Decision 19-08-027 August 15, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Golden State Water Company, on Behalf of its Bear Valley Electric Service Division (U913E), for Approval and Recovery of Costs, and Authority to Increase Rates and Other Charges, (Including a Requested Total Operating Revenue Requirement of $37,240,204 (decrease of 4.4%) for TY2018 and $38,969,869, $41,309,234, and $43,593,202 (Increases of 4.6%, 6.0% and 5.5%) for TY 2019, 2020 and 2021, Respectively) Related to Electric Service by Its Bear Valley Electric Service Division.	Application 17-05-004

DECISION RESOLVING 2018 GENERAL RATE CASE APPLICATION FOR GOLDEN STATE WATER COMPANY, ON BEHALF OF ITS BEAR VALLEY ELECTRIC SERVICE DIVISION

TABLE OF CONTENTS

Title **Page**

DECISION RESOLVING 2018 GENERAL RATE CASE APPLICATION FOR GOLDEN STATE WATER COMPANY, ON BEHALF OF ITS 2018 BEAR VALLEY ELECTRIC SERVICE DIVISION

Summary

We hereby approve the Settlement Agreement (Appendix A of this decision) which resolves all issues in the 2018 General Rate Case Application of Golden State Water Company filed on behalf of its Bear Valley Electric Service Division (GSWC/BVES). The Settlement Agreement covers the entire scope of the proceeding including base rate revenue requirements for 2018 through 2022, marginal cost, revenue allocation, rate design treatment, and approval of specified projects. The Settlement Agreement provides for: (a) a decrease in retail utility rates for the 2018 Test Year to reflect a reduction in adopted revenue requirements by $ 2.075 million or 5.7%, and (b) annual increases in post-test-year revenue requirements by approximately 3.55%, 3.43%, 3.04%, and 2.68% for 2019-2022, respectively.

We conclude that the Settlement is: (a) reasonable in light of the whole record, (b) consistent with the law, and (c) in the public interest. The Settlement Agreement is supported by all parties to the proceeding, except for Snow Summit, Inc. We have considered the limited objections relating to revenue allocation raised by Snow Summit, Inc. but find them unpersuasive. Accordingly, we reject Snow Summit's proposal to adopt a revenue allocation methodology inconsistent with the Settlement Agreement.

Since we issue this decision subsequent to the 2018 Test Year period, the adopted retail rate adjustments must account for the time passage since January 1, 2018 to make ratepayers neutral as to such timing effects of rate change implementation. To neutralize the impacts on recovery of adopted revenue requirements due to this time passage, we previously approved a

General Rate Case Revenue Requirement Memorandum Account in Decision (D.) 17-11-008, as discussed below. The cumulative balance accrued in this Memorandum Account shall be transferred to the Base Revenue Requirement Balancing Account and amortized in accordance with the tariff provisions.

The revenue requirement changes adopted herein provide the funds for GSWC/BVES to operate its electric distribution system at reasonable rates pursuant to Public Utilities Code Section 451, to take all actions "...necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." We therefore direct GSWC/BVES to implement the terms of the Settlement Agreement, as authorized in the ordering paragraphs below.

Finally, this decision adopts specific maintenance, safety and reliability programs for the BVES Division to be included in the annual Risk Spending Accountability Report (RSAR) pursuant to D.19-04-020. The utility is required to file the RSAR annually as an information-only advice letter with the Energy Division's Tariff Unit.

This proceeding is closed.

1. Description of BVES District Operations

Bear Valley Electric Service District (Bear Valley or BVES) is a wholly owned subsidiary of American States Water Company, and which is operated through another subsidiary, Golden State Water Company (GSWC). BVES provides retail electric service to the Big Bear Lake resort area in the San Bernardino Mountains. The BVES service territory is a resort community, consisting of approximately 24,000 customers, of which 22,500 are residential customers and approximately 1,500 are commercial, industrial, or public authority customers.

BVES is a winter-peaking electric utility and serves two ski resorts. The BVES system consists of one 8.4 megawatt (MW) natural gas generation plant, 575 miles of overhead and 91 miles of underground conductors, and 13 substations. BVES's generation plant began commercial operation in 2005 and is located at its main office in Big Bear Lake. BVES's distribution facilities are located within the control area operated by the California Independent System Operator (CAISO), but are not directly interconnected with the CAISO-controlled high-voltage transmission grid. The BVES distribution system connects to the CAISO grid through transmission and distribution facilities owned, controlled, and operated by Southern California Edison Company (SCE).

The rates for BVES customers include three main components: the base revenue requirement, the supply costs revenue requirement and surcharges. The first two categories comprise the cost of providing electric service which are reviewed in the General Rate Case (GRC). The third category includes additional costs not generally part of the utility's annual operating costs. These costs are recovered through the base revenue requirement balancing account charge, the supply adjustment charge, and the public purpose program charge. Of these three, only the public purpose program rate is established in the GRC. Therefore, this GRC decision establishes the costs and rates related to base costs, supply costs and the public purpose program.

2. Procedural Background

On May 1, 2017, BVES filed its GRC Application (A.) 17-05-004 (or Application), for approval and recovery of specified costs, and authority to revise rates and other charges for electric service to take effect on or before January 1, 2018. The application was filed pursuant to California Public Utilities Code Sections 381, 451, 454, and 701, Rules 2.1, 2.2 and 3.2 of the Commission's

Rules of Practice and Procedure, in compliance Commission's prior directives as discussed below.[1]

In Decision (D.) 14-11-002, the Commission directed BVES to file its next GRC application for a 2017 Test Year prior to January 31, 2016, with cost allocation and rate design components to be submitted by March 1, 2016. On December 2, 2015, BVES filed a Petition to Modify D.14-11-002 to, among other things, extend the mandated filing date for its next GRC. In D.16-02-021, the Commission granted BVES leave to file its next GRC by March 31, 2017 and its cost allocation and rate design components by May 1, 2017. By letter dated March 13, 2017, BVES again sought to defer its GRC filing to May 1, 2017, and its cost allocation/rate design component to May 15, 2017. The Commission granted the request. BVES timely filed its GRC application pursuant to that schedule.

On June 2, 2017, the Commission's Office of Ratepayer Advocates (ORA)[2] protested the Application. On June 5, 2017, Snow Summit, Inc. (a ski resort operator and BVES customer) also filed a protest. City of Big Bear Lake (City), and Big Bear Area Regional Wastewater Agency (BBARWA) filed motions for party status. City and its residents, and BBARWA receive electric service from BVES, and both raised issues regarding the application and sought to participate in the proceeding.

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[1] Unless otherwise noted, subsequent section references pertain to the California Public Utilities Code and all rules sections pertain to the Commission's Rules of Practice and Procedure.

[2] The Office of Ratepayer Advocates was renamed the Public Advocates Office of the Public Utilities Commission pursuant to Senate Bill No. 854, signed by the Governor on June 27, 2018 (Chapter 51, Statutes of 2018). During the bulk of this proceeding all references were made to the Office of Ratepayer Advocates or "ORA." Accordingly, for purposes of this decision, the term "ORA" shall be used a reference to the Public Advocates Office.

A prehearing conference (PHC) was held on July 24, 2017 before Administrative Law Judge (ALJ) Adeniyi Ayoade. Motions for party status by the City and BBARWA were orally granted at the PHC and are confirmed herein. The assigned Commissioner's Ruling and Scoping Memo (Scoping Memo) issued August 25, 2017. The Scoping Memo set evidentiary hearings (EH) for December 4-6, 2017.

Because the adopted schedule would preclude a final Commission decision by the start of the 2018 Test Year period, BVES filed a motion on September 8, 2017 (Motion), to establish a GRC Revenue Requirement Memorandum Account (GRC Memo Account) to track the change in revenue requirement to be adopted in this GRC effective from January 1, 2018 until implementation of the final Commission decision. BVES also requested authority to accrue interest at the Federal Reserve three-month commercial paper rate. By D.17-11-008, the Commission granted the Motion.

On November 28, 2017, the ALJ postponed the EH dates in order to have a public participation hearing prior to the EH. On December 5, 2017, the Commission reset the EH for January 11 – 12, 2018. On January 3, 2018, BVES moved to reschedule the EH due to unavailability of its key witness. On January 10, 2018, the ALJ granted the request, resetting the EH for February 26-27, 2018. On January 26, 2018, ORA and BVES jointly requested EH rescheduling to allow time for update testimony to reflect changes due to federal tax legislation (the Tax Cuts and Jobs Act of 2017 (TCJA)). On February 4, 2018, by e-mail to the ALJ (copied to the service list), ORA and Applicant reported that all parties agreed to continue the EH dates. Accordingly, a final schedule required that BVES submit Supplemental Testimony on April 9, 2018 to update for the impacts of the TCJA. ORA served updated Results of Operations testimony on May 11, 2018. BVES served reply testimony on May 24, 2018.

An EH was held on May 30, 2018. ORA engaged in no cross-examination of BVES witnesses. Snow Summit and the City/BBARWA cross-examination was generally limited to cost allocation and Applicant's pole loading and tree attachment removal programs.

During the EH, ORA moved to update its testimony in consideration of BVES Supplemental Testimony. ALJ Ayoade granted the motion. The update was filed by June 8, 2018. Snow Summit submitted updated testimony by June 12, 2018. BVES submitted comments to the updates on June 15, 2018.

On or about June 22, 2018, ORA and Snow Summit filed a Motion to Enter a Stipulation into the Record to resolve disputes related to depreciation, cost of capital, and certain non-revenue issues.

Opening briefs were filed June 25, 2018, and reply briefs were filed July 9, 2018.

Following subsequent actions regarding execution of the Settlement Agreement, as discussed below, the case was submitted on April 25, 2019.

3. Procedural Events Regarding the Settlement Agreement

In accordance with Rule 12.1(b), a settlement conference was noticed on November 7, 2018. The settlement conference was held on November 16, 2018. Additional settlement discussions occurred thereafter.

On November 28, 2018, ORA and BVES filed a "Joint Motion for Approval and Adoption of a Settlement Agreement" resolving all issues between the two parties. BBARWA and the City needed their boards' approvals to sign on to the Settlement. Although the City and BBARWA were not signatories to the Settlement Agreement when the November 28 Joint Motion was filed, a statement was authorized by counsel for the City and BBARWA to be included in the November 28 Joint Motion, as follows:

> Staff from the City and BBARWA cannot bind their elected decision-making bodies but they have reviewed the material terms of the proposed settlement agreement and staff will recommend signing the agreement at the next regularly scheduled Board and Council meetings.

