STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN APPLICATION 22-05-006:

This is the proposed decision of Administrative Law Judge Carolyn Sisto. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 14, 2023 Business Meeting. To confirm when the item will be heard, please *see* the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Acting Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF ALJ SISTO (Mailed 11/9/23)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFICORP (U901E), for an Order Authorizing a General Rate Increase Effective January 1, 2023.	Application 22-05-006

DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFICORP D/B/A PACIFIC POWER

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DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFICORP D/B/A PACIFIC POWER

Summary

This decision approves a base revenue requirement of $101,288,005 which is an increase of $18.989 million for PacifiCorp (doing business as Pacific Power) pursuant to its Test Year (TY) 2023 General Rate Case application. Much of the rate increase is associated with requested funding for PacifiCorp's vegetation management program and its wildfire mitigation plans for the TY 2023 GRC term. The approved revenue requirement increase is approximately 31.9 percent lower than the $27.9 million increase PacifiCorp originally requested in Application 22-05-006. The total TY 2023 base revenue requirement adopted herein will increase PacifiCorp customers' rates by approximately 17.5 percent on average, which is lower than the 25.7 percent increase initially requested by the utility. The reduction is associated with the amortization of deferred unrecovered balances; the denial of the capital amount requested for a facility that will not be fully online in the TY; the denial of PacifiCorp's requested increase to its return on equity, and the denial of certain requested operations and maintenance expenses.

This decision directs PacifiCorp to delay recovery of costs associated with its Foote Creek II-IV Project until the upgraded facilities are operational and requires PacifiCorp to recover the amortization expenses associated with its Cholla Unit 4 over eight years.

This decision also approves PacifiCorp's proposal to increase its California Alternate Rates for Energy discount from 20 percent to 25 percent and approves mandatory time-of-use energy pricing for larger general service use customers.

Issues related to PacifiCorp's wildfire mitigation memorandum accounts and the accounts' deferred expenditures will be addressed in Track 2 of this proceeding. Application 22-05-006 remains open to address these unresolved issues.

1. Background

PacifiCorp, doing business as Pacific Power (PacifiCorp), is a multi-jurisdictional utility providing retail electric service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 47,800 customers in California, across more than 11,000 square miles in portions of Del Norte, Modoc, Shasta, and Siskiyou counties.[1]

Through a series of decisions issued between 2014 and 2018, the California Public Utilities Commission (Commission) granted several requests from PacifiCorp to file Post Test Year (TY) Adjustment Mechanism Increases and delay General Rate Case (GRC) application filings.[2] On January 14, 2021, the Commission adopted Decision (D.) 21-01-006 granting PacifiCorp's petition to modify D.20-02-025 to extend PacifiCorp's GRC filing by one year from TY 2022 to TY 2023.

On May 5, 2022, PacifiCorp filed its GRC Application (A.) 22-05-006 requesting authority to increase its rates for electric service effective January 1, 2023. PacifiCorp filed an amended application on May 13, 2022, with a revised list of testimony and appendices. PacifiCorp requested a TY 2023 base revenue requirement of $110.25 million. This represents a 34 percent increase over its 2022 present base revenue requirement of $82.3 million. Approximately

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[1] PacifiCorp Amended Application at 2.

[2] *See* decisions (D.) D.12-10-006, D.13-07-026, D.14-06-018, D.15-12-018, D.16-09-046, and D.20-02-025.

three quarters of PacifiCorp's proposed increase was attributed to wildfire mitigation and vegetation management costs. The requested increase would result in a net overall revenue requirement increase of 25.7 percent when commodity costs and other items not examined during this proceeding are included in the calculation.

On May 19, 2022, PacifiCorp filed a motion requesting the Commission authorize a January 1, 2023, effective date for its 2023 TY GRC revenue requirement as well as a General Rate Case Revenue Requirement Memorandum Account (GRC RRMA). No party filed a response in opposition to PacifiCorp's request.

On June 10, 2022, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and the California Farm Bureau Federation (Farm Bureau) filed timely protests to PacifiCorp's application.

A prehearing conference (PHC) was held on June 30, 2022, to address the issues of law and fact, determine the need for hearing, set the schedule for resolving the matter, and address other matters as necessary.

On August 9, 2022, the assigned Commissioner issued a Scoping Memo and Ruling.

On November 3, 2022, D.22-11-001 granted PacifiCorp's request to make its 2023 TY GRC revenue requirement effective as of January 1, 2023, and to establish a GRC RRMA.[3]

Two remote public participation hearings were held on November 7, 2022.

[3] D.22-11-001 granted PacifiCorp's request to implement the GRC RRMA via a Tier 1 AL specifying its accounting methodology, and directed PacifiCorp is to use the Federal Reserve three-month commercial paper rate to accrue interest on any balance beginning January 1, 2023, in its GRC RRMA. *See* Federal Reserve three-month Commercial Paper Rate – Non-Financing, as issued by the Federal Reserve Statistical Release H.15 or its successor.

On December 22, 2022, Cal Advocates and the Farm Bureau served direct testimony. Concurrent rebuttal testimony was served on February 8, 2023. On February 14, 2023, the ALJ took evidentiary hearings for Track 1 off of the procedural schedule.

On March 13, 2023, an Administrative Law Judge (ALJ) ruling ordered an independent third-party audit of costs recorded in certain wildfire mitigation memorandum accounts that were included as part of PacifiCorp's application and established a separate track and schedule for consideration of the wildfire mitigation memorandum accounts. A.22-05-006 was the first time PacifiCorp sought recovery of wildfire mitigation-related costs. Because the sum of PacifiCorp's Wildfire Mitigation Memorandum Accounts represented a large potential rate increase to customers, it is in the public interest to ensure that each memorandum account has recorded appropriate costs, that those costs are not duplicative, and each cost is incremental. PacifiCorp was directed to hire an independent auditor to review the Wildfire Mitigation Memorandum Accounts that are included as part of its application, to ensure PacifiCorp's wildfire mitigation costs are properly recorded and reported in PacifiCorp's application, supported by appropriate documents, incremental to costs previously authorized or requested for recovery, and are consistent with PacifiCorp's approved Wildfire Mitigation Plans. The Wildfire Mitigation Memorandum Accounts referenced above are PacifiCorp's Fire Risk Mitigation Memorandum Account (FRMMA); the Wildfire Mitigation Plan Memorandum Account (WMPMA); and the Fire Hazard Prevention Memorandum Account (FHPMA).

PacifiCorp's requested recovery of the costs recorded in its Wildfire Mitigation Memorandum Accounts and the associated audit were moved into

Track 2 of this proceeding and will therefore be addressed in a subsequent decision.

An ALJ ruling issued on March 24, 2023, adopted modeling procedures for the results of operations and rates to ensure a confidential decision-making process is applied to both Tracks of this proceeding.

On April 7, 2023, PacifiCorp filed additional supplemental testimony regarding its wildfire accounting processes, which will be considered in Track 2 of this proceeding.

On May 2, 2023, PacifiCorp filed a motion seeking to include and recover costs associated with the third-party wildfire accounting audit directed in the March 13, 2023, ruling in its GRC RRMA. This request was denied by an ALJ ruling issued July 6, 2023. The costs associated with the audit are not considered in this proceeding and shall not be recovered through PacifiCorp's GRC RRMA.

On July 17, 2023, opening briefs in Track 1 of this proceeding were filed by PacifiCorp, Cal Advocates, and the Farm Bureau. Reply briefs were filed by PacifiCorp and the Farm Bureau on August 11, 2023.

On October 2, 2023, the assigned ALJ directed PacifiCorp to serve updated testimony to remove the costs that will be considered in Track 2 of this proceeding from its revenue requirement and associated workpapers. This updated testimony was served by PacifiCorp on October 9, 2023.

2. Jurisdiction

Public Utilities (Pub. Util.) Code §454 requires the Commission to ensure investor-owned utility (IOU) rates are just and reasonable.[4] IOUs are required to

[4] All references to code herein refer to the California Public Utilities Code. §454 states, in part, that "public utility shall not change any rate or so alter any classification, contract, practice or rule as to the result in any new rate, except upon a showing before the Commission and a finding by the Commission that the new rate is justified."

prove that new rates are justified, and the Commission is directed to review the evidence presented to determine whether the application meets the statutory requirements.

3. Issues Before the Commission

The issues to be determined or otherwise considered in Track 1 of this proceeding are as follows:

1. Whether PacifiCorp's request to increase its authorized revenue requirement for electric service inclusive of all operating expenses and capital costs is just and reasonable. This includes, among other items, whether the proposed capital investments and expenses related to vegetation management are reasonable;
2. Whether PacifiCorp's proposed Capital Structure and Rate of Return and Return on Equity is just and reasonable;
3. Whether PacifiCorp's proposed retirement plans for its coal generation facilities serving California and the associated proposed changes to the depreciation schedules and decommissioning costs for those plants are reasonable;
4. Whether PacifiCorp's proposed cost allocation and rate design is reasonable;
5. Whether PacifiCorp should be authorized to continue to use the Post Test-Year Adjustment Mechanism;
6. Whether PacifiCorp's proposed wildfire mitigation cost forecasts based on its 2023 TY are reasonable;
7. Whether PacifiCorp's proposed mechanism to recover wildfire mitigation costs between general rate cases is reasonable;
8. Whether PacifiCorp's application has any impact on environmental and social justice communities; and
9. The impact of the proposed rate increase on affordability.

4. Interjurisdictional Cost Allocation Methodology

PacifiCorp's application and workpapers used the utility's Jurisdictional Allocation Methodology (JAM) which is based on its 2021 Integrated Resource Plan (IRP), the 2020 Interjurisdictional Cost Allocation Protocol (2020 Protocol), and the Summary of its Results of Operations (RO) to compile cumulative, quantitative forecasts for its revenue requirement calculations.[5] PacifiCorp specifically requested to use the 2020 Protocol and its JAM model to allocate its California distribution and generation revenue requirement totals. The utility explained that a large reason the 2020 Protocol was adopted was to address requirements associated with the ratemaking treatment of coal-fired power generation units in Oregon and Washington, and Wyoming's differing requirements regarding coal-fired units.[6]

No party objected to PacifiCorp's proposed use of the 2020 Protocol and JAM model.[7] We therefore find that the use of PacifiCorp's JAM model and 2020 Protocol are appropriate for calculating the quantitative forecasts for PacifiCorp's California revenue requirement for TY 2023.

5. Policy Testimony

Three issues encompass the "policy testimony" in this proceeding. These are: the Energy Cost Adjustment Clause (ECAC), the Post-Test Year Adjustment Mechanism (PTAM), and the Risk-Based Decision Making (RBD) Framework.

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[5] PacifiCorp Results of Operations Model, "CA GRC JAM Dec 2023 Test Period," and Exhibit PAC/900 at 4.

