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BEFORE THE CALIFORNIA 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 (U 913 E), for Approval of Costs and Authority to Increase General Rates and Other Charges for Electric Service by Its Bear Valley Electric Service Division	Application A1202013

GENERAL RATE CASE

VOLUME 1

APPLICATION FOR APPROVAL OF COSTS
AND
INCREASE IN GENERAL RATES
AND
CERTAIN OTHER CHARGES

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February 16, 2012

TABLE OF CONTENTS

Page

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APPLICATION FOR APPROVAL OF COSTS
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A. INTRODUCTION AND SUMMARY

Golden State Water Company ("GSWC" or the "Company"), on behalf of its Bear Valley Electric Service ("BVES") Division, hereby submits this General Rate Case Application ("GRC" or this "Application"), and associated prepared testimony and documents, in compliance with Ordering Paragraph #6 of Decision 09-10-028,[1] and in accordance with California Public Utilities Code Sections 381, 451, 454, and 701 and Rules 2.1, 2.2 and 3.2 of the Commission's Rules of Practice and Procedure. This Application seeks approval for certain costs incurred by BVES and recovery of such costs in rates; authority for BVES to increase general rates, energy supply charges and certain other charges; authority to implement additional programs and change certain unmetered charges and fees; and authority to implement certain revenue adjustment

[1] In D. 10-03-016, the Commission modified D.09-10-28 by adding ordering paragraph #6 which requires GSWC to file its next general rate case application for BVES for Test Year 2013 by January 31, 2012. This filing deadline was extended to no later than February 21, 2012 by letter from Mr. Paul Clanon, Executive Director, dated January 26, 2012.

mechanisms and memorandum accounts, as set forth in this Application and associated direct testimony and documents.

The requested rate increase and charges are necessary because the present rates and charges are insufficient, unjust and unreasonable in that they do not produce adequate revenue to yield GSWC a fair, just and reasonable return on capital invested and to be invested in plant, property and other equipment devoted to providing quality electric service to the BVES service area.

BVES rates have four major components: base rates, supply rates, adjustment rates for base rates and supply rates, and other energy charges.

- Base rates are intended to cover all costs incurred by BVES from owning and operating BVES' system(*e.g.*, operation and maintenance costs, administrative costs, capital costs, *etc.*), excluding supply costs.
- Supply rates are intended to recover current energy supply costs incurred by BVES to provide service to its customers. These costs include costs of purchased power (conventional and renewable), natural gas costs for BVES' power plant, transmission costs, California Independent System Operator Corporation ("CAISO") costs, ancillary charges and scheduling fees.
- The adjustment rates include rate mechanisms to recover/refund past under/over collections of either base rates and/or supply rates.
- Other energy charges include a public purpose charge, which includes the California Energy Commission (CEC) renewable technologies, CEC R&D programs, low-income energy efficiency programs and the low-income payment assistance program (CARE). It also includes a general office surcharge and Taxes and Fees, which include the PUC Reimbursement surcharge and the CEC surcharge.

Unlike BVES previous GRC application which dealt only with base rate revenues, this Application includes a review of supply costs and supply rates.[2] BVES maintains a Purchased Power Adjustment Clause (PPAC) balancing account to track the difference between all revenues collected from supply charges and all supply costs incurred by BVES. BVES requests

[2] In Advice Letter A 248-E, a compliance filing ordered in D. 02-07-041, BVES noted that it would include a review of the PPAC balancing account and a proposal for new PPAC rate components in its forthcoming general rate case application.

Commission authority to recover in supply rates all supply costs booked into the PPAC for the period April 1, 2001 through August 31, 2011. It is important to note that BVES is not seeking an increase in the *overall* supply rates. In fact, BVES projects a reduction in supply rates once an under-collection in supply costs booked in the PPAC balancing account has been recovered. BVES expects this reduction in supply rates to occur in September 2014.

BVES will supplement this Application in approximately thirty days with BVES' proposed cost allocation and rate design. The cost allocation and rate design are contingent upon the overall revenue request. Rather than bifurcating this proceeding into two phases, submitting the base rates revenue requirement, supply cost and supply rates portion of the Application first will allow for consideration of the overall Test Year 2013 ratemaking components more quickly. This process was used in BVES' last GRC application process.[3] BVES has discussed this two-step process with the Division of Ratepayer Advocates ("DRA") and it has advised the Company that DRA will not object.

B. BACKGROUND

1. BVES' Service Territory and its Unique Characteristics

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, comprised primarily of residential customers. BVES provides service to approximately 23,300 customers, of which 21,900 are residential customers and approximately 1,400 are commercial, industrial, or public-authority customers. BVES also provides service to two ski resorts in its territory.

Unlike other utilities in California, BVES is a winter peaking utility. The BVES winter peak load typically occurs when tourism peaks and snowmaking machines at the ski resorts are operating. Its maximum winter peak load was set in 2010 at approximately 44 MW. In the summer months, BVES' load ranges from approximately 11 MW (early summer mornings) to a maximum of approximately 24 MW (weekend holiday, mid-mornings and late evenings).

2. BVES' System

The BVES system is comprised of one 8.4 MW generation plant, 205 miles of overhead and 54 miles of underground conductors, and 13 substations. BVES' generation plant, the Bear

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[3] Application 08-06-034.

Valley Power Plant (BVPP), began commercial operation in 2005 and is located at BVES' main office in Big Bear Lake.

BVES' distribution facilities are located within the control area operated by the 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).

C. NEED FOR INCREASE IN RATES AND CHARGES

BVES' last general rate case was in 2009. The Commission Decision 09-10-028 for the 2009 rate case Application 08-06-034 adopted rates and revenue requirements for four test years: 2009, 2010, 2011 and 2012. A summary of Test Year 2013 present and proposed rates compared to the 2012 adopted rates and revenues is provided in Chapter 3 of Volume 2 (Results of Operation) of this Application.

In this Application, BVES requests a Test Year 2013 9.85% increase in total revenues, which will result in a 7.79% increase in an average BVES electric bill rate. BVES anticipates the under-collections in the PPAC balancing account to reach zero by September 2014. When that occurs, BVES proposes to reduce the Amortization Charge to zero which will result in a 5.5% reduction in average rates.

The $4.01 million increase in total revenues is driven primarily by three components: (1) $1.64 million as a result of placing the 2010 Commission authorized GSWC general office (GO) allocation in BVES base rates;[4] (2) $1.05 million as a result of actual sales being substantially lower than the adopted sales forecast; and (3) $1.32 million as a result of a proposed increase for inflation and other factors from adopted 2012 rates to Test Year 2013. BVES requests that the Commission increase the authorized 2012 base rate revenue requirement from $21.09 million to $22.4 million for Test Year 2013 and authorize BVES to increase its total revenues by $4.01 million (9.85%) from $40.69 million to $44.70 million, which results in a 9.85% increase in revenues. Although BVES is requesting a $4.01 million increase in total revenues, $860,000 will come from sources other than regular electric bills.[5] Thus, the total increase in rates is 7.79%.

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[4]The Commission authorized the GO allocation adjustment to be included in the Base Rate Revenue Adjustment mechanism, for test year 2013, the authorization is moved out of the BRRAM and into base rates.

[5] $720,000 from the SER and Added Facilities rates related to the proposed supplemental sales to Snow Summit, plus $100,000 other operating revenue, plus $40,000 from a new Standby Rate.

BVES is not proposing any overall increase in supply rates for Test Year 2013. However, BVES requests changes in supply rate components and will be reducing supply rates when the PPAC balance under-collection reaches zero. The supply rate reduction is projected to occur in September 2014, and would decrease average rates by approximately 5.5%. Details of the request are included in Volume 4 and specific supply rates are included in Volume 6.

