.00	$10.00
Multi Family	3,745		$6.00	$6.00
Customer Charge - 3 Phase	0			
Single Family			$16.00	$20.00
Multi Family			$12.00	$12.00
Aggregate Charge	1,646		$2.00	$2.00
Non-Standard Meter Reading Fee	0		$22.00	$22.00
Minimum 1 Phase	71,571			
Single Family	71,054			
Multi Family	517			
Minimum 3 Phase	0			
Single Family				
Multi Family				
Minimum Seasonal	0			
On-Peak kWh (Jun - Sept)	5,690		4.3560 ¢	4.3560 ¢
Off-Peak kWh (Jun - Sept)	35,358		(1.6334) ¢	(1.6334) ¢
First 400 kWh (Jun-Sept)	38,703,048		9.2802 ¢	9.0279 ¢
Next 600 kWh (Jun-Sept)	26,842,157		11.9733 ¢	11.7210 ¢
All add'l kWh (Jun-Sept)	7,600,557		11.9733 ¢	11.7210 ¢
First 400 kWh (Oct-May)	68,555,364		8.2126 ¢	7.9893 ¢
All add'l kWh (Oct-May)	51,108,843		10.5959 ¢	10.3725 ¢
On-Peak kWh (May - Sept)	6,621			
Off-Peak kWh (May - Sept)	42,635			
First 400 kWh (May-Sept)	46,944,979			
Next 600 kWh (May-Sept)	29,314,016			
All add'l kWh (May-Sept)	8,306,352			
First 400 kWh (Oct-Apr)	60,622,730			
All add'l kWh (Oct-Apr)	47,621,892			
Subscriber Solar kWh	0		12.2436 ¢	11.9126 ¢
Unbilled	0			
TAA		Tax Year 1	-3.02%	-3.02%
Subscriber Solar kWh Adj	0	Tax Year 2	-1.51%	-1.51%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 6 - Composite			
Customer Charge	157,116		$53.00
Seasonal Service	0		$636.00
Minimum Charge	14		$53.00
Facilities kW	15,576,842		$3.99
All kW (Jun - Sept)	6,921,590		$13.27
All kW (Oct - May)	8,655,252		$11.74
kWh (Jun-Sept)	2,063,156,225		$3.8878 ¢
kWh (Oct-May)	3,526,754,594		$3.4405 ¢
All kW (May - Sept)	7,107,269		
All kW (Oct - Apr)	8,469,573		
Voltage Discount	569,738		($0.96)
kWh (May-Sept)	2,527,546,695		
kWh (Oct-Apr)	3,062,364,124		
Subscriber Solar kWh	1,977,670		7.1250 ¢
Unbilled	0		
TAA		Tax Year 1	-2.61%
		Tax Year 2	-1.30%
Subscriber Solar kWh Adj	25,489		
Schedule No. 6-135 - Net Metering - Composite			
Customer Charge	4,434		$53.00
Seasonal Service	0		$636.00
Minimum Charge	0		$53.00
Facilities kW	505,379		$3.99
All kW (Jun - Sept)	206,980		$13.27
All kW (Oct - May)	298,398		$11.74
kWh (Jun-Sept)	60,590,666		3.8878 ¢
kWh (Oct-May)	109,661,558		3.4405 ¢
All kW (May - Sept)	228,131		
All kW (Oct - Apr)	277,248		
Voltage Discount	26,614		($0.96)
kWh (May-Sept)	72,856,846		
kWh (Oct-Apr)	97,395,377		
Unbilled	0		
TAA		Tax Year 1	-2.61%
		Tax Year 2	-1.30%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 6-136 - Net Metering - Composite			
Customer Charge	611		$53.00
Seasonal Service	0		$636.00
Aggregate Charge	59		$2.00
Facilities kW	94,165		$3.99
All kW (Jun - Sept)	40,576		$13.27
All kW (Oct - May)	53,589		$11.74
kWh (Jun-Sept)	8,593,599		3.8878 ¢
kWh (Oct-May)	15,566,358		3.4405 ¢
All kW (May - Sept)	46,788		
All kW (Oct - Apr)	47,377		
Voltage Discount	0		($0.96)
kWh (May-Sept)	10,344,291		
kWh (Oct-Apr)	13,815,666		
Unbilled	0		
TAA		Tax Year 1	-2.61%
		Tax Year 2	-1.30%
Schedule No. 6B - Demand Time-of-Day Option - Composite			
Customer Charge	192		$53.00
Seasonal Service	0		$636.00
Facilities kW	14,844		$3.99
All on-peak kW (Jun - Sept)	4,915		$13.27