The November 28 Joint Motion also included the following statement:

> In the event the City and/or BBARWA authorize the execution of the Settlement, the Settling Parties were to file a motion requesting an amended Settlement, including the City and/or BBARWA as signatories, be approved by the Commission.

On December 5, 2018, the BBARWA Board of Directors approved adoption and execution of the Settlement Agreement. On January 28, 2019, the City Council for the City did the same. An amendment to the Settlement Agreement (Amendment) was prepared and executed by each of the Settling Parties. The Amendment modified the Settlement Agreement to define "Settling Parties" as BVES, ORA, the City and BBARWA. The Amendment also provided that, except for the Amendment, no other provision of the Settlement Agreement is modified, and its terms and conditions apply to all Settling Parties.

Snow Summit filed an opposition to the Settlement Agreement on December 28, 2018. The Settling Parties filed a reply on January 14, 2019.

On February 5, 2019, the Amended Settlement Agreement was filed, signed by all parties, except Snow Summit, for approval consistent with

Rule 12.1(d). The Settling Parties requested Commission approval of the Amended Settlement Agreement, without modification.

By e-mail ruling on March 29, 2019, the ALJ called for additional information relating to the Settlement Agreement as follows:

a. Identification of operation/maintenance and capital programs covering safety, reliability or maintenance requirements;

b. Authorized amount of each identified program; and

c. Formula to calculate attrition year budgets for these programs.

The ALJ also ordered Settling Parties to confirm that the correct rate of return figures were used in calculating the results of operation (RO), together with active links to the revenue requirements derived in the Settlement Agreement. Settling Parties responded to the ALJ ruling on April 25, 2019.

4. Review of the Settlement Agreement

The Settlement Agreement resolves all disputes among Settling Parties in this proceeding, including revenue requirements for 2018-2022, marginal cost, revenue allocation and rate design treatment of certain accounts, and approval of certain special projects. Snow Summit's objections to the Settlement are addressed later in this decision. Except for the limited objections of Snow Summit, no other party opposed the Settlement Agreement.

We summarize the major issues resolved in the Settlement below, comparing parties' original positions to the Settlement amount. Since the record evidence and arguments are voluminous, we focus on the settled results. However, that does not mean that we have overlooked individual issues raised by parties. We have reviewed the evidence and considered arguments raised in evaluating and adopting the Settlement as discussed below.

4.1. 2018 Base Revenue Requirements (Sections 5.1.3) [3]

In its Application, Bear Valley originally proposed a Test Year 2018 Rate Revenue Requirement amount of $25,927,926, compared to ORA's initial recommendation of $22,045,878. In response to the passage of the TCJA, the Settling Parties ultimately agreed on a Test Year 2018 Base Revenue Requirement request of $22,500,000. This total results from the cumulative effects of individual accounts and cost categories for which the Settling Parties reached agreement, as discussed below. The Base Revenue Requirement excludes the cost of energy supply, a subset of which are the costs to operate the BVES power plant. The cost of energy supply is a pass-through expense item to retail customers. The Base Revenue Requirement also excludes costs of the Public Purpose Program and other miscellaneous charges.

The adopted total revenue requirement for 2018 results in a $2.075 million reduction from 2017. From 2017 to 2018, the base revenue requirement increases from $20.9 million to $22.5 million, the supply costs revenue requirement (recovered from the Supply and Transmission Charges) decreases from $14.849 million to $11.312 million, and the public purpose program revenue requirement decreases from $0.847 million to $0.709 million.

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[3] The section number shown parenthetically after each of the subheading items herein references the applicable portion of the Settlement Agreement at issue.

4.2. Summary of Earnings (Section 5.1.5)

The Settlement Agreement (in Table 4 thereof) presents a "Summary of Earnings" for Test Year 2018, comparing the pre-settlement positions of Applicant and ORA with the figures agreed to in the Settlement Agreement.[4]

That table sets forth the derivation of revenue requirements to fund operating and maintenance (O&M) expenses, and to finance capital-related expenditures to serve customers. The figures in the table reflect the costs or methodologies found reasonable as inputs to the results of operations model used to calculate the revenue requirements.

The resulting Summary of Earnings in Settlement Agreement incorporates a Base Revenue Requirement of $22.5 million, a Rate Base of $47.227 million, and a weighted-average cost of capital/rate of return of 8.31% as follows:[5]

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[4] In response to the ALJ ruling dated April 25, 2019, Settling Parties provided an Excel workbook entitled "BVES 2018 TY GRC RO Model GRC Settlement 040419." The Test Year 2018 base revenue amounts and other items agreed to by the Settling Parties were provided in "Tab 7 Summary of Earnings SOE" of the Excel workbook. Plant additions were provided in "Tab #RB2 Plant Additions 10-21."

[5] Table 4 of the Settlement adds "Supply Cost Revenues" and "Public Purpose Program" costs to "Base Rate Revenues" to arrive at total revenue requirements figure as follows:

- Base Rate Revenues $22,500,000
- Supply Cost Revenues $11,312,278
- Public Purpose Programs $709,036
- Total Revenue Requirements $34,521,314

Total Operating Revenue	**$22,500.**
Operating Expense	$4,266.
Maintenance Expense	$1,166.
Administrative & General Expense	$8,725.
Depreciation & Amortization	$2,300.
Tax not on Income	$1,142.
Net Operating Revenue Before Income Tax	$4,901.
Income Taxes	$977.
Net operating Revenue	$3,925.
Rate Base	$47,227.
Rate or Return on Rate Base	8.31%

4.3. Post-Test Year Revenue Requirements (for 2019-2021) (Section 5.2)

For the years 2019 through 2021, after accounting for the TCJA, Applicant originally sought approval of base revenue requirements of $26,271,700, $28,144,532, and $29,880,027 respectively, net of Public Purpose Program or Supply Cost revenues. These amounts represent increases of $1,501,325, $1,872,832 and $1,735,495 for the years 2019, 2020, and 2021. ORA's TCJA-adjusted recommendation resulted in annual year-over-year increases in Base Revenue Requirement of $373,078, $485,292, and $453,283 for the years 2019, 2020, and 2021.

The Settling Parties did not use an explicit numerical formula to calculate the post-test-year base revenue requirements for individual projects or programs. Rather they negotiated overall increases in base revenue requirements for each year beyond 2018 to cover expected increases for operation and maintenance and/or rate base costs. The Settling Parties reached agreement on increases in base revenue requirements for 2019 -2022 of $1,200,000 in 2019, $1,200,000 in 2020, and $1,100,000 in 2021.

4.4. GRC Rate Cycle Extension to 2022 (Section 5.3)

In its Application, Bear Valley proposed a four-year GRC rate cycle (2018 to 2021). Bear Valley also proposed several capital addition programs to be completed over the 2018-2021 GRC cycle, including wildfire safety-related programs. No party opposed the proposed wildfire safety-related programs. However, to reduce costs, ORA, the City and BBARWA each recommended that two of the larger four-year capital programs (which were wildfire safety-related) be extended beyond the 2018-2021 rate-cycle period. In addition to the cost concerns regarding the safety-related projects, ORA asserted that some of the four-year programs could not be completed within a four-year rate cycle (2018-2021) anticipating that a final decision in this proceeding would not be issued by the beginning of 2018.

In an effort to address cost and timing concerns, the Settling Parties propose an extension of the GRC rate cycle, and all associated capital additions programs, by one year. The resulting GRC rate cycle covers five years (2018-2022). Settling Parties further propose an increase in the 2022 base revenue requirement by $1,000,000 for a total of $27,000,000 for 2022.

4.5. Composite Depreciation Rate (Section 5.4.1)

A public utility recovers the original cost of plant and equipment over the course of its useful life by means of annual depreciation expense. As a basis for computing depreciation, Bear Valley applies mortality characteristics (*e.g.*, service lives, retirement dispersions, etc.) to produce straight-line remaining life depreciation rates. Bear Valley tracks expenses and investments in its facilities using Federal Energy Regulatory Commission accounts described as "transmission." While transmission is generally defined as lines with capacity of 115 kilovolts (kV) and above, Bear Valley from its inception has applied that term to its 34.5 kV primary distribution backbone system.

For the 2018 Test Year, Bear Valley originally proposed a 2.88% composite depreciation rate. ORA supported a lower composite depreciation rate of 1.87%. ORA's recommendation was based upon asset service lives of larger investor-owned utilities (IOUs). BVES disputed the validity of such comparisons given BVES' relative size to the larger IOUs.

The Settling Parties agree that BVES should apply a 2.3% composite depreciation rate for this GRC cycle, and submit a new depreciation study in its next GRC filing.

4.5.1. Accounting for Depreciation Expense

Bear Valley proposed to change its accounting practices to adopt a mid-year convention for calculating depreciation expense of new plant. ORA recommended that the Commission approve this proposal. The Settling Parties agree that BVES should implement the mid-year convention for calculating depreciation.

4.6. Rate of Return on Rate Base (Section 5.5)

The parties originally proposed conflicting proposals for the weighted cost of capital/rate of return on rate base. Each of the supporting components as originally proposed by the parties, together with the Settlement results, are discussed below.

4.6.1. Capital Structure

Bear Valley originally proposed a capital structure of 57% equity/43% debt for calculating its rate of return. ORA originally proposed a 54.13%

equity/45.87% debt capital structure. The Settling Parties agree to a capital structure of 57% equity/43% debt, consistent with what was adopted for GSWC in D.18-03-035 for calendar years 2018-2020.[6]

4.6.2. Debt Cost

Bear Valley proposed a debt cost of 6.60% in calculating the adopted rate of return whereas ORA proposed 6.40%. The Settling Parties agree to a debt cost of 6.60%. The 6.60% figure agrees with the debt cost adopted for GSWC in D.18-03-035 for the calendar years 2018-2020.

4.6.3. Return on Equity

Bear Valley originally sought approval of an adopted return on equity of 11.00%. ORA originally proposed a return on equity of 9.45%. After taking into account the effects of the TCJA that reduced federal corporate taxes, the Settling Parties request that the Commission adopt a return on equity of 9.60%.