[6] Exhibit PAC/900 at 11.

[7] Exhibit Cal Advocates-03 at 3.

5.1. Energy Cost Adjustment Clause

PacifiCorp proposed to continue the use of the ECAC Mechanism, as adopted in D.06-12-011, which authorizes the utility to file an annual application to true-up actual net power costs and provide a forecast of net power costs for the following year.

The Farm Bureau argued that PacifiCorp's proposed increase to its annual revenue requirement, in combination with the 2023 ECAC, could result in customers seeing a rate increase of 35.8 percent. However, PacifiCorp was granted authority to delay its GRC filing in D.20-02-025 and to continue use of the ECAC in D.22-11-008, and Cal Advocates provided additional information about the revenue requirement request in its testimony and associated workpapers.[8]

Upon review of the testimony and filings from PacifiCorp and Cal Advocates, we agree that PacifiCorp met the requirements adopted in Ordering Paragraph (OP) 9 of D.22-11-008 when filing the instant application. As noted in the Summary above, PacifiCorp's customers can expect an approximately 17.5 percent increase in rates starting in TY 2023, on average, far below the 35.8 percent implied by the Farm Bureau. Predicting the rate impacts associated with future ECAC filings is not feasible using the evidence admitted in this proceeding. Therefore, we find PacifiCorp's request to continue using ECAC to file annual applications to be reasonable and in line with Commission precedent.

[8] Exhibit CA-03 and CA-03-WP.

5.2. Post-Test Year Adjustment Mechanism and Post-Test Year Adjustment Mechanism Attrition Factor

In D.06-12-011, the Commission authorized a PTAM for major capital additions that allows PacifiCorp to recover the California-allocated share of reasonable costs related to any plant additions greater than $50 million on a total company basis.[9] D.06-12-011 also authorized a PTAM Attrition Factor adjustment that is effective on January 1 in the years between GRCs that allows PacifiCorp to adjust base rates for changes in inflation with an offsetting productivity factor of 0.5 percent.[10] PacifiCorp's PTAM and the PTAM Attrition Factor were most recently reauthorized in D.20-02-025, and in A.22-05-006, the utility requested to continue its use to adjust rates, when necessary, between general rate cases. No party contested the continued use of the PTAM in this proceeding. We find that the PTAM is an efficient means to set fair and reasonable rates and authorize PacifiCorp to continue using it. It will be authorized for use in 2025 and 2026, and shall be calculated as the greater of (1) the September Global Insight U.S. Economic Outlook forecast of Consumer Price Index with an offsetting productivity factor of 0.5 percent, or (2) zero.

During the years between this GRC and PacifiCorp's TY 2026 filing, the PTAM shall continue to be filed on October 15 as a Tier 2 Advice Letter (AL), with new rates effective January 1 of the following year. Given the effective date of this decision, a PTAM factor based on the Consumer Price Index is not found to be reasonable for 2024.

[9] Exhibit PAC/100 at 16.

[10] Exhibit PAC/100 at 16.

Additionally, PacifiCorp may use the PTAM for any major capital additions in 2023 and 2024 based on California allocated costs, so long as the requested adjustment is based on actual cost data and in-service dates. A PTAM for major capital additions may be filed for 2023 as soon as reasonably feasible following the effective date of this decision, and a PTAM for major capital additions may be filed October 15, 2024. Should PacifiCorp seek to continue its PTAM process after 2026, it should specifically request to do so in its next GRC application.

5.3. Risk-Based Decision-Making Framework

Pursuant to Pub. Util. Code §750, the Commission adopted formal procedures to consider safety in each energy utility's GRC applications. D.14-12-025 incorporated a risk-based decision-making framework (RDF) into the Rate Case Plan requirements for GRCs filed by the larger utilities in California immediately but gave the small and/or multijurisdictional utilities (SMJU) an additional three years to implement the new process. D.14-12-025 also does not require SMJUs to implement a Risk Assessment Mitigation Phase (RAMP). PacifiCorp transitioned to this prescribed RDF in its last GRC, A.18-04-002 (2019 GRC).[11]

5.3.1. Non-Wildfire-Related Risk Assessment

PacifiCorp largely referenced documents that were filed in A.18-04-002 when addressing its RDF in the instant proceeding, specifically Exhibit PAC/1000, which was submitted as part of its 2019 GRC testimony. Its top ten risks identified remained unchanged:

1. Substation Transformer Failure
2. Substation Circuit Breaker Failure

[11] Exhibit PAC/1200 at 1-2.

3. Substation Transformer Bushing Failure
4. Substation Circuit Breaker Oil / Sulfur Hexafluoride (SF6) Gas Leak
5. Transformer Radiator Failure
6. Relay Failure or Mis-operation
7. Distribution Underground Conductor Failure
8. Distribution Overheard Pole Failure
9. Distribution Overhead Conductor Failure
10. Distribution Overhead Pole Mounted Equipment Failure – Aging Infrastructure

PacifiCorp stated that its risk assessment occurred in 2018, and since then, it has "shifted focus to understand and evaluate wildfire risks consistent with the wildfire mitigation plan (WMP) ratemaking and proceedings."[12]

D.19-04-020, in part, established standards for how SMJUs should demonstrate risk assessment competency and reasonably disclose specifics surrounding their risk mitigation plans and associated costs as a precondition for Commission approval of their GRC applications. D.19-04-020 specifically adopted a Voluntary Agreement establishing RDF standards for SMJUs.[13] Because this agreement was adopted after PacifiCorp filed its 2019 GRC, the 10 RDF elements adopted within it were not included in its rate case testimony for that proceeding. Therefore, A.22-05-006 marks the first time PacifiCorp is bound by D.19-04-020's RDF standards.

Instead of focusing on the 10 RAMP elements defined in the 2019 Voluntary Agreement, PacifiCorp only pointed us back to the documentation

[12] Exhibit PAC/1200 at 5

[13] D.19-04-020 Attachment B

filed in its 2019 GRC, which does not adequately address the new elements. PacifiCorp noted that its prior documentation filed for its 2019 GRC did not include any costs or expenses for non-wildfire mitigation risk-based decision-making, and that it did not have any non-wildfire mitigation costs or expenses in 2020, 2021, or 2022.[14] It further suggested that only $105,000 in capital costs requested in A.22-05-006 are for non-wildfire risk related improvements in California, and those costs are forecasted only to improve physical security of its substations.[15]

We find that PacifiCorp has failed to identify the root cause of the 10 top risks it described in its 2019 GRC, and PacifiCorp does not adequately describe the controls or mitigation measures it has implemented, or intends to implement, to address those top 10 risk factors.[16] This includes wildfire- and non-wildfire related risks. PacifiCorp requested very little incremental funding to support additional RAMP or RDF processes, which was solely focused on substation security. PacifiCorp has not addressed or mentioned the company's safety culture, executive engagement, and compensation policies in its testimony, which are requirements of the Voluntary Agreement.

Given that multiple aspects of the RDF and its associated Voluntary Agreement have not been adequately addressed in PacifiCorp's testimony and briefs in this proceeding, we direct PacifiCorp to file an updated RDF assessment that fully addresses each of the 10 RAMP elements in its next GRC application. The utility shall not rely on the assessment conducted in 2018 to fulfill this requirement; instead, it shall conduct a fully new assessment and submit

[14] Exhibit PAC/1900 at 2

[15] Exhibit PAC/1900 at 2

[16] Exhibit PAC/1200 at 11

information directly addressing each of the 10 RAMP elements adopted in the D.19-04-020 Voluntary Agreement.

5.3.2. Wildfire Cost Recovery Mechanism Proposal

PacifiCorp proposed to mitigate the potential for rate-shocks associated with its wildfire mitigation costs by recording incremental costs in its Wildfire Mitigation Plan Memorandum Account (WMPMA) and recovering the recorded costs incrementally through annual advice letter filings between its GRCs. PacifiCorp noted it expects to require a "significant and sustained level of capital spending" to address California policy requirements including wildfire mitigation costs of $290 million during 2022 and 2023.[17] PacifiCorp's intent for the annual filings was to spread recovery of wildfire-related mitigation costs over several years, rather than having all wildfire-related costs incurred during a three-year GRC cycle added to rates at one time.[18]

The Farm Bureau argued that PacifiCorp's proposal to use its WMPMA to track forecasted wildfire mitigation operation and maintenance costs and recover costs in an annual AL filing is "delusional" given the utility's failure to provide adequate analysis of its wildfire accounting and spending in this proceeding.[19]

We note that the costs associated with PacifiCorp's wildfire-related mitigation memorandum accounts will be reviewed in significantly more detail in Track 2 of this proceeding.[20] Further, the balances in the wildfire mitigation

[17] Exhibit PAC/300C at 3-4.

[18] PacifiCorp Reply at 43.

[19] CFBF Reply Brief at 7.

[20] The Wildfire Mitigation Memorandum Accounts to be more fully addressed in Track 2 of this proceeding are PacifiCorp's Fire Risk Mitigation Memorandum Account (FRMMA), the Wildfire Mitigation Plan Memorandum Account (WMPMA), and the Fire Hazard Prevention Memorandum Account (FHPMA).

memorandum accounts that are ultimately found just and reasonable in GRCs may be amortized over differing time periods, depending on the facts and circumstances associated with the requested amounts, rather than being added to rates at one time.

It should not be necessary to use advice letters to add incremental wildfire mitigation costs annually on top of what PacifiCorp requests in its GRC applications other than PTAM adjustments. As discussed in the RDF, incremental planning should occur in the three years between each of PacifiCorp's GRC filings, and appropriate cost recovery and risk management processes should be included in the forecasts in each GRC filing.[21] We agree with the Farm Bureau that evaluating PacifiCorp's wildfire mitigation costs "within the GRC allows the ALJ and Commission to see the volume of expenses ratepayers are expected to absorb rather than the yearly blank check PacifiCorp is requesting that not only eliminates ratepayer protection but also obfuscates the cumulative impact these future increases will have."[22] Therefore, we find PacifiCorp's request to file annual ALs to recover costs that are incremental to this proceeding's TY 2023 revenue requirement to be unreasonable. Discussion about the amount of wildfire-related revenue requirement proposed in PacifiCorp's application, as it relates to TY 2023 and this GRC application, is provided in more detail in Section 6.2 below.

Further, PacifiCorp is directed to better substantiate its wildfire mitigation risk planning and associated mitigation spending, with a fully updated RDF

[21] The Commission directed PacifiCorp to file a GRC every three years in D.07-07-004.

[22] Farm Bureau Opening Brief at 18.

analysis in each future GRC filing, beginning with its next GRC filing, as further discussed in Section 9 below.