All on-peak kW (Oct - May)	6,971		$11.74
kWh (Jun-Sept)	1,281,170		3.8878 ¢
kWh (Oct-May)	2,099,521		3.4405 ¢
All On-peak kW (May - Sept)	5,072		
All On-peak kW (Oct - Apr)	6,688		
Voltage Discount	0		($0.96)
kWh (May-Sept)	1,563,144		
kWh (Oct-Apr)	1,817,547		
Unbilled	0		
TAA		Tax Year 1	-2.61%
		Tax Year 2	-1.30%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 6A - Energy Time-of-Day Option - Composite			
All kWh under 50 kWh/kW (Jun-Sept)	44,585,441		22.1562 ¢
All additional kWh (Jun-Sept)	80,754,202		4.3099 ¢
All kWh under 50 kWh/kW (Oct-May)	73,546,803		19.6073 ¢
All additional (Oct-May)	153,778,261		3.8141 ¢
On-Pk kWh (Jun-Sept)	65,422,495		6.0000 ¢
Off-Pk kWh (Jun-Sept)	59,917,149		(2.3358) ¢
On-Pk kWh (Oct-May)	124,025,012		5.3097 ¢
Off-Pk kWh (Oct-May)	103,300,051		(2.0671) ¢
Customer Charge	31,870		$53.00
Facilities kW (May - Sept)	1,149,761		
Facilities kW (Oct - Apr)	1,365,599		
Voltage Discount	203,454		($0.61)
On-Peak kWh (May - Sept)	79,326,838		
Off-Peak kWh (May - Sept)	70,006,450		
On-Peak kWh (Oct - Apr)	110,209,144		
Off-Peak kWh (Oct - Apr)	93,122,275		
Subscriber Solar kWh	29,568,815		7.1250 ¢
Unbilled	0		
TAA		Tax Year 1	-2.91%
		Tax Year 2	-1.46%
Subscriber Solar kWh Adj	(1,649,518)		
Schedule No. 6A-135 - Composite			
All kWh under 50 kWh/kW (Jun-Sept)	1,790,597		22.1562 ¢
All additional kWh (Jun-Sept)	3,521,773		4.3099 ¢
All kWh under 50 kWh/kW (Oct-May)	5,330,608		19.6073 ¢
All additional (Oct-May)	12,790,668		3.8141 ¢
On-Pk kWh (Jun-Sept)	3,345,042		6.0000 ¢
Off-Pk kWh (Jun-Sept)	1,967,328		(2.3358) ¢
On-Pk kWh (Oct-May)	10,972,800		5.3097 ¢
Off-Pk kWh (Oct-May)	7,148,476		(2.0671) ¢
Customer Charge	1,797		$53.00
Facilities kW (May - Sept)	93,220		
Facilities kW (Oct - Apr)	132,834		
Voltage Discount	16,106		($0.61)
On-Peak kWh (May - Sept)	4,206,143		
Off-Peak kWh (May - Sept)	2,416,795		
On-Peak kWh (Oct - Apr)	10,109,190		
Off-Peak kWh (Oct - Apr)	6,701,518		
Unbilled	0		
TAA		Tax Year 1	-2.91%
		Tax Year 2	-1.46%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 6A-136 - Commercial			
All kWh under 50 kWh/kW (Jun-Sept)	0		22.1562 ¢
All additional kWh (Jun-Sept)	0		4.3099 ¢
All kWh under 50 kWh/kW (Oct-May)	0		19.6073 ¢
All additional (Oct-May)	0		3.8141 ¢
On-Pk kWh (Jun-Sept)	0		6.0000 ¢
Off-Pk kWh (Jun-Sept)	0		(2.3358) ¢
On-Pk kWh (Oct-May)	0		5.3097 ¢
Off-Pk kWh (Oct-May)	0		(2.0671) ¢
Customer Charge	0		$53.00
Facilities kW (May - Sept)	0		
Facilities kW (Oct - Apr)	0		
Voltage Discount	0		($0.61)
On-Peak kWh (May - Sept)	0		
Off-Peak kWh (May - Sept)	0		
On-Peak kWh (Oct - Apr)	0		
Off-Peak kWh (Oct - Apr)	0		
Unbilled	0		
TAA		Tax Year 1	-2.91%
		Tax Year 2	-1.46%
Schedule No. 8 - Composite			
Customer Charge	2,823		**$71.00**
Facilities kW	4,249,794		**$4.81**
On-Peak kW (Jun - Sept)	1,442,193		**$15.73**
On-Peak kW (Oct - May)	2,597,774		**$13.92**
On-Peak kWh (Jun - Sept)	186,186,148		**5.8282** ¢
On-Peak kWh (Oct - May)	270,238,556		**5.1577** ¢
Off-Peak kWh (Jun - Sept)	524,787,623		**2.9624** ¢