4.6.4. Weighted-Average Cost of Capital/Rate of Return on Rate Base

The following table presents the weighted-average cost of capital/rate of return on rate base of 8.31% as proposed in the Settlement. The weighted figures shown incorporate Settling Parties' agreed-upon capital structure, cost of debt, and return on equity, as discussed above:

[6] D.18-03-035 adopted the ratemaking capital structures, costs of equity, costs of debt and overall rates of return for a three-year period (2018-2020) for four applicants, including GSWC, the operator of BVES. Settling Parties' references to D.18-03-005 as a basis for debt cost and capital structure is an apparent technical error.

Capital Element	Capital Structure	Cost Factor	Weighted Cost of Capital
Debt	43%	6.60%	2.84%
Equity	57%	9.60%	5.47%
Total Return	100%		8.31%

4.7. Rate Base Value (Section 5.6)

The rate base includes the fixed assets constructed or acquired to provide utility services to its customers. BVES originally forecasted a 2018 rate base value of $46,998,584, which was prior to the passage of the TCJA. BVES forecasted a TCJA-adjusted 2018 rate base value at $47,227,227. ORA originally recommended a value of $44,129,914, and revised that figure to $43,348,053 after passage of the TCJA.

The differences in rate base values are attributable to parties' differing assumptions regarding capital expenditures for plant, depreciation reserve, materials and supplies, and working cash. The Settling Parties agree to a 2018, TCJA-adjusted rate base value of $47,227,227, on a weighted-average basis, as detailed below:

Cost Element	**$000s**
Plant in Service	$ 102,326
Construction Work in Progress	421
Depreciation Reserve	(45,285)
Materials & Supplies	699
Other Adjustments	(1,593)
Deferred Income Taxes	(12,686)
Working Cash	509
Common	2,836
Total Rate Base Value	**$ 47,227**

The rate base value of $47,227,227 as shown corresponds to Settling Parties' position on capital expenditures detailed below.

4.8. Capital Projects Funded by Base Revenue Requirements (Section 6)

The plant component of rate base includes separate amounts for production, transmission, distribution, and common plant functions. In its Application and testimony, BVES claimed the need for certain plant and blanket plant projects to be funded by base rate revenues. BVES identified a number of specific capital projects and blanket capital project to enhance safety and/or improve reliability. [7]

To mitigate and reduce the safety risk of pole failures, BVES proposes to substantially accelerate its pole loading assessment and remediation activities beyond its ongoing General Orders (GOs) 95 and 165 compliance requirements.

[7] *See* Exhibit BVES-1, Chapter 9, Part B. In its supplement filing dated April 25, 2019, the Settling Parties provided additional information identifying the specific projects intended to enhance safety and/or improve reliability, including upgrades of the 30-year old Palomino Substation and of the natural gas-fired Bear Valley Power Plant.

There are approximately 8,000 wood poles in the BVES service area that have not undergone any pole loading assessments.

ORA did not dispute the necessity of the proposed capital projects but objected to their costs. The City and BBARWA did not dispute the necessity of the Tree Attachment Removal Program and the Pole Loading Assessment and Remediation Project, but objected to their costs.

Except for two Major Plant Additions discussed below, the Settling Parties agree that BVES should be authorized to construct the plant projects and blanket plant projects set forth in its Application using agreed-upon base revenue amounts (Settlement Agreement, Sections 5.1 through 5.3). To recover the costs of two four-year capital programs, discussed below, and the blanket capital projects, Settling Parties propose they be amortized over a five-year GRC cycle.

4.9. Capital Projects/Costs Not Funded by Base Revenue Requirements (Section 7)

In its Application and related testimony, BVES included the Pineknot Substation Project and Grid Automation Project in its capital additions budget and base revenue requests. BVES can enhance safety and the reliability of its distribution system by converting the Pineknot Substation from an overhead-type to an underground pad-mounted design. This change will eliminate a wiring configuration that is a potential safety issue. Replacement of substation equipment with enclosed pad mount transformers, voltage regulators, re-closers, and bus work will increase reliability and capacity.

The Grid Automation Project is also intended to improve the reliability and maintenance of BVES grid by the installation of remote real-time monitoring and control equipment.

ORA did not object to these two capital addition projects, but did not support the base revenue requirements requested to fund the two projects.

The Settling Parties agree to the exclusion of the Pineknot Substation Project and Grid Automation Project from GRC base rate revenue requirements funding. Settling Parties further agree that BVES be permitted to construct and/or implement the two projects as "Major Plant Additions" via separate Tier 1 Advice Letter filings. Through the Tier 1 Advice Letter filings, BVES may be allowed to recover up to $2,936,929 (in 2016 dollars), plus an allowance for funds used during construction (AFUDC) for the Pineknot Substation Project, and up to $3,881,689 (in 2016 dollars) plus AFUDC for the Grid Modernization Project. Bear Valley may use base rate revenues authorized in Sections 5.1 through 5.3 of the Settlement to recover costs over those estimates.

The advice letters should include the following information for each project. For the Pineknot Substation project, the advice letter should report the costs of any trenching, labor, supporting structures, and other activities and equipment necessary to place the project in service; the type of boring technology and cables, if used; and the cause and amount of any project cost overruns. For the Grid Modernization project, the advice letter should report information on any costs in relation to this project authorized by D.19-01-037 in Rulemaking 14-12-014 on reliable reporting pursuant to Public Utilities Code Section 2774.1. In addition, the advice letter should report the labor and material costs associated with the elements of this project.

4.10. Supply Adjustment Balancing Account (Section 5.8)

BVES originally claimed an October 31, 2016 cumulative over-collection balance in its Supply Adjustment Account of $5,446,284. ORA re-calculated the balance in the Supply Adjustment Account to correct data and formulae errors in the BVES calculations. ORA concluded that the October 31, 2016 balance in the Supply Adjustment Account should be $8,105,044. Based upon additional information BVES subsequently provided to ORA, the Settling Parties entered into a stipulation dated March 29, 2018 resolving Supply Adjustment Account issues.

In the stipulation, the Settling Parties agreed that the October 31, 2016 cumulative over-collection balance in the Supply Adjustment Account was $5,446,284 as of October 31, 2016 and $4,814,389 as of October 31, 2017. The Settling Parties further agreed in the stipulation that BVES should file an Advice Letter to replace the credit rate of $0.01582 per kilowatt hour with a new customer refund tariff (New Supply Adjustment Credit). This New Supply Adjustment Credit shall be calibrated to amortize the cumulative over-collection balance in the Supply Adjustment Balancing Account over 12 months.

The Settling Parties also agreed that when the cumulative over-collection balance in the Supply Cost Balancing Account is equal to or less than $200,000, BVES should promptly file a Tier 1 Advice Letter to (a) terminate the New Supply Adjustment Credit and (b) modify its Preliminary Statement to provide that if the cumulative balance in the Supply Adjustment Balancing Account is plus or minus $500,000, BVES should file a Tier 1 Advice Letter request to eliminate such balance over twelve months.

4.11. Special Request #1 – Snow Summit Supplemental Service (Section 8.1)

Bear Valley requested authority (as Special Request #1) to provide supplemental service to Snow Summit Ski Resort using the existing

A-5 Time-of-Use (TOU) Primary Tariff. The resulting net revenues are expected to generate approximately $1 million to the benefit of all ratepayers.

ORA did not object to Special Request #1, but requested that BVES file an Advice Letter if Snow Summit agreed. Snow Summit objected, claiming that use of the A-5 rate would result in Snow Summit subsidizing other ratepayers by $1 million dollars for years to come. Snow Summit claimed that the proposed changes to Rule 2H and associated Added Facilities Agreements were premature and could derail negotiations with BVES for supplemental service.

The Settling Parties agree that BVES may offer supplemental service to Snow Summit as provided in Special Request #1, and may file a Tier 1 Advice Letter if and when an agreement is reached. If an agreement between BVES and Snow Summit regarding supplemental service is materially different than the provisions of Special Request #1, such an agreement would be filed via a Tier 3 Advice Letter with a description of material changes.

4.12. Special Request #2 – Replace Snow Summit Substation (Section 8.2)

Bear Valley requested authority (as Special Request #2) to replace the existing Snow Summit Substation in the event the proposal under Special Request #1 to provide supplemental sales to Snow Summit has not been subject to a binding commitment with Snow Summit owners by December 1, 2020.

ORA did not object to Special Request #2. Snow Summit claimed that Special Request #2 was premature, that it was likely to come to an agreement with BVES, and that a more focused application for authority to replace Summit Substation could be filed later.

The Settling Parties agree that BVES should be authorized to replace the existing Snow Summit Substation, as provided in Special Request #2. The authorized costs for recovery of this project using a Tier 1 Advice Letter filing would be $999,773 in 2016 dollars, plus AFUDC.

The Settling Parties further agree that if this project's cost exceeds $999,773 in 2016 dollars, plus applicable AFUDC, BVES may use a portion of its capital additions budget authorized in Sections 5.1 through 5.3 of the Settlement to cover remaining costs to complete this project.

4.13. Special Request #3 -- Rule 20A Replacement of Overhead Lines with Underground Facilities (Section 8.3)

BVES proposed changes in Paragraph A of Rule 20 for undergrounding of facilities (as Special Request #3). ORA recommended denial of Bear Valley's proposal. Bear Valley agrees to withdraw Special Request #3.

4.14. Special Request #4 – Modification of Special Service Charges (Section 8.4)

BVES proposed (as Special Request # 4) to modify the late payment charge so that if a bill is unpaid for more than 30 days after the bill is rendered, a charge equal to 0.75% of the unpaid balance would be assessed. ORA requested it be denied, claiming it was unjustified. The Settling Parties agree to a late charge equal to 1% of the unpaid balance if a bill is unpaid for more than 45 days.

4.15. Special Request #5 – Modification of Street Lighting Service Tariff (Section 8.5)

BVES proposed changes in its street lighting service tariff (Special Request # 5). ORA did not object. The Settling Parties agree that BVES is authorized to implement the revised street lighting tariff.

4.16. Special Request #6 – Amortization of Fire Hazard Prevention Memorandum Account Costs (Section 8.6)

BVES proposed to recover $304,042 in the Fire Hazard Prevention Memorandum Account amortized over twelve months (as Special Request #6). ORA did not object.

The Settling Parties agree that BVES may implement a $0.00210/kilowatt-per-hour line item surcharge on all BVES customers to recover $304,042 in the Fire Hazard Prevention Memorandum Account.

4.17. Special Request # 7 – Cost Recovery of RPS Costs in Memorandum Account

As Special Request #7, BVES proposed recovery of $452,784 over a twelve-month period as a surcharge line item in the Renewable Portfolio Standard (RPS) Tariff, based upon the authorized applicable sales for the applicable time period. ORA raised no objection.