6. Revenue Requirement

PacifiCorp stated the increased revenue it is requesting is largely associated with higher costs to conduct wildfire and vegetation management programs in its California service territory. As previously noted, the Wildfire Mitigation Memorandum Account costs will be addressed in a separate decision in Track 2 of this proceeding. The following costs are evaluated in this decision:

1. Rate base and cash working capital;
2. Cost of capital;
3. Depreciation of coal-fired power units;
4. Decommissioning costs associated with coal-fired power units;
5. Proposed increase in CARE discount from 20 percent to 25 percent;
6. California-specific distribution rates;
7. Cost allocation and rate design changes;
8. Revenues associated with Pryor Mountain Wind Renewable Energy Certificate (REC) sale;
9. TY 2023 wildfire mitigation-related capital expenditures; and
10. TY 2023 wildfire-related operation and maintenance related expenses.

PacifiCorp provided updated testimony related to the costs associated with its revenue requirement for Track 1 issues on October 9, 2023. It removed the costs associated with the amortization of the wildfire prevention amounts recorded in the Wildfire Mitigation Plan Memorandum Account (WMPMA), the Fire Hazard Prevention Memorandum Account (FHPMA) and the Fire Risk Mitigation Memorandum Account (FRMMA). The updated requested revenue requirement increase was $21.9 million for TY 2023.[23] This would result in an average overall rate increase of approximately 20.1 percent across all customer classes.[24]

Rate Schedule	Proposed Net Rate Increase
Residential	20.2%
General Service	20.2%
Schedule A-25	20.1%
Schedule A-32	20.1%
Schedule A-36	20.1%
Large General Service/Schedule AT-48	20.1%
Irrigation/Schedule PA-20	20.1%
Lighting Class	16.3%
Total California	**20.1%**

The contested revenue requirement changes considered and adopted in this decision are described in Sections 6.1-6.3 below.

6.1. Capital Structure and Rate of Return

PacifiCorp proposed an overall rate of return of 7.59 percent, consisting of the following capital structure and cost components:

- 52.25 percent equity
- 47.74 percent long-term debt
- 0.01 percent preferred stock
- 4.41 percent cost of debt
- 6.75 percent cost of preferred stock

[23] Exhibits PAC/2000 at 2 and PAC/2100-2101.

[24] Exhibits PAC/2200 at 2 and 2201-2205.

- 10.5 percent return on equity.[25]

Cal Advocates noted that PacifiCorp's requested common equity ratio of 52.25 percent is in line with those the Commission has approved for other California electric utility companies.[26]

While no party contested PacifiCorp's requested cost of debt or preferred stock, Cal Advocates, argued that the overall rate of return should be 6.81 percent, by recommending that PacifiCorp should collect a 9.0 percent return on equity (ROE), given that the Commission has reduced the 2023 ROE for other electric utilities in California in recent Cost of Capital proceedings.[27] Cal Advocates further noted that PacifiCorp's issuer credit ratings from Standard and Poor (S&P) and Moody's are A and A3 while the average credit ratings of the two proxy group utilities are BBB+ and Baa1, indicating that PacifiCorp has lower investment risk than other electric utilities.[28]

The Farm Bureau proposed PacifiCorp's ROE should be 9.5 percent, based on considerations associated with the other states the utility operates in, and specifically noted that PacifiCorp did not provide adequate justification for why its ROE should be higher in California compared to those states.[29] Specifically, the Farm Bureau noted that PacifiCorp's approved ROEs for Oregon,

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[25] Exhibit PAC/1300 at 2 and Exhibit JRW-1 at 3.

[26] Exhibit CA-02at 90.

[27] The Commission has recently reduced the ROEs for the large electric IOUs in TY 2023. *See* D.22-12-031, as corrected by D.23-01-002 and upheld by D.23-08-024. For example, PG&E's ROE is 10.0 percent for TY 2023, down from 10.25 percent in 2022.

[28] Cal Advocates Opening Brief at 22.

[29] CFBF Opening Brief at 4.

Washington, and Wyoming are 9.5 percent, its ROE for Utah is 9.65 percent, and its previously-approved ROE for California is 10 percent.[30]

We note that the Farm Bureau did not object to PacifiCorp's proposed capital structure itself, but instead proposed alternative ratios of 49.99 percent long-term debt, 0.01 percent preferred stock and 50 percent common equity.[31] PacifiCorp countered that the Farm Bureau did not adequately account for the differing utility regulations across states, which can impact a utility's risk and its calculated cost of capital.[32] We find PacifiCorp's proposed capital structure reasonable given Cal Advocates' concurrence that the proposed equity ratio is in line with other California electric utility companies, however, we note that 52.25 percent equity ratio is approaching the higher end.[33]

PacifiCorp suggested it faces higher regulatory risks than utilities within its identified proxy group reviewed by national risk evaluators.[34] PacifiCorp further argued that current market trends following the COVID-19 pandemic and associated political activities to boost government bond interest will create downward pressure on utility stocks.[35]

We note, however, that PacifiCorp's requested ROE for its California service territory is nearly 1 percent higher than the average authorized ROEs in Oregon, Utah, Washington, and Wyoming. Further, macroeconomic events such as the COVID-19 pandemic and interest rates are not specific to PacifiCorp or

[30] CFBF Opening Brief at 4-6.

[31] Exhibit CBFB/100 at 5-10.

[32] PAC Opening Brief at 15-16.

[33] The Commission recently adopted equity ratios of 52 percent for the large electric IOUs in TY 2023. *See* D.22-12-031, as corrected by D.23-01-002 and upheld by D.23-08-024.

[34] Exhibit PAC/200 at 52 and Exhibit PAC/XXX (opening brief) at 24-25.

[35] Exhibit PAC /200 at 10-26 and Exhibit PAC/XXX (opening brief) at 20-26.

California. PacifiCorp's requested 10.5 percent ROE in California exceeds those approved in D.22-12-031, for TY 2023 as corrected in D.23-01-002 and upheld in D.23-08-024, for the four larger energy utilities.[36] We therefore agree with Cal Advocates and the Farm Bureau that PacifiCorp's requested increase in its ROE is unreasonable, given the recent downtrend in ROE rates approved for 2023 for other, larger electric utilities operating in California and the ROE approved in other states in PacifiCorp's service territory.

We find that the existing ROE of 10 percent provides PacifiCorp with a sufficient return without requiring additional rate increases. Therefore, PacifiCorp shall calculate a new Cost of Capital that incorporates its existing ROE of 10 percent, rather than the 10.5 percent ROE calculated in its workpapers, when filing its Tier 1 AL implementing the rates associated with the revenue requirement adopted in this decision.[37]

6.2. Capital Additions

PacifiCorp proposed to include the $1.125 million capital costs associated with upgrading the technology at its Foote Creek II-IV wind power facilities.

[36] *See* D.22-12-031 at 35-37.

[37] We note that Commission regulation does not guarantee utilities will earn either the authorized rate of return (ROR) or ROE that are adopted and used by the Commission in setting just and reasonable rates. Rather, a utility's actual or recorded ROR or ROE may be higher or lower than what the Commission used in setting rates depending on how the utility manages its costs. If the utility's actual costs end up lower (or higher) than the costs adopted in the authorized revenue requirement, then its recorded ROR could be higher (or lower) than the authorized ROR, and the earned ROE might be higher (or lower) than that used in setting the rates authorized in this decision. We further note the legal standard for setting the fair ROE has been established by the United States Supreme Court in two cases: the Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia, 262 U.S. 679 (1923).

This project is expected to be in service in December 2023.[38] It would replace 64 original wind turbines with new generators to provide additional power.[39]

Cal Advocates recommended that the Commission fully reject PacifiCorp's requested amount for the Foote Creek Project, because it "would result in a $300,000 increase to the revenue requirement." Cal Advocates argued that there would be an absence of costs in service for the Foote Creek Project "well into the test period, "and that PacifiCorp had failed to indicate (1) associated costs for each milestone and (2) an historical comparable project for cost comparison. Cal Advocates noted that PacifiCorp admitted that it does not expect the Foote Creek Project to be completed until late 2023, and that the project had already been delayed by nearly six months due to weather conditions. Cal Advocates suggested PacifiCorp should instead request recovery of the Foote Creek Project through its PTAM after the project is fully operational.[40] Further, Cal Advocates suggested that the Foote Creek Unit I project could potentially be considered as historically comparable.[41]

PacifiCorp countered that Foote Creek I cannot directly be compared to the ongoing Foote Creek II-IV project, largely because it occurred in the early stages of the COVID-19 pandemic, which caused significant schedule delays throughout 2020.[42]

While we note that PacifiCorp believes the Foote Creek Project is currently on schedule for its expected completion in December 2023, we agree with Cal

[38] PacifiCorp Reply at 33-34.

[39] Exhibit PAC/1500 at 2-4.

[40] Cal Advocates Opening Brief at 8-10.

[41] 3 Cal Advocates-04 at 6.

[42] Exhibit PAC/1500 at 3.

Advocates that the appropriate mechanism to request recovery of the project is through its PTAM. As noted in Section 4.2 above, any major capital additions in 2023 and 2024 can be sought through PacifiCorp's PTAM, so long as the requested adjustment is based on actual cost data and in-service dates and reflects the appropriate allocation to California ratepayers. A PTAM for major capital additions may be filed for 2023 as soon as reasonably feasible following the effective date of this decision, and a PTAM for 2024 major capital additions may be filed October 15, 2024.

6.3. Wildfire Mitigation Costs

PacifiCorp requested specific revenue requirements associated with wildfire mitigation capital expenditures, which would relate largely to infrastructure improvements and additional operations and maintenance expenses, which would relate largely to planning for future grid hardening and vegetation management improvements. The proposed wildfire mitigation capital costs and operations and management expenditures are discussed in more detail below.

6.3.1. Wildfire Mitigation Capital Expenditures

PacifiCorp requested to add $77.1 million to rate base for wildfire mitigation capital expenditures that were forecasted to be placed in service between 2022 and 2023.[43] Cal Advocates recommended approving $47.42 million of incremental wildfire mitigation capital expenditures based on a method that examined supporting documentation provided by PacifiCorp and uses recorded data from July 2021 through October 2022 totaling $23.58 million and then

[43] Exhibit PAC/1200 at 18, Table-5; Exhibit PAC/1200 at 19, Table-5, Exhibit PAC/800 at 28 and Table-4; and PAC 1600 at 13. As previously noted, the costs accrued in PacifiCorp's Wildfire Mitigation Memorandum Accounts will be considered in a separate decision in Track 2 of this proceeding.

applies an average monthly spending amount of $1.7 million for the months November 2022 through December 2023. Cal Advocates specifically noted that the supporting documentation provided by PacifiCorp was adequate for it to conduct is additional review of the proposed wildfire mitigation capital expenditures.

Specifically, Cal Advocates explained that its recommendation was reasonable due to what it described as "steep monthly fluctuations of costs in service"[44] while Cal Advocates testimony originally asserted its reasoning was based on PacifiCorp being unable to entirely meet its requested total costs in service of $37.1 million for 2022 and $37.1 million [for] 2023.[45]

PacifiCorp responded that Cal Advocates' method is inappropriate because it does not account for the fact that wildfire mitigation investments are "ramping up in response to increased risk in PacifiCorp's service territory and correlate to the Company's Wildfire Mitigation Plan."[46] PacifiCorp further explained that capital costs are not placed in service on a uniform average monthly basis because more construction is accomplished in the 3rd and 4th quarters due to more favorable weather conditions.[47] PacifiCorp argued that contrary to Cal Advocates' assertion regarding 2022, PacifiCorp actually exceeded the $37.1 million forecast, with the final 2022 wildfire mitigation capital costs placed in service totaling $44.6 million.[48]

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[44] Cal Advocates Opening Brief at 11.

[45] Exhibit Cal Advocates-04 at 11.

[46] Exhibit PAC 1700/McCoy Rebuttal at 13.

[47] PacifiCorp Opening Brief at 39.

[48] PacifiCorp Opening Brief at 39.

We find PacifiCorp's forecast for wildfire mitigation capital expenditures reasonable. PacifiCorp has had little, if any, wildfire mitigation capital expenditures prior to this GRC cycle and is implementing new wildfire mitigation programs, so a ramp up period is not unexpected. We also note that PacifiCorp's assertion that it exceeded its forecast for 2022 was not refuted by Cal Advocates.

6.3.2. Wildfire Mitigation and Vegetation Management O&M Expenses

For TY 2023 PacifiCorp forecasted an increase of $8.367 million above the recorded 2022 amount for vegetation management expenses. Cal Advocates stated it did not oppose PacifiCorp's forecasts for vegetation management based on historic expenses and PacifiCorp's annualized estimated costs for 2022 Vegetation Management Programs. We therefore find PacifiCorp's vegetation management forecasts reasonable for TY 2023.

Regarding wildfire mitigation operations & maintenance (O&M) expenses, Cal Advocates recommended decreasing PacifiCorp's proposed wildfire mitigation O&M expenses from the original application amount $2,346,721 to $1,297,172.[49] Cal Advocates noted that PacifiCorp revised its wildfire mitigation operations and maintenance forecasts three times in this proceeding.

Cal Advocates did not oppose PacifiCorp's requests for the following wildfire mitigation O&M expenses for TY 2023:

1. Grid Design and System Hardening ($150,000)
2. Vegetation Analytics and Mapping ($44,000)
3. Grid Operations and Protocols ($0)
4. Data Governance ($0)

[49] Cal Advocates Opening Brief at 13.

5. Resource Allocation ($440,000)

In its rebuttal testimony, PacifiCorp removed its request for $80,000 for asset management and inspections and did not dispute Cal Advocates' recommendation to reduce its risk assessment and mapping costs by $4,302, to $181,698.[50] Further, PacifiCorp did not contest Cal Advocates' recommendation to reduce its transmission costs associated with wildfire mitigation O&M to $862 per year.[51]

Cal Advocates further suggested the Commission should use historical costs recorded for its situational awareness and forecasting, which for the period of 2019-2021 averaged to $255,120 annually. PacifiCorp did not agree with Cal Advocates' proposal to use historical recorded costs but revised its TY 2023 forecast for situational awareness and forecasting to $531,829, which is $645,131 lower than what it originally requested.[52]

The Farm Bureau suggested that none of the costs requested by PacifiCorp were adequately supported by a cost-benefit analysis that could be fully reviewed in this proceeding. It stated to fully evaluate the appropriate costs for PacifiCorp's California-based customers, the utility should provide information about the costs associated with undergrounding, which may provide a higher safety score, but may be overly expensive when compared to other options that still provide significant risk reduction at a much lower cost.[53]

We agree with Cal Advocates and the Farm Bureau that PacifiCorp's analysis filed in this proceeding was lacking accuracy and should have reflected

[50] Exhibit PAC/1600 at 2; Cal Advocates Opening Brief at 14.

[51] Exhibit PAC/1600 at 2.

[52] Exhibit PAC/800.

[53] Farm Bureaus Opening Brief at 16-17.

more detailed consideration of historical costs. However, we find that overall PacifiCorp has provided enough support to make a reasonableness finding for purposes of adopting a TY 2023 revenue requirement for wildfire mitigation expenses in this proceeding. In Section 9, below, we require PacifiCorp to make a more substantial and detailed showing for its wildfire mitigation costs and expenses in its next GRC.

Upon review, we find the adjusted amounts Cal Advocates recommended for the TY 2023 wildfire mitigation O&M, to be reasonable for incorporation in the rates approved in this GRC. We agree with Cal Advocates that PacifiCorp did not adequately identify the "mix of factors" used to develop its forecasts, nor did it appropriately define the historical costs for types of work or projects that are included in the forecasted costs.[54]

The approved wildfire mitigation and operation and management expenses to be recovered in rates are as follows:

1. Grid Design and System Hardening: $150,000
2. Vegetation Analytics and Mapping: $44,000
3. Resource Allocation: $440,000
4. Risk Assessment and Mapping: $181,698
5. Transmission: $862
6. Situational Awareness and Forecasting: $255,120
7. Emergency Planning and Preparedness: $35,432
8. Stakeholder Cooperation and Community Engagement: $123,205

These amounts total $1,230,317 million annually for PacifiCorp's 2023 TY 2023 GRC period.

[54] Exhibit PAC/800; Cal Advocates – PacifiCorp-021-FNZ at Question 20 b; and Cal Advocates Opening Brief at 14-15.

6.4. Uncontested Issues Related to Revenue Requirement

The items discussed below (tax calculations, cash working capital, and labor/non-labor escalation expenses) were not disputed by parties to this proceeding.

6.4.1. Tax Calculations

Cal Advocates specifically noted that after independently reviewing PacifiCorp's documentation, it had no objections to PacifiCorp's tax calculations.[55] The Farm Bureau did not address PacifiCorp's tax calculations.

Upon review, and because no parties raised issues, we find PacifiCorp's tax calculations, as described in its application, testimony, briefs, and workpapers, to be reasonable for this GRC.

6.4.2. Cash Working Capital

Cal Advocates initially opposed the Cash Working Capital (CWC) calculations PacifiCorp included in its application. Specifically, Cal Advocates requested to exclude federal and state income taxes, and taxes other than income from PacifiCorp's CWC calculations, citing Standard Practice U-16-W. Cal Advocates' proposed calculation, which would also slightly reduce PacifiCorp's total working capital, would reduce PacifiCorp's proposed CWC by $6,955.[56]

However, in its opening brief, Cal Advocates stated it does not oppose PacifiCorp's calculations for its California CWC, given the utility's use of a Lead-Lag method to calculate its CWC on a Detailed Basis.[57]

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[55] Exhibit Cal Advocates-02 at 7.

[56] Exhibit Cal Advocates-02 at 6-7.

[57] Cal Advocates Opening Brief at iii and 6.

The Farm Bureau did not address PacifiCorp's CWC calculations in testimony or briefs.

Upon review, we find PacifiCorp's CWC calculations to be reasonable and they are therefore approved in this decision.

6.4.3. Labor and Non-Labor Escalation Expenses

PacifiCorp requested an incremental increase in labor and non-labor expenses to be recovered from its California ratepayers.[58] Cal Advocates also testified that it does not oppose PacifiCorp's request for incremental expenses for Labor & Non-Labor Escalation Expenses of $1,484,394.[59] The Farm Bureau did not address this expense in its testimony.

Upon review, we find this incremental increase to be reasonable and it is therefore approved.

7. Depreciation and Amortization of Coal Unit Decommissioning Costs

7.1.1. Depreciation

PacifiCorp proposed the following modifications to the depreciable lives of its existing coal-fired power generation units:

1. Colstrip Units 3 and 4 (decreased from 2027 to 2025)
2. Craig Unit 2 (increased from 2026 to 2028)
3. Hyden Unit 1 (decreased from 2030 to 2028)
4. Hyden Unit 2 (decreased from 2030 to 2027)
5. Naughton Units 1 and 2 (decreased from 2029 to 2025).

PacifiCorp noted that these adjustments were included and adopted in its 2021 IRP.[60]

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[58] Exhibit PAC/903C – Labor Escalators.

[59] Exhibit Cal Advocates-03 at 2.

[60] Exhibit PAC/400 at 6-8.

The purpose of depreciation is to allow a utility to recover the original cost of the asset, as well as the net salvage value (salvage minus cost of removal), over the life of the asset. This ensures assets are paid for by the customers who benefit from the use of the asset and the shareholders who provided the capital invested in the assets are repaid for their investment. To meet these objectives, the Commission uses the Straight-line Remaining Life depreciation method described by Standard Practice U-4.

Under the straight-line remaining life depreciation method, the undepreciated asset amount (original cost less accumulated depreciation plus the estimated net salvage) is depreciated over the remaining life of the asset. The net salvage includes the cost of removal of the asset at the end of its useful life as well as any salvage value the asset may have at that time. Currently, for California (and Utah, Idaho, and Wyoming) the asset lives of PacifiCorp's coal burning power plants in the instant application are based on a 2018 depreciation study that would accelerate the depreciation for its existing coal plants to occur between 2025 and 2028, rather than between 2023 and 2029, as approved in D.20-02-025.

No party to this proceeding specifically opposed PacifiCorp's modest increase in its depreciation rates, depreciation expense calculations, nor its proposed accelerated coal plant retirement dates.[61] Upon review of its testimony and the supporting information provided in its 2021 IRP, we find PacifiCorp's proposed expedited depreciation rates to be reasonable, given the shift in nearby state policies and California regulations.

[61] Cal Advocates-02 at 11 and Cal Advocates-03C at 4

7.1.2. Amortization

In this application, PacifiCorp requested to recover $4,131,795 annually in amortization expenses beginning in TY 2023. PacifiCorp's accelerated coal plant retirement accounted for $1,218,447 of this annual amortization expense.

PacifiCorp also requested to amortize deferred, unrecovered plant balance; closure costs; and estimated decommissioning costs from the December 2020 closure of the Cholla Unit 4 facilities. PacifiCorp filed for and was granted approval to establish a memorandum account to defer all costs associated with this closure to a future proceeding.

In its GRC, PacifiCorp sought to recover $5,149,809 in amortization expenses resulting from the Cholla Unit 4 closure over a three-year period, which is an additional annual amortization expense of $1,716,603, on top of the amortization expenses it seeks for its other accelerated coal plant retirements described above.

Cal Advocates initially suggested that PacifiCorp's amortization expense increase associated with its accelerated coal plant retirement (described in Section 7.1.1 above) could be collected over eight years, rather than four, which would span two GRC periods. Cal Advocates suggested this extended recovery time would reduce the annual increase to $643,726 collected over eight years, rather than $1,218,447 per year over four years. Cal Advocates did not dispute the amount of the amortization, but suggested the same amount could be recovered by PacifiCorp over an eight-year period to reduce customer rate impacts.[62]

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[62] Exhibit CA-03 at 3-4

In its opening brief, however, Cal Advocates "acknowledges that it mistakenly misinterpreted the costs" associated with amortization of PacifiCorp's retiring coal units. We agree with Cal Advocates and approve PacifiCorp's request to recover amortization costs associated with the coal plants described in Section 7.1.1 above in a three-year period.

Separately, Cal Advocates opposed PacifiCorp's proposal to recover the $5,149,809 in amortization expenses associated with the closure of Cholla Unit 4 over a three-year period. Cal Advocates noted that the rate impacts to customers would be significantly lower if the Cholla Unit 4-related amortization expenses were recovered over eight years, or two GRC cycles. Specifically, Cal Advocates noted that recovering the Cholla Unit 4 closure costs over eight years would result in $643,726 collected annually over eight years instead of $1,716,603 annually over three years. According to Cal Advocates, extending the Cholla Unit 4 memorandum account's amortization period "will provide assurance to PacifiCorp on the recoverability of the total closure cost while mitigating the increased economic pressure on ratepayers."[63]

PacifiCorp argued that its three-year amortization period for the Cholla Unit 4 memorandum account was based on its current GRC cycle, and that extending the amortization period could result in ratepayers that never benefitted from the operations of that facility paying costs associated with its closure.[64]

We agree with PacifiCorp that some of the customers affected by this GRC may not have received the benefit of Cholla Unit 4's operations. However, the

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[63] Exhibit Cal Advocates-03C at 5

[64] Exhibit PAC/1700 at 18-20.

rate impacts associated with its amortization expenses would be significantly lower if the cost recovery occurs over a longer period. We therefore agree with Cal Advocates that the amortization costs associated with Cholla Unit 4 should be collected over eight years to result in a lower rate increase for customers in the TY 2023 GRC period.

PacifiCorp is authorized to recover the $5,149,809 in amortization expenses associated with the closure of Cholla Unit 4 over an eight-year period, which will result in a TY 2023 revenue requirement increase of $643,726. PacifiCorp shall update the amortization rate for Cholla Unit 4 in its AL implementing this decision.

8. Rate Spread and Rate Design

PacifiCorp proposed to spread its rate increase equitably across customer classes and to implement several new time-of-use (TOU) rates for different types of customers in this application. This section discusses the impacts to customers and the party responses to each proposal.

8.1. Rate Spread

PacifiCorp conducted an analysis to determine its revenue allocation across customer classes, which was based on equal percentage marginal costs (EPMC). This analysis resulted in a rate increase for all customer classes but would have hit agricultural customers with a rate increase of more than 60 percent. To mitigate the impact to agricultural customers, PacifiCorp proposed to spread the overall rate increase equally across customer classes, rather than base the rate increase on EPMC. This would have resulted in an increase of approximately 25 percent for each customer class.[65]

[65] Exhibit PAC/1800 at 14 and Exhibit PAC/1100 at 2-4.

We note that the projected rate increase for residential customers under the equal percentage rate spread proposal is relatively equivalent to the rate impacts that would occur under EPMC. Cal Advocates did not provide specific opposition to PacifiCorp's proposed revenue allocation. The Farm Bureau supported PacifiCorp's equal percentage rate spread proposal, despite opposing the total rate increase.[66] No party directly opposed PacifiCorp's proposal to spread the anticipated rate increases equally across customer classes.

As previously noted in Section 6 above, PacifiCorp submitted an updated set of testimony on October 9, 2023, that describes the revenue requirement without the proposed recovery of the Wildfire Mitigation Memorandum Accounts as defined in Section 4.3.2 above. Its October 9, 2023, testimony maintained the equal percentage rate spread proposal, while resulting in a lower overall percentage increase of approximately 20.1 percent across the customer classes.

We also note that any rate increases related to the costs accrued in PacifiCorp's Wildfire Mitigation Memorandum Account will be addressed in Track 2 of this proceeding.

Upon review of the testimony, party briefs, and updated workpapers filed in October 2023, we find PacifiCorp's proposal to spread its rate increases equally across customer classes, rather than using the EPMC calculations, to be reasonable because it mitigates the potential adverse impacts to larger customer classes while still maintaining a relatively equal cost-of-service burden on its smaller customer classes.

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[66] CFBF Opening Brief at 19.

8.2. Rate Design

PacifiCorp proposed TOU rate options for its residential customer class in California and its non-residential general use customers in California.

8.2.1. Schedule DT

PacifiCorp's proposed residential TOU proposal, Schedule DT, is in line with those approved for other California utilities. The proposed on-peak period would be 5:00 p.m. to 9:00 p.m. each day, and off-peak hours would be any other hour of each day. PacifiCorp proposed to charge customers enrolled in Schedule DT an adder of 6.900 cents per kilowatt hour (kWh) during peak hours, and provide a credit of –1.747 cents per kWh during off-peak hours. PacifiCorp estimated this would result in total baseline energy rates of 22.434 cents per kWh on-peak, and 13.787 cents per kWh off-peak. This compares to an average 15.534 cents per baseline kWh for standard Schedule D customers. Participation in Schedule DT would be optional.[67] To develop the price of the on-peak adder and off-peak credits, the company compared the hourly prices from the Energy Imbalance Market (EIM) for the PAC-W, PAC-E, and Malin nodes for the 36-month period ending June 2021. It found the average hourly price between 5:00 p.m. and 9:00 p.m. to be 158 percent of the average for the other 20 hours of the day. The adder represents approximately 158 percent of the off-peak hours price and applies only to hours where PacifiCorp's grid faces the most need for customers to reduce or better manage energy use. PacifiCorp also proposed that the energy charge that is time-differentiated should be recovered in base ECAC rates on a revenue neutral basis.

[67] Exhibit PAC/1100 at 7-9, Exhibit PAC/1104 at 1, and Exhibit PAC/1105 at 1.

8.2.2. Schedule AT-29

PacifiCorp also proposed to offer its non-residential customers whose loads are less than 500 kilowatts (kW) an option to enroll in a TOU rate with peak hours in line with those proposed in Schedule DT (5:00 p.m. to 9:00 p.m.). Under its proposed Schedule AT-29, customers that would otherwise qualify to enroll in PacifiCorp's Schedules A-25, A-32, or A-36, could opt to be charged higher rates during peak hours, but pay a declining kWh/kW energy charge. PacifiCorp stated that this proposed rate design allows it to charge customers an average energy price that declines as a customer's load factor increases. This modified average energy price is intended to function like a conventional demand charge, but would cap how high the average kWh/kW energy cost would be for customers with lower load factors. PacifiCorp proposed this tariff option largely to address the demand charges faced when certain commercially- or privately-operated electric vehicle (EV) battery charging stations have low utilization. The infrastructure for EV battery charging is frequently designed to support high utilization for the future, when more EVs will be driving through PacifiCorp's service territory. In many remote locations, or at fleet hubs where the transition to EVs is only just beginning, however, the usage of that new infrastructure has a low load factor.

Customers that are enrolled in PacifiCorp's smaller general service rates, such as EV service providers, bus system, or fleet operators, could participate in Schedule AT-29, as off-peak charging and the declining average energy price for increased load factors could reduce their overall electric costs.[68]

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[68] Exhibit PAC/1100 at 9-14.

PacifiCorp suggested that customers enrolled in its proposed Schedule AT-29 with low load factors will still pay a higher price than those with higher load factors, but the rate design will effectively cap their average demand and energy charges.

PacifiCorp's proposed off-peak credit for Schedule AT-29 was set at -1.581 cents per kWh, and the on-peak adder was set to 8.000 cents per kWh. Like Schedule DT discussed above, the on-peak adder reflects approximately 158 percent of the nodal EIM prices during off-peak hours. The prices proposed for Schedule AT-29 are based on Schedule A-32, using revenue-neutral on- and off-peak adders to the Schedule ECAC-94 energy rates.

PacifiCorp also plotted the average energy cost of 50 kW Schedule A-32 customers using the proposed $7.07 per kW cost for demand and facilities charges and the proposed 12.748 cents per kWh energy charge against load factors, in order to better understand the relationship between average energy cost and load factors. PacifiCorp stated its Schedule AT-29 rate proposal, at 21.831 cents for the first 50 kWh/kW and 15.334 cents for all additional kWh resulted in a "very similar average cost... for all customers with load factors greater than about 20 percent." PacifiCorp's calculations suggested that the average energy and demand costs for customers with load factors less than 20 percent enrolled in Schedule AT-29 would be, on average, between 25.000 and 20.000 cents per kWh, rather than the more than $1.00/kWh charges they would incur on Schedule A-32.[69]

[69] Exhibit PAC/1100 at 12-14 and Exhibit PAC/1105 at 2.

8.2.3. Schedule PA-115

PacifiCorp has an existing pilot tariff, Schedule PA-115, that is only available for up to 25 irrigation customers in the Tule Lake area, which provides an on-peak period of 2:00 p.m. through 6:00 p.m., Monday through Friday during June, July and August, excluding the Independence Day holiday. During the on-peak hours, the customers enrolled in Schedule PA-115 are charged 30.022 cents per kWh. The same customers receive a 4.254 cent per kWh credit for off-peak usage.

PacifiCorp proposed to make this TOU rate available to all agricultural pumping service customers that are otherwise eligible for Schedule PA-20. It also proposed to allow customers enrolled in Schedule PA-115 to select peak hours of 2:00 p.m. to 6:00 p.m. or 6:00 p.m. to 10:00 p.m. during the summer months of July through September. The options are based on a previously completed pilot through which PacifiCorp learned that irrigators need flexibility to stagger the schedules for their customers that irrigate from canal water systems.[70] PacifiCorp proposed that the adder for on-peak hours be set at 4.570 cents per kWh, resulting a total on-peak energy rate of 16.352 cents per kWh. The credit for off-peak usage would be set at 0.923 cents per kWh, resulting in a total off-peak rate of 10.859 cents per kWh. PacifiCorp also proposed to maintain its PA-20 TOU option's total energy charge differential. PacifiCorp explained that the proposed TOU periods are the same as those it provides to TOU irrigation customers in neighboring Oregon, and that making its seasons and TOU periods consistent across the border will reduce confusion for customers that operate on both sides

[70] Exhibit PAC/1100 at 14-15.

of the states' border.[71] Further, PacifiCorp requested to recover the time-differentiated energy charges in its proposed Schedule PA-115 within base ECAC rates on a revenue neutral basis.[72]

PacifiCorp also explained that TOU participants will still be eligible to enroll in its net billing program (Schedule NB-136) for customer-generators, but that the export prices would be a flat rate to resolve metering constraints and reduce complexity for customers across state lines.[73] Any customer generators enrolled in the net billing program and Schedule AT-48 would also be compensated for exported energy at the flat export credit price, as discussed in more detail below.

8.2.4. Schedules AT-47 and AT-48

PacifiCorp proposed to modify the energy charges for its existing Schedules AT-48 and AT-47, for which large general service customers (500kW and greater) are eligible. PacifiCorp notes that the adjusted prices proposed for its Schedules AT-48 and AT-47 would "achieve the target functionalized revenue requirement changes, but with energy charges modified so they would vary by time of use."[74]

The proposed TOU periods would be 5:00 p.m. to 9:00 p.m., like Schedules DT and AT-29 described above. However, rather than using the 158 percent price differential based on EIM hourly pricing, PacifiCorp proposed that the differential between on- and off-peak energy charges be set at the market-based

[71] Exhibit PAC/1100 at 16, Exhibit PAC/1104 at 2, and Exhibit PAC/1103.

[72] Exhibit PAC/1100 at 16 and Exhibit PAC/1103.

[73] Exhibit PAC/1100 at 16-17 and Exhibit PAC/1102.

[74] Exhibit PAC/1100 at 17.

differential of 1.029 cents per kWh, as shown in Exhibit PAC/1104 and Exhibit PAC/1103.

8.2.5. Street and Area Light Price Re-Design

PacifiCorp proposed to change the prices charged for company-owned streetlights and other area lights to be based on the level of lighting service provided, rather than on the bulb-type or other technology differentials. The rates for streetlights are provided to entities, including PacifiCorp, to illuminate public streets and highways, while the rates for area lights are provided to residential and commercial customers that need to illuminate driveways or alleys.

PacifiCorp currently offers four tariffs for company and customer-owned lights:

- Schedule OL-15 – Outdoor Area Lighting – No New Service
- Schedule LS-51 – Street and Highway Lighting Service Utility Owned System
- Schedule LS-53 – Special Street and Highway Lighting Service Customer Owned System Energy Only Service
- Schedule 58 – Street and Highway Lighting Service Customer Owned System No New Service

The current pricing PacifiCorp offers for company-owned street and area lights is based on technology and lamp types, which the utility suggested can be complicated for lights that are not metered, or not metered separately from the other more standard customer usage rates.[75]

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[75] Exhibit PAC/1100 at 18. For example, a 7,000 lumen mercury vapor area light is $17.48/month, while a 4,000 lumen light-emitting diode (LED) streetlight is $10.31. Pacificorp also noted that it already converts company-owned lights to LED, rather than fixing non-LED equipment when it fails.

PacifiCorp proposed to charge the level of lighting service based on ranges of light-emitting diode (LED) equivalent lumens, regardless of which lamp type is currently in place. Under this proposal, all bulb types would be charged at the same price for street and area lights.[76]

PacifiCorp noted that, because LED has emerged as the dominant lighting technology for street and area lighting, it is reasonable to adjust its rates to remove the current differential, which has, to date, disincentivized PacifiCorp from converting its lights to LED.

PacifiCorp also requested to create a new customer-funded option that would, in part, recover costs associated with converting PacifiCorp-owned streetlights to LED bulbs.[77] According to PacifiCorp, streetlight customers can currently save on rates by requesting the company-owned lights they pay for be converted to LED. Because this lowers PacifiCorp's revenue, the customers requesting LED conversion do not currently receive a line extension allowance, and therefore must pay for the full conversion costs. The LED customer-funded program proposal is intended to provide the same customers an opportunity to pay for only a portion of the conversion. The proposal aims to ensure that early adopters that have already paid for LED conversions are not adversely impacted. It would provide customers opting to enroll in the "customer-funded conversion" program lower overall street light prices, while still incentivizing customers to convert to LED technology, given its energy savings.[78]

Separately, PacifiCorp proposed to reopen Schedule OL-15 to new customers, because it provides an option for customers that need external

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[76] Exhibit PAC/1100 at 19-20.

[77] Exhibit PAC/1100 at 19-20.

[78] Exhibit/1100 at 20-23 and Exhibit PAC/1106.

illumination that is farther from the existing meter than the distribution line(s). To prevent added costs to such customers, PacifiCorp offered to own and maintain new area lights so long as they can be connected to existing distribution poles.

PacifiCorp further proposed to transfer customers on Schedule LS-58 to Schedule LS-53 for energy-only service, because the prior parameters of Schedule LS-58 do not align with its proposed level of service for company-owned street and area lights. The utility noted that customers that are currently on Schedule LS-58 would be notified of this change.

8.2.6. Paperless Bill Credit

PacifiCorp proposed to add a monthly $0.50 credit to Schedule 300 and Rule 9 customers that have enrolled in paperless billing. The amount of this credit is associated with the savings of not sending paper bills via mail, which is approximately $0.49 per mailing. Any customer that has or will enroll in paperless billing would be eligible for this credit.[79] We find the credit amount to be reasonable, given its alignment with the mailing costs to individual customers, and support PacifiCorp's effort to reduce resource usage by encouraging customers to enroll in paperless billing.

8.2.7. Temporary Service Charge

PacifiCorp proposed to increase its temporary service charges from $58 for single-phase and $115 for three-phase service to $167 for all temporary service installations, based on the current rate for one hour of journeyman time. This methodology aligns with that used when the temporary service charge was initially calculated by PacifiCorp in 1982. PacifiCorp stated that this charge has

[79] Exhibit PAC/1100 at 24 and Exhibit PAC/1107.

not been modified since its inception and does not reflect the current costs associated with providing temporary service.[80] Upon review of PacifiCorp's testimony and workpapers we find this proposed adjustment to be reasonable to reflect to cost of an hour of journeyman time and to also simplify the temporary service charges for customers by consolidating the single- and three-phase costs into one cost structure.

8.2.8. Housekeeping Items

PacifiCorp proposed changes to two sheets in Schedule 300, Sheet Nos. 4733-E and 3953-E, to correct inaccurate references to other sheets in the tariff. It also proposed to add back the charges for field visits and unauthorized reconnections to Sheet 3953-E, which were inadvertently deleted.

For its general service rate customers, PacifiCorp proposed to add the primary metering discount to Schedule A-25, as it is already specifically listed for other non-residential schedules.

Finally, PacifiCorp proposed to remove references to pre-2005 Daylight Savings Time definitions.

8.2.9. Discussion

No parties directly responded to the rate design changes described in Section 8.2.1-8.2.7 above. According to the updated workpapers filed by PacifiCorp on October 9, 2023, the average non-CARE residential customer using 850 kWh per month will see an average monthly bill increase of $26.09 per month.

Upon review of PacifiCorp's testimony and workpapers we find the proposed Schedules DT, AT-23, PA-115, AT-47 and AT-48, and PacifiCorp's

[80] Exhibit PAC/1100 at 25 and Exhibit PAC/1108.

proposed street and area light tariff re-design proposals to be reasonable. Further, we find it reasonable to authorize PacifiCorp to offer its paperless bill credit and to update its temporary service charge, given the costs the utility provided to send paper documents and temporary service connections.

Finally, we agree that PacifiCorp's tariff sheets would be clarified with the implementation of the housekeeping items described in Section 8.3 above. Upon review of Exhibit PAC/1100 and Exhibit PAC/1102, we find these proposed housekeeping changes to be reasonable.

8.3. CARE Credit increase

The California Alternate Rates for Energy (CARE) discount is intended to reduce the cost of electric service to customers that meet specific thresholds. PacifiCorp identified the magnitude of the rate impact requested in this case and requested to increase its CARE discount from the previously approved 20 percent to 25 percent, to protect customers that may otherwise be more adversely impacted by the rate changes authorized in this decision.[81]

No party contested PacifiCorp's request to increase its CARE discount. We find it, in part, addresses issue 8 identified in Section 3 above, by assisting otherwise vulnerable customers. Therefore, PacifiCorp's request to increase its CARE discount to 25 percent for its California tariff schedules is approved.

9. Future GRC Testimony Requirements

As discussed in Section 4.3 above, PacifiCorp must conduct a new, thorough RDF assessment for each GRC cycle, that, at a minimum, addresses each of the 10 RAMP elements described in the Voluntary Agreement adopted in D.19-04-020.

[81] Exhibit PAC/1100 at 6-7 and PAC/1102.

Separately, Track 2 of this proceeding will address PacifiCorp's wildfire mitigation memorandum account deferred cost accounting more thoroughly. The independent audit, which was necessary to ensure transparency regarding PacifiCorp's WMP cost recovery and accounting requests, and the associated procedural processes will likely delay cost recovery of the Wildfire Mitigation Memorandum Account recorded costs being evaluated in Track 2. To avoid similar delays in the future, we direct PacifiCorp to include specific WMP revenue requirement forecasts for every separate year in its GRC cycle, when filing all future GRCs. More details regarding PacifiCorp's wildfire cost accounting and reporting requirements will be addressed in a separate decision in Track 2 of this proceeding.

Additionally, we find it necessary to set specific requirements for PacifiCorp to, in its next GRC application:

1. Produce the historical spending and accrual data, including the aggregate historical data of the most recent depreciation study and additional data for any of the elapsed years between the study year and the GRC base year; and
2. Provide detailed documentation to support the timing of and costs of its retirement plans for all coal facilities serving California customers consistent with its most recent IRP.

10. Conclusion

This decision modifies and approves PacifiCorp's amended requested revenue requirement, as served in testimony on October 9, 2023, that removed the request for amortization of specific deferred Wildfire Mitigation Memorandum Account costs, which will be considered in Track 2. It authorizes a base revenue requirement of $101,288,005 for PacifiCorp (doing business as Pacific Power) pursuant to A.22-05-006, which is an increase of $18.99 million.

The revenue requirement adopted herein will increase PacifiCorp customers' rates by approximately 17.5 percent on average, which is 31.9 percent lower than the 25.7 percent increase initially requested by the utility.

This decision adopts PacifiCorp's Interjurisdictional Cost Allocation Methodology and its proposal to continue its use of its ECAC and PTAM to true-up costs annually. It authorizes PacifiCorp to increase its CARE discount to 25 percent and adopts its modified TOU tariffs, including the new mandatory TOU requirements for certain general service customers.

It adopts PacifiCorp's proposed capital structure, its uncontested cost of debt and preferred stock, and directs PacifiCorp to retain its existing 10 percent ROE, rather than its proposed 10.5 percent ROE, when implementing the rate increase adopted in this decision. As a result, PacifiCorp's adopted rate of return is 7.34 percent:

	Cost Factor	**Capital Structure Weight**	**Weighted Cost**
Return on Long-Term Debt	4.41%	47.74%	2.10%
Return on Preferred Stock	6.75%	0.01%	0.00%
Return on Equity	10.00%	52.25%	5.23%
Rate of Return on Rate Base			**7.34%**

This decision also directs PacifiCorp to remove the capital addition costs associated with its Foote Creek Project and instead seek recovery of them in a PTAM filing in 2024.

Finally, it directs PacifiCorp to spread recovery of the amortization expenses associated with its Cholla Unit 4 decommissioning over eight years, rather than over three years, to mitigate the rate impacts to California electric customers. The revenue requirement increase authorized by this decision will largely provide for the funding of PacifiCorp's wildfire mitigation plans and vegetation management program.

Therefore, PacifiCorp's approved increases for TY 2023 are:

	Requested ($ millions)	**Approved ($ millions)**	**% Difference**
Vegetation O&M	8.5	8.5	0%
Wildfire Mitigation O&M Costs	2.4	1.2	50%
Incremental Wildfire Mitigation Capital	6.1	6.1	0%
Labor & Non-Labor Escalation	1.5	1.5	**0%**
Incremental Decommissioning	1.2	1.2	**0%**
Cholla Unit 4	1.7	0.6	**64.7%**
Foote Creek II-IV	.145	0	**100%**
Return on Equity and Capital Structure	1.3	0	**100%**
Total	22.8	19.1[82]	**16.2%**

Continued consideration of PacifiCorp's Wildfire Mitigation Memorandum Account balances and cost accounting practices will occur in Track 2 of this proceeding.

11. Comments on Proposed Decision

The proposed decision of ALJ Carloyn Sisto in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice

[82] Totals may not reconcile due to rounding.

and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

12. Assignment of Proceeding

President Alice Reynolds is the assigned Commissioner and Carolyn Sisto is the assigned Administrative Law Judge in this proceeding.

13. Findings of Fact

1. With respect to individual uncontested issues in this proceeding, we find that PacifiCorp has made a *prima facie* just and reasonable showing, unless otherwise stated in this decision.

2. PacifiCorp's revenue requirement will increase by $18.989 million to recover the approved Track 1 costs proposed in A.22-05-006.

3. The PTAM allows PacifiCorp to adjust base rates for changes in inflation calculated as the greater of: (i) the September Global Insight U.S. Economic Outlook forecast of Consumer Price Index for the following calendar year with an offsetting productivity factor of 0.5 percent; or (ii) zero.

4. The ECAC and PTAM are efficient means for setting fair and reasonable rates.

5. The Jurisdictional Allocation Methodology proposed by PacifiCorp was uncontested and results in California ratepayers paying an appropriate share of system- wide costs and just and reasonable rates.

6. The 2020 Interjurisdictional Cost Allocation Protocol (2020 Protocol) provides for just and reasonable rates for California ratepayers.

7. The 2020 Protocol reflects differing regulations of coal-fired units across California, Washington, Oregon, and Wyoming.

8. The Commission recently reduced the return on equity the large energy IOUs may collect for 2023 in D.22-12-031, as corrected in D.23-01-002 and upheld in D.23-08-028.

9. PacifiCorp's current 10 percent return on equity, as adopted in D.20-02-025, is reasonable and in line with those recently adopted by the Commission for the large energy IOUs for 2023.

10. The following elements of PacifiCorp's revenue requirement are not contested:

- Methodologies for computing and forecasting taxes;
- Cash working capital calculations; and
- Labor (based on actual contracts and budgeting) and Nonlabor (based on Global Insight indices) escalation.

11. PacifiCorp's Foote Creek Project is not yet in service.

12. PacifiCorp requested to include $1.125 million in capital costs associated with the Foote Creek II-IV project in rates.

13. The PTAM provides an efficient mechanism for new capital additions to be added to PacifiCorp's revenue requirement, so long as the requested adjustment is based on actual cost data and in-service dates and the costs allocated to California ratepayers are appropriate.

14. The Commission uses the Straight-line Remining Life depreciation method described by Standard Practice U-4.

15. The asset lives of PacifiCorp's coal burning power plants are based on a 2018 Depreciation Study that was used to develop the utility's 2021 IRP.

16. PacifiCorp's 2021 IRP reflects that its system operates on an integrated basis across its entire six-state territory and engages in least-cost planning on a system-wide basis.

17. PacifiCorp's 2021 IRP referenced in this proceeding sees depreciation of its coal plants occurring between 2025 and 2028.

18. The accelerated depreciation is due to state-specific policy changes in PacifiCorp's service territory.

19. PacifiCorp requested to recover $1,218,447 annually in amortization expenses associated with the accelerated retirement of its coal plants.

20. PacifiCorp is required to meet various states' requirements associated with reducing its baseload of fossil fueled generation.

21. The rate impacts to California customers would be significantly lower if the Cholla Unit 4-related expenses were recovered over eight years.

22. An eight-year recovery period for Cholla Unit 4-related expenses would reduce the annual increase to $643,726 collected over eight years, rather than $1,716,603 per year over three years.

23. Decision 19-04-020 in A.15-05-002 approved a voluntary agreement between the Commission's Safety Enforcement Division and the SMJU, including PacifiCorp. The agreement provided a framework for the risk-based decision-making components of PacifiCorp's instant and future GRC filings.

24. PacifiCorp did not provide an adequate RDF analysis that projected the risks and expected mitigation costs as described in the Voluntary Agreement adopted in D.19-04-020.

25. PacifiCorp's marginal cost of service study supports the company's proposed rate spread and rate design.

26. PacifiCorp's proposed equal rate spread brings rates for each customer category closer to reflecting the cost of service for those rate schedules, while mitigating rate impacts to agricultural customers.

27. PacifiCorp's proposed Schedule DT provides residential customers the option to enroll in a TOU rate designed to mitigate demand during on-peak hours.

28. PacifiCorp's proposed Schedule AT-29 provides an option for non-residential customers with low load factors to enroll in a TOU rate that includes a declining kWh-per-kW energy charge that could reduce the burden of customers providing electric vehicle charging stations for public or small fleet use.

29. PacifiCorp's proposal to expand its Schedule PA-115 TOU rate would open the schedule as optional for any agricultural pumping service customers to enroll and provides a second peak-hour pricing option.

30. PacifiCorp's proposal to continue its Net Billing program schedule (Schedule NB-136) for customer generators creates a flat export credit price that is less complex for all eligible customers.

31. PacifiCorp's proposal to modify the energy charges for its Schedules AT-47 and AT-48 to vary by time of use aligns with the TOU periods proposed for its residential and smaller general service use customers.

32. PacifiCorp's proposal to modify its seasonal on-peak demand charge to a flat demand charge for Schedules AT-47 and AT-48 provides a shorter on-peak TOU window for larger non-residential customers.

33. PacifiCorp's proposed changes to its street and area lighting schedules (Schedules OL-15, LS-51, LS-53, and LS-58) bases pricing on the level of service, rather than on the specific technology and lamp type deployed by the customer and could encourage a broader shift to LED technology.

34. PacifiCorp's proposed Customer-Funded LED Conversion option provides lower prices to customers that pay for the conversion of streetlights to LED, to provide fairness for early adopters that have already paid for LED conversions

and to continue incentivizing customers to pay for LED conversions themselves, when it is feasible.

35. PacifiCorp's proposal to re-open Schedule OL-15 reflects the lower cost to install and maintain LED lights on existing distribution poles while ensuring the company can easily access the newly installed LED lamps.

36. PacifiCorp's proposal to close Schedule LS-58 and transition customers to Schedule LS-53 for energy service only reflects that the company is responsible for replacing the bulbs.

37. PacifiCorp's proposed paperless bill credit aligns with the cost of mailing individual customer bills through the US Postal Service and provides customers the option to choose a less resource-intensive option for receiving their bills.

38. PacifiCorp's temporary service charge was established in 1982 based on the loaded rate for one hour of journeyman time.

39. PacifiCorp's proposed increase in its temporary service installation charges combines single- and three-phases into one charge and update the fee to the current loaded rate for one hour of journeyman time.

40. PacifiCorp's proposed housekeeping items amend inadvertent changes and mistakes to its Schedule 300, add the primary metering discount available to other general service rate schedules to Schedule A-25, and remove outdated references to pre-2005 Daylight Savings Time hours.

41. PacifiCorp's proposed increase in its CARE discount could mitigate the impact of the rate increases associated with this proceeding for CARE-eligible customers.

42. PacifiCorp's cost of service and proposed rate allocation is reasonable.

43. PacifiCorp's proposal to equally spread the rate impacts of its requests across customer classes would reduce the otherwise unreasonable increase to agricultural customers in its California service territory.

44. PacifiCorp's proposed TOU time periods for Schedule DT, Schedule AT-29, and Schedules AT-47 and AT-48 align with the on-peak hours adopted in other California IOU ratecases.

45. PacifiCorp's proposal to provide all agricultural pumping service customers optional TOU rates is reasonable and should reduce complexity of service for customers that span the Oregon and California border.

46. PacifiCorp's proposed changes to its street and area lighting schedules will incentivize the company to convert older lamps to new LED technology while still providing an incentive for customer-paid conversion to LED lamps.

47. PacifiCorp's proposed paperless bill credit will incentivize customers to adopt less resource-intensive methods to receive their monthly statements, and the cost of the credit is in line with the costs PacifiCorp pays to process and send paper bills to individual customers.

48. PacifiCorp's proposed increase to its temporary service installation charge aligns with the current rate for one hour of journeyman work.

49. PacifiCorp's housekeeping items will clarify existing requirements for Schedule 300, provide a consistent primary metering discount across its general service customer schedules, and remove outdated references to pre-2005 Daylight Savings Time hours.

50. PacifiCorp's proposed increase to its CARE Credit will mitigate some of the rate impacts associated with this GRC for its CARE-eligible customers.

51. In its next GRC application, PacifiCorp should conduct a fully new RDF analysis that helps it forecast future wildfire and non-wildfire risk-related costs

for the full GRC period. The updated RDF analysis should, at a minimum, address all 10 of the RAMP elements adopted in the Voluntary Agreement in D.19-04-020.

52. PacifiCorp should not file annual Advice Letters to recover incremental wildfire related costs.

53. In all future GRC applications, PacifiCorp should (1) provide the historical spending and accrual data, including the aggregate historical data of the most recent depreciation study and additional data for any of the elapsed years between the study year and the GRC base year; and (2) provide detailed documentation to support the timing of and costs of its retirement plans for all coal facilities serving California customers consistent with its most recent IRP.

Conclusions of Law

1. Applicants for rate increases are required to establish their requests are just and reasonable by the preponderance of the evidence. PacifiCorp bears the burden of establishing that its requests are just and reasonable pursuant to Pub. Util. Code § 451.

2. Pub. Util. Code § 454.8 requires, in part, "the commission shall consider a method for the recovery of these costs which would be constant in real economic terms over the life of the facilities, so that ratepayers in a given year will not pay for the benefits received in other years."

3. PacifiCorp's continued use of the ECAC should be authorized.

4. The PTAM for use in 2024 and 2025 should be authorized. The PTAM for use in 2024 should only be related to capital costs, not the inflation adjustment, as described in Section 5.2 above.

5. The PTAM factor may continue to be filed on October 15, as a Tier 2 AL, with rates effective January 1 of the year following approval of PacifiCorp's request.

6. PacifiCorp should be authorized to continue to use the PTAM for 2023 and 2024 Major Capital Additions, so long as the requested costs are based on California's allocation and on actual cost data and in-service dates.

7. The PTAM for Major Capital Additions may continue to be filed on October 15 as a Tier 2 AL, with rates effective January 1, for 2025.

8. The PTAM Tier 2 AL for Major Capital Additions in 2023 may be filed as soon as reasonably feasible with rates effective within 30 days thereafter.

9. We should approve use of the 2020 Protocol and the JAM proposed by PacifiCorp, as it was uncontested in this proceeding.

10. The proposed capital structure should be adopted.

11. We should authorize a return on equity of 10 percent.

12. We should approve accelerated depreciation for PacifiCorp's coal burning plants.

13. We should defer to the IRP proceeding to consider the best mix of generation resources for PacifiCorp.

14. Expenditures outside of PacifiCorp's application which are already in rate base are not properly before us; we will not engage in a retroactive review.

15. We should defer to D.19-04-020 in A.15-05-002 which approved a voluntary agreement between the Commission's Safety Enforcement Division and the SMJU, including PacifiCorp. The agreement provides a framework for the risk-based decision-making components of PacifiCorp's next GRC filing.

16. The following elements of PacifiCorp's revenue requirement are not contested, except accelerated amortization of its Cholla Unit 4 coal unit, and should be approved:

- Methodologies for computing and forecasting taxes;
- Cash working capital calculations; and
- Labor (based on actual contracts and budgeting) and Nonlabor (based on Global Insight indices) escalation.

17. PacifiCorp's revised proposals for rate spread and rate design are appropriate and should be approved.

18. PacifiCorp should develop new RDF analyses for each GRC going forward that include updated analyses of its risks and proposed mitigation measures.

19. We should review PacifiCorp's investments in wildfire mitigation strategies as necessary in its GRC applications going forward.

20. PacifiCorp should recover the costs associated with accelerated depreciation of its coal-fired power units over three years, given the policy requirements necessitating the accelerated decommissioning of those assets.

21. PacifiCorp should spread the amortization costs associated with the accelerated closure of its Cholla Unit 4 coal-fired power unit over eight years, to decrease the rate impacts to California customers.

22. Costs associated with the Foote Creek II-IV Project upgrades should not be recovered until the upgraded turbines are in service.

23. PacifiCorp should request recovery of the $1.125 million in capital costs for the turbine upgrades at the Foote Creek II-IV facilities after the new turbines are fully operational.

24. PacifiCorp's cost of service and proposed rate allocation is reasonable.

25. PacifiCorp's proposal to equally spread the rate impacts of its requests across customer classes reduces the otherwise unreasonable increase to agricultural customers in its California service territory and should be adopted.

26. PacifiCorp's proposed TOU time periods for Schedule DT, Schedule AT-29, and Schedules AT-47 and AT-48 align with the on-peak hours adopted in other California IOU ratecases and should be adopted.

27. PacifiCorp's proposal to provide all agricultural pumping service customers optional TOU rates is reasonable and should be adopted to reduce complexity of service for customers that span the Oregon and California border.

28. PacifiCorp's proposed changes to its street and area lighting schedules should be adopted to incentivize the company to convert older lamps to new LED technology while still providing an incentive for customer-paid conversion to LED lamps.

29. PacifiCorp's proposed paperless bill credit should be adopted to incentivize customers to adopt less resource-intensive methods to receive their monthly statements, and the cost of the credit is in line with the costs PacifiCorp pays to process and send paper bills to individual customers.

30. PacifiCorp's proposed increase to its temporary service installation charge should be adopted to reflect the current rate for one hour of journeyman work.

31. PacifiCorp's housekeeping items should be adopted to clarify existing requirements for Schedule 300, provide a consistent primary metering discount across its general service customer schedules, and remove outdated references to pre-2005 Daylight Savings Time hours.

32. PacifiCorp's proposed increase to its CARE Credit should be adopted to mitigate some of the rate impacts associated with this GRC for its CARE-eligible customers.

33. In its next GRC application, PacifiCorp should conduct a fully new RDF analysis that helps it forecast future wildfire and non-wildfire risk-related costs for the full GRC period. The updated RDF analysis should, at a minimum, address all 10 of the RAMP elements adopted in the Voluntary Agreement in D.19-04-020.

34. PacifiCorp should not file annual ALs to recover incremental wildfire related costs.

35. In its next GRC application, PacifiCorp should provide an updated RDF analysis that thoroughly addresses the 10 RAMP requirements established in D.19-04-020.

36. In its next GRC application, PacifiCorp should produce the historical spending and accrual data, including the aggregate historical data of the most recent depreciation study and additional data for any of the elapsed years between the study year and the GRC base year.

37. In its next GRC application, PacifiCorp should provide detailed documentation to support the timing of and costs of its retirement plans for all coal facilities serving California customers consistent with its most recent IRP.

38. In its next GRC applications, PacifiCorp should (1) provide the historical spending and accrual data, including the aggregate historical data of the most recent depreciation study and additional data for any of the elapsed years between the study year and the GRC base year; and (2) provide detailed documentation to support the timing of and costs of its retirement plans for all coal facilities serving California customers consistent with its most recent IRP.

O R D E R

IT IS ORDERED that:

1. Application 22-05-006 is granted to the extent set forth in this Decision. PacifiCorp, doing business as Pacific Power (PacifiCorp), is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the base revenue requirement of $101,288,005, effective upon PacifiCorp's filing of a Tier 1 Advice Letter implementing this Decision.

2. PacifiCorp, doing business as Pacific Power (PacifiCorp), shall file a Tier 1 Advice Letter within 30 days of issuance of this decision to implement the revenue requirement and ratemaking adopted herein. The revenue requirement and revised tariff sheets will be effective as of the date of PacifiCorp's Tier 1 Advice Letter implementing this Decision.

3. PacifiCorp, doing business as Pacific Power, is authorized to implement an overall rate of return of 7.34 percent.

4. PacifiCorp, doing business as Pacific Power, may continue the use of the Energy Cost Adjustment Clause and Post-Test Year Adjustment Mechanism for the years 2023-2025.

5. PacifiCorp, doing business as Pacific Power, shall remove $1.125 million in capital addition costs associated with its Foote Creek II-IV wind power facilities from the revenue requirement when filing the Tier 1 Advice Letter implementing the cost recovery authorized in this decision.

6. PacifiCorp, doing business as Pacific Power, shall utilize the depreciable lives of the following coal-fired units consistent with its 2021 Integrated Resource Plan:

   - Colstrip Units 3 and 4 (decreased from 2027 to 2025)
   - Craig Unit 2 (increased from 2026 to 2028)

- Hyden Unit 1 (decreased from 2030 to 2028)
- Hyden Unit 2 (decreased from 2030 to 2027)
- Naughton Units 1 and 2 (decreased from 2029 to 2025).

7. PacifiCorp, doing business as Pacific Power, shall recover $1,218,447 annually to recover the costs associated with the coal-fired units described in Ordering Paragraph 7 above.

8. PacifiCorp, doing business as Pacific Power, shall recover $643,726 in costs associated with its Cholla Unit 4 coal-fired unit annually for eight years.

9. PacifiCorp, doing business as Pacific Power, shall implement an equal percentage rate spread across all customer classes when implementing the increase in rates approved in this decision.

10. PacifiCorp, doing business as Pacific Power, is authorized to implement the new, optional, time-of-use residential Schedule DT.

11. PacifiCorp, doing business as Pacific Power, is authorized to provide new time-of-use rates for its general service, non-residential customers under Schedule AT-29, Schedule PA-20, and Schedules AT-47/48.

12. PacifiCorp, doing business as Pacific Power, is authorized to modify its street and area lighting tariffs to reflect the level of service rather than specific technology or lamp bulb type.

13. PacifiCorp, doing business as Pacific Power, is authorized to implement a Customer-Funded Conversion option for its street and area lighting tariffs that incentivizes customers to continue paying for upgrades to Light-Emitting Diode lamps. This option shall charge customers that upgrade their own lamps less for energy service than those that rely on Pacific Power to install the technology and bulb upgrades.

14. PacifiCorp, doing business as Pacific Power, shall transfer customers on Schedule LS-58 to Schedule LS-53 for energy-only service. Pacific Power shall provide at least 60 days' notice to affected customers and shall continue replacing the bulbs for the affected customers' lamps.

15. PacifiCorp, doing business as Pacific Power, is authorized to offer a paperless bill credit of $0.50 per month.

16. PacifiCorp, doing business as Pacific Power, is authorized to charge $167 for all temporary service installations, based on the current rate for one hour of journeyman time.

17. PacifiCorp, doing business as Pacific Power, is authorized to correct inaccurate references in its Schedule 300 tariff sheet and add back the inadvertently deleted charges for field visits and unauthorized reconnections.

18. PacifiCorp, doing business as Pacific Power, is authorized to add a primary metering discount to Schedule A-25 that aligns with the primary metering discount available to other general service customer schedules.

19. PacifiCorp, doing business as Pacific Power, is authorized to remove references to prior-2005 Daylight Savings Time hours from its tariffs.

20. PacifiCorp, doing business as Pacific Power, is authorized to increase its California Alternative Rates for Energy discount from 20 percent to 25 percent during this general rate case cycle.

21. In its next General Rate Case Application, PacifiCorp, doing business as Pacific Power, shall provide the results of a new Risk-Based Decision-Making Framework analysis that addresses each of the 10 Risk Assessment Mitigation Phase elements defined in the Voluntary Agreement adopted in Decision 19-04-020.

22. In its next General Rate Case (GRC) Application, PacifiCorp, doing business as Pacific Power, shall include forecasts of the specific, annual costs associated with its wildfire mitigation plans for each year of the GRC period.

23. In its next General Rate Case (GRC) Application, PacifiCorp, doing business as Pacific Power, shall provide historical spending and accrual data, including the aggregate historical data of the most recent depreciation study and additional data for any elapsed years between the study year and the GRC base year.

24. In its next General Rate Case Application, PacifiCorp, doing business as Pacific Power, shall provide detailed documentation to support the timing and costs of its retirement plans for all coal facilities serving California customers.

25. Application 22-05-006 remains open to address Track 2 wildfire-mitigation-related cost issues defined in the Amended Scoping Memo and Ruling issued on October 5, 2023.

This order is effective today.

Dated ______________________________, at San Francisco, California.