Off-Peak kWh (Oct - May)	976,265,495		**2.6216** ¢
On-Peak kW (May - Sept)	1,784,756		
On-Peak kW (Oct - Apr)	2,355,074		
Voltage Discount	1,886,120		($1.13)
On-Peak kWh (May - Sept)	233,519,498		
On-Peak kWh (Oct - Apr)	547,943,680		
Off-Peak kWh	1,176,014,644		
Unbilled	0		
TAA		Tax Year 1	-2.50%
		Tax Year 2	-1.25%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 8-135 - Commercial			
Customer Charge	168		$71.00
Facilities kW	150,062		$4.81
On-Peak kW (Jun - Sept)	50,706		$15.73
On-Peak kW (Oct - May)	91,835		$13.92
On-Peak kWh (Jun - Sept)	5,879,321		5.8282 ¢
On-Peak kWh (Oct - May)	8,781,642		5.1577 ¢
Off-Peak kWh (Jun - Sept)	16,950,396		2.9624 ¢
Off-Peak kWh (Oct - May)	31,614,263		2.6216 ¢
On-Peak kW (May - Sept)	62,750		
On-Peak kW (Oct - Apr)	83,255		
Voltage Discount	85,966		($1.13)
On-Peak kWh (May - Sept)	7,373,997		
On-Peak kWh (Oct - Apr)	17,805,917		
Off-Peak kWh	38,045,708		
Unbilled	0		
TAA		Tax Year 1	-2.50%
		Tax Year 2	-1.25%
Schedule No. 8-136 - Commercial			
Customer Charge	0		$71.00
Facilities kW	0		$4.81
On-Peak kW (Jun - Sept)	0		$15.73
On-Peak kW (Oct - May)	0		$13.92
On-Peak kWh (Jun - Sept)	0		5.8282 ¢
On-Peak kWh (Oct - May)	0		5.1577 ¢
Off-Peak kWh (Jun - Sept)	0		2.9624 ¢
Off-Peak kWh (Oct - May)	0		2.6216 ¢
On-Peak kW (May - Sept)	0		
On-Peak kW (Oct - Apr)	0		
Voltage Discount	0		($1.13)
On-Peak kWh (May - Sept)	0		
On-Peak kWh (Oct - Apr)	0		
Off-Peak kWh	0		
Unbilled	0		
TAA		Tax Year 1	-2.50%
		Tax Year 2	-1.25%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	
Schedule No. 9 - Composite			11,901,211	
Customer Charge	1,872		**$266.00**	
Facilities kW	8,792,631		**$2.28**	
On-Peak kW (Jun - Sept)	2,857,444		**$14.33**	
On-Peak kW (Oct - May)	5,600,405		**$12.68**	
On-Peak kWh (Jun - Sept)	337,257,779		**5.1477**	¢
On-Peak kWh (Oct - May)	653,220,065		**4.5555**	¢
Off-Peak kWh (Jun - Sept)	1,318,310,247		**2.6165**	¢
Off-Peak kWh (Oct - May)	2,538,543,863		**2.3155**	¢
On-Peak kW (May - Sept)	3,521,492			
On-Peak kW (Oct - Apr)	4,930,214			
On-Peak kWh (May-Sept)	487,619,452			
On-Peak kWh (Oct-Apr)	1,307,424,280			
Off-Peak kWh	3,052,288,222			
Unbilled	0			
TAA		Tax Year 1	-2.43%	
		Tax Year 2	-1.21%	
Schedule No. 9A - Energy TOD - Composite				
Customer Charge	108		$266.00	
Facilities Charge per kW	243,087		$2.28	
On-Peak kW (Jun - Sept)	76,062		$4.73	
On-Peak kW (Oct - May)	169,650		$4.18	
On-Peak kWh (Jun - Sept)	6,818,306		5.1477	¢
On-Peak kWh (Oct - May)	7,138,084		4.5555	¢
Off-Peak kWh (Jun - Sept)	5,708,900		2.6165	¢
Off-Peak kWh (Oct - May)	22,274,997		2.3155	¢
On-peak kW summer	0			
On-peak kW winter	0			
On-peak kWh summer	0			
On-peak kWh winter	0			
Off-peak kWh summer	0			
Off-peak kWh winter	0			
On-Peak kWh	23,854,513			
Off-Peak kWh	18,085,775			
Unbilled	0			
TAA		Tax Year 1	-2.43%	
		Tax Year 2	-1.21%	

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 10 - Irrigation			
Annual Cust. Serv. Chg. - Primary	10		**$122.00**
Annual Cust. Serv. Chg. - Secondary	3,273		**$37.00**