The Settling Parties agree that BVES may implement a 0.00322/kilowatt-per-hour line item surcharge on all BVES customers, based upon the calculations in Exhibit K of the Settlement Agreement. Settling Parties agree to: (a) implementation of this line item surcharge, if necessary, by Tier 1 Advice Letter filing, and (b) that the RPS Memorandum Account remain open.

4.18. Special Request # 8 – Termination and Removal of Memorandum Accounts from Preliminary Statement

In Special Request #8, BVES requested authority to terminate the Generation Facility Capital Related Memorandum Account, the Generation Facility Operation and Maintenance Account, the Industry Restructuring Memorandum Account and the Power Purchase Agreement Memorandum

Account, and remove such accounts from BVES' Preliminary Statements. ORA did not object.

The Settling Parties agree that BVES may terminate such accounts and remove them from Bear Valley's Preliminary Statements via a Tier 1 Advice Letter filing, if necessary.

4.19. Special Request #9 – Recovery of Energy Efficiency and Solar Initiative Program Costs (Section 8.9)

BVES requested authority to collect unrecovered costs in memorandum accounts for the Solar Initiative (SI) Program and the Energy Efficiency (EE) Program (as Special Request #9). ORA did not object. The Settling Parties agree that BVES be authorized to collect (i) $627,344 of unrecovered costs of the EE program at a rate of $156,836 annually, and (ii) $268,000 of unrecovered costs of the SI program at a rate of $67,000 annually as part of the PPP surcharge and implemented through a Tier 1 Advice Letter filing.

4.20. Long Run Marginal Cost Study (Section 9.1)

Bear Valley submitted a long run marginal cost (LRMC) study that developed marginal customer, energy and demand costs for each rate class or rate schedule. ORA reviewed Bear Valley's LRMC study and had no objection. Snow Summit objected to two issues in the LRMC study, resulting in Bear Valley agreeing to (i) use 46% of its transmission and distribution investment level rather than the 50% originally used, and (ii) not allocate coincident demand-driven costs among customer classes.

The Settling Parties agree to the results of Bear Valley's LRMC study results as set forth in Table 13 of the Settlement Agreement.

4.21. Revenue Allocation for Test Year 2018 (Section 9.2)

For Test Year 2018 revenue allocation purposes, BVES initially recommended the use of equal percentage marginal costs (EPMC)[8] with one modification applied to the proposed 2018 decrease in revenue requirement. The modification was that BVES proposed no change to the existing revenue allocation for the Permanent Residential customer class. For all other rate classes, including the Seasonal/Part-time Residential customer class, BVES originally recommended to allocate only the proposed decrease in the 2018 revenue requirement (net of allocation to the Permanent Residential class) on an EPMC-basis. Subsequently, BVES modified its recommendation such that the change in allocation for each customer class (other than the Permanent Residential customer class) would be proportional to the difference between the existing allocation and EPMC-based allocation.

ORA did not agree with Bear Valley's revenue allocation proposal but proposed a modified EPMC-based allocation method which provided all customer classes, including the Permanent Residential class, with a decreased revenue allocation. ORA's recommended revenue allocation was based on the average of an EPMC-based allocation and a system average percent (SAP) change allocation. ORA proposed to weight the two methods equally.

Snow Summit also objected to Bear Valley's revenue allocation proposal, arguing that Bear Valley should move substantially faster towards a full marginal-cost rate allocation. Snow Summit proposed that all customers (except

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[8] The EPMC method allocates revenues among customer classes based on a LRMC methodology, as follows: (1) the revenue allocation is calculated assuming customer rates were based entirely on LRMC, and then (2) the LRMC results are scaled so as to equal the adopted revenue requirement.

Permanent Residential) move toward EPMC by the same percentage in 2018 with a 2% increase in revenue allocation to Permanent Residential customers for 2018.

The City and BBARWA proposed that the allocation to the A-5 secondary customer class (BBARWA) be limited no more than 25% over EPMC.

The Settling Parties agree to allocate the decrease in Test Year 2018 revenues to every customer class (including the Permanent Residential customer class) compared to revenues at current rates. The percentage decrease in allocation for the Permanent Residential and Seasonal Residential customer classes will approximate the same percentage decrease for each customer class. The decrease for all remaining classes will be proportional to the difference between the existing allocation and the EPMC-based allocation. The applicable percentage decrease by customer class is depicted in Table 16 of the Settlement Agreement.

Snow Summit continues to disagree with the revenue allocation for Test Year 2018 proposed in the Settlement Agreement. We address the substantive basis for Snow Summit's objections and its own affirmative proposal outlined below.

4.22. Revenue Allocation for 2019-2021 (Section 9.3)

Bear Valley proposed that annual increases in the base rate revenue requirement for the remaining three years of the GRC cycle (2019-2021) be implemented on a SAP basis. Accordingly, the change in the annual revenue allocation, on a percentage basis, would vary by year, but with the same percentage change across all customer classes in a given year.

ORA agreed with Bear Valley's recommendation to implement the post-2018 revenue increases on a SAP basis. Snow Summit recommended that the revenue allocation in the years 2019-2021 be implemented in a manner that would continue the movement toward full EPMC allocation, with the intention of achieving a complete transition in seven years.

The Settling Parties agree that the annual increases for the years 2019-2021 will be implemented on a SAP basis. The resulting annual percentage changes by customer class and by year are depicted in Table 17 of the Settlement Agreement.

As previously noted, Snow Summit continues to disagree with the revenue allocation for 2019-2021 proposed in the Settlement Agreement. We address the substantive basis for Snow Summit's objections and its own affirmative proposal in Section 5 below.

4.23. Revenue Allocation for 2022 (Section 9.4)

The Settling Parties agree to an additional year (2022) for the current GRC cycle, and to an increase of the base revenue requirement, on a SAP basis, of $1 million for 2022. The agreed-upon revenue allocations to each customer class for the years 2019-2022 are set forth in Section 9.4 and Table 17 of the Settlement Agreement. We address the substantive basis for Snow Summit's objections to the 2022 revenue allocation proposal and its own affirmative proposal in Section 5 below.

4.24. 2018 Revenues and System Average Rates (Section 9.5)

Based upon the Settlement Agreement of: i) a modified EPMC cost allocation method; (ii) a 2018 revenue requirement of $34,521,314; and (iii) BVES sales, customer counts and miscellaneous revenue forecasts agreed to in the Settlement, the Settling Parties agree to the summary of 2018 revenues and system average rate change as set forth in Table 18 of the Settlement Agreement.

4.25. Post-Test-Year Adjustments of Retail Rates for 2019-2022 (Section 10)

Bear Valley originally requested post-test-year adjustments in retail rates for the years 2019 through 2021, after taking into account the effect of the TCJA, representing annual increases in the Base Revenue Requirement of $1,501,325, $1,872,832 and $1,735,495 for the years 2019, 2020, and 2021, respectively. Bear Valley characterized these requested base revenue requirements as being based upon a traditional revenue requirements approach, similar to that which was used to develop the Test Year 2018 base rate revenue requirement.

ORA did not provide updated recommendations for 2019-2021 Base Rate Revenue Requirements after the passage of the TCJA. However, in its original recommendation, ORA proposed annual increases for 2019-2021 based upon Global Insight forecast of changes in the Urban Consumer Price Index (CPI-U), with an offsetting productivity factor of 0.5%, resulting in annual increases of 1.8%, 2.3% and 2.1%, respectively.

The Settling Parties agree on base revenue requirements increases of $1,200,000 in 2019, $1,200,000 in 2020, $1,100,000 in 2021, and $1,000,000 in 2022. These dollar increases represent percentage increases in BVES' overall revenue requirements of approximately 3.55%, 3.43%, 3.04%, and 2.68% for 2019-2022, respectively.

Section 10 of the Settlement Agreement presents a table for 2019-2022 reflecting the agreed-upon retail rate adjustment methods. The Settling Parties propose that recovery of the additional revenue requirements for 2019-2022 for each customer class be achieved by adjusting energy rates for each customer class. The increased revenue requirement for each customer class will be divided by the adopted sales forecast for that class. That amount will be added to the existing volumetric rates for each customer class. For customer classes with multiple tiers, the energy rate will be added to each tier on an equal cents-per-kilowatt-hour basis. The Settling Parties further agree that Bear Valley may use the 2019-2021 base rate revenues (net of Public Purpose Program or Supply Cost revenues) for expenses, capital projects, or a combination of both.

4.26. Risk-Based Decision-Making Framework for GRCs (Section 11.2)

On December 4, 2014, pursuant to D.14-12-025, the Commission ordered that Bear Valley, along with the other small electric utilities, shall transition to including a risk-based decision-making framework into their GRC application filings beginning three years from the order issuance date. Since BVES filed its 2018 GRC application prior to December 4, 2017, it is not required to transition to a risk-based decision-making framework in this proceeding. BVES, however, voluntarily attempted to begin the transition to include a risk-based decision-making framework into its 2018 GRC application.

BVES set forth proposed risk scores for a risk-based decision-making framework in its Application. This process started with identifying the top risks to BVES. These top risks were: downed electrical wires, loss of import energy from SCE, sustained electrical outages, wildfire (public safety), electrical pole failure, wildfire (significant loss of property), line attached to fallen tree, catastrophic equipment failure, transformer oil spill, sustained outages affecting health, Bear Valley Power Plant failure, and aging structures. The next step was the development of risk-mitigation measures considered and risks to be mitigated. Based on its analysis, Bear Valley outlined a request for GRC funding of risk-mitigation measures including a description of how each request was predicted to reduce risk.

ORA recommended that in future filings, Bear Valley include an explanation of what risks changed after an initial calculation, and an explanation as to why any given risk score was changed during internal work sessions. ORA also recommended that in future GRCs, Bear Valley provide comparison of prior versus current risk scores, with explanation of changes.

The Settling Parties agree that in its next GRC, Bear Valley should compare the risk scores in this GRC to risk scores in its next GRC, identify risk scores that change, and explain why they changed. Bear Valley will not be required to provide a record of scores that changed as a result of internal working sessions.

We separately address the reporting requirements and deadlines imposed on Bear Valley pursuant to D.19-04-020 regarding its Risk Spending Accountability Report below in Section 7 of this decision.