At rates proposed in this Application, BVES would have the opportunity to earn a rate of return on rate base (ROR) of 9.81% for test year 2013, based on a 12.00% return on equity (ROE), and a capital structure of 44.4% long-term debt and 55.6% common equity. This is a fair and reasonable rate of return, which will assist GSWC to attract capital at a reasonable cost and to maintain adequate borrowing capability and credit.

Expressed on a $/kWh basis, the proposed rate increase of 7.79% would have the effect of increasing by approximately $7.56/month the average residential bill in 2012 of $97.06/month.[6]

D. SUMMARY OF TESTIMONY AND SUPPORTING MATERIAL

1. <u>Volume 2 – Results of Operation</u>

a. *Chapter 1 – Introduction*:

This chapter provides an overview of BVES' operations, system, energy needs, organization and staffing, rate structure, and rate history. Unlike other California electric utilities, BVES is a winter peaking utility. This is due to several factors, including its location and the fact that it serves a ski resort community. Its peak winter peak load was set in 2010 at approximately 44 MW. It has one generating plant, with a capacity of 8.4 MW. BVES has a small but dedicated staff of 48 employees, nearly all of which reside in BVES' service territory.

BVES' rate structure includes four major components: Base Rates, Supply Rates, Adjustment Rates for both Base and Supply Rates, and Surcharges. BVES' most recent general rate increase was approved by the Commission in D.09-10-028, which the Commission modified in D. 10-03-016.

[6] This is an average effect, based on average residential consumption of 450 kWh/month based on 2012 rates. Actual, proposed Test Year 2013 customer rates will be in Volume 6 and may differ due to changes in marginal cost allocation and rate design.

b. Chapter 2 – Summary and Policy Issues:

The purpose of this chapter is to summarize various components of the rate increase request and to identify policy issues regarding this Application including: supply cost issues; marginal cost study and rate design; past and future power supply charges; rate of return; small utility regulatory challenges; energy efficiency programs; a new solar program; modification of the Base Revenue Requirement Adjustment Mechanism (BRRAM) to track seasonally adjusted monthly sales; establishment of a post test year attrition mechanism; modification of the GSWC general office cost allocation process; a proposed Snow Summit substation upgrade and supplemental sales tariff; new plant additions for an undergrounding project in City of Big Bear; and the establishment of a pensions and benefits balancing account.

c. Chapter 3 -- Summary of Earnings:

This chapter presents a summary of earnings (SOE), both historical and projected for Test Year 2013. It also describes the rate increase required to achieve the proposed rate of return on rate base requested in this Application.

BVES requests that the Commission authorize BVES to increase its total revenues from \$40.69 million to \$44.70 million for Test Year 2013 which results in an increase in total revenues of 9.85%. At present rates (excluding Base Adjustment rate revenue), the resulting total revenues will only provide a 4.68% rate of return for BVES. Granting BVES' request for a total revenue increase of \$4.01 million will permit BVES to recover its operating expenses plus the proposed 9.81% rate of return.

d. Chapter 4 (Part A) -- Sales and Customers:

This chapter provides BVES' historic and forecasted sales, as well as energy usage by customer. It also describes the forecast mode and the sales forecast by rate class from 2011 through 2016.

For years 2006 through 2010, there was a decline in recorded sales (kWh) of approximately 12.7 million kWh, from 144.9 million kWh in 2006, 139.1 million kWh in 2007, 137.1 million kWh in 2008, 138 million in 2009 and 132.2 million in 2010. BVES forecasts an increase of 2.2% in sales between 2010 and 2013. For years 2011 to 2016, sales (kWh) are forecasted to be approximately 132.2 million, 134.6 million, 139.4 million, 144.7 million, 147.9 million and 149.5 million, respectively.

e. *Chapter 4 (Part B) – Revenue at Present Rates*:

This chapter provides historical and estimated revenue information by rate class based on BVES' current rates and other miscellaneous charges. It includes detailed breakdown of revenues generated by each rate schedule within each of the four rate classes – residential, commercial, power/industrial and street lighting/other operating revenue. It also includes 2010 recorded and 2011 through 2016 estimated supply rate revenue by customer class.

f. *Chapter 5 – Operation & Maintenance Expenses*:

This chapter addresses BVES' recorded and estimated operation and maintenance (O&M) expenses other than administrative and general (A&G) expenses. BVES' O&M costs are separated into four primary components: production; transmission; distribution; and customer accounting.

Most of the production O&M expenses are contractor related, with annual costs in the years 2006 through 2010 being between a low of approximately $337,000 and a high of approximately $502,000. For years 2011 through 2016 BVES anticipates an increase in annual costs from approximately $474,000 to approximately $558,000.

Transmission O&M costs in this case refers to the costs of operating and maintaining BVES' "backbone" high voltage transmission loop connecting 13 substations. Annual costs in the years 2006 through 2010 were between a low of approximately $46,000 and a high of approximately $104,000. For years 2011 through 2016, BVES projects increase in annual costs from approximately $114,000 to approximately $177,000.

Distribution expenses in this case refer to the costs of operating and maintaining BVES' distribution lines and meters. Annual distribution expenses in the years 2006 through 2010 were between a low of approximately $1,179,000 and a high of approximately $1,604,000. For years 2011 through 2016, BVES anticipates an increase in annual costs from approximately $1,753,000 to approximately $2,612,000.

Annual costs for customer service between the years 2006 through 2010 were between a low of approximately $492,000 and a high of approximately $679,000. For years 2011 through

2016, BVES projects an increase in annual costs from approximately $693,000 to approximately $939,000.

BVES seeks authorization to add two additional staff personnel: an engineering inspector and a regulatory compliance project engineer.

g. *Chapter 6 – Administrative & General Expenses*:

This chapter addresses BVES' recorded and projected administrative and general (A&G) expenses. Part A addresses BVES' A&G cost allocation from the San Dimas General Office of GSWC (SDGO). For 2009 through 2012, those costs (excluding pension and benefits costs) are expected to total approximately $3.1 million, $4.1 million, $4.2 million and $4.3 million, respectively. For 2013 through 2016, those same costs are expected to be approximately $3.5 million, $3.6 million, $3.7 million and $3.8 million, respectively.

Part B of this chapter addresses A&G expenses at BVES' Bear Valley Office (BVO), including staff, outside services, and other BVO expenses. Chapter 6B – Appendix provides an overview of BVES' staff positions from 2009 through 2012. Such BVO costs recorded for 2006 through 2010 were approximately $1.6 million, $2.9 million, $3.6 million, $3.6 million and $3.8 million, respectively. For 2011 through 2016, these costs are projected to be approximately $4.8 million, $5.2 million, $5.6 million, $5.8 million, $6 million, and $6.4 million, respectively.

h. *Chapter 7 – Book Depreciation and Depreciation Reserve*:

This chapter addresses BVES' depreciation and amortization expenses and accumulated provisions (reserves) for depreciation and amortization. The book depreciation recorded for years 2006 through 2010 are approximately $2 million, $2.2 million, $2.2 million, $2.3 million and $2.2 million, respectively. The book depreciation forecasted for 2011 through 2016 are approximately $2 million, $2.1 million, $1.8 million, $2.1 million, $2.2 million and $2.3 million, respectively.

i. *Chapter 8 – Income and Other Tax Expenses*:

This chapter addresses BVES' recorded and forecast tax expenses as a component of the overall revenue requirement. The testimony covers three basic areas including: Taxes Other, Income Taxes and Deferred Federal Income Tax Adjustments to Rate Base.

j. Chapter 9 (Part A) – Rate Base:

Part A presents a description of BVES' average rate base for the recorded years 2006 – 2010 and projected average rate base for 2011 through 2016. It also includes a description of the development of recorded working cash for 2006 – 2010 and projected working cash for 2011 – 2016.