Monthly Cust. Serv. Chg.	14,850		**$14.00**
All On-Season kW	425,282		**$7.14**
Voltage Discount	4,699		($2.05)
First 30,000 kWh	90,734,008		**7.1126** ¢
All add'l kWh	54,847,557		**5.2573** ¢
Total On Season	145,581,565		
Post Season			
Customer Charge	7,027		$14.00
kWh	51,252,091		4.8789 ¢
Total Post Season	51,252,091		
Unbilled	0		
TAA		Tax Year 1	-2.59%
		Tax Year 2	-1.29%
Schedule No. 10-135 - Irrigation			
Annual Cust. Serv. Chg. - Primary	1		$122.00
Annual Cust. Serv. Chg. - Secondary	55		$37.00
Monthly Cust. Serv. Chg.	285		$14.00
All On-Season kW	26,155		$7.14
Voltage Discount	10		($2.05)
First 30,000 kWh	3,703,888		7.1126 ¢
All add'l kWh	3,271,622		5.2573 ¢
On-Peak kWh	132,217		14.0520 ¢
Off-Peak kWh	494,707		4.0492 ¢
Total On Season	7,602,434		
Post Season			
Customer Charge	123		$14.00
kWh	1,697,996		4.8789 ¢
Total Post Season	1,697,996		
Unbilled	0		
TAA		Tax Year 1	-2.59%
		Tax Year 2	-1.29%
Schedule No. 10-TOD			
Annual Cust. Serv. Chg. - Primary	3		$122.00
Annual Cust. Serv. Chg. - Secondary	266		$37.00
Monthly Cust. Serv. Chg.	1,196		$14.00
All On-Season kW	63,002		$7.14
Voltage Discount kW	2,363		($2.05)
On-Peak kWh	4,395,923		14.0520 ¢
Off-Peak kWh	13,428,677		4.0492 ¢
Total On Season	17,824,600		
Post Season			
Customer Charge	605		$14.00
kWh	6,433,787		4.8789 ¢
Total Post Season	6,433,787		
Unbilled	0		
TAA		Tax Year 1	-2.59%
		Tax Year 2	-1.29%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite			
Annual Facility Charge	21,139		$7.00
Annual Customer Charge	638		$49.02
Annual Minimum Charge	0		$84.02
Monthly Customer Charge	7,644		$4.19
All kWh	15,963,151		3.5697 ¢
Unbilled	0		
TAA		Tax Year 1	-2.52%
		Tax Year 2	-1.26%
Schedule 15.2 - Traffic Signal Systems - Composite			
Customer Charge	32,811		$5.50
All kWh	7,776,370		8.0005 ¢
Unbilled	0		
TAA		Tax Year 1	-2.46%
		Tax Year 2	-1.23%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial (Discontinued)				
Customers moved to appropriate general service schedules				
Schedule 6A				
Customer Charge	15		$53.00	
Voltage Discount	0		($0.61)	
All kWh under 50 kWh/kW (Jun-Sept)	82,148		22.1562	¢
All additional kWh (Jun-Sept)	0		4.3099	¢
All kWh under 50 kWh/kW (Oct-May)	156,310		19.6073	¢
All additional (Oct-May)	0		3.8141	¢
On-Pk kWh (Jun-Sept)	45,621		6.0000	¢
Off-Pk kWh (Jun-Sept)	36,527		(2.3358)	¢
On-Pk kWh (Oct-May)	86,807		5.3097	¢
Off-Pk kWh (Oct-May)	69,503		(2.0671)	¢
TAA		Tax Year 1	-2.91%	
		Tax Year 2	-1.46%	
Schedule 9				
Customer Charge	21		$266.00	
Facilities kW	25,596		$2.28	
On-Peak kW (Jun - Sept)	8,668		$14.33	
On-Peak kW (Oct - May)	16,941		$12.68	
On-Peak kWh (Jun - Sept)	91,666		5.1477	¢
On-Peak kWh (Oct - May)	244,288		4.5555	¢
Off-Peak kWh (Jun - Sept)	362,605		2.6165	¢
Off-Peak kWh (Oct - May)	900,095		2.3155	¢
On-peak kW summer				
On-peak kW winter				
On-peak kWh summer				
On-peak kWh winter				
Off-peak kWh summer				
Off-peak kWh winter				
TAA		Tax Year 1	-2.43%	
		Tax Year 2	-1.21%	
Primary Voltage				
Customer Charge	15		N.A.	