4.27. Vegetation Management Costs in 2018 Rates (Section 11.4)

In D.17-12-024, the Commission adopted new regulations to enhance the fire safety of overhead electric power lines in high fire-threat areas. Those new regulations included increased minimum clearances around electric power lines in High-Fire Threat Districts (HFTD). BVES' service territory is a HFTD. D.17-12-024 authorized electric utilities to track the costs incurred to implement the new regulations in their Fire Hazard Prevention Memorandum Account (FHPMA) for purposes of cost recovery in a future GRC. As stated in Ordering Paragraph 9.i. of that decision: "Companies shall record in their FHPMA only those costs that are not being recovered elsewhere."

The Settling Parties agree that it is reasonable to establish the amount of vegetation management costs included in Bear Valley's revenue requirement to facilitate compliance with the D.17-12-024 directive to track incremental costs.

This was not a litigated issue. Bear Valley proposed vegetation management costs of $338,793 for Test Year 2018. The Settling Parties agree that amount is reasonable for the vegetation management costs to be included in the 2018 Base Revenue Requirement. Bear Valley will rely on the $338,793 figure to calculate incremental vegetation costs tracked in its FHPMA.

4.28. New Staff Positions (Section 11.6)

No party disputed the Bear Valley request for five reorganized positions. The Settling Parties agree that Bear Valley should be authorized to establish the following staff positions: 1) System Safety and Reliability Engineer; 2) Engineering Estimator; 3) IT Operations Support Specialist; 4) Substation Technician; and 5) GIS Specialist.

4.29. Next GRC Application Filed Prior to April 30, 2022 (Section 11.7)

Though not a litigated issue, the Settling Parties agree that (a) BVES should file its next GRC application, with a 2023 Test Year, prior to April 30, 2022; (b) the cost allocation and rate design components of the application be filed no later than six weeks after filing the application, and (c) the application include a four-year GRC cycle.

4.30. Pension Costs in 2018 Rates (Section 11.5)

In D.14-11-002, the Commission authorized BVES to establish the Pension Balancing Account (PBA) to track the difference between pension costs allocated to BVES and authorized in rates and the actual BVES pension costs based on Accounting Standard Codification 715-10 (ASC 715-10) Compensation – Retirement Benefits. The Settling Parties agree that it is reasonable to establish the amount of pension costs included in BVES' 2018 revenue requirement to facilitate tracking of incremental costs in the PBA.

The Settling Parties agree that BVES' proposed amount of $545,742 for Test Year 2018 is a reasonable authorized pension amount to be tracked in the PBA.

4.31. Refunding of Over-Collections in Base Revenue Requirement Balancing Account (BRRBA)

Bear Valley's Preliminary Statement provides that BVES is to address the disposition of the balance in the BRRBA at the close of each year in a Tier 2 Advice Letter if the under-collection or over- collection is equal to or greater than 5% of the revenue requirement for the previous twelve months. The Settling Parties agree that the disposition of any over-collection balance for 2018 and 2019 recorded in the BRRBA should be refunded in 2020 using the refund mechanisms set forth in the BRRBA.

4.32. Disposition of GRC Memo Account (Section 11.3)

In D.17-11-008, BVES was authorized to establish a GRC Memo Account. The GRC Memo Account tracks the revenue differential between the BVES base rates in effect as of December 31, 2017 and base rates to be adopted in this GRC proceeding. The disposition of the GRC Memo Account was not a litigated issue.

The Settling Parties agree that disposition of the GRC Memo Account should be implemented in conjunction with disposition of the balance in the BRRBA for 2018 and 2019. For disposition of the GRC Memo Account, its balance should be added to, or subtracted from, (as the case may be) the balance in the BRRBA and addressed by utilizing the existing BRRBA process to collect any shortfall (or refund any overcollection) in the GRC Memo Account. If the Settlement Agreement is approved, the Settling Parties agree that BVES be authorized to file a Tier 1 Advice Letter for an adjustment to the BRRBA as provided above.

The Settling Parties agree that (i) with the adjustment of the BRRBA revenue requirements for 2018 and 2019 of $22,500,000 and $23,700,000, respectively, and (ii) implementation of a surcharge or a credit in the event the 2018 and 2019 BRRBA revenue requirements create a shortfall or overcollection of revenues, the disposition of all amounts in the GRC Memo Account will have been achieved and the GRC Memo Account should be closed.

5. Snow Summit Opposition to the Settlement

Snow Summit opposes the Settlement Agreement regarding the treatment of revenue allocation and the related proposal to extend the GRC cycle by one year. Snow Summit does not object to any other provisions of the Settlement Agreement, but argues that the revenue allocation proposal and related proposal to extend the GRC cycle render the entire Settlement defective. Snow Summit argues that the Commission may reject a settlement if even one provision is inconsistent with Commission policy.[9]

Snow Summit argues that Settlement Agreement's provisions on revenue allocation are inconsistent with principles endorsed by the Commission for more than 30 years regarding use of marginal cost and EPMC to allocate revenue requirements. Snow Summit claims that the Settlement Agreement would make only minimal movement toward EPMC in 2018, with no movement during the subsequent four years. Snow Summit claims the revenue allocation proposed in the Settlement Agreement perpetuates inequitable subsidies. On this basis, Snow Summit claims that the Settlement Agreement cannot result in just and reasonable rates.

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[9] D.03-04-030, at 43, rejecting a settlement with broad support as being inconsistent with the Commission's policies and contrary to the public interest.

As the sole customer of Bear Valley in the A-5 TOU Primary class, Snow Summit claims it has provided significant subsidies to other customer classes for years. Snow Summit claims that customers in classes other than the permanent residential class also subsidize other customers, diverting revenue that could be invested more productively. Snow Summit also argues that the proposed Settlement Agreement allocates a greater revenue responsibility to the seasonal residential customers, a class that already pays more than it would under an EPMC allocation.

Snow Summit acknowledges that low-income residents face economic challenges but argues that revenue allocation is not the right tool to address income inequality. Snow Summit argues that because the residential customers cover a wide variety of economic circumstances, efforts to protect deserving low-income residential customers through revenue allocation would result in other customers subsidizing the electric use of wealthy residential customers. Bear Valley has a California Alternate Rates for Energy (CARE) rate schedule to assist low-income residential customers.

Snow Summit argues that the Commission has previously concluded that avoiding cross-subsidies and supporting cost-causation principles achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs. Snow Summit cites Commission findings that "rates based on marginal costs will simultaneously achieve economic efficiency and equity by ensuring that customers' rates are commensurate with the costs they cause."[10]

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[10] D.08-07-045, at 46.

Snow Summit argues that use of a SAP change approach might make sense if revenue allocation to individual customer classes was at or near EPMC. In the case of BVES, however, Snow Summit claims that revenue allocation to individual customer classes deviates significantly from EPMC. Snow Summit states that the Commission rejected the use of SAP for allocating base rate revenues in D.86-08-083. The SAP approach does not change allocations among customer classes and makes no progress toward EPMC. Snow Summit claims that allocation percentages and resulting subsidies would remain unchanged through at least 2022 under the Settlement Agreement.

Snow Summit argues that unlike instances where increases in revenue requirements may restrict movement to full EPMC, concerns about rate shock or sharply increasing rates is not present here. Snow Summit believes that BVES should move more persistently toward 100% EPMC.

Snow Summit proposes a revenue allocation approach leading to 100% EPMC allocation by the end of the next GRC cycle. As a result, the revenue allocation for the permanent residential class in 2019 through 2021 (or 2022) would likely be higher as compared to the Settlement Agreement. Snow Summit's revenue allocation proposal calls for:

a. 2% increase for the permanent residential class for 2018, in line with broader measures of inflation.

b. Revenue allocation to all other customer classes for 2018 based on 35.1% movement toward EPMC, so that all customer classes move toward EPMC at the same rate.

c. For 2019 through 2021 (and through 2022 if the GRC cycle is extended), revenue allocation to each customer class to achieve 100% EPMC for all classes by the end of the next GRC cycle.

Snow Summit provided a variation of their proposal presenting:

a. A freeze in revenue requirement for the permanent residential class for 2019 (rather than increasing the permanent residential revenue allocation by 2%).

b. 100% EPMC allocation, with any rate increases to individual customer classes capped at 9.47%, a level determined not to result in rate shock.

c. Increases in revenue allocation for the permanent residential class no larger than 4.94% to avoid rate shock.

c. Increases to other rate classes based on EPMC.

d. Full EPMC allocation, with increases to individual customer classes capped at the Commission's "preferred" method of SAP plus 5%.

Based on the Settlement (section 9.4, Table 17), a cap based on SAP plus 5% would cap increases for individual customer classes at - 8.19% for 2018, 8.55% for 2019, 8.43% for 2020, 8.04% for 2021, and 7.65% for 2022.

Snow Summit argues that in any event, progress toward EPMC for the years after 2018 should continue, rather than adopting the Settlement's SAP method. If progress toward EPMC for the post-2018 years is implemented, Snow Summit would not oppose extending the GRC cycle to 2022.

5.1. Discussion

We have considered the objections of Snow Summit, as well as the responses thereto provided by the Settling Parties.

The Settlement Agreement employs a hybrid of two commonly used revenue allocation methodologies, EPMC and SAP. A similar hybrid of these two revenue allocation methodologies was approved in Bear Valley's two previous GRCs. In D.09-l0-028,[11] we set forth guiding principles regarding the use of EPMC in setting revenue allocations. While we have made use of

[11] D.09-10-028 at 6-7.

EPMC as a primary goal, it is not always feasible to reach that goal in a single proceeding.[12] Circumstances may render it impractical or against the public interest to immediately transition to full EPMC. While we strive towards reaching 100% EPMC, we use discretion in applying this policy on a case-by-case basis.

After noting the EPMC discussion in D.09-10-028 (the 2009 GRC for BVES), we stated in D.14-11-002 that we "may implement EPMC over a series of GRCs. With the use of 20% in the current proceeding, movement towards 100% EPMC has begun and may continue in future GRCs, based upon considerations detailed in D.09-10-028."[13]

In the earlier cases cited by Snow Summit, we adopted some form of limits, caps or phasing in when using the EPMC methodology. None of the cases cited by Snow Summit resulted in a 100% EPMC allocation. Several of the cases cited, however, combined the use of EPMC with the SAP methodology (similar to the hybrid EPMC/SAP methodology in the instant Settlement Agreement).

As previously noted in D.86-12-009, economic efficiency is not our sole consideration, but rate impacts are also an important concern when contemplating use of EPMC. Thus, use of EPMC must be balanced against other considerations.