The recorded average rate base for 2006 through 2010 was approximately $37.4 million, $37 million, $36.6 million, $36 million and $34.8 million, respectively. The forecast average rate base for 2011 through 2016 are approximately $35.1 million, $37.4 million, $43.3 million, $49.2 million, $52.8 million and $55.8 million, respectively. The average working cash for years 2006 through 2010 was approximately $928.6 million, $950.1 million, $962.1 million, $782.4 million and $368.7 million, respectively. The projected working cash for 2011 through 2016 are approximately $370.1 million, $383.9 million, $398.8 million, $421.4 million, $436.5 million, and $449.1 million, respectively.

k. Chapter 9 (Part B) – Plant Additions:

Part B describes historical plant additions as well as projected plant additions for BVES' system. Historical plant additions for 2009 through 2011 were approximately $1 million, $1.7 million and $4.2 million, respectively. Projected plant additions for 2012 through 2016 are approximately $3.5 million, $10.3 million, $4.4 million, $6.7 million and $3.3 million, respectively. The proposed projects include substation upgrades, transmission and distribution pole replacements and upgrades, a major undergrounding project for the main street of the City of Big Bear, and a new warehouse and office expansion for the BVES General Office.

l. Chapter 10 Escalation and Net-to-Gross Factor:

This chapter presents the cost escalation factors used by BVES to reflect the effect of inflation and to describe the development of BVES' Net-To-Gross Factor to be used in this Application for computing the increased revenue required to achieve the ROR that BVES is requesting.

2. <u>Volume 3 – Special Requests</u>

BVES proposes eight special requests (Special Requests). The Special Requests are discussed in detail in Volume 3. Below is a brief summary of each Special Request.

a. Chapter 1 – Special Request #1 – Energy Efficiency Programs:

This chapter presents a new budget for BVES' energy efficiency (EE) programs that is similar to the existing EE budget first authorized in the 2009 GRC. The new EE budget expenditures for 2013 – 2016 will be $230,000 per year in a one-way balancing account as compared to EE program budgeted amounts of approximately $205,000, $212,000, $220,000 and $229,000 (nominal dollars) for 2009 – 2012 authorized in the last GRC.

b. Chapter 2 – Special Request # 2 – Solar Initiative Program:

This chapter sets forth a proposal to create a new Bear Valley Solar initiative program in response to residential customer demand. This eight-year program has a total budget of $1,209,242 (2010 dollars), with an average annual cost of approximately $183,000. While this is a small impact on BVES total revenue requirement, it is an important first step to correct what BVES believes is an oversight in the State's policy to encourage renewable development. BVES is unable to provide any rationale to its customers as to why they have been excluded from the California Solar Initiative. This program, in a small way, provides some equity to BVES customers.

c. Chapter 3 – Special Request #3 – Base Revenue Requirement Adjustment Mechanism (BRRAM) to Track Seasonally Adjusted Monthly Sales.

This chapter describes BVES' request that the BRRAM monthly target revenue be based on the seasonally adjusted monthly revenues rather than one-twelfth of the annual revenue requirement. The annual values are the same under either method. BVES sales typically vary each month based on seasonal weather and vacation schedules. The Commission adopted annual value does not change with either the one-twelfth or seasonal method. However, tracking sales for the BRRAM account based on the current one-twelfth of annual sales creates a distortion in the BRRAM account, which needlessly distorts BVES' quarterly financial statements.

d. Chapter 4 – Special Request #4 – Post Test Year Attrition Mechanism and Rate Case Plan.

This chapter discusses the need for a post test year attrition mechanism (PTAM). BVES' last GRC in 2009 had four Test Years (2009-2012). The revenue requirement for each of the four years was authorized. Thus there was no need for a PTAM over the past four years because attrition was addressed by the authorized revenue requirement for each of the four years. This Application is again based on a four-year rate case period as set by the Commission in BVES' last GRC.[7] However, this application has one test year (TY 2013) and three attrition years, rather than three additional test years. BVES proposes the next GRC filing would be due January 2016, with a test year of 2017. In order to maintain this proposed four-year rate case period, BVES requests the Commission address the method to be used to necessarily adjust the base revenue requirement for the years 2014, 2015 and 2016. The proposed PTAM components will make adjustments for O&M expenses, overall A&G expenses, tax rate changes and carrying costs of capital additions.

e. Chapter 5 – Special Request #5 -- General Office Update Process:

This chapter describes BVES' request that its general office cost allocation be updated through an advice letter filing, using the Commission's determination of the GSWC general office allocation in the most recent GSWC general rate case. BVES' test year 2013 general office (GO) allocation values use the allocation and costs included in GSWC's A. 11-07-017, details are provided in Chapter 6, Volume 2 of the BVES. In its application, GSWC notes that the GO portion known as "Centralized Operation Support" benefits only water operations so there should be no allocation to BVES customers. Thus, use of the A. 11-07-017 GO costs and allocations result in a $752,000 reduction over the current BVES GO costs and allocations. The authorized BVES cost and allocation will be determined by the Commission in its decision regarding A. 11-07-017, which is expected to be effective January 1, 2013, the same date BVES expects a decision regarding this GRC Application. BVES is also requesting authority to update the Commission determined GO allocation in the forthcoming test year 2016 GSWC general rate case for water operations.[8]

[7] D.09-10-028 authorized BVES to maintain a four-year rate case period.
[8] GSWC is on a three year rate case plan for its water operations vs. a four year rate case plan for BVES.

f. Chapter 6 – Special Request # 6 -- Snow Summit Supplement Sale.

This chapter describes a proposed supplemental sale arrangement with Snow Summit, BVES' largest customer. BVES is proposing a substation upgrade[9] and a special rate to support an incremental sale above the level of sales included in the sales forecast for 2013-2016. This sale will be served under a new rate referred to as the Supplemental Energy Rate (SER). If approved by the Commission and Snow Summit, BVES will sell an additional 7.2 million kWh to Snow Summit, which is expected to generate an average of $1.4 million revenue annually. The SER will more than cover the incremental cost of service over the 2013 - 2016 period and provides additional benefits to all other customers. The SER includes an added facilities contract and indexed energy pricing tied to the BVES incremental cost of energy in order to ensure that the costs of providing this service are never shared with other customers. The SER will offset all costs related to the substation investment and added labor involved to manage the sale, providing $720,000 in base rate revenue that will allow BVES to reduce base rates to all other customers. The SER will benefit Snow Summits by reducing its need to burn higher cost diesel fuel to make snow.

g. Chapter 7 – Special Request # 7 -- Plant Additions for Undergrounding.

The chapter describes BVES' request to join with the City of Big Bear in a project to convert overhead lines along Big Bear Boulevard to underground lines. BVES requests $2.4 million to be in the capital expenditures for Test Year 2013. The $2.4 million, which will be incurred by BVES between 2013 and 2016, represents approximately 48% of the total project costs of approximately $5 million. In addition to the request for funding, BVES will include revisions to its current Rule 20 to comply with D. 01-12-009. BVES is not requesting an undergrounding allotment other than the Big Bear Boulevard project in this Application, but will propose an allotment in its next GRC application.

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[9] The total cost of the substation upgrade is projected to $2.6 million of which $2.1 million would be allocated to providing service to Snow Summit load.

h. Chapter 8 – Special Request #8 -- Pension and Benefit Balancing Account.

This chapter describes BVES' proposal to track Pension and Benefit (P&B) costs in a two-way balancing account. Currently, BVES' P&B costs are directly assigned rather than an allocation as part of the General Office cost allocation, which was done in the last GRC. BVES is requesting authorization to create a two-way balancing account to track its P&B costs. The Commission recently authorized GSWC authority to track pension-related costs in a two-way balancing account. The proposed two-way balancing account will track the difference between the adopted P&B costs recovered in rates and the actual P&B costs.