Power Charge All kW	7,726		N.A.	
First 100,000 kWh	238,458		N.A.	
All add'l kWh	0		N.A.	
Unbilled	0		N.A.	
TAA				
Subtotal	238,458			
44KV or Higher				
Customer Charge	21		N.A.	
Power Charge All kW	25,120		N.A.	
First 100,000 kWh	1,598,654		N.A.	
All add'l kWh	0		N.A.	
Unbilled	0		N.A.	
TAA				
Subtotal	1,598,654			
TAA		N.A.		

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No.22 - Indoor Agricultural Lighting Service – 1,000 kW and Over			
Customer Service Charge			
Secondary			$72.00
Primary			$72.00
Transmission			$266.00
Facilities Charge All kW			
Secondary			$1.41
Primary			$1.41
Transmission			$1.41
Power Charge			
Secondary			
Summer-On Peak kW			$8.38
Winter-On Peak kW			$6.02
Primary			
Summer-On Peak kW			$8.26
Winter-On Peak kW			$5.76
Transmission			
Summer-On Peak kW			$8.04
Winter-On Peak kW			$5.45
Energy Charge			
Secondary			
Summer-On Peak kWh			9.4763 ¢
Summer-Off Peak kWh			5.2117 ¢
Winter-On Peak kWh			4.2199 ¢
Winter-Off Peak kWh			3.5267 ¢
Primary			
Summer-On Peak kWh			9.0959 ¢
Summer-Off Peak kWh			4.8313 ¢
Winter-On Peak kWh			3.8394 ¢
Winter-Off Peak kWh			3.1463 ¢
Transmission			
Summer-On Peak kWh			8.8978 ¢
Summer-Off Peak kWh			4.6331 ¢
Winter-On Peak kWh			3.6414 ¢
Winter-Off Peak kWh			2.9483 ¢
TAA		Tax Year 1	-2.43%
		Tax Year 2	-1.21%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price	
Schedule No. 23 - Composite				
Customer Charge	1,134,470		$10.00	
Seasonal Service	0		$117.00	
Minimum Charge	102		$10.00	
kW over 15 (Jun - Sept)	303,570		$8.89	
kW over 15 (Oct - May)	353,344		$7.87	
First 1,500 kWh (Jun - Sept)	245,732,054		11.7120	¢
All Add'l kWh (Jun - Sept)	255,089,575		6.5567	¢
First 1,500 kWh (Oct - May)	491,138,812		10.3646	¢
All Add'l kWh (Oct - May)	394,638,630		5.8024	¢
kW over 15 (May - Sept)	355,316			
kW over 15 (Oct - Apr)	301,598			
Voltage Discount	11,994		($0.48)	
First 1,500 kWh (May - Sept)	308,060,156			
All Add'l kWh (May - Sept)	301,253,476			
First 1,500 kWh (Oct - Apr)	428,643,673			
All Add'l kWh (Oct - Apr)	348,641,766			
Subscriber Solar kWh	2,069,676		**10.3811**	¢
Unbilled	0			
TAA		Tax Year 1	-2.39%	
		Tax Year 2	-1.19%	
Subscriber Solar kWh Adj	(150,134)			

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No. 23-135 - Composite			
Customer Charge	18,738		$10.00
Seasonal Service	0		$117.00
Minimum Charge	10		$10.00
kW over 15 (Jun - Sept)	6,794		$8.89
kW over 15 (Oct - May)	9,813		$7.87
First 1,500 kWh (Jun - Sept)	2,193,840		11.7120 ¢
All Add'l kWh (Jun - Sept)	2,240,351		6.5567 ¢
First 1,500 kWh (Oct - May)	5,247,056		10.3646 ¢
All Add'l kWh (Oct - May)	4,722,287		5.8024 ¢
kW over 15 (May - Sept)	7,841		
kW over 15 (Oct - Apr)	8,766		
Voltage Discount	0		($0.48)
First 1,500 kWh (May - Sept)	2,609,825		
All Add'l kWh (May - Sept)	2,499,478		
First 1,500 kWh (Oct - Apr)	4,852,798		
All Add'l kWh (Oct - Apr)	4,441,433		
Unbilled	0		
TAA		Tax Year 1	-2.39%
		Tax Year 2	-1.19%
Schedule No. 23-136 - Composite			
Customer Charge	1,546		$10.00
Seasonal Service	0		$117.00