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[12] *See* D.92-06-020; 1992 Cal. PUC LEXIS at 472, *58.

[13] *See* D.14-11-002 at 33. In any event, revenue allocation provisions adopted as part of the Settlement Agreement in D.14-11-002 are not precedent setting as to the merits of the instant Settlement Agreement. As stated in D.14-11-002:

> "[T]he Settling Parties intend that the approval of this Settlement by the Commission not be construed as a precedent or statement of policy of any kind for or against any Settling Party in any current or future proceeding." (*See* Exhibit K of D.14-11-002, Section 12.5.)

While BVES' rates have resulted in residential customers paying less than marginal cost, the equity of increasing rates for Bear Valley's permanent residential customers must be considered. Under Snow Summit's revenue allocation proposal, the permanent residential customer class would see greater increases in revenue allocation. Certain other customer classes would see greater deceases.

Authorizing a decrease in rates for certain customer classes while increasing rates for the permanent residential class in the manner proposed by Snow Summit would not equitably allocate costs of electricity. Permanent residential customers utilize electricity for basic needs year-round compared with non-residential customers, such as ski resorts, which consume large quantities of electricity for commercial activities and services. Fixed income residents and those in poverty feel the most severe impact from a rate increase.

We are not persuaded to reject the Settlement Agreement based on the analysis of Snow Summit as presented in the table on page 17 of its filed comments.[14] Snow Summit offers its table as a basis to claim that the Settlement results in more customer classes either moving away from EPMC or having no movement toward EPMC. The table shows Seasonal Residential, A-1, A-4 moving away from EPMC, the A-2 with no movement, and the Street Lighting allocation exceeding the EPMC allocation (moving from being under EPMC to being over EPMC). The implication is that the Settlement Agreement's proposed allocation is not moving toward EPMC for most customer classes.

We find these results, however, do not reflect overall residential customers when separate customer classes are categorized as a single group. The allocation

[14] *See* Snow Summit, Inc. comments filed December 28, 2018.

to the residential customers overall increased from 61.62% to 63.50%. This increased allocation covering all residential customer classes grouped together is consistent with movement toward the EPMC allocation of 65.62%. We recognize that revenue allocation for rate setting purposes is based on separate customer classes, not larger groupings of similar classes. Nonetheless, as part of a complete analysis, we find it informative to consider the alternative perspective of the overall impacts of the Settlement Agreement's revenue allocation on all residential ratepayers grouped into a single category.

Regarding A-2 customers, Snow Summit asserts the allocation results run counter to EPMC. Snow Summit shows the allocation percentage declined slightly (from 7.079% to 7.076%). This small change, however, is in the *right direction* toward the EPMC figure of 6.78%.

Regarding the allocation to the street lights customer class, the Settlement Agreement allocation actually surpasses the EPMC allocation, but by less than $2,000. For the A-1 and A-4 class of customers, the allocations were counter to EPMC movement, but neither result was significant. The A-1 class allocation increased from 12.01% to 12.29%. The EPMC allocation is 11.87%. The increase in allocation factor of 0.29% equates to 2.3% of the allocation to the A-1 class. For the A-4 customer class, the allocation increased from 2.91% to 3.00%, whereas the EPMC allocation is 2.91%. The allocation factor increase of 0.09% equates to about $32,000 (3.1% of the allocation to the A-4 class).

Thus, the allocations identified by Snow Summit as inconsistent with EPMC principles result in only $128,000 misallocated out of total revenues of $33.8 million. This small fraction (4/10ths of 1%) is immaterial.

We conclude that the Settlement's proposed revenue allocation represents a reasonable movement from the current allocation toward EPMC. While conceding that the Settlement results in some movement toward EPMC, Snow Summit characterizes that movement as only "a side effect" of the allocation of the decrease in 2018 revenue requirement to customer classes.

We find that the movement toward EPMC as proposed in the Settlement Agreement is not just a consequence of the reduction in the revenue requirement. We note the analysis summarized in Table 1 of the Settling Parties' Response to Snow Summit[15] which compares three revenue allocation scenarios for Test Year 2018 revenue requirement. The first three columns show:

1. Column (1): current allocation (at the time of application filing),
2. Column (2): EPMC allocation factors (based on Exhibit No. BVES-19), and
3. Column (3): allocation factors from the Settlement Agreement.

Columns (5), (6), and (7) of Table 1 are allocations of the Test Year 2018 Revenue Requirement based on the three different sets of revenue allocation factors in columns (1), (2), and (3). By showing all three allocations using the same revenue requirement (shown in column 4), the effect of the revenue requirement decrease on the allocation is eliminated. The observed differences are therefore entirely attributable to differences in revenue allocation factors.

Column (8) shows the difference between an EPMC allocation (Column 6) and the current allocation (Column 5). The Column (8) entries represent the dollar change in revenue allocation to achieve EPMC. Column (9) shows the dollar difference between the Settlement-proposed allocation (Column 7) and the

[15] *See* Settling Parties' Response filed January 14, 2019.

current allocation (Column 5). These entries represent the change in revenue allocation due to the allocation factors in the Settlement Agreement.

If the movement towards EPMC was merely due to the decrease in the revenue requirement, entries in Column 9 would be zero or very small since the effect of the revenue decrease has been neutralized. But that is not the case. As shown in column 9, there is substantial movement toward EPMC by all customer categories, including the residential allocation *increase* of $636,515, the commercial customer's allocation *decrease* of $287,995, and the industrial customer's allocation decrease of $353,701.

The Settling Parties' Table 1, Column 10 provides an estimate of the amount of movement toward EPMC for Test Year 2018. For the residential customer category, the increase in allocation (Column 9) is 47% of the increase necessary to achieve a 100% EPMC allocation. The movement toward EPMC is even more pronounced for Snow Summit itself.

For the Large Industrial customers, the decrease in cost allocation of $353,701 represents a 67% movement toward 100% EPMC allocation. Isolating the impact on the A-5 TOU Primary class (for which Snow Summit is the only customer), there is a reduction of $325,750, representing a 66% movement toward a 100% EPMC allocation in 2018.

The Settling Parties also provided a Table 2 in their pleading to show the revenue allocation of the residential customers when viewed as an overall category increased from 56.6% in 2012 to 63.5% under the Settlement Agreement. That represents a 6.9% increase, (or 76% of the movement to full EPMC allocation). Table 2 also shows commercial customer allocation has moved (or 77% toward full EPMC allocation), and the industrial customer allocation has moved 75% of the way toward full EPMC allocation.

These results show that the proposed revenue allocation in the Settlement Agreement makes sufficient progress toward a 100% EPMC allocation. We conclude that the Settling Parties have reasonably considered and incorporated EPMC principles, and reached an equitable comprise in revenue allocation that moves towards 100% EPMC. We further conclude that the extension of the GRC cycle is not inconsistent with the conclusions above. We find no merit in Snow Summit's objections to the contrary.

For the reasons discussed above, and in the context of our review of the overall merits of the Settlement Agreement as discussed below, we conclude that Snow Summit's objections are without merit. In particular, Snow Summit offers no substantive basis to show that the Settlement Agreement is unreasonable in light of the whole record, inconsistent with the law, or against the public interest.

6. Adoption of the Settlement Agreement

We adopt the Settlement Agreement based on our evaluation that it conforms to Commission standards, including applicable portions of the Rules of Practice and Procedure. Rule 12.1 (b) requires that a public settlement conference be held providing all parties to the proceeding an opportunity to review and discuss the settlement. The Settling Parties complied with this rule. We received comments in opposition to the Settlement Agreement, and responses to those comments. There has been sufficient opportunity for parties to review and comment upon the Settlement Agreement. Accordingly, we direct the Applicant to implement the terms of the Settlement Agreement in accordance with the ordering paragraphs adopted below.

The Commission's long-standing policy favors resolution of disputes by settlement. This policy supports many worthwhile goals, including reducing litigation costs, conserving scarce resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[16] Reaching settlement also conserves parties' resources in having to prepare comments and possible objections to a proposed decision issued by the Commission.

We recognize that the Settlement reflects the give-and-take among the Settling Parties, resulting in a series of tradeoffs that constitute an integrated whole. No single settlement provision is to be evaluated in isolation. Compromises were reached among adverse, knowledgeable and experienced parties involving a range of factual and legal disputes. In assessing its reasonableness, we look at the entire Settlement, as explained in D.10-04-033:

> In assessing settlements, we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on whether any single provision is the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.[17]

Although we have long favored settlement of disputes, we have specific rules regarding approval. As prescribed by Rule 12.1(d) of the Rules of Practice and Procedure, the Commission will not approve a settlement unless the settlement is (a) reasonable in light of the whole record, (b) consistent with law, and (c) in the public interest. We conclude that the instant Settlement satisfies these criteria, as discussed below.

6.1. Reasonable in Light of the Whole Record

In reference to Rule 12.1(d), we find that the Settlement reasonable in light of the whole record which includes the application filing, supporting exhibits and testimony of parties received into evidence, and additional filed materials

[16] D.05-03-022, *mimeo.* at 7-8.

[17] D.10-04-033, *mimeo.* at 9.

and pleadings. Evidentiary hearings were conducted where expert witnesses testified, and exhibits were received into the record. Disputed issues were briefed in opening and reply briefs. Snow Summit filed a separate opposition to the Settlement Agreement (with reply by Settling parties) relating to revenue allocation issues. Finally, the Settling Parties provided additional supporting materials in response to the ALJ's ruling as noted previously. We conclude that the record contains sufficient information for the Commission to judge the reasonableness of the Settlement Agreement.

We reject Snow Summit's claims that the Settlement is not reasonable in light of the whole record based on its objections regarding the revenue allocation methodology. We address the merits of Snow Summit's objections relating to revenue allocation in the previous discussion above. For the reasons noted in that discussion, we find that Snow Summit's objections lack merit. We conclude that in light of the whole record, the Settlement produces a reasonable outcome, and effectively resolves all issues.

6.2. Consistent with Law

We find the Settlement terms consistent with the law, and that nothing in the Settlement contravenes existing statutory law or prior Commission decisions. In addition to complying with applicable statues, the Settling Parties complied with Rule 12 of the Commission's Rules of Practice and Procedure regarding settlements.