3. <u>Volume 4 – Supply Costs</u>

The purpose of Volume 4 is to provide both historical and forecast information regarding BVES' supply costs. This volume has five chapters.

a. Chapter 1 -- Introduction and Summary.

This chapter provides and introduction, a brief summary and the names of each witness sponsoring testimony in Volume 4.

b. Chapter 2 – Purchased Power Adjustment Clause Balancing Account Under-Collection as of March 31, 2001.

This chapter sets forth the accounting procedures and calculations used to establish the under-collection balance in the PPAC as of March 31, 2001. This March 31, 2001 balance is the starting point for the review of supply costs and supply revenues in the PPAC balancing account from April 1, 2001 through August 31, 2011 (Review Period).

The starting balance is based upon KPMG, LLP audit conducted pursuant to Resolution E-3704, which concluded that the under-collection in the PPAC as of March 31, 2001, on a recorded basis, was $10,760,734. Using generally accepted accounting principles (GAAP), BVES determined that, on an accrual basis, the under-collection in the PPAC balancing account as of March 31, 2001 was $15,676,922. The accrual basis includes $4.3 million in unpaid energy charges, interest charge differences on the two methods and other unpaid charges and fees.

c. Chapter 3 – Power Purchase Adjustment Clause Costs, April 1, 2001 through August 31, 2011.

The chapter describes costs booked into the PPAC balancing account during the Review Period. These costs included the costs of purchasing and producing energy, the costs of transmission, and other power-related costs incurred during the Review Period.

The amounts booked into the PPAC balancing account were last reviewed as a result of Application 01-08-020 filed August 17, 2001. At the time the application was filed, BVES had no internal generation and purchased all of its power through third-party suppliers. Over the 18 months prior to BVES filing the application a substantial under-collection of costs had accumulated in the PPAC balancing account due to the spiraling costs of wholesale power caused by the California energy crisis.

Power Purchase Agreements. During the Review Period, costs from a number of power purchase agreements (PPAs) with a number of different power suppliers were booked into the PPAC balancing account. These costs arose with respect to PPAs with following suppliers:

- Dynegy Power Marketing (Dynegy) (May 2000 through April 2001)
- Mirant Americas Energy Marking (Mirant) (May 2001 – December 2006)
- Pinnacle West Capital Corporation (Pinnacle West) (November 2001 – March 2004)
- Pinnacle West (November 2002 – December 2008)
- Shell Energy (January 2009 – December 2013)
- County Sanitation District No. 2 of Los Angeles (LACSD) (August 2011 – August 2021).

In August 2001, BVES[10] filed an application (A.01-08-020) with the Commission seeking, among other things, approval of a PPA with Mirant Contract and a PPA with Pinnacle West. These two PPAs were negotiated and executed during the height of the energy crisis in California. BVES also sought an increase in PPAC charges to recover both substantial under-collections accumulating in the PPAC account (which included costs arising from the Dynegy

[10] The application was filed by Southern California Water Company ("SCWC"), Golden State Water Company's predecessor. SCWC filed the application for its Bear Valley Electric Service division. Even though actions were taken by SCWC on behalf of BVES, all actions taken by SCWC shall be referred to herein as actions taken by BVES.

PPA) as well as projected increased energy costs as a result the PPA with Mirant and the PPA Pinnacle West Contract.

The parties reached a settlement agreement (Settlement Agreement) that fully resolved and settled all issues and was approved by the Commission in D.02-07-041. The Settlement Agreement resulted in, among other things, a reduction of $1,763,366 in power purchase costs booked into the PPAC account from April 1, 2001 through July 31, 2002, a reduction in the requested increase in PPAC Charges, and the imposition of a cap on energy costs that limited BVES' ability to recover no more than a $77.00/MWh unit-cost ceiling on a weighted average twelve-month basis (the $77/MWh Cap). This $77/MWh Cap would remain in effect for a decade[11] and eventually would require BVES to write-off an additional $1,584,926 of power purchase costs booked into the PPAC. Because of the protection afforded to ratepayers, the Commission declared that so long as the $77/MWh Cap was in place, costs resulting from PPAs were recoverable in rates without further review.[12]

A new blend-and-extend Pinnacle West PPA reduced BVES' cost of energy to $74.65/MWh. The term of the contract was from November 1, 2002 through December 31, 2008. As part of this new blend-and-extend contract, Pinnacle West purchased from BVES the energy under the Mirant PPA and the existing Pinnacle West PPA at the contract prices and "blended" it with lower-priced power to achieve the new "blended" price of $74.65/MWh. As a result, BVES was able to reduce its three-year weighted average cost of the existing Mirant PPA and the existing Pinnacle West PPA of $87.41/MWh down to a price level below the Commission-adopted cap of $77/MWh.

Following the expiration of the Pinnacle West PPA, BVES executed a contract with Shell Energy North America (US) L.P. ("Shell") for four power products (an annual baseload product for 13 MW of energy; a seasonal baseload product for 7 MW of energy (December, January and February) and 5 MW of energy (November); a heat rate call option product, (15 MW of capacity during the winter months of January through March and 5 MW of capacity the other months of the year); and a system resource capacity product for 15-35 MW of capacity varying by month and year. The Commission approved the Shell contract, and its four distinct power products, in Decision 09-05-025.

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[11] In accordance with D.02-07-041 and as authorized by Advice Letter 248-E, the $77/MWh Cap was removed from BVES' tariffs effective September 1, 2011.
[12] Decision 09-05-025 at p. 1 and Decision 11-06-030 at p. 1.

In 2009, BVES executed a 10-year power purchase agreement with the County Sanitation District No. 2 of Los Angeles County ("LACSD") for RPS-eligible energy from its Palos Verdes Landfill gas-to-energy facility. In D.11-06-030, the Commission approved the LACSD agreement for RPS-eligible energy.

In summary, BVES booked a total of approximately $119 million of long-term PPA costs into the PPAC balancing account during the Review Period. The costs relating to the Dynegy, Mirant and Pinnacle West PPAs booked into the PPAC balancing account were reviewed and approved as a result of the Settlement Agreement and D.02-07-041. The costs relating to the blend-and-extend Pinnacle West PPA, the Shell PPAs and the LACSD PPA booked into the PPAC balancing account through August 31, 2011 are recoverable in rates without further review because those energy costs were incurred while the $77/MWh Cap was in effect.[13] As a result of the Settlement Agreement and the $77/MWh Cap, BVES was required to write off a total of $3,348,292 of energy-related costs that otherwise would have been booked into the PPAC balancing account, to the benefit of BVES' ratepayers.

To balance its loads and resources, BVES purchased short energy and sold surplus energy through both the day-ahead market and the CAISO markets in a manner that was prudent and minimized costs to BVES' ratepayers.

Bear Valley Power Plant Costs. Although the majority of BVES' energy is derived from non-dispatchable resources (*i.e*., PPAs with blocks of energy, short-term purchases and sales, etc.) BVES has one dispatchable resource in its 8.4 MW power plant (BVPP). Its primary benefit is to provide peaking capacity to BVES to make up for transmission limitations on SCE transmission facilities serving BVES' transmission system. BVES dispatched BVPP in a prudent manner to maximize benefits and minimize costs to BVES' ratepayers.

Natural Gas Costs. BVES purchased natural gas for BVPP. It also purchased gas transportation and storage services. The natural gas-related contracts were prudently administered by BVES. The natural gas products and services were prudently purchased and the costs were reasonable.

Transmission Costs. SCE provides transmission service to BVES under tariffs and rates approved by the Federal Energy Regulatory Commission (FERC). However, once FERC has approved the service terms and rates, BVES is required to pay SCE the FERC-approved rates

[13] Decision 09-05-025 at p. 1 and Decision 11-06-030 at p. 1.

and amounts and recover them in retail rates under the file-rate doctrine and established principles of Federal preemption. These FERC-approved tariffs were administered by BVES in a prudent manner. Those transmission costs that BVES had limited discretion to control were managed consistent with the objective of minimizing costs to BVES' ratepayers.

Schedule Coordinator Costs. Every utility must either be or have a schedule coordinator ("SC") to interface with the CASIO. BVES obtained its SC services via contract. During the Review Period, BVES entered into contracts with Mirant and APX for SC services. BVES prudently administered these SC contracts and the resulting costs were reasonable.

CAISO Charges. The CAISO manages the electric grid in which BVES is located. BVES must pay to the CAISO certain FERC-approved charges for grid management services (including ancillary services). BVES has no alternative to purchasing these services at FERC-approved rates. BVES monitored compliance of the CAISO under its FERC-approved tariffs. These FERC-approved tariffs were administered by BVES in a prudent manner and the costs are reasonable.

Summary of PPAC Costs and Write-offs. Excluding the required adjustments to energy costs due the $77/MWh Cap, a total of $151,022,008 of costs were booked into the PPAC Account for the subject period April 1, 2001 through August 31, 2011, as summarized below:

1. Long-term firm purchased power costs of $119,125,317.
2. Purchases of short energy of $8,991,332 less revenues from the sale of surplus energy of $7,578,100 for a net cost of short term energy of $1,413,232.
3. SCE transmission costs of $15,302,522.
4. CAISO costs of $10,442,590.
5. Scheduling Coordinator costs of $922,625.
6. Natural gas costs of $768,174, natural gas transportation costs of $324,424 and natural gas storage costs of $30,624.
7. Resource adequacy costs of $1,930,000.
8. Heat rate option costs of $762,500.

To comply with the Settlement Agreement and the resulting $77/MWh Cap, BVES wrote off energy costs in the PPAC by $3,348,292, resulting in total power costs booked into the PPAC Account of $147,673,735.

To be clear, BVES is not seeking, on a prospective basis, the authority to recover $147,673,735 of PPAC costs. As discussed in Chapter 5 of Volume 4, most of these PPAC costs have already been recovered through $162,744,670 of revenues collected and booked into the PPAC account as a result of authorized PPAC charges (*i.e.*, transmission charges, energy charges and amortization charges). If the Commission approves the revenues booked into the PPAC account as described in Chapter 5 of Volume 4, BVES only seeks authority to recover, on a prospective basis as of September 1, 2011, $6,475,708 in PPAC costs, which is the under-collection amount in the PPAC as of August 31, 2011.

d. Chapter 4 -- Forecast Supply Expenses 2011 through 2016.

The purpose of this chapter is to provide a description and basis for the forecast of supply costs for this Application. BVES' power supply costs are comprised of three major components. These are energy and capacity costs, including resource adequacy (RA) capacity, transmission costs and CAISO ancillary services.

BVES has fixed most of its energy and capacity costs through a series of long-term energy and RA purchases. As a result of these long-term energy purchases, BVES' total power supply costs are fairly stable, with 75 to 85 percent of all energy and capacity costs fixed through 2012. BVES is currently planning to enter into a new series of long-term energy purchases that will both lower power supply costs while maintaining a high degree of certainty of the level of costs during the contract period.

BVES is projecting that its total power supply costs will remain relatively stable in 2011, 2012 and 2013 at approximately $14,400,000 to $14,800,000 with the average *total* cost per MWh of approximately $95/MWh.[14] Beginning in 2014, when the current annual baseload contract ends, BVES' power supply costs are projected to decline slightly on a cost/MWh basis and remain fairly constant under the assumption that BVES executes proposed contracts at the current bid price.

e. Chapter 5 -- Supply Balancing Account and Proposed Revenue Components.

As discussed earlier, the source of revenues booked into the PPAC balancing account is the following three charges: the Power System Delivery Charge, the Energy Charge for Purchases (Energy Charge), and the Amortization Charge. The Power System Delivery Charge is intended to recover costs related to transmission service. The Energy Charge is intended to

[14] The $95/MWh is measured at SCE's delivery point. After adding in 13% losses, the cost to the customer is about $107/MWh.

recover all purchased power costs and fuel-related costs. The Amortization Charge is intended to recover (or refund) any under-collection (or over-collection) balances that accrue in the PPAC account whenever the PPAC-related costs and PPAC revenues are out of balance with one another. Since 2001, there has been a very large amount of under-collections in the PPAC account, which has necessitated the maintenance of the Amortization Charge at its current level of \$.02246 per KWh, which was originally established in D.02-07-041.

BVES in proposing to change the name of these three charges effective Test Year 2013 to more accurately describe their functions: The Power System Delivery charge will be called the Transmission Charge, the Energy Charge will be called the Supply Charge, the Amortization Charge will be called the Supply Adjustment Charge. Furthermore the PPAC will be named the Supply Adjustment Clause. The procedures for the Supply Adjustment Clause will be identified in a revision to BVES Preliminary Statement L. [15]

There was a significant increase in PPAC revenue between 2002 and 2003 due to the increase in the Amortization Charge. Revenue increased steadily to 2006 where it reached a maximum of \$17,348,185 in 2006. There was a slight decline in revenue between 2007 and 2009 and a larger drop in revenues in 2010. Since the economy of BVES' service territory is extremely dependent on tourism, electric sales were directly affected by the economic recession. Total PPAC revenues during the Review Period equaled \$162,744,670.

With a starting PPAC balance (under-collections) of \$15,676,922 as of March 1, 2001, total PPAC revenues of \$162,744,670, and total PPAC costs of \$147,673,735,[16] the resulting balance (under-collection) in the PPAC balancing account as of August 31, 2011 was \$6,475,708.

The revenue forecast is based on no net increase in the *overall* PPAC charges in Test Year 2013. BVES proposes to decrease the Supply Adjustment Charge from \$0.02246 to \$0.01729 per kWh and change the other two supply charge components, (Power System Delivery Charge or "transmission charges" and the Energy Charge or "supply charges") "PPAC Revenue" by a combined \$0.00517 per kWh. Thus, BVES proposes no net increase in overall PPAC charges in Test Year 2013.[17]

[15] Volume 6 will provide a revised Preliminary Statement.
[16] This is the net amount after reducing the PPAC costs by \$3,348,292 as a result of the Settlement Agreement and the \$77/MWh Cap.
[17] \$0.01729 + \$0.00517 = \$0.02246.

The Test Year 2013 increases in the Power System Delivery Charge or "transmission charges" and the Energy Charge or "supply charges" are needed to more closely cover the 2013 through 2016 forecast of transmission and supply costs. In this Application, BVES proposes to increase the Power System Delivery Charge (or "transmission charges") from approximately $0.0138 per kWh, on average,[18] to approximately $0.0330 per kWh on average and to decrease the Energy Charge (or "supply charges") from approximately $0.0865 per kWh on average[19] to $0.0725 kWh on average. The changes in these two charges are forecast to result in a PPAC cumulative balance of zero by the end of 2016. Volume 6 includes the proposed Test Year 2013 Energy Charges and Power System Delivery Charges for each of its electric tariff schedules.

BVES plans to reduce the Supply Adjustment Charge from $0.01729 per kWh to zero when the under-collection balance initially reaches zero, which is expected to occur around September 2014.[20] BVES estimates, based on current cost and revenue forecasts, that once the under-collection has been fully amortized, the reduction of the Supply Adjustment/Amortization Charge rate to zero will result in a 5.5% reduction in system average rates. Specific supply rate design is discussed in Volume 6.

4. Volume 5 – Cost of Capital

BVES recommends an authorized rate of return (ROR) at 9.81% based on a return on equity (ROE) of 12.00%. In its last general rate case (GRC), BVES was authorized a ROR of 9.15% base on a ROE of 10.50%, based upon a settlement with DRA which was adopted by the Commission in D. 09-10-028. The recommended ROR and ROE are based upon the following:

Weighted Cost of Capital

Cost Component	Weight	Cost	Weighted Cost
Long-Term Debt	44.40%	7.06%	3.135%
Common Equity	55.60%	12.00%	6.672%
Rate of Return			**9.81%**

[18] This is an average value. Transmission charges vary by customer class from $0.0105/kWh for residential customers to $0.0182/kWh for commercial customers to $0.0077/kWh for very large power-use customers without any variation by tier structure.

[19] This is an average value. Supply charges vary by customer class and especially by tier and time-of-use from a low of $0.04335/kWh for off-peak A5 to a high of $0.1520/kWh for tier #3 residential customers.

[20] The request will be made by advice letter as authorized in the BVES Preliminary Statement.

5. <u>Volume 6 – Cost Allocation and Rate Design</u>

As discussed above, BVES intends to submit its proposed marginal costs analysis, cost allocation, rate design, new rates, updates to Commission tariff rules, and preliminary statement language in a supplement to this Application in approximately four weeks. Issues addressed in the forthcoming Volume include the following.

Rate Design Policy: Volume 6 discusses rate design policy, and the application of the results of the Marginal Cost Study to making changes to BVES' rates. This includes the policy addressing the application of equal percentage of marginal cost (EPMC) methods of allocating the rate increase to customer classes as well as changes in the tier structure pricing.

Marginal Costs: Included in Volume 6 are the results of BVES' Marginal Cost Study that includes an explanation of how BVES' developed its estimate of the marginal of providing energy, peak and non-coincident demands and customer services. It explains how marginal cost estimates were used by BVES to develop an estimate of revenue based on marginal cost data by customer class for use in allocating the rate increase to classes.

Revenue Allocation: Revenue Allocation is the process used to determine each rate group's responsibility for the overall revenue requirement developed in Volume 2, the Results of Operation. The Revenue Allocation process is based upon cost considerations including the Marginal Cost Study and BVES' policies addressing fairness and impacts this Application may have on customers. The objective is to begin to balance consideration of marginal cost of service and rate impacts on customers by moving classes toward EPMC.

Rate Design: Volume 6 includes a discussion of how BVES applied the policies and principles addressed in Volume 6. The results are shown in tables using dollars and percent increases to individual rate schedules. New Tariff Schedules are described and supported. In some cases changes to rates not only take the form of numbers but also the method of applying those numbers as expressed in application of "special conditions" associated with each rate. The goal is to generate revenue for the 2013 Test Year that recovers the revenue requirement and simultaneously addresses cost of service and policy principles adopted in this Application. Included as part of the rate design in this Application are modifications of Rules and Preliminary Statements to accommodate different terms and changes in the use of terms and names for rate components. The details are available in work papers regarding Volume 6.

Unbundled Rates: Volume 6 separates rates by customer class and function, consistent with Commission direction for possible unbundled rates. The purpose of unbundling is to appropriately display the components of tariffs so that customers can see the cost components that make up the prices that they are being charged. The basic elements of BVES' cost structure include Electric Supply, Transmission, Distribution and Other costs.

New Rates: Volume 6 introduces three new rates proposed by BVES: In support of the Special Request # 6, the Snow Summit incremental sale requires a Supplemental Energy Rate and an Added Facilities charge. Also BVES is proposing a new Standby Charge for certain customers.

Revisions to Rules: Volume 6 includes revisions to rules: 2, 4, 7, 9, 10, 13, 15, 16, 19, and 20 in conformance with Commission direction.

E. FORMAL MATTERS AND PROCEDURAL REQUIREMENTS

This Application is filed in compliance with Ordering Paragraph #6 of Decision 09-10-028,[21] and in accordance with California Public Utilities Code Sections 381, 451, 454, and 701 and Rules 2.1, 2.2 and 3.2 of the Commission's Rules of Practice and Procedure.

The applicant's legal name is Golden State Water Company (GSWC). GSWC files this Application on behalf of its Bear Valley Electric Service, which is a regulated division of GSWC. GSWC is a regulated subsidiary of American States Water Company. GSWC's mailing address and principal place of business is 630 East Foothill Boulevard, San Dimas, California, 91773. GSWC's main telephone number is (909) 394-3600. Correspondence and communications regarding this Application should be addressed to:

Keith Switzer
Vice President, Regulatory Affairs
Golden State Water Company
630 East Foothill Boulevard
San Dimas, California 91773
(909) 394-3600 Ext. 759
(909) 394-7427 (fax)
KSwitzer@gswater.com

[21] In D. 10-03-016, the Commission modified D.09-10-28 by adding ordering paragraph #6 which requires GSWC to file its next general rate case application for BVES for Test Year 2013 by January 31, 2012. This filing deadline was extended to no later than February 21, 2012 by letter from Mr. Paul Clanon, Executive Director, dated January 26, 2012.

with a copy to:
Fred Yanney
Fulbright & Jaworski L.L.P.
555 South Flower Street
41st Floor
Los Angeles, California 90071
(213) 892-9200
(213) 892-9494
fyanney@fulbright.com

GSWC is a corporation duly organized and existing under and by virtue of the laws of the State of California and represents the consolidation, effective on December 31, 1929, upon the order of the Commission, of some twenty corporations which were formerly operated under the jurisdiction of the Commission as public utilities, together with subsequent acquisitions and additions. The Commission authorized the implementation of a holding company structure and the formation of American States Water Company as the parent company of Southern California Water Company (GSWC's predecessor). GSWC is a public utility rendering electric service, through its BVES division, in the vicinity of Big Bear Lake in San Bernardino County. BVES also is licensed by the City of Big Bear Lake.

A copy of GSWC's Restated Articles of Incorporation as amended on September 16, 2005 were previously filed as an exhibit to GSWC's Application No. A.06-02-03.

GSWC's latest available Balance Sheet and Income Statement are attached hereto as Exhibit A.

No transaction requiring the reporting of a material financial interest, as defined in General Order No. 104-A, has occurred since the last Annual Report filed by GSWC, and except as reported therein, GSWC does not propose at present to become party to any transaction requiring a report of such material financial interest.

If BVES' request in this Application is granted, there will be an increase over its authorized 2012 base rate revenue requirement of $21.09 million to $22.41 million for Test Year 2013 and BVES' total revenues will increase from $40.69 million to $44.70 million. This request for $4.01 million increase in total revenues for Test Year 2013 represents a 9.85% increase over total revenues for Test Year 2012. The requested increase in rates over 2012 authorized rates is 7.79%. Expressed on a $/kWh basis, the proposed rate increase of 7.79% would have the effect of increasing by approximately $7.56/month the average residential bill in

2012 of $97.06/month.[22] BVES seeks no net increase in the *overall* PPAC charges in Test Year 2013. BVES proposes to decrease the Supply Adjustment Charge from $0.02246 to $0.01729 per kWh and change the other two supply charge components, (Power System Delivery Charge or "transmission charges" and the Energy Charge or "supply charges") "PPAC Revenue" by a combined $0.00517 per kWh. Thus, BVES proposes no net increase in overall PPAC charges in Test Year 2013.[23] The increase sought by this Application reflects increased costs and increased rates of returns to BVES for the services or commodities furnished by it.

The original cost of BVES' property and equipment and the depreciation reserve are provided in Volume 2, Results of Operation, Chapter 7 and Chapter 9 Part A. The summary of earnings on a depreciated rate base for the test period or periods upon which applicant bases its justification for increase are included in Volume 2, Results of Operation, Chapter 3. BVES has provided recorded values for revenues, expenses and plant additions for 2010.

BVES uses methods prescribed in the Internal Revenue Code ("IRC") (e.g. the modified accelerated cost recovery system for post-1986 vintages and including bonus depreciation pursuant to IRC Sec. 168(k)) provided to compute depreciation deduction for the purpose of determining BVES' federal income tax payments and BVES has used the same methods in calculating federal income taxes for the test period for rate making purposes.

Within 10 days of the filing of this Application, GSWC will cause to be published a notice of the general terms of the proposed increase in a newspaper of general circulation in the area served. Within 20 days of the filing of this Application, GSWC will mail a notice stating the general terms of the proposed rate increases to the officers of political subdivisions and interested parties listed on Exhibit B attached hereto. Within 45 days of the filing of this Application, GSWC will provide each customer of record, the information required by Rule 3.2(d) of the Commission's Rules of Practice and Procedure. Proof of compliance will be filed with the Commission within 20 days after compliance of the last action required in this paragraph. Proof of publication shall include a sworn verification listing the newspapers and publications dates and a sample of each different notice.

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[22] This is an average effect, based on average residential consumption of 450 kWh/month based on 2012 rates. Actual, proposed Test Year 2013 customer rates will be in Volume 6 and may differ due to changes in marginal cost allocation and rate design.

[23] $0.01729 + $0.00517 = $0.02246.

Consistent with Rules 2.1(c) and 7.1 of the Commission's Rules of Practice and Procedure, GSWC proposes to categorize this Application as a ratesetting proceeding (as defined in Rule 1.3(e)). The issues in this Application include: forecast sales, operating expenses, additions to plant, supply cost issues; marginal cost study and rate design; past and future power supply charges; rate of return; small utility regulatory challenges; energy efficiency programs; a new solar program; modification of the BRRAM to track seasonally adjusted monthly sales; establishment of a post test year attrition mechanism; modification of the GSWC general office cost allocation process; a proposed Snow Summit substation upgrade and supplemental sales tariff; new plant additions for an undergrounding project in City of Big Bear; and the establishment of a pensions and benefits balancing account.

BVES has no information at this time from which it can predict whether this Application will be protested or whether hearings will be necessary. If this matter is timely protested, BVES respectfully requests that the matter be set for a Prehearing Conference, at which time evidentiary hearings may be scheduled.

BVES respectfully requests that the Commission issue a decision as soon as practicable, but no later than the schedule set forth below to permit the requested rates and other requests to be in effect January 1, 2013:

Application filed	February 16, 2012
Rate Design/Cost Allocation Supplement filed	March 16, 2012
Protests/Responses Due[24]	April 16, 2012
Prehearing Conf/Scoping Memo	April 20, 2012
DRA/Intervener Response (Testimony)	June 15, 2012
GSWC Rebuttal	July 13, 2012
Formal Settlement Negotiations	July 17, 2012
Hearings	July 24, 2012
Initial Briefs	August 31, 2012

[24] Although the protest period is 30 days, BVES will not object to any protest filed within 30 days after the rate design/cost allocation supplement is filed.

Reply Briefs	Sept 10, 2012
Proposed Decision	November 1, 2012
Comments on Proposed Decision	November 21, 2012
Replies to Comments on Proposed Decision	November 27, 2012
Expected Commission Meeting/Decision	December 13, 2012

F. <u>CONCLUSION</u>

GSWC's Bear Valley Electric Service division's present rates are unjust and unreasonable and do not and will not produce a fair and reasonable return. The requested rate increase, along with the Special Requests sought by this Application, will enable BVES to earn a fair and reasonable rate of return on the property of GSWC dedicated to rendering public electric service in its Bear Valley service area.

G. PRAYER FOR RELIEF

WHEREFORE, Golden State Water Company for its Bear Valley Electric Services Division prays that this Commission issue an Order:

1) Finding that the present rates and charges are unjust and unreasonable
2) Finding that the rates and charges proposed herein are fair, just and reasonable.
3) Authorizing BVES a rate of return on rate base (ROR) of 9.81% for test year 2013, based on a 12.00% return on equity (ROE), and a capital structure of 44.4% long-term debt and 55.6% common equity.
4) Authorizing BVES to increase its authorized base rate revenue requirement to $22.41 million for Test Year 2013 and authority to increase total revenues by $4.01 million for Test Year 2013.
5) Approving the Special Requests set forth in Volume 3.
6) Approving the amount of under-collections in the PPAC balancing account, as of March 31, 2001, was $15,676,922.

7) Approving the recovery of the following costs booked into the PPAC balancing account, subject to the adjustment required by the Settlement Agreement and $77/MWh Cap for the Review Period of April 1, 2001 through August 31, 2011:

   a) Long-term firm purchased power costs of $119,125,317.

   b) Purchases of short energy of $8,991,332 less revenues from the sale of surplus energy of $7,578,100 for a net cost of short term energy of $1,413,232.

   c) SCE transmission costs of $15,302,522.

   d) CAISO costs of $10,442,590.

   e) Scheduling Coordinator costs of $922,625.

   f) Natural gas costs of $768,174, natural gas transportation costs of $324,424 and natural gas storage costs of $30,624.

   g) Resource adequacy costs of $1,930,000.

   h) Heat rate option costs of $762,500.

8) Confirming that BVES properly wrote off energy costs in the PPAC by $3,348,292 in full compliance with the Settlement Agreement and the $77/MWh Cap, resulting in total power costs booked into the PPAC Account of $147,673,735 for the Review Period.

9) Confirming that PPAC revenues of $162,744,670 collected during the Review Period and booked into the PPAC balancing account is correct, with a resulting under-collection amount of ($6,475,708) as of August 31, 2011.

10) Authorizing BVES to collect, on a prospective basis as of September 1, 2011, the under-collection amount of ($6,475,708) that existed in the PPAC balancing account as of August 31, 2011.

11) Authorizing a decrease of the Supply Adjustment Charge from $0.02246 to $0.01729 per kWh and changing the other two supply charge components (Power System Delivery Charge and the Energy Charge) by a combined $0.00517 per kWh such that there is no overall change in PPAC charges.

12) Authorizing proposed rates, charges, rate schedules and Preliminary Statement as requested in this Application and supporting testimony.

13) Granting such further, additional or other relief as the Commission may deem to be necessary or proper in light of this Application.

Dated at San Dimas, California: February 16, 2012

Respectfully submitted,

BY: /s/ Keith Switzer

Keith Switzer
Vice President of Regulatory Affairs
Golden State Water Company
630 East Foothill Boulevard
San Dimas, California 91773
(909) 394-3600 Extension 759
KSwitzer@gswater.com

VERIFICATION

I am Vice President of Regulatory Affairs for, and an officer of, Golden State Water Company, and am authorized to make this verification on its behalf with respect to the within Application. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 16th day of February 2012, at San Dimas, California.

Keith Switzer

Keith Switzer
Vice President, Regulatory Affairs
Golden State Water Company

EXHIBIT A

GSWC Balance Sheet and Income Statement

GOLDEN STATE WATER COMPANY

BALANCE SHEET

	December 31 2011	December 31 2010
	(in thousands)	
Assets		
Utility Plant, at cost		
Water	$ 1,187,556	$ 1,108,205
Electric	73,825	68,813
	1,261,381	1,177,018
Less - Accumulated depreciation	(410,644)	(375,740)
	850,737	801,278
Construction work in progress	41,208	50,089
Net utility plant	891,945	851,367
Other Property and Investments		
State Water Project	5,124	5,287
Other physical property, net	709	709
Other Investments	3,568	2,678
Funds held in trust	225	225
Total other property and investments	9,626	8,899
Current Assets		
Cash and cash equivalents	-	1,541
Accounts receivable - customers (less allowance for doubtful accounts of $715 in 2011 and $670 in 2010)	20,399	17,507
Other accounts receivable - customers (less allowance for doubtful accounts of $290 in 2011 and $335 in 2010)	7,755	6,174
Intercompany receivable	785	2,057
Income taxes receivable from Parent	9,662	7,421
Unbilled revenue	16,188	20,348
Materials and supplies, at average cost	1,926	1,779
Regulatory assets - current	27,641	34,152
Prepayments and other current assets	3,763	5,695
Deferred income taxes - current	8,467	7,814
Total current assets	96,586	104,488
Regulatory and Other Assets		
Unamortized debt expense and redemption premium	5,783	4,671
Regulatory assets	140,642	101,801
Other accounts receivable	1,838	3,777
Other	5,761	3,475
Total deferred charges	154,024	113,724
Total Assets	$ 1,152,181	$ 1,078,478

	December 31 2011	December 31 2010
	(in thousands)	
Capitalization and Liablities		
Capitalization		
Common shareholder's equity	$ 384,677	$ 358,295
Long-term debt	340,395	299,839
Total capitalization	725,072	658,134
Current Liabilities		
Long-term debt - current	291	376
Accounts payable	31,227	25,463
Intercompany payable	-	34,575
Income taxes payable to Parent	-	-
Accrued employee expenses	7,544	7,212
Accrued interest	3,938	3,251
Regulatory liabilities	-	-
Deferred income taxes - current	-	-
Unrealized loss on purchased power contracts	7,431	6,850
Other	16,161	16,032
Total current liabilities	66,592	93,759
Other Credits		
Advances for construction	75,353	78,325
Contributions in aid of construction	100,037	95,460
Deferred income taxes	107,923	101,474
Unamortized investment tax credits	1,972	2,063
Accrued pension and other postretirement benefits	68,352	42,152
Regulatory liabilities	-	-
Other	6,880	7,111
Total other credits	360,517	326,585
Total Capitalization and Liabilities	$ 1,152,181	$ 1,078,478

GOLDEN STATE WATER COMPANY

STATEMENT OF INCOME

MONTH, YEAR TO DATE AND TWELVE MONTHS ENDED

December 31, 2011 and 2010

	THIS MONTH		Increase	Percent	YEAR TO DATE		Increase	Percent	TWELVE MONTHS ENDED		Increase	Percent
	December, 2011	December, 2010	(Decrease)	Change	December, 2011	December, 2010	(Decrease)	Change	December, 2011	December, 2010	(Decrease)	Change
Operating Revenues												
Water	$ 19,622,617	$ 19,875,516	$ (252,899)	-1.27%	$ 298,321,170	$ 289,293,380	$ 9,027,790	3.12%	$ 298,321,170	$ 289,293,380	$ 9,027,790	3.12%
Electric	3,704,784	3,687,253	17,531	0.48%	36,279,758	35,800,603	479,155	1.34%	36,279,758	35,800,603	479,155	1.34%
Other	-	-	-	-	-	-	-	-	-	-	-	-
Total operating revenues	23,327,401	23,562,769	(235,368)	-1.00%	334,600,928	325,093,983	9,506,945	2.92%	334,600,928	325,093,983	9,506,945	2.92%
Supply Costs												
Water Purchased	2,996,503	2,848,204	148,299	5.21%	47,530,144	46,864,575	665,569	1.42%	47,530,144	46,864,575	665,569	1.42%
Supply cost balancing accounts	926,916	515,818	411,098	79.70%	18,748,178	20,622,308	(1,874,129)	-9.09%	18,748,178	20,622,308	(1,874,129)	-9.09%
Power for pumping	379,257	214,487	164,769	76.82%	8,597,746	9,113,025	(515,280)	-5.65%	8,597,746	9,113,025	(515,280)	-5.65%
Power for resale	1,564,354	1,409,301	155,053	11.00%	13,574,390	13,078,147	496,244	3.79%	13,574,390	13,078,147	496,244	3.79%
Pump taxes	1,052,490	854,504	197,986	23.17%	13,550,285	11,473,017	2,077,268	18.11%	13,550,285	11,473,017	2,077,268	18.11%
Total supply costs	6,919,520	5,842,314	1,077,206	18.44%	102,000,744	101,151,072	849,672	0.84%	102,000,744	101,151,072	849,672	0.84%
Revenues Less Supply Costs	16,407,881	17,720,455	(1,312,574)	-7.41%	232,600,184	223,942,911	8,657,272	3.87%	232,600,184	223,942,911	8,657,272	3.87%
Other Operating Expenses												
Other operation expenses	2,466,679	2,795,356	(328,676)	-11.76%	25,090,959	25,365,721	(274,762)	-1.08%	25,090,959	25,365,721	(274,762)	-1.08%
Maintenance expenses	1,433,027	1,963,569	(530,542)	-27.02%	14,481,629	15,654,260	(1,172,632)	-7.49%	14,481,629	15,654,260	(1,172,632)	-7.49%
Administrative and general expenses	5,095,798	6,755,597	(1,659,799)	-24.57%	59,392,310	54,345,276	5,047,034	9.29%	59,392,310	54,345,276	5,047,034	9.29%
Depreciation and amortization	2,641,832	3,047,730	(405,898)	-13.32%	37,148,600	36,573,341	575,259	1.57%	37,148,600	36,573,341	575,259	1.57%
Property and other taxes	1,086,437	904,552	181,886	20.11%	12,618,221	12,304,845	313,376	2.55%	12,618,221	12,304,845	313,376	2.55%
Total other operating expenses	12,723,773	15,466,803	(2,743,030)	-17.73%	148,731,719	144,243,444	4,488,275	3.11%	148,731,719	144,243,444	4,488,275	3.11%
Operating Income	3,684,109	2,253,652	1,430,457	63.47%	83,868,465	79,699,468	4,168,997	5.23%	83,868,465	79,699,468	4,168,997	5.23%
State income taxes	186,230	111,035	75,195	67.72%	5,683,641	5,418,231	265,410	4.90%	5,683,641	5,418,231	265,410	4.90%
Federal income taxes	890,087	106,039	784,048	739.40%	20,425,823	19,564,524	861,299	4.40%	20,425,823	19,564,524	861,299	4.40%
Total income taxes	1,076,317	217,074	859,243	395.83%	26,109,464	24,982,755	1,126,709	4.51%	26,109,464	24,982,755	1,126,709	4.51%
Income Before Interest Charges	2,607,792	2,036,578	571,214	28.05%	57,759,001	54,716,713	3,042,288	5.56%	57,759,001	54,716,713	3,042,288	5.56%
Interest expenses (income)	654,873	1,255,778	(600,905)	-47.85%	22,690,531	20,857,811	1,832,719	8.79%	22,690,531	20,857,811	1,832,719	8.79%
Non-regulatory income (loss):												
Income taxes on non-regulatory items	(219,325)	3,063,537	(3,282,861)	-107.16%	185,348	5,898,863	(5,713,515)	-96.86%	185,348	5,898,863	(5,713,515)	-96.86%
Other	459,951	(6,207,746)	6,667,697	-107.41%	(384,679)	(14,647,552)	14,262,873	-97.37%	(384,679)	(14,647,552)	14,262,873	-97.37%
Total non-regulatory Income(loss)	240,626	(3,144,210)	3,384,836	-107.65%	(199,331)	(8,748,689)	8,549,358	-97.72%	(199,331)	(8,748,689)	8,549,358	-97.72%
Net Income(loss)	$ 2,193,545	$ (2,363,410)	$ 4,556,955	-192.81%	$ 34,869,139	$ 25,110,212	$ 9,758,926	38.86%	$ 34,869,139	$ 25,110,212	$ 9,758,926	38.86%