Aggregate Charge	393		$2.00
Minimum Charge	0		$10.00
kW over 15 (Jun - Sept)	552		$8.89
kW over 15 (Oct - May)	982		7.8700
First 1,500 kWh (Jun - Sept)	228,752		11.7120 ¢
All Add'l kWh (Jun - Sept)	234,472		6.5567 ¢
First 1,500 kWh (Oct - May)	417,772		10.3646 ¢
All Add'l kWh (Oct - May)	648,715		5.8024 ¢
kW over 15 (May - Sept)	761		
kW over 15 (Oct - Apr)	773		
Voltage Discount	0		($0.48)
First 1,500 kWh (May - Sept)	239,106		
All Add'l kWh (May - Sept)	308,302		
First 1,500 kWh (Oct - Apr)	409,460		
All Add'l kWh (Oct - Apr)	572,843		
Unbilled	0		
TAA		Tax Year 1	-2.39%
		Tax Year 2	-1.19%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	**Forecast Billing Units**	**TCJA Year**	**January 1, 2021 Effective Delivery Price**
Schedule No.31 - Composite			
Secondary Voltage			
Customer Charge per month	0		$137.00
Facilities Charge, per kW month	0		$5.75
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	0		$0.90
Oct - May	0		$0.80
Maintenance, per On-Peak kW day			
Jun - Sept	0		$0.45
Oct - May	0		$0.40
Excess Power, per kW month			
Jun - Sept	0		$41.89
Oct - May	0		$37.07
Regular, per On-Peak kW day			
May - Sept	0		
Oct - Apr	0		
Maintenance, per On-Peak kW day			
May - Sept	0		
Oct - Apr	0		
Excess Power, per kW month			
May - Sept	0		
Oct - Apr	0		
Primary Voltage			
Customer Charge per month	25		$621.00
Facilities Charge, per kW month	34,929		$4.58
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	67,470		$0.88
Oct - May	47,316		$0.78
Maintenance, per On-Peak kW day			
Jun - Sept	1,510		$0.44
Oct - May	0		$0.39
Excess Power, per kW month			
Jun - Sept	142		$39.56
Oct - May	655		$35.01
Regular, per On-Peak kW day			
May - Sept	83,149		
Oct - Apr	41,654		
Maintenance, per On-Peak kW day			
May - Sept	1,861		
Oct - Apr	0		
Excess Power, per kW month			
May - Sept	175		
Oct - Apr	576		

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No.31 - Composite Cont'd			
Transmission Voltage			
Customer Charge per month	59		$696.00
Facilities Charge, per kW month	291,905		$2.70
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	657,860		$0.78
Oct - May	307,104		$0.69
Maintenance, per On-Peak kW day			
Jun - Sept	0		$0.39
Oct - May	150,561		$0.35
Excess Power, per kW month			
Jun - Sept	6,767		$33.21
Oct - May	1,067		$29.39
Regular, per On-Peak kW day			
May - Sept	810,741		
Oct - Apr	270,354		
Maintenance, per On-Peak kW day			
May - Sept	0		
Oct - Apr	132,544		
Excess Power, per kW month			
May - Sept	8,339		
Oct - Apr	939		

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule No.31 - Composite Cont'd			
Supplemental billed at Schedule 6/8/9 rate			
Schedule 8			
Facilities kW	27,799		$4.81
On-Peak kW (Jun - Sept)	2,699		$15.73
On-Peak kW (Oct - May)	26,884		$13.92
On-Peak kWh (Jun - Sept)	905,085		5.8282 ¢
On-Peak kWh (Oct - May)	2,558,532		5.1577 ¢
Off-Peak kWh (Jun - Sept)	4,024,260		2.9624 ¢
Off-Peak kWh (Oct - May)	7,522,766		2.6216 ¢
On-Peak kW (May - Sept)	3,340		
On-Peak kW (Oct - Apr)	24,372		
Voltage Discount	27,713		($1.13)