Snow Summit claims that the revenue allocation provisions of the settlement are not consistent with law. Under Section 451 of the Public Utilities Code, all rates charged by a utility must be just and reasonable. Any unjust or unreasonable charge is unlawful. Snow Summit argues that the settlement does not result in just and reasonable rates, as required by Section 451. Snow Summit claims that the settlement disregards Commission policy by proposing rates based upon SAP to allocate revenues after 2018. Snow Summit claims that the Commission has disavowed the SAP methodology for purposes of revenue allocation, except in extraordinary circumstances. We separately address in Section 5 of this decision Snow Settlement's objections regarding the Settlement's treatment of revenue allocation.

In reference to Rule 12.1 (d), however, we conclude that the Settlement is consistent with the law, and complies with applicable statutes and prior Commission decisions. In agreeing to the terms of the Settlement, the parties considered relevant statutes and Commission decisions and assert that the Settlement is consistent therewith. We do not detect that any element of the Settlement is inconsistent with Public Utilities Code Sections, Commission decisions, or the law in general. We conclude, in particular, that the Settlement is consistent with Sections 451 and 454, which prevent a change in utility rates unless the Commission finds such a change justified.

6.3. In the Public Interest

In reference to Rule 12.1(d), we conclude that the Settlement is in the public interest, and particularly in the interest of Bear Valley's customers. The Settlement provides for a reduction in the Test Year 2018 annual revenue requirement of approximately $5.1 million compared to 2018 revenues at 2017 rates. It fairly resolves disputes and provides more certainty to customers regarding present and future costs, which is in the public interest.

A settlement that "commands broad support among participants fairly reflective of the affected interests" and "does not contain terms which contravene statutory provisions or prior Commission decisions" meets the "public interest" criterion.[18] In this instance, although the Settlement is not supported by one party, we have independently addressed the merits of that disputed issue in Section 5 of this decision. We reject Snow Summit's claims that the settlement is not in the public interest. As discussed in Section 5, we do not find support for Snow Summit's claims that the Settlement's revenue allocation proposal (a) requires some customers to unreasonably subsidize other customers, (b) contradicts marginal cost principles that encourage energy conservation and promote equity, and (c) is exacerbated by the extension of the GRC cycle to 2022.

In all other respects, there is no opposition to the terms of the Settlement. The Settling Parties represent divergent interests. Bear Valley, the applicant, is a for-profit company responsible for providing safe and reliable electric utility service to its customers. ORA is the Commission's independent ratepayer advocacy office focused on ratepayer interests. The City and the BBARWA governing bodies comprised of representatives elected by customer/ratepayers of Bear Valley, have signed on to the Settlement. The resolution of issues in the Settlement to the satisfaction of those divergent interests indicates that the overall result is in the public interest.

7. Reporting Requirements Pursuant to D.19-04-020 and Section 591

Bear Valley is subject to the reporting requirements of Public Utilities Code Section 591 which states:

> (a) The commission shall require an electrical or gas corporation to annually notify the commission, as part of an ongoing proceeding or in a report otherwise required to be submitted to the commission, of each time since that notification was

[18] *See* D.10-06-015, *mimeo*, at 11-12, citing D.92-12-019, *mimeo*, at 7.

> last provided that capital or expense revenue authorized by the commission for maintenance, safety, or reliability was redirected by the electrical or gas corporation to other purposes.
>
> (b) The commission shall ensure that the notification provided by each electrical or gas corporation is also made available in a timely fashion to the Office of the Safety Advocate, Public Advocate's Office of the Public Utilities Commission, and parties on the service list of any relevant proceeding.[19]

In recognition of the Section 591 requirements, D.19-04-020 approved a "Voluntary Risk-Based Decision-Making Framework" for use by the small and multi-jurisdictional utilities (SMJUs), including Bear Valley, in their GRCs. As noted in D.19-04-020, an Energy Division (ED) staff proposal had suggested that the SMJUs file interim annual RSARs beginning on June 30, 2019 for the 2018 record year and that the SMJUs would receive further instructions from the Commission's ED Director. Because it may be difficult for the SMJUs to strictly follow Staff's suggested approach for the first few years of transition, D.19-04-020 approved a general, simplified approach for the SMJUs to follow in their annual RSAR reports for the time-being. We directed the SMJUs to follow the general RSAR procedures outlined in Attachment 3 of D.19-04-020, providing the same level of detail on the utility's risk mitigation and risk spending as presented in its GRC, unless otherwise directed by Commission Staff.

Within the GRC, Bear Valley presented risk mitigation programs in their response to the Commission's risk-based decision-making framework. We adopt the programs listed in Table 1 as the maintenance, safety and reliability programs for reporting purposes for the RSAR from 2018 through 2022.

[19] Amended by Stats. 2018, Ch. 51, Sec. 42 (SB 854) Effective June 27, 2018.

Table 1 - Adopted Maintenance, Safety and Reliability Programs

Expense	Capital
Specific Program	**Specific Program**
Pole Loading Assessment and Remediation	Pole Loading Assessment and Remediation
Vegetation Management	Tree Attachment Removal
Electrical Preventative Maintenance	BVPP - Install Engine System Manager
Predictive Based Maintenance of Overhead Lines	BVPP - Oil Filter Conversion and Cylinder Upgrades
	Safety and Technical Upgrades of Palomino Substation
Remaining Maintenance Expenses	Replacement of Fawnskin Conductors
Power Generation Maintenance (FERC 551-554)	Replacement of Summit Conductor
Transmission System Maintenance (FERC 568-574)	Replacement of Baldwin Conductors
Regional Market Equipment Maintenance (FERC 576)	**Blanket Programs**
Distribution System Maintenance (FERC 590-598)	GO 174 Substation Safety and Reliability Compliance Projects
General Plant Maintenance (FERC 935)	Wire Upgrade and Relocation Project
	GO 95/165 Safety and Reliability Compliance Projects
	Shifting Tree Attachment to Poles/Underground Projects
	Public Works Project Support
	Office Furniture and Equipment Project
	BVPP Misc. Tools & Safety Equipment Project
	Field Operations Misc Tools & Safety Project
	Minor Additions to General Structure Project

Bear Valley should file its annual RSARs in the applicable GRC proceeding in which funding for the risk mitigation activities was authorized and in the current or most recent GRC at the time of its filing and continuing annually.

On June 24, 2019, the Executive Director granted an extension to Bear Valley to file their 2018 RSAR to within sixty days of the issuance of this decision. The letter requires the filing of the RSAR as an information-only advice letter served on the service list of this proceeding. For future reports, it is appropriate to set the due date to March 31 consistent with the direction for the larger utilities included in D.19-04-020 in order to promote fairness in meeting the compliance requirements.

8. Comments on Proposed Decision

The proposed decision of the ALJ 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 and Procedure. Comments were filed on August 5, 2019 by the Settling Parties and by Snow Summit, and reply comments were filed on August 12, 2019 by the Settling Parties.

In consideration of the comments on the Proposed Decision, we have made certain modifications and corrections. Nothing in the comments, however, justifies rejection of the Settlement Agreement. Snow Summit expresses disagreement with the revenue allocation in the Settlement Agreement, and believes the pace of adoption toward 100% EPMC allocation should be faster. Yet, nothing in its comments shows that the Settlement Agreement violates Commission policy.

Snow Summit disputes Settling Parties' analysis of revenue allocation by grouping similar classes into broader categories. We recognize that revenue allocation is based on separate customer classes. Nonetheless, for purposes of a complete perspective, it is informative to see the impacts of the revenue allocation proposal in the Settlement Agreement in terms of broader customer categories.

Moreover, approval of the Settlement Agreement does not depend solely upon the analysis of revenue allocation based on customer categories as shown by the Settling Parties. The revenue allocation in the Settlement Agreement is part of an integrated package which reflects the give and take among the parties involved. Adoption of the revenue allocation proposal in the context of the Settlement Agreement is within our discretion given the record before us.

9. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Adeniyi Ayoade is the assigned ALJ in this proceeding.

Findings of Fact

1. On May 1, 2017, GSWC, on behalf of the BVES Division, filed its GRC A.17-05-004, for approval and recovery of specified costs, and authority to revise rates and other charges for electric service to take effect on or before January 1, 2018.

2. Since the Commission's decision in this matter is being issued subsequent to the 2018 Test Year period, any retail rate adjustments to implement the Commission's decision must account for the passage of time to make ratepayers neutral as to the later implementation date. For this purpose, a GRC Memo Account was authorized in D.17-11-008.

3. On November 28, 2019, ORA and the Applicant filed a "Joint Motion for Approval and Adoption of a Settlement Agreement" resolving all issues between the two parties. BBARWA and the City of Big Bear Lake subsequently joined in the Settlement. Snow Summit, Inc. was the only party to oppose the Settlement.

4. The Settlement Agreement resolves all disputes among Settling Parties in this proceeding, including general base revenue requirements (for Test Year 2018 and for the 2019-2022 period), marginal costs, revenue allocation and rate design treatment of specified accounts, and approval of special projects.

5. The Settling Parties did not use an explicit numerical formula to calculate base revenue requirements for individual projects or programs for the post test-year period (*i.e.,* 2019-2022). Rather they negotiated overall increases for

each year beyond Test Year 2018 to cover expected increases for operation and maintenance expenses and/or rate base costs.

6. There has been sufficient opportunity in accordance with Commission rules for all parties to review and discuss the Settlement Agreement.

7. Snow Summit, Inc. objections to the Settlement Agreement were limited to the issue of revenue allocation and related effects on extension of the GRC to include a fifth year.

8. BVES initially proposed a Test Year 2018 Base Revenue Requirement of $25,927,926. ORA's initial proposal was for $22,045,878. Settling Parties agreed on a Test Year 2018 Base Revenue Requirement for $22,500,000, as being reasonable and sufficient to fund utility operations and maintain facilities.

9. The Settling Parties agreed on a weighted-average cost of capital/rate of return on rate base of 8.31% based on a return on equity of 9.6% and a 43% debt/57%equity ratio as being reasonable. The agreed-upon cost of capital values incorporate the cost of debt and capital structure adopted for GSWC for 2018-2020 in D.18-03-035.

10. BVES forecasted a 2018 rate base value at $47,227,227. ORA recommended a value of $43,348,053. The Settling Parties agree to a 2018, TCJA-adjusted rate base value of $47,227,227, which adjusts for the TCJA.

11. The Settling Parties agree (a) to exclude the Pineknot Substation Project and Grid Automation Project from GRC base rate revenue funding, and (b) that BVES be permitted to construct and/or implement these projects via Tier 1 Advice Letter filings to recover up to $2,936,929 (in 2016 dollars), plus AFUDC for the Pineknot Substation Project, and up to $3,881,689 (in 2016 dollars) plus AFUDC for the Grid Modernization Project.