On-Peak kWh (May - Sept)	1,135,182		
On-Peak kWh (Oct - Apr)	5,187,756		
Off-Peak kWh	8,687,706		
TAA		Tax Year 1	-2.50%
		Tax Year 2	-1.25%
Schedule 9			
Facilities kW	283,278		$2.28
On-Peak kW (Jun - Sept)	96,907		$14.33
On-Peak kW (Oct - May)	180,946		$12.68
On-Peak kWh (Jun - Sept)	14,609,917		5.1477 ¢
On-Peak kWh (Oct - May)	21,736,230		4.5555 ¢
Off-Peak kWh (Jun - Sept)	47,389,695		2.6165 ¢
Off-Peak kWh (Oct - May)	90,512,658		2.3155 ¢
On-Peak kW (May - Sept)	119,427		
On-Peak kW (Oct - Apr)	159,292		
On-Peak kWh (May-Sept)	21,123,545		
On-Peak kWh (Oct-Apr)	43,505,207		
Off-Peak kWh	109,619,747		
TAA		Tax Year 1	-2.43%
		Tax Year 2	-1.21%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule 32 - Service From Renewable Energy Facilities - Commercial			
Customer Charges:			
Distribution Voltage < 1 MW			$55.00
Distribution Voltage > 1 MW			$72.00
Transmission Voltage	36		$266.00
Administrative Fee:			
All Voltages / per Generator	13		$113.00
All Voltages / per Delivery Point	39		$154.00
Delivery Facilities Charges:			
Secondary Voltage < 1 MW			$7.52
Primary Voltage < 1 MW			$6.56
Secondary Voltage > 1 MW			$8.37
Primary Voltage > 1 MW			$7.24
Transmission Voltage	245,396		$4.35
Daily Power Charges:			
On-Peak Secondary Voltage < 1 MW			
June - September:			$0.57
October - May:			$0.48
On-Peak Primary Voltage < 1 MW			
June - September:			$0.57
October - May:			$0.47
On-Peak Secondary Voltage > 1 MW			
June - September:			$0.72
October - May:			$0.61
On-Peak Primary Voltage > 1 MW			
June - September:			$0.71
October - May:			$0.59
On-Peak Transmission Voltage			
June - September:	526,626		$0.71
October - May:	913,271		$0.61
On-Peak Secondary Voltage < 1 MW			
May - September:			
October - April:			
On-Peak Primary Voltage < 1 MW			
May - September:			
October - April:			
On-Peak Secondary Voltage > 1 MW			
May - September:			
October - April:			
On-Peak Primary Voltage > 1 MW			
May - September:			
October - April:			
On-Peak Transmission Voltage			
May - September:	649,010		
October - April:	803,981		
Renewable Energy PPA	172,556,857		5.7290 ¢

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule 32 - Service From Renewable Energy Facilities - Cont'd			
Supplemental billed at Schedule 6/8/9 rate			
Schedule 9			
Facilities kW	41,883		$2.28
On-Peak kW (Jun - Sept)	15,180		$14.33
On-Peak kW (Oct - May)	26,325		$12.68
On-Peak kWh (Jun - Sept)	4,703,542		5.1477 ¢
On-Peak kWh (Oct - May)	4,209,024		4.5555 ¢
Off-Peak kWh (Jun - Sept)	6,552,517		2.6165 ¢
Off-Peak kWh (Oct - May)	8,628,050		2.3155 ¢
On-Peak kW (May - Sept)	18,708		
On-Peak kW (Oct - Apr)	23,175		
On-Peak kWh (May-Sept)	6,800,551		
On-Peak kWh (Oct-Apr)	8,424,390		
Off-Peak kWh	8,868,192		
TAA		Tax Year 1	-2.43%
		Tax Year 2	-1.21%

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Schedule 34 - Renewable Energy Purchases for Qualified Customers – 5,000 kW and Over - Commercial			
Customer Charge	12		
Total	242,230,000		5.3783 ¢
Contract 1			
Monthly Fixed Charge	12		$232.00
Customer Charge per HLH kW	1,004,562		$1.92
Demand Charge per HLH kW (May - Sept	381,956		$12.93
Demand Charge per HLH kW (Oct - Apr)	622,606		$8.67
kWh HLH (May - Sept)	101,240,704		4.3940 ¢
kWh LLH (May - Sept)	142,951,672		2.7600 ¢
kWh HLH (Oct - Apr)	168,476,287		3.3060 ¢
kWh LLH (Oct - Apr)	204,431,337		2.7600 ¢
TAA		Tax Year 1	-2.42%
		Tax Year 2	-1.21%
Contract 2			
Customer Charge	12		
On-Peak kWh (May-Sept)	57,264,151		6.5680 ¢
On-Peak kWh (Oct-Apr)	179,663,027		4.9410 ¢
Off-Peak kWh (May - Sept)	239,492,626		4.1280 ¢
Off-Peak kWh (Oct-Apr)	229,035,745		4.1280 ¢
TAA		Tax Year 1	-2.28%
		Tax Year 2	-1.14%
Contract 3			
Customer Charge	12		
Block 1	376,680,000		5.8419 ¢
Block 2 - Market			
Block 2 - Index	911,946,197		4.4906 ¢
Total	1,288,626,197		

Exhibit B

Pricing Non-Residential Schedules, excluding Schedules 7, 11, and 12

Schedule	Forecast Billing Units	TCJA Year	January 1, 2021 Effective Delivery Price
Lighting Contract - Post Top Lighting - Composite			
Customers	4		
Energy Only Res	48		$2.1800
Energy Only Non-Res	207		$2.1858
Subtotal	255		
KWH Included	7,387		
Unbilled	0		
Annual Guarantee Adjustment			
Residential			$ 6,795
Commercial			$ 3,742,344
Industrial			$ 823,370
Irrigation			$ 231,623
Public Street & Highway Lighting			$ 4,655
Total AGA			$ 4,808,787

Exhibit B

Pricing Schedules 7, 11, and 12

Description	Sch No.	Lamp Units	kWh	Price	Price Units	Revenue
Security Area Lighting						
Level 1 (0-5,500 LED Equivalent Lumens)	7	80,037		**9.10**	$/mo	$728,334
Level 2 (5,501-12,000 LED Equivalent Lumens)	7	23,298		**10.61**	$/mo	$247,190
Level 3 (12,001 and Greater LED Equivalent Lumens)	7	31,462		**12.96**	$/mo	$407,743
Street Lighting - Company-Owned System						
Level 1 (0-3,500 LED Equivalent Lumens)	11	32,060		**11.82**	$/mo	$378,953
Level 2 (3,501-5,500 LED Equivalent Lumens)	11	197,233		**12.74**	$/mo	$2,512,752
Level 3 (5,501-8,000 LED Equivalent Lumens)	11	20,644		**13.19**	$/mo	$272,290
Level 4 (8,001-12,000 LED Equivalent Lumens)	11	574		**13.71**	$/mo	$7,871
Level 5 (12,001-15,500 LED Equivalent Lumens)	11	22,536		**14.60**	$/mo	$329,020
Level 6 (15,501 and Greater LED Equivalent Lumens)	11	7,800		**17.75**	$/mo	$138,445
Dec. Series Level 3 (5,501-8,000 LED Equivalent Lumens)	11	5,104		**23.15**	$/mo	$118,165
Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)	11	-		**6.04**	$/mo	$0
Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)	11	276		**6.57**	$/mo	$1,813
Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)	11	-		**6.99**	$/mo	$0
Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)	11	-		**7.46**	$/mo	$0
Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)	11	12		**8.00**	$/mo	$96
Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)	11	-		**9.72**	$/mo	$0
Cust. Funded Conv. - Dec. Series Level 3 (5,501-8,000 LED Equivalent Lumens)	11	-		**5.52**	$/mo	$0
Street Lighting - Customer-Owned System	**12**		**26,868,874**	**0.045465**	$/kWh	**$1,402,868**
TAA			TCJA Tax Year	-1.75%		
			TCJA Tax Year	-0.87%		