12. The Summary of Earnings Table set forth in Table 4 of the Settlement reflects the elements of 2018 test year revenue requirement to fund operations and maintenance and to earn a return on rate base to serve customers as agreed to among the Settling Parties.

13. Each of the outstanding special requests, as identified and agreed to within the Settlement Agreement are reasonable.

14. The Settling Parties agree to the results of Bear Valley's Long Run Marginal Cost study results set forth in Table 13 of the Settlement Agreement.

15. The Settling Parties agree that disposition of the GRC Memo Account adopted pursuant to D.17-11-008 should be implemented in conjunction with disposition of the balance in the BRRBA for 2018 and 2019.

16. The Settling Parties reflect a range of different interests.

17. The Settlement Agreement, based on the whole record, including additional information supplied by Settling Parties on April 24, 2019, conveys sufficient information for the Commission to discharge its future regulatory obligations with respect to the parties and their interests.

18. In light of the whole record, including prepared testimony, evidentiary hearings, briefs, and other filed pleadings, there is sufficient basis to conclude that the Settlement Agreement is reasonable.

19. The Settlement Agreement is consistent with law and with applicable statutes and prior Commission decisions. The Settling Parties considered relevant statutes and Commission decisions.

20. The Settlement Agreement is in the public interest.

21. Under the terms of the Settlement Agreement, Bear Valley agrees to compare the risk scores in this GRC to risk scores in its next GRC, identify risk scores that change, and explain why they changed. Bear Valley will not be

required to provide a record of scores that changed as a result of internal working sessions.

22. Snow Summit has not provided persuasive evidence to show that the revenue allocation provisions of the Settlement Agreement are unreasonable or inconsistent with prior Commission policy.

23. This Commission has made use of EPMC a primary goal for allocating revenue among customer classes in past proceedings, but it is not always feasible to reach that goal in a single rate proceeding.

24. Rate impacts are an important concern when contemplating the use of a particular revenue allocation methodology.

25. A balancing of the interests of all customers groups should take into account: 1) rate increases that result from use of EPMC; 2) comparison to historical allocation of rates and movement towards 100% EPMC; and 3) total rate changes that move gradually towards 100% EPMC.

26. Under Snow Summit's revenue allocation proposal, the primary residential customer class would see greater increases in revenue allocation while other customer classes would see greater decreases.

27. The Settlement Agreement employs a hybrid of two commonly used revenue allocation methodologies, EPMC and SAP Change. A similar hybrid of these two revenue allocation methodologies was approved in Bear Valley's two previous GRC proceedings.

28. The previous cases cited by Snow Summit regarding Commission treatment of revenue allocation involved some form of caps or phasing-in when using the EPMC methodology. None of the cases cited used a 100% EPMC allocation.

29. As shown in Table 1 of the Joint Settling Parties' response to Snow Summit, and as discussed in Section 5.1 of this decision, the proposed revenue allocation in the Settlement makes significant progress toward a 100% EPMC allocation.

Conclusions of Law

1. The Settlement Agreement, set forth in Attachment A of this decision, meets the Commission's standards for approval prescribed in Rule 12 of the Rules of Practice and Procedure, in that it is (a) reasonable in light of the whole record, (b) consistent with law, and (c) in the public interest.

2. The Settlement Agreement should be approved and adopted in its entirety. The Applicant should be required to implement the applicable retail tariff rate changes and all other terms of the Settlement Agreement in conformance with the ordering paragraphs adopted herein.

3. Objections to the Settlement Agreement set forth by Snow Summit regarding revenue allocation methodologies do not provide a basis for rejection of the Settlement Agreement.

4. The Commission may determine that circumstances render it impractical or against public policy to immediately transition to EPMC for revenue allocation purposes.

5. The Settlement Agreement does not constitute precedent for any future proceeding or issues to be brought before the Commission.

6. In order to give effect to the Settlement Agreement expeditiously, this decision approving the Settlement should be made effective today.

7. Once disposition of all amounts in the GRC Memo Account (as authorized in D.18-11-008) have been completed, as outlined in the Settlement Agreement,

and set forth in Ordering Paragraph 4 of this decision, the GRC Memo Account should be closed.

8. Consistent with the Settlement Agreement, (a) BVES should file its next GRC application, with a 2023 Test Year, prior to April 30, 2022; (b) the cost allocation and rate design components of the application should be filed no later than six weeks after filing the application, and (c) the application should incorporate a four-year general rate case cycle.

9. In view of the timing of implementation of this decision, it is appropriate to revise the due date for the filing by Bear Valley of its Risk Mitigation Accountability Report, as set forth in Ordering Paragraph 9 of this ordering pursuant to the requirements of D.19-04-020 and Public Utilities Code Section 591.

10. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Settlement Agreement (attached as Appendix A hereto) is approved and adopted Golden State Water Company on behalf of its Bear Valley Electric Service Division, shall comply with and implement the adopted Settlement Agreement in accordance with all terms and attachments set forth therein.

2. The Joint Motion filed on November 28, 2018, jointly by Applicant (*i.e.*, Golden State Water Company on behalf of its Bear Valley Electric Service (BVES) Division) and the Office of Ratepayer Advocates, for adoption of Settlement Agreement regarding the Test Year 2018 General Rate Case of Bear Valley, including attrition years is granted.

3. The General Rate Case (GRC) Revenue Requirement Memorandum Account previously approved in Decision 17-11-008 shall include the monthly

differential between base rates in effect as of December 31, 2017, and base rates adopted in the instant proceeding for the period beginning January 1, 2018 through the effective date of this decision. The amount accrued in the GRC Memorandum Account shall be transferred to the Base Revenue Requirement Balancing Account and amortized over a twelve-month period consistent with the tariff provisions. The GRC Revenue Requirement Memorandum Account is closed.

4. Golden State Water Company, on behalf of the Bear Valley Electric Service Division (BVES), shall file a Tier 1 Advice Letter within 30 days of the effective date of this order with revised tariff sheets for its BVES in accordance with the terms of the Settlement Agreement, including Exhibit L therein (entitled 2018 Retail Rates).

5. Golden State Water Company, on behalf of the Bear Valley Electric Service Division, shall file a Tier 1 advice letter within 60 days of the effective date of this order to amortize the (over-collection) balance in the Supply Adjustment Balancing Account through a credit according to the terms and conditions of Section 5.8 of the Settlement Agreement.

6. When the cumulative (over-collection) balance in the Supply Adjustment Balancing Account is equal to or less than $200,000, Golden State Water Company, on behalf of the Bear Valley Electric Service Division, shall file a Tier 1 Advice Letter to terminate the credit ordered above consistent with Section 5.8 of the Settlement Agreement.

7. Within 14 days following the termination of the credit ordered above, Golden State Water Company, on behalf of the Bear Valley Electric Service Division, shall file a Tier 1 Advice Letter modifying the tariff provisions of the

Supply Adjustment Mechanism consistent with Section 5.8 of the Settlement Agreement.

8. Golden State Water Company, on behalf of the Bear Valley Electric Service Division, is authorized to file a Tier 1 Advice Letter upon completion and placement of the Pineknot Substation Project into commercial operation to recover the costs associated with funding the project up to a cost of $2,936,929 (2016 dollars) plus an allowance for funds used during construction in accordance with Section 7.1.1 of the Settlement Agreement.

9. Golden State Water Company, on behalf of the Bear Valley Electric Service Division, is authorized to file a series of annual Tier 1 advice letters to recover the costs associated with funding the Grid Modernization Project up to a cost of $3,881,689 (2016 dollars) plus an allowance for funds used during construction in accordance with Section 7.1.2 of the Settlement Agreement.

10. Golden State Water Company, on behalf of the Bear Valley Electric Service Division, is authorized to file a Tier 1 advice letter if and when an agreement is reached with Snow Summit, Inc. regarding supplemental service consistent with the utility's proposal contained in Special Request #1 in accordance with Section 8.1 of the Settlement Agreement. If an agreement is materially different than the provisions of Special Request #1, the utility is authorized to file a Tier 3 Advice Letter with an explanation of the material changes.

11. Golden State Water Company, on behalf of the Bear Valley Electric Service Division, is authorized to file a Tier 1 Advice Letter effective 30 days after filing to recover the costs of replacing the Snow Summit substation in the event the agreement discussed in the utility's proposal in Special Request #1 is not reached by December 1, 2020 consistent with Section 8.2 of the Settlement Agreement.

12. The Summary of Earnings for Test Year 2018 as set forth in the Settlement Agreement, Table 4 is adopted, consistent with the adopted revenue requirements and underlying provisions set forth in the Settlement Agreement.

13. The revenue allocations for 2018-2022 for customer classes of the Bear Valley Electric Service Division, as set forth in Section 9.2 of the adopted Settlement Agreement, are adopted. The applicable percentage decreases by customer class as depicted in Table 16 of the Settlement Agreement shall be applied.

14. The retail rate adjustment methods as set forth in Section 9.10 of the Settlement Agreement for 2019-2022 shall be used reflecting the agreed-upon retail rate adjustment methods. As prescribed in the Settlement Agreement, recovery of the additional revenue requirements for 2019-2022 for each customer class shall be achieved by adjusting energy rates for each customer class.

15. Golden State Water Company, on behalf of its Bear Valley Electric Service Division, shall file its next general rate case (GRC) application, with a 2023 Test Year, prior to April 30, 2022. The cost allocation and rate design components of the application shall be filed no later than six weeks after filing the application. That application shall include a four-year GRC cycle.

16. The Adopted Maintenance, Safety and Reliability Programs for Bear Valley Electric Service Division from 2018 through 2022 are adopted.

17. Golden State Water Company, on behalf of its Bear Valley Electric Service Division, shall file an information-only advice letter within 60 days of the issuance of the final decision in this proceeding, and annually by March 31 of each succeeding year, which includes a comparison of actual expenditures to adopted expenditures as approved in this decision for safety, reliability, and maintenance programs pursuant to the reporting requirements of

Decision (D.) 19-04-020 and Public Utilities Code Section 591 relating to the Risk Spending Accountability Report. The March 31 due date revises the date previously set in D.19-04-020. The advice letters shall be filed with the Energy Division's Tariff Unit and served on the appropriate general rate case proceedings.

18. Application 17-05-004 is closed.

This order is effective today.

Dated August 15, 2019, at San Francisco, California

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners