Golden State
Water Company
A Subsidiary of American States Water Company

November 23, 2011 **PUBLIC VERSION**

Advice Letter No. 258-E (U 913 E)

California Public Utilities Commission

Attention: Energy Division
Advice Letter Filings Room 4005

Golden State Water Company ("GSWC") hereby transmits for filing an original and four conformed copies of the following Advice Letter applicable to its Bear Valley Electric Service ("BVES") division

SUBJECT: Purchase and Sale Agreement for *Renewable Energy Credits* between Golden State Water Company and County Sanitation District No. 2 of Los Angeles

I. INTRODUCTION

A. Purpose of Advice Letter.

Pursuant to D.10-03-021,[1] Golden State Water Company ("GSWC"), on behalf of its Bear Valley Electric Service Division ("BVES"), submits this Tier 3 advice letter ("Advice Letter") for approval of Confirmation No. 2 for the sale and purchase of renewable energy credits ("RECs") under and pursuant to an existing EEI Master Power Purchase and Sale Agreement, as amended, ("Master Agreement") between GSWC and the County Sanitation District No. 2 of Los Angeles ("LACSD"). The Master Agreement and Confirmation No. 1 between GSWC and LACSD (for the sale and purchase of RPS bundled energy) were approved by the Commission in D.11-06-030 on June 23, 2011. Confirmation No. 2 (for the sale and purchase of RECs) between GSWC and LACSD ("Parties") is the subject of this Advice Letter.

[1] The Commission authorized investor-owned utilities to submit REC contracts for CPUC review and approval by advice letter, starting April 1, 2010. D.10-03-021, Appendix D, p. 3.

Confirmation No. 2, if approved, would be undertaken and completed pursuant to the Master Agreement previously approved by the Commission in D.11-06-030.

Purchase of these RECs under Confirmation No. 2 will be a very significant step forward for BVES in its efforts to meet its RPS obligations at a reasonable price. The price of these RECs is competitive in comparison to the prices of any other RPS alternative available to BVES at the time Confirmation No. 2 was negotiated and executed. There are no limitations on BVES as to the amount of RECs that it may use to meet its RPS obligations. In D.10-03-021, the Commission specifically exempted BVES from the 25% of annual procurement target ("APT") limitation placed on the use of RECs by the larger investor-owned utilities.[2] In addition, Senate Bill X1 2 ("SB X1 2") authorizes BVES to use 100% RECs to meet its RPS obligations.[3]

BVES submits this Advice Letter for Commission review and approval of Confirmation No. 2 and to establish BVES' authority to recover costs of payments, made pursuant to Confirmation No. 2, through BVES' Power Purchase Adjustment Clause ("PPAC"). BVES requests the Commission issue a resolution no later than June 30, 2012 approving Confirmation No. 2 in its entirety and all payments to be made by BVES under Confirmation No. 2, and containing the findings required by the definition of "CPUC Approval" adopted in D.07-11-025 and D.08-04-009.

B. Background Information

Confirmation No. 1 (for bundled RPS energy) and the Master Agreement were executed by the Parties in September 2009. Confirmation No. 1 relates to the sale and purchase of bundled RPS energy from a generating facility LACSD operated at its Palos Verdes Landfill ("Generating Facility"). LACSD has owned and operated this landfill gas-to-energy Generating Facility for over 20 years. When the Generating Facility was in operation, it produced approximately 2.4 megawatts ("MW") of energy per hour.[4] The Generating Facility was certified by the California Energy Commission ("CEC") as an RPS-eligible generator on July 29,

[2] D.10-03-021 at p. 47.
[3] Section 25, SB X1 2, new Section 399.18(b) of the California Public Utilities Code.
[4] The Generating Facility ceased operations on October 1, 2011.

2008. The Generating Facility is the RPS facility that generated the RECs which are the subject of Confirmation No. 2.

The Commission approved Confirmation No. 1, along with the Master Agreement, on June 23, 2011.[5] From the date the Parties executed Confirmation No. 1/Master Agreement (September 2009) to the date the Commission approved Confirmation No. 1/Master Agreement (June 2011), GSWC understands that much, if not all, of the power from LACSD's Generating Facility was sold as "brown" power while LACSD retained the RECs in a WREGIS subaccount.

Before the Commission was able to review and approve the Master Agreement and Confirmation No. 1, a dispute between the Parties arose. On February 9, 2011, the Board of Directors of LACSD took action seeking to cancel the Master Agreement and Confirmation No. 1. GSWC objected, claiming that the Master Agreement and Confirmation No. 1 were still in effect, and only the obligations of BVES were subject to the condition precedent that the Commission approve the Master Agreement and Confirmation No. 1. As part of a settlement of the dispute between the Parties under Confirmation No. 1 to the Master Agreement (*i.e.*, bundled RPS energy from the Generating Facility), the Parties executed Confirmation No. 2 for the purchase and sale of RECs from the Generating Facility. Confirmation No. 2 is described in more detail immediately below.

C. General Project Description

The following table provides information related to the Generating Facility and Confirmation No. 2.

Generating Facility Name	Palos Verdes Landfill Gas-to-Energy Facility
Owner/Developer	County Sanitation District No. 2 of Los Angeles County
Capacity (MW)	N/A (No electricity purchased under Confirmation No. 2)
Capacity Factor	N/A (No electricity purchased under Confirmation No. 2)

[5] D.11-06-030.

Expected Generation (MWh/Year)	N/A (No electricity purchased under Confirmation No. 2)
Initial Commercial Operation Date (COD)	Generating Facility is operational
Date Contract Delivery Term Begins	First business day following date of CPUC Approval
Delivery Term (Years)	60 days, beginning first business day following date of CPUC Approval
Vintage (New/Existing/Repower)	Existing
Location (City and State)	Rolling Hills Estates, California
Control Area	CAISO
Nearest Competitive Renewable Energy Zone	N/A
Type of Cooling, if applicable	N/A
Price Relative to Market Price Referent (MPR)	N/A (no electricity purchased)

D. General Deal Structure

The following table summarizes the substantive features of Confirmation No. 2 for the sale and purchase of RECs.

Confirmation No. 2 with LACSD

Vintage of RECs	Amounts of RECs	Delivery Date of RECs	Generating Facility	Type of Fuel	Location
2010 and 2011	2010 – 20,793 2011 – 15,650*	Within 60 days of CPUC Approval	LACSD (Existing)	Landfill Gas	Rolling Hills Estates, CA

*All of the RECs generated from the Generating Facility in 2011 are to be sold to, and purchased by, BVES. It is estimated that approximately 15,650 RECs will be generated in 2011. The actual number of 2011 RECs may be different.

Under Confirmation No. 2, BVES will purchase CEC-certified RPS-eligible RECs – 20,793 RECs generated in 2010 and approximately 15,650 RECs generated in 2011.[6] The effective date of Confirmation No. 2 is the first business day following the date on which the CPUC approval of Confirmation No. 2 becomes final. The date upon which the RECs will be sold by LACSD and purchased by GSWC is a date no later than 60 days from the effective date of Confirmation No. 2, unless a longer period of time is required to complete the transaction.

As part of the settlement, LACSD required that in the event CPUC approval of Confirmation No. 2 does not occur before June 30, 2012, Confirmation No. 2 shall be of no force or effect regarding the 20,793 RECs generated in 2010. LACSD further required that in the event CPUC approval of Confirmation No. 2 does not occur prior to October 1, 2012, neither Party is liable to the other Party for any obligations under Confirmation No. 2.

Prior to delivery of the RECs, LACSD agrees to take all necessary steps to allow the RECs to be tracked in the Western Renewable Energy Generation Information System ("WREGIS"). LACSD represents and warrants that the RECs conform to the definition and attributes required for compliance with the RPS program, as set forth in D.08-08-028, as modified by subsequent Commission decision or legislation.

As required by the Commission, Confirmation No. 2 includes the following three non-modifiable standard terms and conditions: (1) Transfer of renewable energy credits; (2) Tracking of RECs in WREGIS; and (3) Applicable Law.[7] REC-only contracts of California IOUs other than multi-jurisdictional utilities ("MJUs") must contain a fourth STC: Commission Approval. This fourth STC is in the Master Agreement, which was approved by the Commission in D.11-06-030. Thus, all required STCs for a REC-only contract are included in Confirmation No. 2 and/or the Master Agreement.

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[6] All of the RECs generated from the Generating Facility in 2011 are to be sold to, and purchased by, BVES pursuant to Confirmation No. 2. It is estimated that approximately 15,650 RECs will be generated in 2011. The actual number of 2011 RECs may be different.

[7] D.11-01-025, Appendix B entitled "Summary of TREC Rules Announced in D.10-03-021, and Compiled in Appendix D to D.10-03-021, as Modified by this Decision."

E. RPS Statutory Goals.

Senate Bill ("SB") 1078 established the California RPS Program, requiring an electrical corporation to increase its use of eligible renewable energy resources to 20 percent of total retail sales no later than December 31, 2017. The Legislature subsequently accelerated the RPS goal to reach 20 percent by the end of 2010. The Legislature recently passed legislation (SB X1 2) that increases the RPS target to 33 percent by 2020. This bill was signed by the Governor on April 12, 2011. The law will take effect December 10, 2011 (91 days after the end of the current special session of the California Legislature).

This Advice Letter and Confirmation No. 2 are consistent with, and contribute towards, the RPS goals set forth in R.08-08-009. They provide an opportunity for oversight of BVES' RPS procurement process; provide updated information on the status of BVES' efforts to acquire RPS-eligible energy; facilitate review of BVES' latest Integrated Resource Plan (see Exhibit 1); provide information on how Confirmation No. 2 contributes to BVES' renewables portfolio and Confirmation No. 2's contract structures (see Appendices D and G); and provide information on how BVES is diligently pursuing all possible options to meet its RPS requirements while minimizing total RPS program costs to its customers.

Energy Division was consulted at various points by BVES as it developed and proceeded through its RFP process for RPS resources. In accordance with D.08-05-029, BVES has continued to keep the Energy Division apprised of its activities concerning its efforts to procure RPS-eligible renewable resources, including the preparation of this Advice Letter.

Confirmation No. 2, if approved by the Commission, will result in the acquisition of urgently needed RECs for BVES. These RECs represent a very significant contribution to BVES' near-term RPS goals. Approval of Confirmation No. 2 is consistent with current and pending RPS statutory goals.

F. Request for Confidentiality of Information Contained in Application.

In support of this Advice Letter, BVES has provided confidential information in the confidential versions of Appendices A, B and D. This information is being submitted in the manner directed by D.08-04-023 and the August 22, 2006 Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with D.06-06-066 to demonstrate the confidentiality of the material and to invoke the protection of confidential utility information provided under either the terms of the IOUs Matrix, Appendix 1 of D.06-06-066 and Appendix C of D.08-04-023, or General Order 66-C. A separate Declaration Seeking Confidential Treatment for Certain Data and Information is being filed concurrently with this Advice Letter.

II. CONSISTENCY WITH COMMISSION DECISIONS

BVES' procurement process complies with all applicable RPS-related decisions and resolutions, as described below.

A. BVES Procurement Plan

1. Commission Requirements for BVES Procurement Plan

Under California Public Utilities Code Section 454.5[8], each electric utility is required to file a proposed electricity procurement plan for Commission review and approval. Section 454.5 specifies that the plan address various issues, including: the price risk associated with the utility's portfolio for obtaining power; the duration of the plan; a competitive procurement process; a showing that the procurement plan will meet specified goals, including renewable resources; a risk management policy, strategy and practices; and a mechanism for recovery of administrative costs related to procurement. Section 454(i) provides that an electrical corporation serving fewer than 500,000 customers in California may file a request for exemption from the requirements of a procurement plan set forth in Section 454.5.

BVES filed for an exemption to the procurement plan under Section 454.5 in Advice Letter No. 224-E in August 2008. In Resolution E-4232, dated February 20, 2009, the Commission granted BVES' request for exemption.

[8] All statutory references are to the California Public Utilities Code, unless otherwise indicated.

As compared to the three large California electric utilities, BVES is extremely small. Indeed, the Commission recognized BVES' extremely small size in D.05-11-025 where the Commission was addressing whether the large utility RPS procurement requirements should be applied to small energy service providers ("ESPs"), community choice aggregators ("CCAs") and small and multi-jurisdictional utilities. The Commission stated it was sensitive to the needs of small service providers and did not want to impose a "one size fits all" RPS regulatory scheme on them. The Commission recognized that small utilities have limited resources and often have load profiles and equipment that differ from those of larger utilities.[9]

The Commission provided additional procurement guidance in D.08-05-029 where it stated that it is neither fair nor necessary for small utilities to file complex annual procurement plans required of the large utilities. The Commission declared that BVES and other small utilities may undertake their RPS procurement planning "in any way that comports with their general planning process."[10]

The fact that the Commission has not required BVES to follow the same procurement process that the three large electric utilities follow does not mean BVES has no procurement planning process. Indeed, BVES has a comprehensive, well-designed integrated resource plan which it utilizes for its procurement program. It is described immediately below.

2. IRP Assessment of Renewable Energy Resource Needs

BVES has issued six requests for proposals ("RFPs") between 2006 and 2011, all including requests for renewable energy and/or RECs. Overall, BVES has had limited response to its solicitations and has found those responses to be generally unsatisfactory from a least-cost best-fit perspective. As a result, none of the offers received under BVES' six RFP solicitations over a five-year period has resulted in any signed contracts for RPS energy, despite BVES' diligent efforts.[11]

One difficulty faced by BVES in acquiring RPS resources is its relatively small annual electrical requirements. BVES believes that renewable energy developers are unwilling to sell a

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[9] D.05-11-025 at p. 13.
[10] D.08-05-029 at p. 17.
[11] IRP at p. 18.

portion of a power plant's output to BVES when they can sell their project's entire output to one of the larger utilities in California that is also in great need of RPS-eligible energy. Other difficulties faced in acquiring RPS resources is the need to shape RPS resources to meet BVES' atypical demand and winter peak requirements.[12] BVES is concerned that this situation may continue until the supply and demand of renewable resources come into balance and renewable energy developers become more willing to sell portions of the project's output to multiple buyers.

Through 2010, BVES had an aggregate RPS deficit of approximately 50,000 MWh of RPS-eligible energy. It is currently estimated that BVES will require approximately 26,000 MWh of RPS electricity products in each of the years 2011, 2012 and 2013. Although BVES has received RPS bundled energy this year under Confirmation No. 1 with LACSD, the Generating Facility has ceased operations as of October 1, 2011. BVES urgently needs to procure additional amounts of RPS bundled energy and/or RECs now and in the near future to meet its RPS obligations.

3. Impact of Proposed Confirmation No. 2 on BVES' Portfolio Needs

If Confirmation No. 2 is approved by the Commission, the RECs purchased by BVES would have no effect on BVES' resource portfolio needs. RECs require no integration into BVES' existing resource portfolio.

B. Consistency with Commission Guidelines for Bilateral Contracting

1. Confirmation No. 2 Is a Bilateral Contract

Confirmation No. 2 was not the result of an RFP solicitation by BVES. Confirmation No. 2 is a bilateral contract which formed a key element of a settlement of a dispute between LACSD and GSWC under Confirmation No. 1 to the Master Agreement.

[12] IRP at p. 19.

2. Consistency with Commission Guidelines for Bilateral Contracting

The Commission has developed guidelines pursuant to which utilities may enter into bilateral contracts for RPS-eligible energy. In D.03-06-071, the Commission authorized entry into bilateral contracts provided the contracts did not require Public Goods Charge funds and were prudent. In a subsequent decision, the Commission held that bilateral contracts were permissible provided that they were at least one month in duration.[13] It also concluded that a utility's bilateral RPS contracts must be submitted for approval by advice letter and that they must be "reasonable."[14]

Bilateral contracts must also include the Commission's standard terms and conditions ("STCs"), originally established in D.04-06-014, as required by Public Utilities Code Section 399.14(a)(2)(D). These STCs are compiled in D.08-04-009, as modified by D.08-08-028. As a result, there are now 13 STCs.

No bilateral RPS contract can be allocated supplemental energy payments ("SEPs").[15] Subsequently, SB 1036 eliminated the responsibility of the California Energy Commission to award SEPs to eligible renewable energy resources to cover above-market costs of renewable energy contracts. In its place, the Commission established for each electrical corporation a limitation on the total costs expended above the market price referent ("MPR")[16] for the procurement of energy resources for contracts negotiated through competitive solicitations.[17] This limitation on total costs expended above the MPR was identified as "above-market funds" or "AMFs." BVES' AMFs were originally set at $328,376.[18] Since Confirmation No. 2 was

[13] D.06-10-019 at p. 29. The Commission also reiterated that all RPS-eligible contracts are subject to Commission approval.
[14] D.06-10-019 at p. 31, citing D.03-06-071, mimeo., at p. 59.
[15] Id. at p. 32.
[16] The AMFs needs of a project is the difference between the project's levelized contract price ($/MWh) and the applicable levelized MPR (multiplied by the amount of generation expected to be delivered over the term of the contract. Resolution E-4199 at pp. 32-33.
[17] Resolution E-4199 at p. 3.
[18] Id. at p. 68.

negotiated through a bilateral-contracting process and is a REC-only contract, the limitation on total costs above the MPR is inapplicable.[19]

In D.09-06-050, the Commission developed additional criteria for approval of contracts with a duration of less than 10 years, including a "fast track" approval process. The Commission concluded that bilateral contracts should be reviewed using the same standards as contracts resulting from RPS solicitations.[20] Contracts of less than 10 years that do not meet the criteria for fast-track treatment should be reviewed using Tier 3 advice letters process.[21]

The Commission also set forth its reasonableness review standards in Resolution E-4199. The Commission will evaluate whether the proposed contract price is reasonable, the project is viable, the contract terms and conditions comply with Commission decisions, the project complies with the IOU's approved procurement plan (in this case, BVES' IRP) and if the project is, on balance, in the best interests of the ratepayer.[22]

Confirmation No. 2 satisfies all of the above requirements, as evidenced by the information provided in this Advice Letter. Specifically, Confirmation No. 2: (i) is submitted for approval via a Tier 3 Advice Letter; (ii) is not eligible for AMFs; (iii) is competitively priced when compared against the other RPS options available to BVES at the time Confirmation No. 2 was executed; (iv) is consistent with BVES' IRP, and (v) along with the Master Agreement include all required STCs, without modification.

3. Disappointing Results from RPS Solicitations

Confirmation No. 2 is a bilateral contract that resulted from a settlement of a dispute over RPS bundled energy under Confirmation No. 1. Until recently, BVES had no alternative but to pursue bilateral procurement of RPS resources due to the poor responses it had received as a result of its RPS solicitations.

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[19] Regardless of whether a proposed contract is eligible or not for AMFs, the Commission requires that AMFs Calculator information be included in all advice letters or applications seeking approval. BVES has included AMF Calculator information, even though AMFs funds are ineligible in this case.
[20] D.09-05-060 at p. 29.
[21] Id. at p. 11.
[22] Id. at p. 18.

Beginning in 2006, and continuing through 2011, BVES has diligently solicited proposals from potential providers of renewable energy to enable BVES to comply with its RPS obligations in a cost-effective manner. Over this period of time, BVES has issued a substantial number of Requests for Proposals ("RFPs") to many large and small bidders and other parties as well.

2006 RFP. In November 2006, BVES sent RFPs to over 50 prospective bidders to acquire renewable resources to satisfy BVES' RPS requirements. BVES requested a minimum of 30,000 MWh annually of renewable energy beginning in year 2010. BVES received three responses to its RFP. All three proposals were for solar photovoltaic systems, ranging in size from 1 MW to 26 MW with prices ranging from $175/MWh to $335/MWh.

At the conclusion of the bid evaluation process, BVES management rejected two bids, and pursued negotiations with the third bidder in an effort to reach agreement on a generating facility and pricing structure that would be acceptable for both parties. These negotiations ultimately were unsuccessful.

2007 RFP. In June 2007, BVES sent RFPs to over 90 prospective bidders to acquire capacity and energy to meet BVES' long-term power supply requirements. The RFP also included an option for potential vendors to submit bids for renewable energy. BVES received a total of six proposals in response to its 2007 RFPs. Three proposals were for non-renewable resources. One proposal included renewable, non-renewable and hybrid resources. And the remaining two proposals were for renewable resources.

One bid for a proposed 12 MW solar photovoltaic project with solar tracking capability was later withdrawn by the bidder due to its inability to acquire the necessary land rights for the proposed project and uncertainty regarding its bid price.

A second bidder offered 237 GWh annually by January 2010, potentially meeting all of BVES' energy requirements (both non-renewable and renewable requirements) with renewable energy. This bid was later withdrawn by the bidder because of its inability to find an acceptable site and the fact that BVES' supply needs could not accommodate 20-30 MWs of baseload energy.

A third bidder's proposal included both renewable and non-renewable resources, including a 7.5 MW solar photovoltaic generating station located on a nearby lakebed. BVES had serious concerns regarding the viability of constructing a large solar generation facility in the middle of a tourist resort and the ability to bring the facility on-line by August 2009. The bidder proposed that it would acquire sufficient resources (both fossil and renewable) to meet all of BVES' power requirements for 2009 through the bidder's new-project on-line date, at an unspecified price. This proposal would have required BVES to essentially turn over all of its power supply activities to the bidder by 2010 and allow the bidder to arbitrage energy in the marketplace for its benefit, rather than BVES' benefit. BVES' management rejected this proposal.

Either because bids were withdrawn or were deemed imprudent, no viable proposals for renewable energy resulted from BVES' 2007 RFP solicitation.

2008 RFP. In October 2008, BVES sent RFPs to over 80 prospective bidders to acquire renewable energy resources for the BVES system through a power purchase agreement ("PPA"), an asset purchase arrangement or a turnkey project. BVES requested proposals that could meet all or a portion of its projected 30,000 MWh requirement for renewal energy in 2010 and thereafter. Only two responses to the RFP were received and both proposals were for the construction of solar photovoltaic systems.

BVES compared each 2008 proposal price against the 2006 bidder, with whom BVES was still negotiating and whose price was lower ($175 per MWh). In light of this more attractive option, BVES concluded that the cost of both 2008 proposals were not competitive.

Primarily based upon these three successive and discouraging RFP processes, BVES concluded that the greatest difficulty facing BVES in acquiring RPS resources is its relatively small annual electrical requirements. BVES believes the small amount of renewable energy needed for RPS compliance, compared to the larger investor-owned and municipally-owned utilities, restricts the number and type of bids with which it is presented. BVES has also found that renewable energy developers are unwilling to sell a portion of a power plant's output to BVES when they can sell their project's entire output to one of the larger utilities in California.

Regardless of the underlying reasons, the responses to BVES' 2006, 2007 and 2008 RPS solicitations were inadequate. In fact, they have been extremely discouraging.

2010 RFP. In spite of these dismal responses, BVES issued another RFP on April 30, 2010. BVES sent its RFP to over 125 prospective bidders to acquire one or a combination of RECs, bundled renewable energy via a PPA, and ownership of California-based generation assets that are RPS-eligible. Out of over 125 potential bidders, BVES received only seven responses, four of which included REC-only offers. Soon after the April 2010 RFP was issued, the Commission stayed its decision authorizing the use of RECs for RPS-compliance purposes.

Out of the total of seven bids, two were rejected early on in the process due to, among other reasons: low viability; high capital costs; non-conformance to the RFP; and utilization of index pricing. Of the remaining bidders, one was deemed the successful bidder. The others were not deemed successful bidders due to a number of factors, including: uncertainty on the use of RECs; too large of a project for BVES' RPS needs; out-of-state delivery point; and high bid prices.

The successful bidder offered a power purchase agreement for bundled solar energy generated in Southern California, with a projected start date of 2014. BVES and the potential bidder engaged in negotiations for a definitive agreement. Recently, BVES advised the bidder that BVES is exploring the availability of RECs as a possible alternative to the power purchase agreement for bundled solar energy.

2011 RFP. BVES issued another RFP on January 4, 2011 to over 140 prospective bidders. The 2011 RFP requested bids to acquire one or any combination of the following: RECs; bundled renewable energy; non-renewable resources; and financial instruments to control CAISO energy costs. Out of over 140 potential bidders, BVES received only eleven bids, several of which included some sort of renewable product ranging from out-of-state RECs to in-state bundled renewable energy as a utility purchase or PPA. After pursuing negotiations with the winning bidder, the bidder withdrew its offer. All of the bids from the 2011 RFP are described in Appendix B, 2011 Solicitation Overview.

2011 RFP for RECs. Given the passage of SB X1 2, its elimination of the matching energy delivery requirement with respect to RECs, and indications that the REC market may have recently changed, BVES believed it prudent and beneficial to issue another RFP to assess the current state of the REC market. On September 15, 2011, BVES issued its latest RFP to over 155 prospective bidders. The RFP requested bids primarily for unbundled RECs. To ensure BVES did not miss an opportunity to acquire attractively-priced bundled RPS-eligible energy, the RFP indicated that such bids would be considered but that BVES prefers unbundled RECs. On October 13, 2011, BVES received several solicitations. BVES has evaluated the solicitations and has a short-list of four solicitations. BVES intends to follow its normal procurement process with regard to the short-listed solicitations.

C. LCBF Methodology and Evaluation

The Commission has adopted, among other things, a process that provides criteria for the rank ordering and selection of least-cost and best fit ("LCBF") RPS resources to comply with the RPS requirements on a total cost basis.[23] Least-cost and best fit are separate concepts. While least-cost can be looked at in a relatively universal manner, best-fit is inextricably linked to the needs of the particular utility.

Since Confirmation No. 2 is the result of bilateral negotiations and a settlement of a dispute under Confirmation No. 1 for bundled RPS energy, BVES did not formally review and rank it against the responses it received in February 2011 for the January 2011 RFP. BVES did compare Confirmation No. 2 to bids received by BVES at the time Confirmation No. 2 was executed and concluded that Confirmation No. 2 is the LCBF relative to those bid proposals.[24] There is a shortage of publicly available data regarding the sale price of RECs generated in California. However, the $30.00 price of RECs under Confirmation No. 2 is well below the $50/REC cap established by the Commission in D.10-03-021.

If Confirmation No. 2 is approved by the Commission, the in-state RECs purchased by BVES would have no adverse effect on BVES' resource portfolio needs. In-state RECs require

[23] Section 399.14(a)(2)(B) of the Public Utilities Code.
[24] See Appendix B, 2011 Solicitation Overview.

no integration into BVES' existing resource portfolio. Therefore, acquisition of in-state RECs under Confirmation No. 2 represents a perfect "best-fit" RPS option for BVES.

BVES has not used time of delivery ("TOD") valuations in its procurement process, its bid evaluations or its calculation of AMFs. Nor has it used debt equivalence or RPS transmission ranking cost methodology or the IOU Transmission Ranking Cost Report in ranking or evaluating bids. Considering the poor response received from the RPS process, BVES concluded that using these factors in evaluating bids was unnecessary and not cost effective. Accordingly, none of these factors were considered by BVES in seeking to purchase the RECs from LACSD under Confirmation No. 2.

Based upon the poor responses regarding BVES' RPS solicitations and very limited opportunities to obtain RPS resources through bilateral contracting processes available at that time, the RECs under Confirmation No. 2 were the least-cost, best-fit option available to BVES at that time to procure RPS-eligible resources. The Commission should approve Confirmation No. 2.

D. Compliance with Standard Terms and Conditions

Bilateral contracts must include the Commission's STCs, originally established in D.04-06-014 and D.07-02-011, as modified by D.07-05-057 and D.07-11-025, as required by Public Utilities Code Section 399.14(a)(2)(D). These STCs are compiled in D.08-04-009, as modified by D.08-08-028. Additional non-modifiable STCs were developed concerning RECs ("STC RECs") and are compiled in D.10-03-021, Appendix C. The STC RECs were finalized in D.11-01-025.

Confirmation No. 2 is subject to the Master Agreement, as modified by Confirmation No. 1. The Master Agreement and Confirmation No. 1 were approved by the Commission in D.11-06-030. BVES stated in its A.10-06-003 for approval of the Master Agreement and Confirmation No. 1 that: it did not include STC -4 Confidentiality, STC -5 Contract Term, nor STC 8-- Product Definitions; it did include portions of STC 7 – Performance Standards/Requirements, and portions of STC 9 – Non-Performance or Termination Penalties and Default Provisions, portions of STC 12 – Credit Terms and STC 16 – Assignment; it did include (with one minor edit) STC 15 – Contract Modifications; it did not include STC 18 – Application of Prevailing Wage. Regarding the non-modifiable STCs, BVES included in the Master Agreement, as modified by Confirmation No. 1: STC 1 -- CPUC Approval, STC 2 – RECs and Green Attributes (with minor conforming changes); STC 6 --Eligibility (with minor conforming changes); STC 17 – Applicable Law, STC REC -1 – Transfer of Renewable Energy Credits and STC REC – 2 – Tracking of RECs in WREGIS. The inclusion of these STCs and STC RECs were summarized in Appendix D – Contract Summary of LACSD Project of Application A.10-06-003.

In D.11-06-030, the Commission approved the STCs and STC RECs, as modified by BVES, in the Master Agreement with LACSD.

In D.11-01-025, Appendix B entitled "Summary of TREC Rules Announced I D.10-03-021, and Compiled in Appendix D to D.10-03-021, as Modified by this Decision", under the heading "Contract review and approval of TREC transactions" the Commission stated " All REC-only contracts must contain the following three non-modifiable standard terms and conditions: (1) Transfer of renewable energy credits; (2) Tracking of RECs in WREGIS; (3) Applicable Law. REC-only contracts of California IOUs other than MJUs must contain a fourth STC: Commission Approval."

Even though in D.11-06-030 the Commission approved these required STCs and STC RECs in the Master Agreement and Confirmation No. 1 with LACSD, for ease of reference and to facilitate Commission approval of Confirmation No. 2, BVES included STC REC-1 Transfer of Renewable Energy Credits, STC REC-2 Tracking of RECs in WREGIS, and STC REC – CPUC Approval on page 3 of Confirmation No. 2. The fourth required STC (STC 17 Applicable Law) is referenced on page 3 of Confirmation No. 2 as being included in Section 10.6 of the ADDITIONAL PROVISIONS section of the Cover Sheet to the Master Agreement. Accordingly, all the required STCs and STC RECs for a REC-only contract are included, without modification, in the Confirmation No. 2 and/or the Master Agreement between LACSD and BVES.

E. Consistent with Unbundled RECs Transaction Limitations

The Commission authorized the use of unbundled RECs and determined the compliance rules for unbundled REC transactions in D.10-03-021, as amended by D.11-01-025. Certain limitations on the use of RECs were placed on the large IOUs. However, this limitation was not imposed upon BVES.

Due to BVES' unique circumstances, the Commission concluded that BVES' customers would be better served by allowing as much RPS procurement flexibility as possible, within the general requirements of the RPS program and flexible compliance rules. The Commission declined to impose the 25% of APT limit on BVES.[25] In addition, the Commission imposed a temporary price cap of $50/REC.[26] The $30.00 price of the RECs in Confirmation No. 2 is well below this price cap. There are no questions regarding delivery of associated electricity to in-state load – the Generating Facility is located within California. The additional information regarding RECs required to be provided with any REC-only contract is included in Appendix H. Accordingly, Confirmation No. 2 complies with the Commission's directives on the use of RECs to satisfy BVES' RPS obligations.

SB X1 2 also provides restrictions on RPS product content categories ("buckets"), including RECs. SB X1 2 authorizes use of REC-only transactions for RPS compliance[27], but it limits the quantity of RECs which the large IOUs may use.[28] These restrictions do not apply to BVES. Section 399.18(b) under SB X1 2 provides that electrical corporations that serve fewer than 30,000 customer accounts and have issued at least four solicitations for eligible RPS resources prior to June 1, 2010, are exempted from the content limitations (*i.e.*, limitations on use of RECs) set forth in Section 399.16. BVES meets those criteria and, thus, is not limited on the use of RECs to satisfy its RPS obligations. SB X1 2 eliminated any energy delivery requirements with respect to out-of-state unbundled RECs. Confirmation No. 2 is consistent with the provisions on use of RECs set forth in SB X1 2.

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[25] D.10-03-021 at p. 47.
[26] Id. at p. 59.
[27] Section 399.21(a) under SB X1 2.
[28] Section 399.16(c) under SB X1 2.

F. Minimum Quantity

In D.07-05-028, the Commission determined that in order to count energy deliveries from short-term (i.e., less than 10 years in duration) contracts with existing facilities toward RPS requirements, RPS-obligated load-serving entities must contract for deliveries of equal to at least 0.25% of their prior year's retail sales through long-term contracts or through short-term contracts with new facilities. This restriction was implemented to satisfy the provisions of Section 399.14(b)[29], which created certain incentives for entering into particular types of RPS procurement contracts.[30] Under this decision, the Commission used contracted-for energy to determine whether the restriction has been satisfied.

The minimum quantity requirements of D.07-05-028 do not apply to REC-only contracts, nor are they necessary. REC-only contracts do not include energy deliveries. Therefore, measurements of contracted-for energy are inapplicable. Moreover, the minimum quantity requirements are unnecessary to act as a "gatekeeper" for REC-only contracts. As discussed above in Section E, the Commission and the Legislature have promulgated specific restrictions applicable to REC-only transactions, which Confirmation No. 2 satisfies.

Even if the Commission were to apply this requirement to REC-only contracts, BVES meets the minimum contracted-for deliveries from long-term contracts through the approval of the Master Agreement and Confirmation No. 1 in D.11-06-030.

G. Tier 2 Short-Term Contract for "Fast Track" Process

BVES is not submitting Confirmation No. 2 under the "fast-track" process. REC-only contracts do not qualify for this more streamlined approval process.

H. Market Price References ("MPR")

Confirmation No. 2 is a REC-only contract and no MPR exists for REC-only contracts.

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[29] Section 399.14 was repealed under SB X1 2, but new Section 399.13(b) provides similar restrictions.
[30] D.07-05-028 at p. 8.

I. Above-Market Funds ("AMFs")

SB 1036 (Chapter 685, Statutes of 2007) authorizes the Commission to provide above-MPR cost recovery through electric retail rates for RPS contracts that are deemed reasonable. Above-MPR cost recovery has a "cost limitation" equal to the amount of funds currently accrued in the CEC's New Renewable Resources Account, which had been established to collect supplemental energy payments ("SEP funds"), plus the portion of SEP funds that would have been collected through January 1, 2012.[31] The total amount of above-MPR funds ("AMFs") for BVES is $328,376.

In order for an RPS contract that has above-MPR costs to be eligible for AMFs, it must meet certain criteria. One of the criteria is that the RPS contract was selected through a competitive solicitation.[32] As stated previously, Confirmation No. 2 is not a result of a competitive solicitation. Nor is there an MPR price for REC-only contracts. Accordingly, AMFs are not available for Confirmation No. 2.

J. Interim Emissions Performance Standard

A greenhouse gas emissions performance standard ("EPS") was established by Senate Bill 1368 (Chapter 464, Statutes of 2006 (SB 1368), that added Section 8341(a) to the Public Utilities Code. It provides, among other things, that no load-serving entity may enter into a long-term financial commitment for baseload generation unless it complies with greenhouse gases ("GHG") emissions performance standards established by the Commission. Pursuant to SB 1368, baseload generation is defined as a power plant that is designed and intended to provide electricity at an annualized plant capacity of at least 60%. In Rulemaking 06-04-009, the Commission established the GHG performance standard as GHG emission rates no higher than those of a combined-cycle gas turbine plant.[33] The Commission also concluded in that decision that net GHG emissions from solar thermal electric facilities, wind facilities, geothermal facilities and generating facilities using landfill gas meet the EPS requirements.[34]

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[31] Resolution E-4229 at pp. 5-6.
[32] Resolution E-4199 at p. 16.
[33] D.07-01-039.
[34] Id. at p. 246, Finding of Fact No. 118 and Conclusion of Law No. 35.

The statute and D.07-01-039 appear to apply only to contracts for procurement of energy, not REC-only transaction. Although D.07-01-039 does not explicitly address the interaction between EPS compliance and REC-only transactions, the Commission distinguished the transfer of RECs from the GHG emissions rate associated with the renewable facility and found that "RECs would not have any value for EPS compliance under our rules."[35] Therefore, Confirmation No. 2 is not a covered procurement subject to the EPS because it does not involve procurement of electric energy.

K. PRG Review and Independent Evaluator Evaluation

PG&E, SCE and SDG&E were respondent utilities in Rulemaking 01-10-024 where it was requested that certain measures and procedures be undertaken to ensure that interim procurement power contracts could be quickly approved. The Commission established certain procedures and protocols for the respondent utilities, including the establishment of a procurement review group ("PRG") for each respondent utility. Each PRG would, among other things, review its utility's procurement strategy, and its utility's proposed procurement contracts before the contracts would be submitted to the Commission for expedited review.[36]

As compared to the three large California electric utilities, BVES is extremely small. Indeed, the Commission recognized BVES' extremely small size in D.05-11-025 where the Commission was addressing whether the large utility RPS procurement requirements should be applied to small energy service providers ("ESPs"), community choice aggregators ("CCAs") and small and multi-jurisdictional utilities. The Commission stated it was sensitive to the needs of small service providers and did not want to impose a "one size fits all" RPS regulatory scheme on them. The Commission recognized that small utilities have limited resources and often have load profiles and equipment that differ from those of larger utilities.[37]

The Commission provided additional procurement guidance in D.08-05-029 where it stated that it is neither fair nor necessary for small utilities to file complex annual procurement plans required of the large utilities. The Commission declared that BVES and other small

[35] Id. at p. 124, see also pp. 121-127.
[36] D.02-08-071 at pp. 24-25.
[37] D.05-11-025 at p. 13.

utilities may undertake their RPS procurement planning "in any way that comports with their general planning process."[38]

BVES has no PRG, nor does it retain an IE. Therefore, Confirmation No. 2 was not submitted, nor reviewed, by a PRG, nor was an independent evaluator involved in any of BVES' RPS solicitations.

III. PROJECT DEVELOPMENT STATUS

The Energy Division 2009 RPS Solicitation Advice Letter Template ("Template") requires information regarding various project factors (*e.g.*, company/development team, technology, development milestones, permitting/certification status, transmission, financing plan, etc.). The Template provides that if the project is already commercially operational, this section may be skipped.[39] The Generating Facility is not new or required to be expanded or upgraded in order to satisfy the requirements of Confirmation No. 2. It operated for over 20 years.[40] Accordingly, no further information need be provided for this section.

IV. CONTINGENCIES AND MILESTONES

The Energy Division Template requires information regarding contingencies and milestones. Confirmation No. 2 contains no contingencies or milestones, except receipt of Commission approval by no later than June 30, 2012.

Confirmation No. 2 provides that in the event CPUC approval does not occur before June 30, 2012, Confirmation No. 2 shall be of no force or effect regarding the 20,793 2010 RECs. In the event CPUC approval of Confirmation No. 2 does not occur prior to October 1, 2012, neither Party is liable to the other Party for any obligations under Confirmation No. 2.

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[38] D.08-05-029 at p. 17.

[39] 2009 RPS Solicitation, Advice Letter Template at p. 7.

[40] The CEC certified the Generating Facility as RPS-eligible on July 29, 2008. LACSD ceased operating the Generating Facility on October 1, 2011.

V. REGULATORY PROCESS

A. Request Approving Resolution by June 30, 2012

Due to the contingencies noted in Section IV above, BVES requests that the Commission issue a resolution approving this advice letter filing no later than June 30, 2012.

B. Modification of PPAC To Permit Booking of REC Costs

BVES has a Purchased Power Adjustment Clause ("PPAC") account. As described in its Preliminary Statement, Section L: "The purpose of the Purchased Power Adjustment Clause is to reflect in rates the utility's cost of purchased electricity, purchased fuel and proceeds from the sale of renewable energy credits." Although the PPAC account includes the *proceeds* with respect to the *sale* of RECs, it does not currently include the *costs* with respect to the *purchase* of RECs.

In Advice Letter 257-E-A, filed on October 24, 2011, BVES requested a modification to its Preliminary Statement, Section L to permit BVES to book the authorized procurement costs with respect to RECs and to recover such costs through its PPAC account. If Advice Letter 257-E-A is not approved, BVES has no existing account or rate recovery mechanism to address the procurement costs of RECs to be used to satisfy BVES' RPS compliance requirements.

By seeking authority to book the procurement costs with respect to Confirmation No. 2 in the PPAC account, BVES is not seeking any rate increase related to such REC costs. Advice Letter 257-E-A seeks no change to any rate component of the PPAC account. Nor is granting authority to book REC-related costs in the PPAC account a fundamentally new or novel concept – the PPAC account already tracks the *revenues* from the sale of RECs. Tracking the *costs* of RECs is simply the other side of the "REC coin."

Without the modification of Preliminary Statement, Section L, as requested in Advice Letter 257-E-A , BVES will be forced to seek permission to withdraw this Advice Letter filing, as BVES would have no lawful means by which to book and recover the costs with respect to Confirmation No. 2. BVES is in urgent need of RECs. Withdrawal of Confirmation No. 2 for approval by the Commission would be a significant setback in BVES' efforts to comply with its RPS obligations.

VI. BVES REQUESTS APPROVAL OF CONFIRMATION NO. 2

The terms of Confirmation No. 2 are conditioned on the occurrence of "CPUC Approval," as it is defined in Confirmation No. 2. In order to satisfy that condition with respect to Confirmation No. 2, BVES requests that the Commission issue a decision that includes the following no later than June 30, 2012:

1. Approves Confirmation No. 2 in its entirety, including payments to be made by BVES pursuant to Confirmation No. 2, subject to the Commission's review of BVES' administration of Confirmation No. 2.

2. Finds that any procurement pursuant to Confirmation No. 2 is procurement from an eligible renewable energy resource for purposes of determining BVES' compliance with any obligation that it may have to procure eligible renewable resources pursuant to the California Renewables Portfolio Standard ("RPS"), D.03-06-071 and D.06-10-050 or other applicable law or decision.

3. Adopts the following finding of fact and conclusion of law in support of CPUC approval:

    a. Confirmation No. 2 is consistent with BVES' 2011 Integrated Resource Plan.

    b. The terms of Confirmation No. 2, including the price of delivered RECs, are reasonable.

4. Adopts the following finding of fact and conclusion of law in support of cost recovery for Confirmation No. 2:

    a. BVES' procurement costs under Confirmation No. 2, as provided in Section 399.14(f)(2), shall be recovered through BVES' PPAC account.

5. Adopts the following findings with respect to resource compliance with the Emissions Performance Standard ("EPS") adopted in R.06-04-009:

   a. Confirmation No. 2 is not covered procurement subject to the EPS because it does not involve procurement of electric energy.

Protests

A protest is a document objecting to the granting in whole or in part of the authority sought in this Advice Letter. A response is a document that does not object to the authority sought, but nevertheless presents information that the party tendering the response believes would be useful to the CPUC in acting on the request.

Anyone wishing to protest this filing may do so by sending a letter within 20 days from the date the CPUC accepts the Advice Letter for filing. The Calendar is available on the CPUC's website at www.cpuc.ca.gov.

The protest must state the grounds upon which it is based, including such items as financial and service impact, the effect that approval of the Advice Letter might have on the protestant, and the reasons the protestant believes the Advice Letter, or a part of it, is not justified. If the protest requests an evidentiary hearing, the protest must state the facts the protestant would present at an evidentiary hearing to support its request for whole or partial denial of the Advice Letter. BVES must respond to a protest within five days.

All protests and responses should be sent to:

California Public Utilities Commission, Energy Division
ATTN: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
E-mail: Honesto Gatchalian (jnj@cpuc.ca.gov) or Maria Salinas (mas@cpuc.ca.gov)

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above).

Copies of any protest or response should also be sent to GSWC at:

Golden State Water Company
ATTN: Nguyen Quan
630 East Foothill Blvd.
San Dimas, CA 91773
E-mail: nquan@gswater.com

If you have not received a reply to your protest or response within 10 business days, contact Nguyen Quan at (909) 394-3600 ext. 664.

A copy of the Notice of Availability is being furnished to the entities listed on the service list for R.11-05-005.

Respectfully submitted,

/s/ Keith Switzer

Mr. Keith Switzer
Vice President of Regulatory Affairs
Golden State Water Company
630 E. Foothill Blvd.
San Dimas, California 91773-9016
Tel: (909) 394-3600
Fax: (909) 394-7427
E-mail: KSwitzer@gswater.com

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. Golden State Water Company (DBA Bear Valley Electric Service)/ 913-E

Utility type:	Contact Person: Nguyen Quan
☒ ELC ☐ GAS	Phone #: (909) 394-3600 ext. 664
☐ PLC ☐ HEAT ☐ WATER	E-mail: nquan@gswater.com

EXPLANATION OF UTILITY TYPE			(Date Filed/ Received Stamp by CPUC)
ELC = Electric	GAS = Gas		
PLC = Pipeline	HEAT = Heat	WATER = Water	

Advice Letter (AL) #: 258-E

Subject of AL: Approval of REC-Contract with LACSD

Keywords (choose from CPUC listing): ______

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other ______

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.10-03-021

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: Yes. See the attached declaration and matrix that identifies all of the confidential information.

Confidential information will be made available to those who have executed a nondisclosure agreement: ☒ Yes ☐ No

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: Nguyen Quan 909-394-3600 ext. 664

Resolution Required? ☒ Yes ☐ No — Tier Designation 1☐ 2☐ 3☒

Requested effective date: June 30, 2012 — No. of tariff sheets:

Estimated system annual revenue effect: (%): $1,093,350

Estimated system average rate effect (%): 2.93%

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed: None

Pending advice letters that revise the same tariff sheets: None

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division	**Golden State Water Company**
Attention: Tariff Unit	**Attention: Nguyen Quan**
505 Van Ness Ave.,	**Regulatory Affairs Dept.**
San Francisco, CA 94102	**630 E. Foothill Blvd.,**
jnj@cpuc.ca.gov and mas@cpuc.ca.gov	**San Dimas, CA 91773 nquan@gswater.com**

BEFORE THE PUBLIC UTILITIES
COMMISSION OF THE STATE OF CALIFORNIA

DECLARATION OF KEITH SWITZER
SEEKING CONFIDENTIAL TREATMENT FOR CERTAIN DATA AND INFORMATION CONTAINED IN ADVICE LETTER 258-E
(BEAR VALLEY ELECTRIC SERVICE – U 913 E)

I, Keith Switzer, do declare as follows:

1. I am presently employed by Golden State Water Company ("GSWC") as Vice President of Regulatory Affairs. Bear Valley Electric Service ("BVES") is a division of GSWC. In my current position, I have acquired knowledge of the operations of BVES and operations of sellers of electricity and related products. Through this experience, I have become familiar with the type of information that would affect the negotiating positions of electricity sellers with respect to price and other terms, as well as other types of information that such sellers consider confidential and proprietary.

2. Based upon my knowledge and experience, and in accordance with Decision ("D") 08-04-023 and the August 22, 2006 "Administrative Law Judge's Ruling Clarifying Interim Procedures for Complying with Decision 06-06-066," I make this declaration seeking confidential treatment of Confidential Version of Appendices A, B, and D ("Protected Information") to GSWC's Advice Letter 258-E on behalf of its BVES division, submitted on November 23, 2011.

3. The Protected Information for which GSWC is seeking confidential treatment falls within the scope of data protected as confidential pursuant to the IOU Matrix attached to the Commission's confidentiality decision, D.06-06-066 (the "IOU Matrix") and or General Order 66-C or relevant statutory provisions, including Public Utilities Code Sections 454.5(g) and 583, and Government Code Section 6254(k).

4. The Protected Information falls within the following IOU Matrix categories:

Description of Data	Matrix Category	Period of Confidentiality
Confidential Version of Appendix D	Item VII (un-numbered category following VII G) – Score sheets, analyses, evaluations of proposed RPS projects	Three years.
Confidential Version of Appendix D	Item VIII A) Bid information	Public after final contracts submitted to CPUC for approval.
Confidential Version of Appendices A and B	Item VIII A) Bid information.	Public after final contracts submitted to CPUC for approval.
Confidential Version of Appendices A and B	Item VIII B) Specific quantitative analysis involved in scoring and evaluation of participating bids.	Three years after winning bidders selected.

5. GSWC intends to comply with the limitations on confidentiality specified in the IOU Matrix for the type of data contained in the Protected Information.

6. I am not aware of any instance of public disclosure of the Protected Information.

7. The Protected Information cannot be provided in a form that is further aggregated, redacted, or summarized and still provide the level of detail and context requested and expected by the Commission.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 23rd day of November, 2011, San Dimas, California.

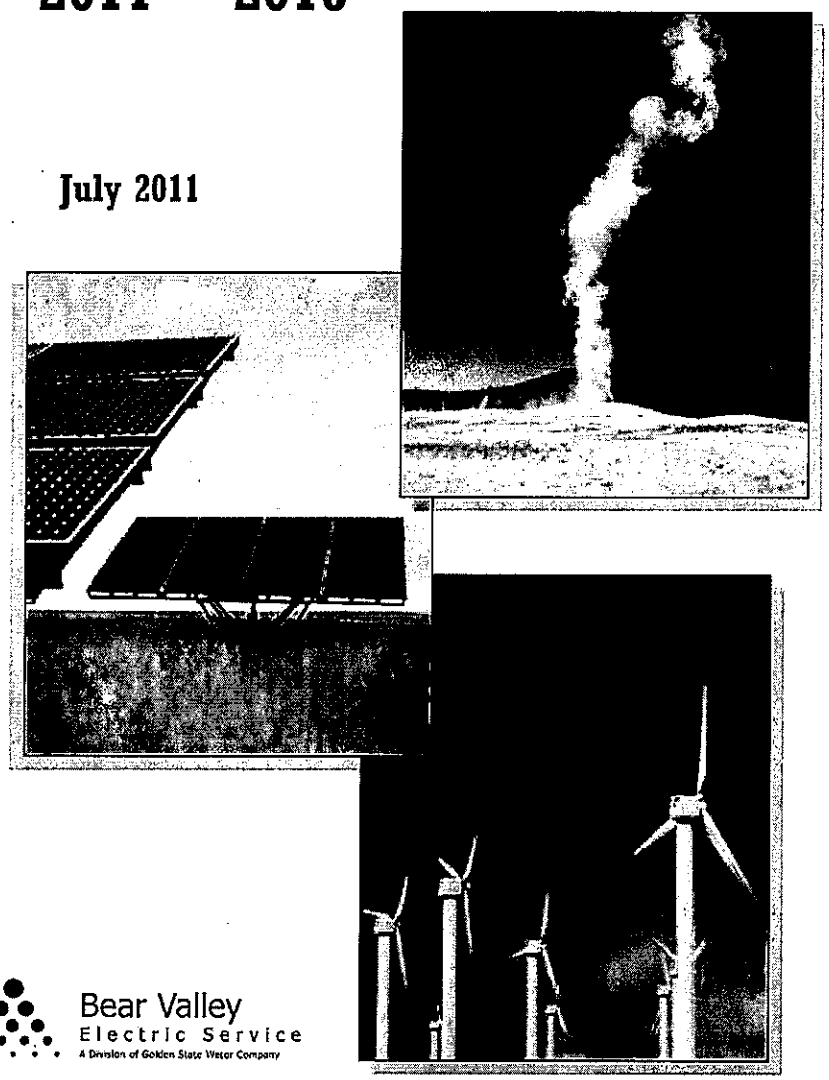
Keith Switzer

Mr. Keith Switzer
Vice President of Regulatory Affairs
Golden State Water Company
630 E. Foothill Blvd.
San Dimas, California 91773-9016
Tel: (909) 394-3600
Fax: (909) 394-7427
E-mail: KSwitzer@gswater.com

EXHIBIT 1 - BVES INTEGRATED RESOURCE PLAN

Bear Valley Electric Service Integrated Resource Plan 2011 – 2016

July 2011



Bear Valley
Electric Service
A Division of Golden State Water Company

This report is printed on 100% recycled paper.

Table of Contents

Table of Contents (continued)

1. Executive Summary

The 2011 Integrated Resource Plan (IRP) for Bear Valley Electric Service (BVES) is the primary document used in planning, evaluating and acquiring generation resources to meet the forecasted energy requirements of BVES' retail customers, consistent with goals set by the State Legislature. The goal of the IRP is to identify reliable, least-cost best-fit energy resources to serve the needs of BVES' electric customers. The amount and type of resources in the IRP must also be consistent with California Public Utilities Commission (CPUC) regulations and California State laws governing, among other issues, resource adequacy, renewable energy and greenhouse gas emissions limits.

BVES continues to experience low growth as a result of the local economic downturn. Housing demand in the Big Bear area has slowed significantly and tourism has experienced a similar decline. The forecast for the period covered by this IRP shows moderate growth, with total electricity requirements projected to increase by 12.8 percent over the five-year period, or 2.6% annually.

With current procurement contracts in place with Shell Energy North America, BVES' loads and resources are in balance for 2011. BVES' purchase contract with Shell for seasonal energy will terminate on December 31, 2011, and its contract for baseload purchase will expire on November 30, 2013. By 2014, BVES will need to have new resources in place to meet essentially all its energy requirements, except for the small portion satisfied by its own local generator, the Bear Valley Power Plant (BVPP).

In January 2011, BVES issued an RFP which included energy to address a forecasted 2012 energy shortfall. BVES plans to move as quickly as it can on acquiring energy in order to avoid the price uncertainty of purchasing from either the CAISO market or the spot market. However, in the short term, the forecast for low natural gas prices is likely to produce favorable spot and/or CAISO market pricing while BVES negotiates agreements and obtains CPUC approval of energy purchases under its 2011 RFP.

The CAISO's Market Redesign and Technology Upgrade (MRTU) has been in operation since April 1, 2009. Overall, the market has performed as designed. While some extreme prices have occurred due to actual system constraints, they have been infrequent and typically reflected actual system constraints. The MRTU will introduce a number of new features and functionality over the next few years, some of which are likely to affect BVES, such as the Resource Adequacy (RA) program and standardized capacity provisions. Refer to Section 5.A for a detailed discussion on MRTU.

BVES continues to monitor and participate in the CPUC's Resource Adequacy (RA) program, although the CPUC has not yet defined BVES' capacity obligation. BVES believes its RA obligations must be in accordance with the CAISO's MRTU; therefore, BVES has planned for RA requirements equal to 115 percent of monthly forecasted load. BVES purchased RA capacity from Shell Energy North America as part of its long-term power purchase agreement to meet these RA obligations.

BVES continues aggressively working to acquire renewable energy resources in accordance with the CPUC's Renewables Portfolio Standard (RPS). In mid-2010, BVES filed two RPS contracts with the CPUC in support of BVES' goal of providing 20 percent of electricity sales from renewable resources. The first contract with the County Sanitation District No. 2 of Los Angeles County (LACSD) for power derived from landfill gas was approved by the CPUC in June 2011; however, it appears unlikely now that LACSD will be able to provide BVES with the amount of energy that was originally anticipated under the contract. The second contract with BioEnergy Solutions, LLC, may not help BVES meet its near-term RPS requirements, since BioEnergy recently ceased production of biogas. While additional RPS-eligible resources are being sought, BVES will also consider acquisition of Renewable Energy Credits as a means of fulfilling its RPS obligations. Refer to Chapter 3 for more information about RPS and pending regulations which may further shape BVES' requirements for renewable resources.

Analysis of BVES' power supply forecast model indicates that its power supply costs will be stable for 2011 with little price risk.[1] Since determining two successful bidders from its 2011 RFP, BVES is currently negotiating agreements to replace its soon-to-expire seasonal baseload contract and its annual baseload contract expiring in November 2013. For peaking/intermediate needs, BVES is considering strike price options to cap market price risk; under a financial option, BVES would make purchases from the MRTU market rather than must-take products. This strategy could provide significant price protection while still allowing BVES to take advantage of declining energy prices.

For the reader's benefit, because acronyms are frequently used throughout this IRP, a glossary of acronyms and their definitions are included in Appendix G.

[1] The only event likely to cause a slight price increase will be the introduction of a small amount of bundled RPS energy from LACSD beginning in August 2011.

2. BVES Loads and Resources

2.A. Description of BVES

Bear Valley Electric Service (BVES) is a division of Golden State Water Company (GSWC), an investor owned utility (IOU). BVES provides electric distribution service to approximately 21,500 residential customers in a resort community with a mix of approximately 40 percent full-time and 60 percent part-time residents. Its service area also includes about 1,400 commercial, industrial and public-authority customers, including two ski resorts.

BVES' historical winter peak load is approximately 44 MW;[2] monthly peaks occur when snowmaking machines at the ski resorts are operating and recreational visitors are present (generally between 7:00 pm and 11:00 pm on weekends). In the summer months, the load in BVES' service area ranges from a minimum of about 11 MW (early summer mornings) to a maximum of approximately 24 MW (weekend holiday, mid-morning and late evenings).

BVES purchases wholesale power to meet the majority of its energy requirements. To aid in meeting peak demand for electric energy, BVES installed and now operates the Bear Valley Power Plant (BVPP), a natural gas-fired, 8.4 MW generation plant in its service area. The BVPP became commercially operational on January 1, 2005.

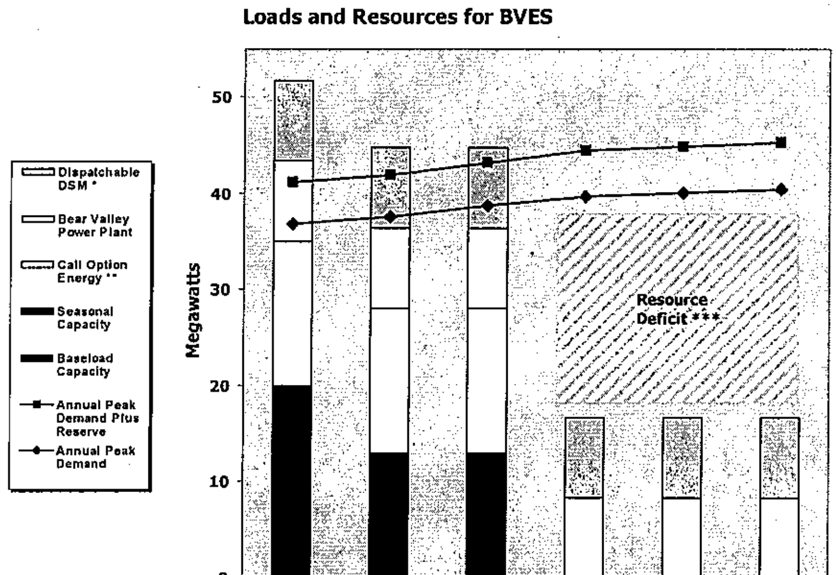
BVES has two receipt points of power from Southern California Edison Company (SCE), the Goldhill transfer station and Radford Feeder. The majority of BVES' power is transmitted over SCE's 33 kV distribution line from SCE's Cottonwood substation to SCE's Goldhill transfer station. The remainder of BVES' energy is transmitted over SCE's 33 kV distribution facilities from SCE's Zanja substation near Redlands, California, over the Radford Feeder to BVES' Harnish substation.[3]

BVES' distribution system is located and operates in the Balancing Area of the California Independent System Operator (CAISO). However, BVES does not own bulk power transmission facilities nor is BVES a Participating Transmission Owner (PTO) under the CAISO Tariff. BVES facilities are not directly interconnected with the CAISO Controlled Grid; rather, its distribution system is interconnected electrically only with distribution facilities owned, controlled, and operated by SCE. These SCE distribution facilities are in turn directly interconnected with SCE transmission facilities that are part of the CAISO Controlled Grid.

[2] The historical peak occurred December 31, 2010. The prior peak of 43 MW occurred December 29, 2006.
[3] BVES refers to the voltage on these SCE lines as 34.5 kV.

2.B Summary of Loads and Resources

Figure 2.1 summarizes the forecast of BVES' resources and requirements through the year 2016.



Year	2011	2012	2013	2014	2015	2016
Dispatchable DSM *	8.35	8.35	8.35	8.35	8.35	8.35
Bear Valley Power Plant	8.4	8.4	8.4	8.4	8.4	8.4
Call Option Energy **	15	15	15			
Seasonal Capacity	7	0	0			
Baseload Capacity	13	13	13			
Annual Peak Demand Plus Reserve	41.1	41.9	43.2	44.4	44.9	45.2
Annual Peak Demand	36.8	37.5	38.7	39.7	40.1	40.4

* Added capacity project proposed for Snow Summit may increase dispatchable DSM to approximately 15 MW in year 2013.
** Call option energy is for winter months only.
*** The resource deficit shown is being addressed through current procurement activities.

Figure 2.1: Loads and Resources for BVES

2.C Forecast of Demand and Energy Requirements

BVES has had little or no growth in annual retail energy sales since 2006. From the levels reached in 2006, energy sales declined significantly in 2007, grew only slightly in 2008 and 2009, and then declined further in 2010. While the national economic recession is partially the cause, the decline in real estate values has had a major effect on the growth of the Big Bear economy and local economic activity.

In 2006, BVES' retail sales were 144,865 MWh; by 2010, energy sales were only 132,203 MWh, representing a decline of 8.7 percent over the four-year period. Figure 2.2 illustrates the trend in BVES energy sales over the period 2003 through 2010.

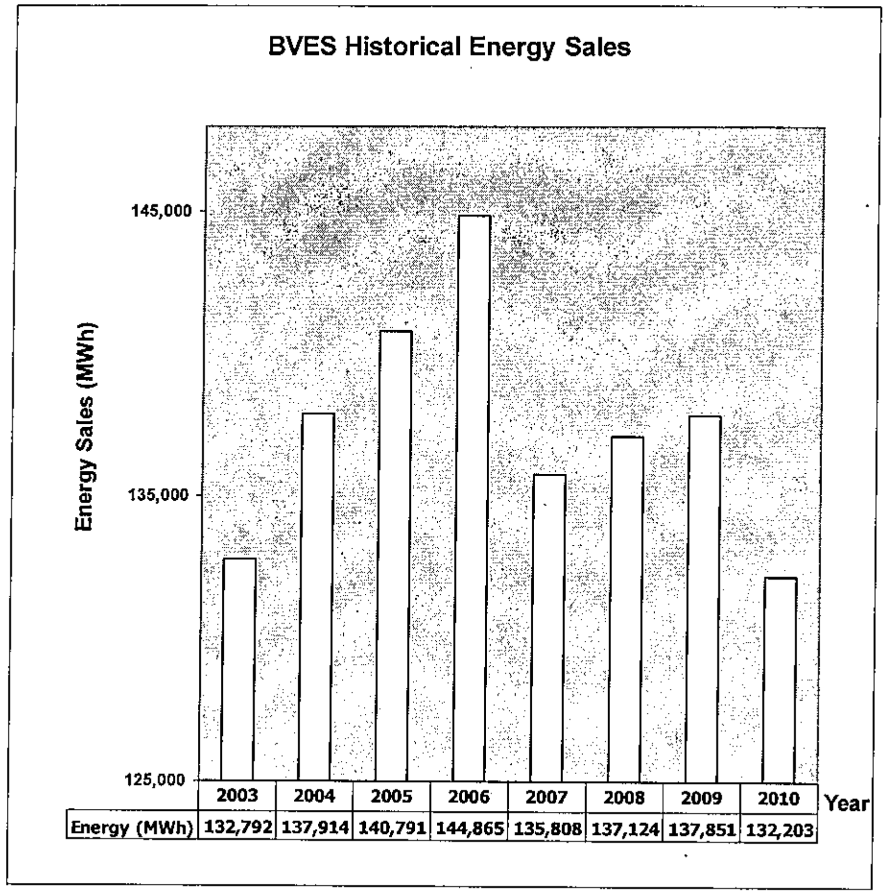


Figure 2.2: BVES Historical Energy Sales

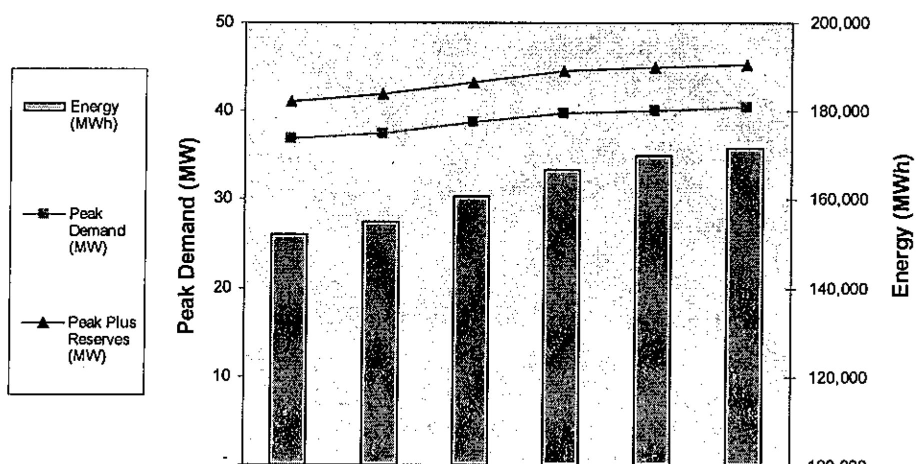
Demand for electricity is a derived demand; that is, consumers do not buy electricity in and of itself. Instead, consumers buy goods and services that require electricity. Both the construction and tourism industries have experienced a decline in the Big Bear area, resulting in lower growth. Two primary factors have contributed to the decline in the Big Bear Lake economy over the last 3 years:

1. The national recession has hit California and in particular the San Bernardino County economy especially hard. Personal income (a measure of wages and salaries, rental income, dividends, and interest income) dropped significantly and consistently from 2007 to 2010 and depressed real estate investment and tourism in the Big Bear Lake region.
2. Real estate values in California fell drastically during the recession as long overdue corrections occurred, leaving many real estate investors without collateral and cautious of investing in real estate until the correction is complete. This has negatively impacted Big Bear Lake real estate investment.

When making annual comparisons, some change in monthly SCE-metered peak demand is due to operating the Bear Valley Power Plant (BVPP) during the high peak periods, which may account for a reduction in monthly peak demands by 3 to 4 MW. However, this reduction due to the BVPP was not used in the analysis.[4]

BVES' energy forecasting methodology, used in this IRP as well as BVES' General Rate Case to be filed in late 2011, used historic customer billing data from January 1996 through October 2010. Past usage and customer counts were used to develop models specific to each rate class. Data were aligned with calendar months, corresponding to monthly weather conditions captured by heating and cooling degree days.[5] A set of regression models was then used to forecast monthly demand and energy for the period 2011 through 2016. Figure 2.3 summarizes BVES' annual forecast for demand and energy requirements.

Forecast of Demand and Energy Requirements



Year	2011	2012	2013	2014	2015	2016
Energy (MWh)	151,932	155,038	160,638	166,722	169,953	171,695
Peak Demand (MW)	36.8	37.5	38.7	39.7	40.1	40.4
Peak Plus Reserves (MW)	41.1	41.9	43.2	44.4	44.9	45.2

Figure 2.3: Forecast of Demand and Energy Requirements

BVES' wholesale energy requirements, as measured by the meters at the two SCE receipt points, include retail sales plus SCE distribution feeder losses and BVES system distribution losses[6] of approximately 13 percent.

As a check of the demand and energy forecasts, the capacity factor[7] was also considered.

[4] The actual SCE-metered monthly peak demands were used, which are 3 to 4 MW less than forecasted; however, a portion of the reduction may have been due to operation of the BVPP during the peak periods.
[5] Weather data came from NOAA for the Big Bear Lake (station 40741) location.
[6] Based on a study by ZGlobal Inc. using 2009 data. The BVES distribution system includes 4 kV and 34 kV systems, and the losses cited include both SCE distribution system losses and BVES system losses.
[7] The capacity factor is the ratio of the electrical energy produced by a generating unit for a period of time compared to the electrical energy that could have been produced at continuous full power operation during the same period.

With the advent of MRTU and specifically Resource Adequacy (RA), utilities are required to demonstrate sufficient supply (contracts or generation facilities) to meet their expected peak load. With RA, the concern of not meeting load is limited to system emergencies or equipment failures (e.g., loss of BVES' primary interconnection with SCE, or loss of operation of BVPP during times when the demand for energy exceeds the physical – not contracted – capacity of the SCE distribution lines exclusively serving BVES).

However, there is a trade-off between the cost of forward system RA contracting, the use of BVPP, and the allocation of Congestion Revenue Rights (CRRs). The amount of CRRs allocated to BVES is determined by the amount of capacity purchased from outside BVES' service territory. When BVES is short capacity and higher values of BVPP output are assumed, the number of CRRs allocated by the CAISO is correspondingly reduced. This presents a delivery cost risk if the amount of energy imported exceeds the CRRs. However, the cost of congestion thus far with MRTU has been extremely low. When BVES is long capacity, it wants to reduce the amount of capacity provided by the BVPP in order to maximize the amount of CRRs allocated by the CAISO.

2.D Current Resources

2.D.1 Shell Energy North America

In June 2007, BVES issued an RFP for Firm Power Supply to procure resources for delivery beginning January 1, 2009.[8] When designing its RFP for generation resources, BVES identified requirements that its future resource mix must meet in addition to providing energy. These additional requirements included:

- All resources had to meet the capacity counting requirements of the California Public Utilities Commission (CPUC) and the CAISO.
- The resource mix had to provide at least 30,000 MWh of renewable energy annually (if renewable energy was offered).
- The monthly total capacity purchase had to be 115 percent of forecasted peak demand, including BVPP and dispatchable demand-side management (DSM), adjusted for coincidence with the CAISO peak.
- Greenhouse gas emissions limits must not be exceeded.

As a result of this competitive bidding process, in August 2008, BVES entered into a power purchase agreement (PPA) with Shell Energy North America (US) L.P. (SENA) and subsequently executed four separate confirmation agreements for four distinct products with delivery dates commencing on January 1, 2009. The PPA covers baseload energy, seasonal baseload energy, an on-peak energy option and resource adequacy (RA) capacity.

The baseload purchase is for 13 MW for the period 2009 through 2013. An analysis of BVES load conducted in late 2008 determined that load only dropped below 13 MW

[8] BVES' prior power purchase agreement (PPA) with Morgan Stanley Capital Group expired on this date.

around 25 hours per year; and, even during those extremely low load hours, load only dropped below 11 MW two or three times per year. By purchasing 13 MW of baseload energy, BVES was able to fix the price of approximately 75 percent of its annual energy requirements.[9]

An updated analysis of BVES' load for this IRP suggests that the current economic recession has slightly decreased BVES' loads. While the *minimum* load of 11 MW remains unchanged, BVES' peak loads appear to have declined by about 1 MW. In the future, a portion of the seasonal baseload requirements may also be satisfied by a dispatchable renewable energy purchase.

The second product is for seasonal baseload energy in the amount of 5 MW in November and 7 MW in December, January and February, which are BVES' high load periods. While loads are generally above 20 MW during all hours of December, January and February, November loads only reach that level if ideal conditions exist for the resorts to begin snowmaking activities.

The third product is a peaking energy heat rate call option. In effect, this product caps BVES' energy cost exposure based on natural gas costs. During the summer (July, August and September), the energy cost is based on a 14,000 BTU/kWh (heat rate) price. For example, if gas costs were $5.00/MMBTU, the energy cost would be $70/MWh. For the rest of the year, the contractual heat rate is 10,500 BTU/kWh.

Under the Shell heat rate option, BVES must purchase the same amount of energy for all sixteen on-peak hours, so the daily evaluation of whether or not to exercise the call option requires some analysis. It may be less expensive to purchase market priced energy for a few hours each day even if the price is greater than the predicted option price, provided the total daily cost is less than purchasing the energy available under the option.

The importance of the heat rate call option is that BVES can choose to fix on-peak energy prices based on gas costs, rather than accept the market price risk that a shortage or interruption in generating capacity results in electricity price spikes. Generally, under normal market conditions, BVES would choose not to purchase energy under this agreement, because the heat rate is generally greater than the CAISO market heat rate, resulting in higher energy costs under normal conditions. Energy amounts under the call option are 5 and 15 MW, depending on the month.

The fourth and final product is RA capacity. Under the CAISO's resource adequacy requirements, BVES must show each month that it has firm capacity equal to at least 115 percent of forecasted peak demand. BVES' RA purchase identifies specific generation units[10] that the CAISO can call upon to meet any capacity deficits. By ensuring that purchases meet the CPUC/CAISO mandates for RA, BVES is able to

[9] Based on 2011 energy requirement of 151,932 MWh.
[10] BVES' RA capacity units are Shell's La Rosita generation units, located about forty miles south of El Centro, CA, unless indicated otherwise.

participate fully in MRTU with little concern about potential penalties related to inadequate resources.

These four products will meet essentially all of BVES' retail energy and capacity requirements. Generally, BVES takes delivery of the baseload product(s) and then determines how to meet any requirements in excess of the baseload needs based on daily economics. For example, if the peaking heat rate call option appears likely to be less expensive than market prices, BVES chooses to exercise the daily option. If market prices appear likely to be less than the option price, BVES purchases energy from the MRTU market or counterparty.

If these four products, plus daily spot energy purchases and the BVPP, do not meet BVES' energy requirements, any remaining energy can be purchased from the MRTU market or counterparty. If the MRTU market continues to demonstrate sufficient stability, BVES may increase its purchases from the MRTU market.

The four Shell products are further detailed in Table 2.4.

Product *	Resource Type	Term Years	MW Capacity	Expected Deliveries ***
Annual Baseload	CAISO Firm Energy	4 yrs, 11 mo	13 MW	113,800 MWh annually
Seasonal Baseload	CAISO Firm Energy	3 yrs	5 - 7 MW, Nov - Feb	18,720 MWh annually
Peaking Call Option	CAISO Firm Energy	4 yrs, 11 mo	15 MW winter; 5 MW other	Up to 53,360 MWh annually
System Resource Adequacy Capacity	Gas Turbine; Combined Cycle Combustion Turbine	4 yrs, 11 mo	18 - 35 MW ** depending on year and month	

* For all products, delivery point is SP15 EZ Gen Hub in MRTU, as defined in the EEI Master Power Purchase and Sale Agreement, as amended.
** MW capacity in RA product refers to the combined amount of RA that BVES will purchase.
*** For cost of delivered products, refer to Appendix H, Power Supply Cost Model.

Table 2.4: Shell Energy PPA Products

2.D.2 Bear Valley Power Plant (BVPP)

The BVPP became commercially operational on January 1, 2005, and the original Permits to Operate (PTOs) were issued on May 16, 2007. Revised PTOs were then issued on March 26, 2009 in compliance with current air district rules that limit each engine to 1,000 hours of operation annually.[11]

[11] The 1,000 hours per engine annual limitation does not include hours BVPP operates due to loss of a transmission line. The limit can be increased by application to the air district (which may take up to one year to process) and under current air district rules, would require additional CEMS equipment to continuously monitor CO.

The BVPP is currently treated as a distributed generation resource by the CAISO. When operating, the BVPP reduces BVES' metered peak demand on the CAISO system, as measured by the SCE meters at Goldhill receipt point.[12] This scenario can be very useful during on-peak periods when power costs may be higher than the marginal cost of operating the BVPP.

Under CAISO rules, generators with Participating Generator Agreements (PGAs) for RA cannot withhold energy from the market. Each generation resource under CAISO control (BVPP is not currently under CAISO dispatch control via a PGA) has a must-bid requirement, subject to operating issues (e.g., lack of fuel, water shortage for hydroelectric resources, etc.) or air emission restrictions.

As a result, power marketers with RA resources are hesitant to sell peaking and intermediate resources because they do not know when the CAISO will call upon them for dispatch. They are willing to offer the resource at its full capacity cost and then bid energy supplies into the CAISO day-ahead market. Regardless of whether or not the generator is dispatched, it will either receive its contract price or it will receive some payment from the Load Serving Entities (LSE) for not making any deliveries.

BVES may be able to reduce energy costs by contracting for as much energy as possible from high capacity factor (baseload) resources and then planning to meet peaking and intermediate load with the BVPP. If energy prices in the hour-ahead CAISO markets are forecasted to be less than the cost of production from the BVPP, then BVES would not operate the BVPP, but would instead purchase energy in the real-time market. Otherwise, the BVPP could be operated.

Operating in this fashion may allow BVES to avoid paying capacity costs for a low capacity factor resource.

2.E Forecast Versus Current Resources Summary

The expiration of the SENA seasonal baseload contracts at the end of 2011 will leave BVES with only its 13 MW annual purchase to meet energy requirements. The SENA baseload purchase provides about 113,880 MWh annually, or about 75 percent of BVES' annual energy requirements.

Beginning in January 2012, BVES will need to cover its high load energy months by either signing a new confirmation agreement for energy under the existing Master Power Purchase Agreement with SENA, purchasing from the CAISO energy market, purchasing short-term energy with a counterparty, or running the BVPP.

Even though BVES is short energy, its Resource Adequacy (RA) position is adequate to meet regulatory requirements through November 2013. BVES has purchased RA capacity from SENA and can use the BVPP to meet its monthly capacity requirements.

[12] Operating the BVPP does not affect SCE's metering at the Harnish receipt point.

2.F. Procurement Plan

In order to meet its ongoing resource needs, BVES issued an RFP in January 2011 for non-renewable and renewable energy. The RFP sought to address the forecasted energy shortfall in early 2012 as well as longer term needs. Also, BVES sought similar contract terms (length) for its next round of annual and seasonal baseload products. Once BVES executes contracts for annual and seasonal baseload products, it is anticipated that BVES will have met its seasonal requirements at least through February 2015[13] and its annual requirements through December 2018.

Since two different suppliers provided the most attractive offers for seasonal baseload and annual baseload in response to the RFP, BVES is currently negotiating separate agreements with both suppliers.

If BVES is able to acquire new energy resources prior to the expiration of the existing PPA with SENA, it will not be necessary to either purchase energy from the CAISO marketplace or make spot market purchases. It should be noted that under either option (spot or CAISO market purchases), while BVES may be assured of supply certainty, it does not have pricing certainty. However, the forecast for natural gas pricing appears likely to produce favorable spot and/or CAISO market pricing in the short term until BVES negotiates agreements and obtains CPUC approval of its purchases from the successful bidders under its 2011 RFP.

BVES can use the BVPP as a physical hedge against high energy prices for January and February 2012 by purchasing natural gas supplies at current low prices. However, after the winter 2012 season, BVES will have sufficient energy to meet the off-peak spring, summer, and fall loads until November 2012.

BVES does not require any additional resource adequacy until December 2013. BVES should begin the procurement process for RA by issuing a Request for Proposal (RFP) for RA in late 2011 with the goal of receiving CPUC approval in 2013.

2. G Summary and Conclusions

BVES is essentially in load-resource balance for 2011. When the Shell seasonal purchase terminates in December 2011, BVES will be short energy during the winter season. When the Shell annual baseload purchase expires in November 2013, BVES will have no energy or qualifying RA capacity resources, other than that provided by the BVPP and possible green or other energy purchases,[14] if approved. By 2014, BVES intends to acquire and have in place new resources to meet essentially all its energy needs.

[13] This assumes that BVES' next seasonal baseload product begins in November 2012 versus January 2012.

[14] BVES may pursue renewable energy credits (RECs) and/or bundled renewable energy. See Section 3.D for more detail.

In January 2011, BVES issued an RFP and began the process of acquiring 12 MW of non-renewable baseload energy and 5 to 7 MW of seasonal baseload energy; renewable purchases were also solicited in the RFP. Currently, due to economic conditions, future energy prices are low compared to recent historical prices, which is advantageous for BVES until it is fully resourced again. By having begun the procurement process in January 2011, BVES anticipates being able to acquire its future long-term energy requirements at attractive prices.[15]

As discussed later in Chapter 6, BVES has several options for acquiring future resources. BVES can either acquire physical resources delivered through the CAISO; or it may choose to fix or cap the price it pays for energy in the physical or financial markets and purchase energy from the MRTU market.

With the current demand and energy forecast requirements of 12 MW of annual baseload capacity, and seasonal baseload capacity of approximately 5 to 7 MW during the non-winter months and 7 MW during the winter months, BVES' resources are currently adequate. However, any renewable resource purchases would reduce the annual and seasonal baseload requirements.

[15] The term of BVES' future contracts will ultimately be decided as part of the negotiation process.

3. Renewable Resources

3.A History of Renewables Portfolio Standard (RPS) Legislation

California State Senate Bill 1078[16] initially established the Renewables Portfolio Standard (RPS) in 2002, requiring investor owned utilities (IOUs) to increase renewable purchases by one percent per year until the total reaches 20 percent of their retail sales by 2017. The 2003 Energy Action Plan accelerated the target date from 2017 to 2010 and was then codified into law via Senate Bill 107 in 2006.

CPUC Decision 08-05-029, issued May 30, 2008, clearly addressed RPS participation by the small and multi-jurisdictional utilities (SMJUs), including BVES, who had continually sought clarification for several years prior to issuance of this welcome decision.

Two legislative bills, SB 14 and AB 64, passed the California legislature in September 2009, both of which would have revised the RPS to 33 percent by 2020. However, the Governor vetoed these bills, criticizing their complexity and their failure to streamline the permitting process. He subsequently issued Executive Order S-21-09, instructing the CA Air Resources Board (CARB) to use its authority under AB 32, California's green house gas (GHG) legislation, to adopt regulations requiring the state's load serving entities to meet a 33 percent Renewable Energy Standard (RES) target by 2020.

The CARB was originally scheduled to vote on the proposed regulation in July 2010 but the Governor asked CARB to postpone the vote until its September 23, 2010 board meeting, due to the momentum surrounding Senate Bill 722 (SB 722), which would have, among other things, codified a 33 percent RPS by 2020. SB 722 did not pass the legislature before it went to permanent recess on September 1, 2010. The CARB then passed the RES at its September, 2010 meeting, though questions remained regarding: (1) the extent to which those regulations would be implemented by a new Governor, (2) the legality of CARB's authority to implement such a regulation, and (3) the outcome of state Proposition 23[17] to delay the implementation by the CARB of AB 32. In the 2010 elections, Proposition 23 was defeated and Jerry Brown was elected governor. Most key state-level stakeholders, including the CPUC, CEC, the legislature and CARB, expressed a preference for a statutory RPS goal versus one derived from executive order.

Such new statutory code became a reality on April 12, 2011, when Governor Brown signed Senate Bill X1-2 (SB 2), codifying into law an increase of the RPS mandate to 33% by 2020. SB 2 makes significant modifications to the current RPS program, including the use of multi-year compliance periods with incremental targets and the specification of minimum product content for most retail sellers' RPS portfolios that changes with each compliance period. SB 2 also modifies certain delivery requirements for out-of-state resources, requires the CPUC to establish cost containment limits, and

[16] Sher, Chapter 516, Statutes of 2002.
[17] Proposition 23 would have suspended AB 32 until California's unemployment rate dropped to 5.5% or below for four consecutive quarters. See Chapter 4 of this document for additional information on Proposition 23.

limits the ability to carry forward unbundled renewable energy credits (RECs). Lastly, SB 2 formally extends the RPS program to publicly owned utilities. There are many questions about how the CPUC will implement the new laws and how they will be integrated with the current rules. There may also be a need to enact "clean-up" legislation.

Regarding implementation, the CPUC opened Rulemaking 11-05-005 (R.11-05-005). The new rulemaking continues implementation and administration of the California Renewables Portfolio Standard (RPS) Program, and now requires additional program modification and development to implement SB 2 (above). In opening R.11-05-005, the CPUC identified seven preliminary categories of RPS program changes required by the new 33% law. The seven preliminary categories are listed below and include some, but not all, of the issues in each category.

1. Modify Renewables Portfolio Standard (RPS) compliance rules
   - Adopt new RPS compliance targets by January 1, 2012.
   - Modify flexible compliance rules, including banking rules for different types of RPS contracts.
   - Modify annual compliance reporting requirements.

2. Modify renewable energy credit (REC) trading rules
   - Modify the definition of a renewable energy credit to eliminate delivery requirement and other changes.
   - Modify REC trading rules to provide that RECs must be retired in the tracking system within 36 months from the initial date of generation of the associated electricity.
   - Implement usage limitations on REC transactions.
   - Develop rules for REC contracts executed prior to June 1, 2010.

3. Modify RPS procurement rules
   - Modify the bid evaluation methodology (i.e., least-cost best-fit) to include evaluations of project viability and workforce recruitment.
   - Modify annual RPS procurement plan requirements to include potential compliance delays, a status update on projects' development schedules, price adjustment mechanisms and risk assessments.
   - Implement requirement that retail sellers must procure minimum quantity of long-term contracts prior to counting short-term contracts with existing facilities for RPS compliance.[18]
   - Develop a methodology for giving preference to "California-based projects."
   - Interpret and implement a provision that RPS transactions must be submitted for CPUC review "unless previously preapproved by the commission."

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[18] This would replace a requirement in D.07-05-028 setting minimum quantity of long-term contracts and/or short-term contracts with new facilities prior to counting short-term contracts with existing facilities.

4. Develop RPS cost containment mechanism
   - Develop a methodology for calculating and administering an RPS cost limitation for each large and multi-jurisdictional utility.[19]
   - Develop a methodology to determine, and continuously monitor, utilities' costs against the cost limits.

5. Modify RPS enforcement rules
   - Establish the process and rules for implementing RPS enforcement.

6. Modify and develop new rules for small and multi-jurisdictional utilities
   - Revise RPS rules for multi-jurisdictional utilities and qualifying successor entities.
   - Implement new RPS rules for very small utilities.

7. Other requirements
   - Implement new requirements for approving utility-owned renewable energy generation facilities.

BVES submitted formal comments stating that its top three priorities are to: develop a cost containment mechanism; modify RPS compliance rules; and modify rules surrounding tradable RECs. BVES will continue to monitor and participate in the proceedings to help craft the required RPS changes applicable to BVES.

3.B BVES' Renewables Contracts Status

BVES has issued five RFPs between 2006 and 2011, all including requests for renewable energy and/or RECs. Overall, BVES has had limited response to its solicitations and found those responses to be unsatisfactory from a least-cost best-fit perspective. As a result, none of the offers received under the RFP process resulted in any signed contracts for renewable energy, despite BVES' diligent efforts.

BVES is currently in negotiations with one bidder under the 2010 RFP offering bundled, California-based solar generation. The 2011 RFP had the highest number of RPS-specific responses to date.

In addition to the open RFP solicitations described above, BVES pursued several bilateral transactions with developers and suppliers. As a result, BVES executed two RPS contracts, which were both approved by the CPUC in June 2011.

The first bilateral contract is for landfill gas-derived power from a landfill owned and operated by the County Sanitation District No. 2 of Los Angeles County (LACSD). The LACSD contract was expected to provide approximately 18,000 to 21,000 MWh per year over its ten-year term. The second bilateral contract is with BioEnergy Solutions, LLC. BioEnergy Solutions produces biomethane, also known as biogas or digester gas,

[19] BVES is notably missing from the full list of IOU's and submitted comments calling attention to this oversight.

by processing cow manure. Under the ten-year contract, BioEnergy Solutions would have injected pipeline quality biogas into PG&E's natural gas pipeline on behalf of BVES, who would then initially utilize the BVPP to generate renewable energy.

In October 2010, the Division of Ratepayer Advocates (DRA) protested the biogas-related contract with BioEnergy Solutions, LLC (BioEnergy) due to pricing concerns. In late 2010, BioEnergy stopped biogas production at its facility, and informed BVES that financing and other issues would prevent BioEnergy from meeting its contractual obligations to BVES. BVES and BioEnergy executed an option agreement requiring BioEnergy to offer to sell biogas to BVES at a price equal to the lowest price of biogas previously offered by BioEnergy to another similar purchaser, when and if biogas production resumes. That option agreement was the primary document in a settlement agreement with DRA and was approved in June 2011.

In February 2011, LACSD notified BVES that its board had voted to cancel the RPS contract,[20] an action which BVES viewed as a formal dispute under the terms of the contract. On June 23, 2011, the CPUC approved the LACSD contract in decision 11-06-030. Negotiations with LACSD are ongoing in an attempt to resolve the parties' differences.

The difficulty BVES has experienced for the past several years in acquiring RPS resources stems in part from its small annual requirement. Renewable developers seem unwilling to sell a portion of a power plant's output to BVES when they can sell their project's entire output to one of the large IOUs or municipal utilities in the state. The need to shape resources to BVES' demand requirement and BVES' winter peak has even further frustrated the effort to acquire resources.

3.C Tradable RECs for RPS Compliance

After issuing several proposed decisions, in March 2010 the CPUC issued decision 10-03-021 formally authorizing the use of Tradable Renewable Energy Credits (TRECs) for RPS compliance. In a move supportive of and recognizing BVES' unique position as one of the smallest IOUs in California, the Commission purposefully did not impose any volumetric cap on the use of TRECs for BVES; the three large utilities were capped at 25% of their annual procurement target (APT). The March TREC Decision also defined the difference between REC-only transactions and bundled contracts. REC-only transactions are those that expressly convey only RECs and not energy; or transactions that transfer both RECs and energy, where the energy associated with the RECs does not serve California customer load.[21] Bundled transactions, which involve

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[20] Under the contract, LACSD is required to offer BVES Renewable Energy Credits (RECs) under certain contract provisions; GSWC's legal counsel does not believe these conditions have been met.

[21] California Public Resources Code 25741 requires that RPS-eligible energy must also be delivered to California customers in order to be counted for RPS compliance. Pub. Res. Code § 25741(a) provides:

> "Delivered" and "delivery" mean the electricity output of an in-state renewable electricity generation facility that is used to serve end-use retail customers located within the state. Subject to verification by the accounting system established by the commission pursuant to subdivision (b) of Section 399.13 of the Public Utilities Code, electricity shall be deemed delivered if it is either generated at a location within the

both energy and credits, are those that serve California load without intermediary transactions that in effect substitute energy that is not RPS-eligible for energy that is eligible.[22] The CPUC's specific recognition of BVES in the March decision is the result of BVES' efforts over the past several years to clearly articulate why a "one-size-fits-all" approach would not benefit BVES' ratepayers. BVES has been active in monitoring RPS proceedings independently as well as through its membership in a working group formally known as the California Association of Small and Multi-jurisdictional Utilities (CASMU).[23]

One month after issuing its "final" decision, the CPUC granted a stay of its TREC Decision in April 2010, while it considered two petitions to modify the Decision.[24] On August 25, 2010, the CPUC issued a proposed decision that would lift the stay and grant some of the modifications sought in the petitions to modify. The proposed decision to lift the stay of the March 2010 TREC Decision left intact BVES' exclusion from the volumetric cap that will apply to the three large California utilities. BVES supported the August 2010 proposed decision lifting the stay of the March TREC decision.

Finally, on January 13, 2011 the CPUC approved its Renewable Energy Credit (REC) decision (D.11-01-025) authorizing the use of RECs for RPS compliance. BVES will endeavor to take full advantage of RECs to meet its RPS obligations, including the issuance of a REC-only RFP in 2011.[25] It should be noted that, despite the very positive development of a final REC decision and SB 2, much uncertainty remains regarding REC transactions, particularly regarding the procedures and processes for out-of-state REC transactions (see SB 2 discussion above).

3.D Renewables Procurement Strategy

As noted above, BVES will try to obtain RECs to meet some or all of its RPS requirements. BVES believes the Commission sent a strong message to BVES by exempting it from the 25% cap imposed on the three large California utilities.[26] Further, RECs appear to be the simplest and possibly least expensive way to meet BVES' RPS requirements. With a REC-only purchase, BVES would not have to integrate a new supply source — renewable energy — into its portfolio. Since wind and solar energy appear to be the most available types of renewable energy, and both are by nature intermittent resources, managing such resources would place an administrative burden on BVES that can be avoided with RECs.

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state, or is scheduled for consumption by California end-use retail customers. Subject to criteria adopted by the commission, electricity generated by an eligible renewable energy resource may be considered "delivered" regardless of whether the electricity is generated at a different time from consumption by a California end-use customer.

[22] D.10-03-021, pp. 2-3.

[23] Current CASMU members include BVES, Pacificorp, CAL-PECO and Mountain Utilities.

[24] One petition to modify was filed jointly by SCE, SDG&E and PG&E while the other was filed by the Independent Energy Producers Association (IEPA).

[25] At the time of this writing, BVES is in early negotiations for a potential unbundled, California-generated REC transaction in response to an unsolicited offer.

[26] BVES may use 100% RECs to meet its RPS obligations; there is no REC cap for BVES.

However, RECs may not be the panacea many view them to be. RECs currently have a PUC-imposed price cap of $50 that expires December 2013. The price cap does not truly cap the price of a REC but rather caps the amount that could be recovered in rates. It may be that the first few years of REC trading in California will find a tight market, with demand exceeding supply. While a cap may have the effect of insulating ratepayers from high REC prices, any price premium in excess of the cap would have to be absorbed by shareholders of Golden State Water Company, BVES' parent. There is also some chance that the price cap may have the unintended consequence of exacerbating a shortage in tradable RECs, if the cap prevents the trade of more costly RECs and thus disincents supply.

Further complicating matters, the CPUC has not yet determined how it will evaluate REC-only transactions for price reasonableness. The Commission, in contemplating REC cost, states in D.10-03-021 that REC prices could "not reliably be approximated by, for example, estimating the cost of RPS-eligible energy and subtracting the cost of conventional power, which parties sometimes call the 'green premium.' Such an RPS energy cost would be extremely difficult to estimate in itself, since RPS power purchase agreements present a wide range of technologies and prices."[27] In addition, SB 2 calls for cost containment mechanisms to be put in place for all IOU RPS-related costs as well as new limits on banking. Finally, current delivery rules make out-of-state RECs unduly burdensome by requiring that out-of-state matching, non-renewable energy be delivered into California in order to count the unbundled, out-of-state REC.[28]

BVES is also continuing its search for bundled renewable energy while it seeks REC-only transactions. Intermittency, cost and deliverability requirements aside, BVES may ultimately determine that it is necessary to acquire both bundled and unbundled (RECs) RPS energy to meet its RPS requirements.

As a result of some uncertainty regarding RECs and the new 33% RPS requirement, BVES will take a two-pronged approach to RPS procurement: seek out acceptable REC-only transactions and continue to solicit and negotiate bundled RPS energy transactions that are cost effective and can be integrated into BVES' existing resource portfolio. Pursuing both RECs and bundled RPS energy will demonstrate BVES' continued commitment to compliance with the RPS laws and regulations, and will increase BVES' chance for achieving compliance.

3.E Summary and Conclusions

Despite diligent efforts, to date BVES has had limited success in procuring renewable energy. Still, BVES will continue to pursue both bundled RPS energy and RECs, preferrably through the RFP process. Since the Legislature and the CPUC have made using 100% REC-only transactions a viable option for BVES' RPS compliance, BVES will seek to utilize such transactions for compliance to the maximum extent possible.

[27] See section 4.7.3 of D.10-03-021.

[28] It appears that SB 2 has diluted or even eliminated such a requirement for out-of-state RECs, but until the CPUC and CEC clarify this, uncertainty remains.

4. Greenhouse Gas Emissions and AB 32

With the passage of Assembly Bill 32 (AB32) in 2006, California is leading the nation in addressing climate change, with an overall goal of reducing GHG emissions to 1990 levels by 2020 and setting a path to further reductions by 2050. There have been several attempts at the federal level to tackle climate change, both through Congressional legislation and EPA regulations. With the exception of GHG reporting requirements for major sources (25,000 metric tons), federal actions have stalled. Nonetheless, California continues to push forward to reach its overall GHG emissions reductions goal.

Per the requirements of AB32, in 2008 the California Air Resources Board (CARB) adopted the Climate Change Scoping Plan, which identifies measures for the various economic sectors that would achieve real GHG reductions. Several measures have been identified for the energy sector that have been or will be developed into regulations. The following apply to BVES:

- AB 32 Cost of Implementation Fee Regulation (Fee Regulation)
- Regulation for the Mandatory Reporting of GHG Emissions (Mandatory Reporting Regulation)
- Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear (GIS) (SF_6 Regulation)

Overall compliance requirements with the above regulations have been limited due to the fact that (1) the Fee and Mandatory Reporting Regulations have threshold exemptions which apply to BVES, specifically for power generation, and (2) BVES owns and maintains few SF_6 regulated equipment or storage containers. Moreover, there is a general trend by CARB to limit compliance activities to major stationary sources as demonstrated with the 2010 revisions to the Mandatory Reporting Regulation.

The 2010 Mandatory Reporting Regulation revisions increased the exemption threshold for reporting for electric generating facilities from 2,500 metric tons (MT) to 10,000 MT, and reduced retail seller reporting obligations as well as verification requirements. In compliance with these revisions, starting in 2012, BVES reporting and verification requirements will be reduced from existing requirements unless and until BVPP emissions exceed CARB's higher threshold for reporting. Currently, the BVPP's natural gas usage is well below the fuel threshold to produce 10,000 MT of carbon dioxide equivalency (CO_2e),[29] and therefore BVES is not required to submit a GHG emissions report for the BVPP. However, as a retail provider of electricity BVES is required to submit an annual report to CARB.

From the above regulations, and assuming that future power generation from the BVPP remains stable compared to historical values, the SF_6 Regulation will be the most

[29] Carbon dioxide equivalency is a quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).

detailed reporting requirement. The SF_6 Regulation implemented in January 2011 sets a maximum annual SF_6 emission rate that annually declines by 1% to achieve a not-to-exceed annual rate of 1% in 2020 and every year thereafter. To ensure compliance with the limits, the SF_6 Regulation requires BVES to develop SF_6 procedures to annually inventory all of its SF_6 cylinders and GIS equipment (i.e., circuit breakers) and track and measure the amount of SF_6 used. BVES is also required to annually report SF_6 emissions using the CARB's GHG Reporting Tool. The overall goal of the SF_6 Regulation is to phase out use of SF_6, which means that BVES may sometime in the future (when technologically and economically feasible) replace its four SF_6 pressurized circuit breakers.

There have been several political and legal attempts to stop and/or delay regulations developed under AB 32, on the basis of economic, environmental justice, and overall AB 32 violation claims. The two most notable are Proposition 23 and the 2011 California Superior Court Case. Proposition 23, formally called the California Jobs Initiative, would have delayed AB 32 until such time unemployment in California dropped to or below 5.5 percent. California voters rejected Proposition 23 in November 2010.

On December 19, 2010, the Association of Irritated Residents and a number of other associations filed suit against CARB, alleging that CARB had failed to meet its obligations under AB 32 and its administrative requirements under the California Environmental Quality Act (CEQA). Plaintiffs petitioned for a Writ of Mandate and the Courts had temporarily issued an injunction against implementing AB 32 measures until CARB met its CEQA requirements. On May 20, 2011, California Superior Court Judge Goldsmith issued his final order on the case, stating that "the Court has set aside ARB's approval of the Scoping Plan, but only as it relates to Cap-and-Trade," meaning that ARB can continue to implement other measures under AB 32, including those applicable to BVES. CARB will undertake additional analysis to determine or demonstrate Cap-and-Trade's effectiveness in meeting the AB 32 goals. As currently written, BVES is exempt from compliance with the Cap-and-Trade Program as an electric generating facility; but discussions are underway regarding the possibility of allocating greenhouse gas emissions reduction credits under the Cap-and-Trade Program to retail sellers such as BVES to help offset other costs related to AB 32 implementation. The Cap-and-Trade program was to have started in January 2012, but in early July, CARB proposed delaying the program one year to ensure that all processes and protocols are working properly.

A key portion of AB 32 is the requirement for increased energy efficiency measures and advanced lighting technologies. AB 32 requires that utilities implement all cost-effective energy efficiency measures prior to acquiring new generation resources.[30]

BVES is ultimately at risk in terms of the indirect impacts of carbon taxes or other costs that raise the price of energy in the wholesale markets. However, it appears several years will pass before any proposed legislation is likely to affect BVES.

[30] Refer to Section 5.C of the IRP for information about BVES' current and planned energy efficiency programs.

5. Other Regulatory Challenges

5.A MRTU

The CAISO's Market Redesign and Technology Upgrade (MRTU) has been in operation since April 1, 2009 and, overall, the market has performed as intended. Given that MRTU represents a complete overhaul of California's system of wholesale power delivery as a result of the California energy crisis in 2001, it has required occasional fine-tuning, as can be expected. While some extreme prices have occurred, they have been infrequent and typically reflected actual system constraints. Concurrent with the first year of operation, the market has experienced reduced demand influenced by the economic downturn across the state, as well as increased renewable production, high hydro generation, and high volumes of self-scheduled energy. That notwithstanding, limitations in the market model resulted in inefficient pricing, reflected in frequent wide price swings between real-time and forward markets.[31]

Load and supply conditions were relatively manageable in 2009. CAISO average system loads decreased 2.5 percent between 2009 and 2010. This continues a trend of four straight years of declining average load within the CAISO footprint, due largely to the weak economy but also in part to several years of relatively mild weather across California. The annual peak system load was 2.8 percent higher in 2010 than in 2009,[32] and occurred during a heat wave on August 25, 2010.[33] Hydro availability in the summer months increased in 2010 relative to 2009, due to a high level of in-state snowpack.[34] The spot market price of natural gas increased by 17 percent in that period;[35] this was the primary factor in moderately higher wholesale costs of power in 2010.[36] Refer to Appendix E for detailed data on natural gas prices.

Approximately 1,500 MW of new gas-fired generation capacity was added in 2010, in addition to 500 MW of renewable capacity. This was offset by approximately 400 MW of generation retired. Approximately 1,147 MW is scheduled to come online in 2011, of which approximately 765 MW will be renewable.[37] This provides some evidence that the state's resource adequacy program and long-term procurement process may be stimulating some investment in new capacity, in addition to meeting short-term capacity needs.

Forward-scheduled energy costs were approximately equal to the cost-based competitive price index in 2010. Real-time energy prices were higher than corresponding day-ahead prices in some periods and lower in others, but real-time energy schedules are also subject to various additional uplift costs. On average, CAISO load paid $37.37 per megawatt-hour of day-ahead-scheduled energy, plus an additional

[31] CAISO Department of Market Monitoring (DMM), *2010 Market Issues and Performance Annual Report*, p. 1.
[32] Ibid, pp. 32-34.
[33] ZGlobal analysis.
[34] CAISO DMM, pp.44-45.
[35] CAISO DMM, p.46.
[36] CAISO DMM, p. 2.
[37] Ibid, pp. 9-10.

$2.54/MWh for real-time and reliability costs.[38] This suggests that the prices BVES pays for energy it procures in the forward markets and schedules should be priced competitively and serves as a hedge against exposure to volatile real-time prices. That said, over-procurement often results in unnecessary expenditure on forward-procured power by load-serving entities, and has facilitated speculators' exploitation of systematic price differences across trading markets.[39]

Perhaps the most significant feature of inefficiency in the CAISO market has been the disparity between the prices of real-time imports, which are relatively inexpensive, and generation internal to the Balancing Area, which is relatively costly. This has been the effect of several operational issues, which include real-time derates on transmission capacity, steep load ramps during super-peak periods, real-time deviations from schedules, particularly by renewable resources, unscheduled flows, and strong hydroelectric production. The consequence of the disparity of pricing is a "buy high, sell low" phenomenon, in which the CAISO must export real-time power to manage these constraints, and recover the shortage relative to schedules by dispatching internal resources upward in real time.

Real-time balancing energy prices continue to exceed prices for both day-ahead scheduled energy and hour-ahead import energy, on average. The real-time premium arises in a relatively small number of pricing periods in which prices spike to higher levels, often near and at times exceeding a price of $750/MWh. These spikes usually only persist a short period of time, typically 15 minutes or less, and affect only the relatively small volume of load that is not forward-scheduled and must thus be settled in the real-time balancing market. These spikes usually reflect short-term modeling limitations, and are not necessarily indicative of non-competitive behavior on the part of market participants.[40] For example, a spike may occur briefly when the load ramps more quickly than the entire available and on-line fleet of generation can ramp simultaneously, but would end as soon as some peaking generators can come online to respond to the high demand, usually within 10 to 15 minutes.[41]

The CAISO is prioritizing market changes intended to address these issues. New software features released in 2010 and/or scheduled for 2011 include:

- **Compensating injections:** This feature, implemented in 2010, aligns the flows used by the market model with actual monitored physical grid power flows. Previously, the market model used estimated flows.
- **Short-term forecast:** This feature will provide more accurate short-term forecasts for dispatch of hour-ahead imports and exports and the real-time market, in order to reduce real-time imbalances.
- **Improved manual load adjustment practices:** The ISO is providing additional training and guidance to its dispatch operators with respect to

[38] Ibid, p. 59.
[39] Ibid, pp. 1-2.
[40] Ibid, p. 5.
[41] Alternatively, the CAISO algorithm could be set to dispatch additional resources in its one- to five-hour outlook, which runs every 30 minutes. This is a software modification that is being implemented in early 2011. However, doing this to avoid occasional spikes may have the unintended and costly consequence of dispatching excess resources that may have minimum run times, thereby resulting in higher costs over longer time periods.

adjustment or bias of short-term load forecasts. This is intended to mitigate operator error in manual interventions and overrides.

- **Accounting for intertie ramping in the hour-ahead scheduling process.** This enhancement will enable the hour-ahead dispatch algorithm to use real-time internal resources, which are dispatchable every five minutes and thus more flexible in matching generation to load, to better accommodate changes in hourly import and export schedules.
- **Timely outage reporting requirements:** Asset owners must now report resource limitations or unavailability prior to the hour-ahead scheduling process.
- **Flexible ramping capacity constraints:** The market short-term look-ahead algorithm will include additional flexible ramping capacity in its short-term unit commitment. This is intended to reduce the frequency of the aforementioned short-term price spikes due to energy ramping constraints.
- **Unit start-up profiles.** This will enable the market dispatch algorithm to count the energy produced between the time a generator is offline and reaches its minimum generation rate. The software historically has not recognized the generation from a resource when it is below the unit's minimum level of output, resulting in excess unscheduled energy on the grid during early morning hours.

As envisioned, the CAISO Market will have new features and functionality added over time. The schedule and scope of these changes is an evolving process, facilitated through the CAISO Market Initiative Roadmap[42] stakeholder process. The following are key market design enhancements which are likely to affect BVES.

5.A.1 Convergence Bidding

The CAISO implemented convergence bidding (also known as virtual bidding) in February 2011. Convergence bids are financial bids to buy or sell energy in the day-ahead market, which are then automatically liquidated and settled at the real-time price. This capability is designed to encourage convergence of day-ahead and real-time prices as participants seek to arbitrage any price differences in these markets. This increase in price convergence has the potential to increase the efficiency of day-ahead unit commitment and energy schedules. Convergence bidding also allows generators to schedule in the day-ahead market and still earn the real-time price. This also allows generators to hedge the financial risk of forced outages after the day-ahead market that could cause a unit owner to pay high real-time energy prices for energy scheduled in the day-ahead market that cannot be delivered. Convergence bidding will be allowed at all locations, or nodes, within the system, including inter-ties with neighboring balancing areas.

The CAISO Department of Market Monitoring has expressed concern that the discrepancy between hour-ahead and real-time prices will be exacerbated with the deployment of convergence bidding if the aforementioned market software enhancements do not mitigate the problem. Currently, this market anomaly can be

[42] For more information, refer to web site http://www.caiso.com/1fb1/1fb1856366d60.html.

exploited with a low-risk simple scheduling strategy, and the incurred Real-time Imbalance Energy Offset cost is charged to load-serving entities. As of April 2011, the DMM has proposed a settlement modification that would allocate such costs back to the market participants that engage in this scheduling strategy. As of this writing, the CAISO has not yet taken action on this proposal.[43]

5.A.2 Resource Adequacy Program

Another key aspect of the market design that will undergo enhancements in 2010 and beyond is California's resource adequacy (RA) program. Currently, utilities contract to meet their capacity obligations through private bilaterally-negotiated contracts. In June 2010, the CPUC issued Decision 10-06-018 indicating that it would not move towards a centralized capacity market or a multi-year forward resource adequacy requirement, at least for the time being. The CPUC concluded that the existing RA contracting mechanisms and practices are sufficient, and that the proposals may pose challenges for non-utility load serving entities.

5.A.3 Standard Capacity Product Provisions

Numerous stakeholders have requested the CAISO and the CPUC collaborate to standardize obligations placed on generation units used to meet resource adequacy requirements, and incorporate these into the CAISO tariff. The goal of such modifications is to facilitate bilateral contracting between load-serving entities and generators to meet resource adequacy requirements, in order to facilitate a liquid trading market for executed resource adequacy contracts, and to provide incentives to minimize RA generation outages. As part of this effort, performance standards for standard thermal generating resources were developed and incorporated in the CAISO tariff and implemented in 2010. Standard capacity terms for renewable resources went into effect in January 2011. Developing appropriate performance standards for these nonconventional resources has been problematic due to their diverse nature and intermittency. The CAISO and the CPUC will continue to work with stakeholders to standardize resource adequacy requirements for demand response programs later in 2011, and are also developing standards for resources needed to complement intermittent renewables, such as ramping, startup, and regulation capabilities. These are expected to be implemented in 2012 or later.

5.A.4 "Backstop" Capacity Procurement Provisions

The interim capacity procurement mechanism (ICPM) provisions of the CAISO Tariff allowing the CAISO to procure capacity in the event of certain capacity deficiencies expired on March 31, 2011. Under the ICPM, the CAISO was authorized to commit

[43] CAISO DMM Presentation on Real-Time Imbalance Energy Offset, 4/29/11, http://www.caiso.com/2b60/2b60bc046d1e0.html.

non-RA capacity resources, usually small peakers on a monthly basis, at an administratively-set price of $41/kW-year, if any of the following conditions occur:

- the day-ahead residual unit commitment (RUC) process is unable to meet the system capacity requirement from RA capacity
- local capacity resources are insufficient for reliability reasons
- an unexpected "significant event" threatens grid reliability
- the CAISO must engage in "exceptional dispatch" of resources to maintain grid reliability.[44]

In 2010, 371 megawatt-months of capacity was procured by the CAISO, at a total cost of $1.4 million.[45] In March 2011, the Federal Energy Regulatory Commission approved the CAISO's proposal to continue indefinitely this procurement authority, now called the Capacity Procurement Mechanism (CPM), but it did not accept the CAISO's proposal to raise the payment to $55/kW-year, on the grounds that such compensation may be inadequate to the generator.[46] The matter remains pending in settlement negotiations at FERC, and the end result may well be a further increase in the procurement price paid by the CAISO.

5.A.5 Scarcity Pricing

The CAISO implemented scarcity pricing for ancillary services (AS) on December 14, 2010. This enhancement allows the price of ancillary services to increase above the current $250 bid cap when supply is insufficient to meet the AS requirements. When such scarcity exists, AS prices will be based on an administratively set demand curve, plus any opportunity cost associated with providing AS capacity instead of energy. Since generation under RA contract is required to bid AS-qualified capacity into the AS markets, scarcity pricing should only be triggered in cases of true physical scarcity.[47]

5.B Resource Adequacy (RA) Requirements

5.B.1 Current State of RA Requirements for BVES

The purpose of the CPUC's Resource Adequacy Requirements (RAR) program (in proceeding R.09-10-032) is to ensure "sufficient resources to the California Independent System Operator (CAISO) to ensure the safe and reliable operation of the grid in real time.... [I]t is designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future."[48]

However, for several years the CPUC has focused on aspects of the RAR related to large utilities and has postponed a decision on RAR requirements for BVES and other

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44 CAISO Annual Report, pp. 27-29.
45 Ibid, p. 158.
46 California Independent System Operator Corp., 134 FERC ¶ 61,211 (2011).
47 CAISO Annual Report, p. 26.
48 For more information, refer to web site https://www1.caiso.com/2465/2465d5952da90.html.

small and multi-jurisdictional utilities (SMJUs). The CPUC's decision D.10-06-018 on June 3, 2010 again deferred this issue.[49]

Until the CPUC provides a decision on RAR for BVES, BVES will continue to submit RAR filings to the CAISO and the California Energy Commission, which in turn will provide RAR information to the CPUC. BVES is not subject to any CPUC compliance penalties, since the CPUC has not set up RAR compliance procedures. BVES' RAR filings are consistent with the reporting assumptions advocated by BVES in comments to the CPUC's RAR proceeding.

Once the CPUC approves BVES RAR requirements, BVES may be required to have capacity resources equal to 115 percent of its forecasted monthly peak load.

5.B.2 Background of RA Proceedings

When the CAISO filed with the FERC for approval of pre-MRTU tariff changes to implement the CPUC's RA program, BVES filed a protest at FERC to which the CAISO agreed that the CPUC had not yet established an RA program for BVES. FERC then ruled that the CAISO should treat all entities the same and should, therefore, impose an Interim Reliability Requirements Program (IRRP) for BVES under the CAISO tariff.[50] In a subsequent order, FERC provided a means to identify such a program until the CPUC developed an RA program for SMJUs.[51] The CPUC has placed BVES issues in Phase II Track 3 of its proceeding, but it has postponed resolution of Phase II Track 3 issues. In a December 2009 scoping memo in R.09-10-032, the CPUC indicated that a scoping memo for Phase II issues would be published in the third quarter of 2010. Thus, resolution of BVES RA requirements will likely be delayed to late 2011.

In order to comply with the FERC ruling, BVES met with the CAISO prior to filing its RA Proposal with the CPUC,[52] which was the basis for the IRRP and included the following key provisions:

- BVES would determine its monthly peak demand for RA requirement purposes based on the State's coincident peak demand. This is preferred over the use of BVES' peak load which is non-coincident with the State's peak load. If BVES' peak load is used, BVES would have to procure additional resources.

- BVES would treat the Bear Valley Power Plant (BVPP) as a distributed generation resource rather than as a generator controlled by the CAISO. Such

[49] D.10-06-018, page 3, states: "Track 3 of Phase 2 was established to address resource adequacy obligations for small and multi-jurisdictional load-serving entities that are not currently subject to the resource adequacy program. We find that it is appropriate to close this proceeding and resolve the Track 3 issues in a more appropriate proceeding."
[50] *California Independent System Operator Corp*, Order Accepting Tariff Revisions, as modified, FERC Docket ER06-723-000, 115 FERC ¶ 61,172 at P 48 (May 12, 2006).
[51] *California Independent System Operator Corp.*, Order on Rehearing, Clarification, and Compliance Filing, Docket No. ER06-723-001, *et al.*, 118 FERC ¶ 61,045 at P 32 (Jan. 22, 2007).
[52] RAR Proposal to Energy Division Staff dated May 18, 2007.

treatment would reduce BVES' peak demand, thereby reducing BVES' reserve requirement.

This proposal, in effect until the CPUC issues a decision, reduces BVES' capacity obligations throughout the year, primarily through reduced coincident peak obligations.

It is not yet known if the CPUC will adopt these changes in their RA and capacity counting conventions in a future decision from R.05-12-013. However, until the CPUC does issue a decision for SMJUs, BVES is attempting to manage the potential financial impact of RA requirements.

5.B.3 Calculation of RA for BVES

Until the CPUC issues its decision, as outlined in BVES' filing to the CPUC, BVES provides an estimate of its CAISO system coincident peak demand to the CEC, who in turn issues to BVES its coincident peak demand. Because BVES is a winter-peaking utility and has its summer peaks on holiday weekends, BVES has proposed that its monthly capacity obligations be set based on weekday loads coincident with the CAISO's monthly peak periods, rather than BVES' higher weekend loads when CAISO loads are generally light and RA requirements for BVES would be higher.[53]

For planning purposes, BVES has assumed that its RA obligations must be in accordance with the CAISO's MRTU as defined by the CAISO tariff; therefore, BVES has planned for RA requirements equal to 115 percent of monthly forecasted load. BVES has purchased RA capacity from Shell Energy North America as part of its long-term PPA to meet these RA obligations.

Table 5.1 illustrates BVES' forecasted RA requirements for 2012 with monthly adjustments for holidays and weekends.

[53] Golden State Water Company, "RAR Proposal to Energy Division Staff Provided by Bear Valley Electric Service (U 913 E)," (May 18, 2007), CPUC Rulemaking 05-12-013, Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.

BVES 2012 Resource Adequacy Requirement (in MW)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Forecasted Peak Demand	34.4	30.5	27.3	22.3	21.4	21.5	21.2	22.2	21.3	20.2	32.8	37.8
Holiday Adjusted Peak Demand	31.4	27.5	27.3	22.3	18.4	21.5	18.2	22.2	18.3	20.2	29.8	34.8
BVPP	-1.2	-1.2	-1.2	-6.0	-2.4	-6.0	-2.4	-6.0	-2.4	-4.8	-1.2	-3.6
Adjusted Peak Demand less BVPP	30.2	26.3	26.1	16.3	16.0	15.5	15.8	16.2	15.9	15.4	28.6	31.2
Reserve Requirements	4.5	3.9	3.9	2.4	2.4	2.3	2.4	2.4	2.4	2.3	4.3	4.7
Total Capacity Obligation	34.7	30.2	30.0	18.7	18.4	17.8	18.1	18.6	18.3	17.7	32.9	35.9
RA Capacity	28	28	28	18	18	18	18	18	18	18	28	28
Dispatchable DSM	8.35	8.35	8.35	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.35	8.35
Total Capacity	36.35	36.35	36.35	18.85	18.85	18.85	18.85	18.85	18.85	18.85	36.35	36.35
Net Capacity Requirements	-1.6	-6.1	-6.4	-0.1	-0.4	-1.1	-0.7	-0.2	-0.6	-1.1	-3.5	-0.5

Table 5.1: BVES Forecasted 2012 Resource Adequacy Requirement

Table 5.2 further summarizes BVES' annual RA requirements for the period 2011 through 2016.

BVES Annual Resource Adequacy Requirement (in MW)						
	2011	2012	2013	2014	2015	2016
Peak Demand	37.1	37.8	39.0	39.9	40.3	40.7
BVPP	-8.4	-8.4	-8.4	-8.4	-8.4	-8.4
Peak Demand less BVPP	28.72	29.39	30.57	31.53	31.92	32.26
Reserve Requirements	4.3	4.4	4.6	4.7	4.8	4.8
Total Capacity Obligation	33.03	33.80	35.15	36.26	36.71	37.10
RA Capacity	35	35	35	0	0	0
Dispatchable DSM	8.35	8.35	15	15	15	15
Total Capacity	43.35	43.35	50	15	15	15
Net Capacity Requirements	-10.32	-9.55	-14.85	21.26	21.71	22.10

Table 5.2: BVES Annual Resource Adequacy Requirement

Pending a CPUC decision regarding RA requirements for BVES, and prior to the implementation of MRTU under its new CAISO tariff RA provisions, BVES was not subject to penalties for non-compliance with RA. However, in the new MRTU environment, there are indirect penalty mechanisms that the CAISO believes apply to all LSEs. For example, should the CPUC disapprove future RA contracts with proposed suppliers, BVES could be exposed to the allocated costs of any RA shortfalls through the mechanisms provided in the CAISO's MRTU Tariff.[54] Indeed, while BVES was not subject to direct RA-related penalties for backstop capacity under the previous market structure, BVES believes that these allocated costs under the MRTU Tariff could be far more significant and less predictable. It will take some time operating in the MRTU environment to determine the magnitude of these allocated costs.

BVES should begin the procurement process for RA by issuing a Request for Proposal (RFP) for RA in late 2011 with the goal of receiving CPUC approval in 2013.

5.B.4 Local RA Capacity

Under MRTU, the CAISO may procure Local RA Capacity (LRAC) if the CAISO determines there is a capacity deficiency within a Local Capacity Area (LCA). A deficiency in LRAC can occur because individual LSEs do not demonstrate sufficient LRAC in annual or monthly resource plans or because of a collective deficiency of local capacity in a LCA. It should be noted that, according to the CAISO, the BVPP cannot be counted as a Local Capacity Resource. When needed, the CAISO will make supplemental procurement for RA under the CPM provisions of its tariff described above. As detailed in the CAISO Tariff,[55] the CPM costs associated with the procurement of LRAC will be allocated proportionately to all deficient LSEs within each Transmission Access Charge (TAC) Area, or in the case of a collective deficiency of local capacity, to all Scheduling Coordinators that serve load in the TAC Area. BVES load is within the SCE TAC Area, and its portion of the load in this area has been determined to be 0.06 percent,[56] or 8MW. Although BVES is not within any specific LCA,[57] the CAISO may allocate CPM cost to BVES because of local capacity shortages elsewhere in the SCE TAC Area. Based on the CAISO 2011 Local Capacity Technical Study, the CAISO does not anticipate a need in 2011 for purchases under CPM in the SCE TAC Area.

The need for BVES to make a forward purchase of Local Capacity must be monitored and evaluated with input from the CAISO's annual "Local Capacity Technical Studies." As of this writing, the current cost[58] the CAISO will charge BVES if additional local capacity is procured will be \$55/KW-year (\$6.01/MWh).

[54] Specifically, MRTU Tariff sections 40 and 43. Through the Capacity Procurement Mechanism (CPM), which is a backstop to the RA process, CAISO will purchase RA capacity on behalf of any LSE that fails to procure its full RA requirement and will allocate those costs to the RA-deficient LSEs depending on the type of RA deficiency (i.e., deficiency in year-ahead system showing, deficiency in year-ahead local showing, deficiency in month-ahead system showing, or deficiency in a month-ahead local showing). In the case of shortages of local or system capacity by LSEs, these costs will be allocated pro rata to each LSE in the Transmission Access Charge (TAC) area based on the ratio of each LSE's resource deficiency to the total resource deficiency of all LSEs in the TAC area. In the case of a collective deficiency of local capacity resources, the CPM costs are allocated to each LSE's proportionate share of load in the TAC area. It remains unclear whether BVES would be able to argue that, in the absence of CPUC system or local RA procurement obligations applicable to BVES, BVES should not be subject to an allocation of CPM costs.
[55] CAISO Tariff Section 43, Capacity Procurement Mechanism.
[56] CAISO 2011 Local Capacity Technical Study.
[57] BVES load does not reside within the "LA Basin" or any other Local Capacity Area as defined in the CAISO 2011 Local Capacity Technical Study.
[58] CAISO Tariff 43.6.1. This cost is being debated by various legislative and regulatory parties.

5.C Energy Efficiency (EE) and Demand Response (DR)

Through Assembly Bill 2021[59] and the CPUC's Decision 04-09-060, the Legislature and CPUC both require that utilities manage their need for generation resources by first making an effort to reduce the need for supply. While AB 2021 and D.04-09-060 do not formally include BVES, the Company has in the past and continues to promote the benefits of reduced consumption. Often the lowest cost supply is obtained by convincing customers to use less energy (e.g., through energy efficient appliances) while still providing the same level of service to the customer. As a result, the CPUC's procurement policy includes a provision requiring that IOUs implement programs that will reduce the customer's need for energy and capacity. These customer oriented programs can take many forms and, together, are referred to as Demand Side Management (DSM).

In its decision D.09-09-047 issued September 24, 2009, the CPUC stated:

> "In Decision (D).04-09-060, the Commission articulated its goal to pursue all cost-effective energy efficiency opportunities in support of the Energy Action Plan commitment that conservation and energy efficiency are first in the "loading order" of electricity and natural gas resources. In accordance with this overarching goal, D.04-09-060 established short- and long-term numerical targets for electricity and natural gas savings. We stated that these targets must be aggressive and must stretch the capabilities and efforts of all those involved in program planning and implementation."

There are two basic forms of DSM. The first addresses the amount of energy required to provide the service the customer wants. Such programs only indirectly reduce the need for peaking capacity. This form of DSM includes Energy Efficiency (EE) programs, sometimes referred to as conservation programs. The second form of DSM directly addresses the capacity component of electricity requirement but only indirectly reduces the energy requirements of customers. This form of DSM includes Demand Response (DR) programs, which provide an incentive to customers to reduce their energy use at times of peak demand on the utility's system. BVES' DSM program is a vital component in managing local system peaks and transmission constraints in the winter, and contributes to reducing the CAISO peaks in the summer months.

BVES collects funds through its rates[60] to fund EE programs. Prior to approval of BVES' 2008 General Rate Case (GRC),[61] EE efforts were limited to two sources: the BVES Low Income Energy Efficiency Program (LIEE) and temporary funds received through SBX1 5 during 2002 and 2003. This funded residential and small commercial rebate programs; however, funding was withdrawn at the start of the state's fiscal budget crisis in 2004.

[59] Levine, Chapter 734, Statutes of 2006.
[60] EE funds are collected through rates rather than via a Public Purpose Program Charge.
[61] Application 08-06-034 was filed on June 27, 2008 and Decision 09-10-028 was issued on October 16, 2009.

With GRC approval obtained later than expected in 2009, BVES could only begin planning its EE program in 2009 and early 2010; therefore, implementation began in mid-2010. Both the LIEE and EE programs have one-way balancing account treatment over the implementation cycles, allowing carryover of spending between years up to the total GRC cycle budget. This allows BVES to manage its programs over a longer timeframe in order to deal with unforeseen implementation issues, such as weather. While the respective program budgets do not have specific administrative cost allocations, the majority of the money is directed toward customer incentives and retrofits.

BVES' new non-low income EE Program as outlined in the GRC was designed to include some basic program designs and a residential and nonresidential market assessment. These components generated information BVES needed to better design EE programs that fit the unique needs of customers in the Bear Valley area. These basic program designs are based on BVES' experience with its SBX1 5 programs and current successful statewide large utility programs. These programs are as follows:

Residential

BVES' Residential Energy Efficiency Program focuses on lighting as well as rebates for high efficiency appliances. Under the current program, customers who purchase refrigerators, room air conditioners, and water heaters that meet specified equipment requirements are provided with a rebate. Many of BVES' customers have taken advantage of the appliance rebate program. BVES has conducted and will continue to conduct a series of lighting exchange events throughout the 2010-2012 program cycle. These events allow customers to exchange less efficient incandescent light bulbs for higher efficiency compact fluorescent lamps (CFLs) and LED nightlights. Various educational materials, including information on proper disposal of CFLs, are also included in this portion of the residential energy efficiency program.

Also for residential customers, BVES has made available via its website a home energy audit to identify opportunities for electricity savings, including the installation of energy efficient equipment and behavior changes. Through its current program, BVES will be able to assess the residential market for energy efficiency and, based on the findings, more measures may be offered to residential customers, most likely in a future GRC proceeding.[62]

Commercial

Commercial lighting comprises a significant portion of energy supplied to BVES' commercial sector. This lighting load also happens to be highly correlated with BVES' peak demand. As a result, improving the efficiency of lighting will also provide a significant peak demand benefit.

[62] BVES plans to file a GRC in November/December of 2011.

Commercial refrigeration was another area in which BVES assisted its commercial customers. An educational, streamlined refrigeration presentation and workshop[63] was held to assist customers in minimizing their refrigeration costs. Afterward, BVES offered individualized site surveys to further identify energy saving opportunities for interested customers. Written evaluations were provided to those customers. The workshop also provided an opportunity to educate customers on lighting and BVES' commercial lighting rebate program detailed below.

In the fall of 2010, BVES began offering financial incentives for customers who retrofit their inefficient lighting fixtures with new high efficiency equipment. While the main focus of the *Small/Medium Business Lighting Cash Rebate Program* is the retrofit of linear fixtures, rebates are also available for LED exit signs and control equipment (occupancy sensors and time clocks). In addition, BVES conducted site surveys at a sample of its large commercial customers to determine a mix of lighting and non-lighting measures that it could offer. As a result, in May 2011 BVES implemented a *Large Customer Energy Efficiency Innovation Grant Program.* This particular program offered technical assistance and a cash grant to eligible projects aimed at assisting major customers to implement new and innovative energy efficiency technologies unique to their businesses.

BVES' new residential and commercial EE programs have been well received by both residential and commercial customers who should save energy and reduce their electric bills. BVES' program will continue to contribute toward the State's goals of more efficient use of energy resources. With the success of this current program, BVES plans to request additional funding and new programs in its next GRC filing to continue offering an energy efficiency program as part of its long term energy resource portfolio. If approved, such programs can help reduce BVES' resource requirement consistent with regulatory policies, while also generating good will within the community and demonstrating social responsibility and corporate leadership.

5.C.1 Low Income Energy Efficiency (LIEE) Program

The Low Income Energy Efficiency (LIEE) program funded by BVES is available only for qualifying low income residential customers. The program has been in existence since 2002 and has reduced the need for supplying more than 500,000 kWh. The LIEE Program provides funding for energy efficient refrigerators, hard-wired compact fluorescent fixtures and free compact fluorescent bulbs for eligible customers who apply. BVES also provides educational materials to all customers promoting the use of energy efficient appliances, weatherization materials, thermostatic controls, and life style changes. However, the effectiveness of educational messages in convincing customers to install more efficient equipment has not been assessed.

[63] The presentation and workshop was conducted by ASW Engineering.

5.C.2 Programs for Demand Response

The one Demand Response (DR) program currently offered by BVES targets its largest customers through a newly designed tariff approved in the 2008 GRC.[64] This tariff provides a lower rate in exchange for the customer's agreement to interrupt or reduce load when called upon by BVES. This DR program currently provides approximately 8.35 MW[65] of winter demand reduction that can be called upon during BVES' highest peak demands. The incentive built into the current tariff amounts to approximately $6.30 per kW per month in the winter months and approximately $7.00 per kW per month year-round when seasonally adjusted.[66] Changes in BVES' 2012 GRC may support an increase in the winter DR capacity in 2013, with a possible reduction in the tariff incentive.

Four BVES accounts are served under the TOU interruptible tariff. It is anticipated that all four accounts will elect zero firm load; that is, they agree to shed 100 percent of their load served under this tariff rate at BVES' request.

As with the EE programs, BVES will assess its DR needs and evaluate programs to develop DR offerings. One potential area to be considered is a load control program that would enable BVES to cycle or interrupt customer load via radio or phone signal. Such a program could include:

- Spa load control
- Air conditioner cycling
- Municipal pumping load interruption/cycling

In summary, there are a number of EE and DR programs that could potentially benefit both BVES and its customers. BVES will primarily rely on the expertise of its EE consultant, Mark McNulty and Associates, while also considering programs being offered in other winter resort areas. As part of its market assessment, BVES will identify the savings potential of the programs it wishes to offer and will present an overall proposal for adoption in the appropriate regulatory proceedings.

5.D Summary and Conclusions

BVES faces multiple regulatory challenges as California's power markets see structural and fundamental changes. State-mandated requirements for utilities to meet higher energy efficiency goals, reduce emissions of greenhouse gases and acquire more renewable resources will change the way BVES chooses its resource mix. Least-cost planning is now just one part of BVES' resource acquisition policy.

CAISO costs can be managed through the use of bilateral supply contracts that are self-scheduled in the Day Ahead Market. Generally, BVES has purchased a large portion of

[64] Rate Schedule Number A-5 TOU.
[65] 8.35 MW is the current value, which may be amended in the future.
[66] Based on seasonally adjusted demand reduction of approximately 1.0 MW in summer and 8.5 MW in the winter (six months of each season).

its supply requirements as must-take, which is scheduled with the CAISO and reduces the exposure to uncertain market prices. This strategy minimizes market risk for BVES. CAISO market prices have been historically low since the 2009 market redesign. However, this may be due largely to the soft economy. While MRTU has helped to move management of power toward forward transacting to minimize the impact of volatile real-time dispatch, it will not insulate load-serving entities from a rebound in fundamentals-driven increases in natural gas and power prices if and when they should occur. Other structural market changes similarly are likely to enhance market efficiency, but do not affect market fundamentals.

Local RA requirements will remain an area of concern for BVES. Although BVES is outside all SCE local capacity areas, the existing CAISO tariff rules could allocate Local RA procurement costs to all loads, including BVES, within the SCE area if the CAISO must procure additional Local RA. It is not financially or operationally logical for BVES to incur financial exposure for local RA capacity that can only be satisfied by purchasing a resource within SCE's service territory but outside BVES' service territory. BVES will continue to monitor the impact of local RA procurement on its rates and will initiate regulatory action if local RA costs become burdensome.

Energy efficiency will be a significant component of BVES' future resource mix. BVES, while implementing some measures, continues working to identify its energy efficiency programs and will be implementing them through 2011 and 2012.

6. Forecasts of Power Supply Costs

There are a number of components of BVES' total power supply costs, of which capacity and energy costs are the largest. Other costs include transmission on SCE owned and operated facilities (including the 33 kV lines from Cottonwood Substation to Goldhill transfer station and Zanja Substation to Harnish Substation), transmission over the CAISO grid, ancillary services charges, reserve requirements, schedule-dispatch charges and CAISO grid-management charges, including charges for congestion revenue rights (CRRs).

The greatest change in the wholesale markets since 2010 has been the sharp decline in natural gas prices and future power supply costs. Due to a variety of factors, including new production methods for natural gas (fracking technology), reduced demand for natural gas due to the national recession, and a wet winter in the western states that has resulted in significantly greater hydroelectric production and a corresponding decline in fossil fuel generation, energy prices for the period 2011 through 2016 have significantly declined compared to 2010. This has provided BVES an opportunity to go into the forward markets and secure long-term supplies of capacity and energy at lower prices than it is currently paying.

6.A Baseline Power Supply Costs

A baseline simulation of power supply costs for the period 2011 – 2016 was performed under the assumptions that:

- Future gas prices remain at current levels (the forward curve does not change)
- BVES only acquires resources from its current RFP for power supply costs
- BVES meets its renewable obligations with RECs[67]
- Any daily imbalances are either purchased or sold through the MRTU market

In effect, the baseline simulation identifies BVES' power supply costs if BVES acquires resources under its January 2011 RFP for power supply for the period 2014 through 2016. Since BVES has tentatively determined that the least-cost way of meeting its RPS goals is through purchasing RECs in the marketplace, no renewable resources were included in any of the simulations. Instead, the additional cost of RECs is calculated and added to the power supply costs.

Currently, the Shell products and BVPP meet almost 100 percent of BVES' energy needs through 2011. However, by 2012 when the seasonal baseload purchase contract expires, BVES is significantly short energy during the winter months and is purchasing almost one-third of its monthly energy requirements through market purchases.

Since the inception of the MRTU market, BVES can meet its monthly short positions with hourly purchases. The price BVES will pay is the Locational Marginal Price (LMP), assuming BVES has purchased sufficient resource adequacy capacity.

[67] This assumption was to simplify the power supply cost forecast. BVES is soliciting both bundled renewable energy and RECs.

The Shell heat rate option has been "out of the money" for all of 2011 and it is not anticipated that BVES will call upon it. However, it remains useful for protecting against any unanticipated price spikes in the market.

The power supply simulation shows that, at least for 2011, BVES is relatively indifferent to the rate of change of natural gas prices.[68] Such a large portion of BVES' energy purchases is under long-term fixed price contracts that short-term changes in natural gas prices do not significantly impact total power supply costs. Beginning in 2012, however, BVES is more exposed to volatility in the natural gas markets.

The results of the power supply simulation are summarized in Table 6.1. Appendix H contains the detailed analysis.

Year *	Total Power Supply Cost	Average Wholesale Delivered Cost per MWh ($/MWh)	Average Wholesale Energy Cost Only ($/MWh)
2008	$14,006,772	$ 89.14	$ 75.85
2009	$13,408,701	$ 89.18	$ 63.34
2010	$14,251,564	$ 94.81	$ 65.02
2011	$14,290,827	$ 94.06	$ 64.37
2012	$14,331,885	$ 92.44	$ 63.45
2013	$14,847,659	$ 92.43	$ 63.94
2014	$13,935,890	$ 83.59	$ 56.48
2015	$14,339,269	$ 84.37	$ 57.52
2016	$14,627,248	$ 85.19	$ 58.40
* Data for years 2008 through 2010 are actuals while subsequent years are forecasts. BVES anticipates these costs to escalate due to renewable energy transmission upgrades and other factors.			

Table 6.1: Forecast of Power Supply Costs

The initial analysis identified some of the important planning issues facing BVES over the next two years:

1. The annual baseload purchase contract with Shell Energy North America (which expires in November 2013) provides about 75 percent of BVES' annual energy requirements with significant cost stability.
2. BVES will be short energy beginning in 2012 when the Shell seasonal baseload purchase contract expires.
3. BVES will be subject to increased cost volatility as a result of its exposure to market based costs rather than fixed cost contracts.
4. Future prices are significantly less than the prices BVES is currently paying for energy.

[68] Refer to Appendix E which illustrates historical changes in natural gas prices.

In 2011, even if natural gas costs increase by $1/MMBTU over current levels (about a 20 percent increase from current levels), BVES' fixed price contracts comprise such a large portion of total energy requirements that the impact of high natural gas costs is only around $200,000. However, when the Shell baseload contract expires in November 2013, BVES is at risk for higher fuel costs if it does not address its future requirements.

The complement to BVES' exposure to higher natural gas prices is that BVES cannot benefit from lower natural gas prices if it purchases firm energy supplies at current market prices.

Because the MRTU energy clearing price is tied to natural gas prices, an increase in natural gas costs causes the clearing price to increase or behave just as a heat rate option. BVES' heat rate option with Shell provides some short-term price protection due to physical shortages. To increase price protection from long-term increases in natural gas prices, BVES is considering acquiring a fixed price option to cap costs.

The baseline simulation provides an estimate of future power supply costs whether BVES purchases firm resources or relies on the market. However, BVES' risk position is very different if BVES relies on market purchases versus firm purchases. Firm purchases that include strike price options fix BVES' future energy costs whether the market price goes up or down. If BVES relies on market purchases, it could benefit if energy prices decline but would see higher total costs if energy prices rise. Meeting the majority of energy requirements through firm purchases is a more risk-averse approach.

6.B Costs Related to Renewable Resources

In its efforts to fulfill its RPS requirement, BVES has attempted to secure bundled energy generated in California. BVES will continue to pursue bundled energy generated in California as well as REC-only transactions to meet its RPS requirements. If the CPUC implements SB 2 as currently interpreted by BVES, RECs may be the least complicated and possibly least costly way for BVES to achieve RPS compliance.

However, there is some uncertainty with regard to how the CPUC, and to some extent the CEC, will interpret SB 2's REC language. Prior to SB 2, buying out-of-state RECs would require "matching" those RECs with out-of-state energy, mimicking bundled in-state renewable energy. For BVES, importing power or matching out-of-state RECs to out-of-state power would be cumbersome and costly.

This discussion assumes that BVES will achieve RPS compliance via REC-only transactions, although BVES will continue to pursue bundled in-state energy to the extent it is cost effective and feasible.

As discussed in Section 3, the cost of RECs is currently capped at $50/MWh. The CPUC has made clear that, although a REC may cost $50, that cost may not be deemed reasonable and thus recoverable in rates. For illustrative purposes, Table 6.2 shows the cost of achieving RPS compliance for the years 2011 through 2016 at two price levels: $30 and $50.[69]

BVES' Projected Cost of RPS Compliance using RECs						
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Projected Annual Retail Sales Volume (MWh)	132,209	134,649	139,405	144,694	147,888	149,479
RPS Requirement (MWh) *	26,442	26,930	27,881	36,174	36,972	37,370
REC Cost @ $30/MWh	$793,254	$807,894	$836,430	$1,085,205	$1,109,160	$1,121,093
REC Cost @ $50/MWh	$1,322,090	$1,346,490	$1,394,050	$1,808,675	$1,848,600	$1,868,488
* The compliance levels described in SB 2 are 20% through 2013, 25% from 2014 through 2016, and 33% by 2020.						

Table 6.2: Projected Cost of RPS Compliance

As shown in the table, assuming a $30 per MWh (REC) cost, BVES may spend approximately $793,000 to $1,121,000 per year between 2011 and 2016 on RECs. The cost almost doubles with REC prices at the cap of $50 per MWh.

6.C SCE Transmission and Distribution Charges

After energy costs, BVES' largest cost component of total power supply costs is transmission costs. BVES pays SCE for transmission service on three SCE 33 kV lines that deliver power up the mountain to BVES, and for SCE wholesale distribution access tariff (WDAT) service (for service from SCE's Victor Substation near Victorville to SCE's Cottonwood Substation in Lucerne Valley and from SCE's Vista Substation to SCE's Zanja Substation near Redlands). BVES also pays the CAISO for transmission of energy imported into and through California. Together these transmission charges are over $2,600,000 annually.

Currently, BVES is charged monthly for four different uses of SCE's non-CAISO grid, all of which are described in the following sections.

[69] Projected annual retail sales, which are the basis for RPS requirements, are derived from total energy requirements identified in the Power Supply Cost Model (Appendix H) less 13% losses.

6.C.1 SCE Wholesale Distribution Access Tariff Charge

BVES receives service under SCE's Wholesale Distribution Access Tariff (WDAT) and is assessed a charge by SCE for facilities not included in the CAISO's grid charges. While CAISO generally operates SCE's transmission system, SCE generally retains control of its distribution system, including 115 kV, 69 kV, and 34.5 kV[70] distribution lines. The WDAT covers service over those facilities.

BVES requires wholesale distribution service from its two energy take-out points on the CAISO-controlled grid. Under a 2004 revised service agreement with SCE, BVES obtains 34 MW of service from SCE's Victor Substation to SCE's Cottonwood Substation and 5 MW of service from SCE's Vista Substation to SCE's Zanja Substation. The monthly fixed charge for this service is $55,014.48.

6.C.2 SCE Non-CAISO Low-Voltage Transmission Charges

Under a 2004 Amended and Restated Transmission Service Agreement and a 2009 Second Amended and Restated 33 kV Added Facilities Agreement, SCE provides 34.5 kV transmission service from its Cottonwood Substation to its Goldhill switching station, where BVES takes delivery. Goldhill is the primary delivery point for capacity and energy. Under these agreements, BVES has contractual rights to 34 MW of transmission capacity via Goldhill.

Under the 2004 Amended and Restated Transmission Service Agreement, BVES also has 5 MW of transmission capacity on the Radford Feeder, from SCE's Zanja Substation to the BVES Harnish Substation, where BVES takes delivery. Generally, the Radford 34.5 kV line is de-energized during the summer fire season, at which time all of BVES' energy requirements are delivered through Goldhill.

Together under these two agreements, BVES has a contractual total of 39 MW of capacity from SCE via these two metered receipt points. These agreements contain separately stated charges. Under the 2004 Agreement, the monthly fixed charge for use of SCE's 34.5 kV lines is $16,246, and a separate monthly fixed charge of $38,137 that will end in 2019. The 2009 Added Facilities Agreement also provides for another $2,922 in monthly fixed charges.

6.C.3 SCE Reliability Services Charge

Under SCE's Transmission Owner (TO) Tariff on file with FERC, SCE charges wheeling customers in its historic control area, including BVES, who are not Participating Transmission Owners (PTOs) under the CAISO tariff, a Reliability Services (RS) Rate for reliability-related costs incurred by the CAISO and passed on to SCE as a PTO, and other costs directly incurred by SCE in maintaining a reliable

[70] As mentioned earlier, SCE refers to its line as a 33 kV line, while BVES refers to the same line as a 34.5 kV line.

transmission grid. With the adoption of RA requirements and the MRTU tariff, SCE's RS costs and the RS Rate have generally declined.

SCE's RS Rate varies for different wheeling customers, and the charges to BVES under its RS Rate have varied significantly over the past few years under an annual true-up process required by SCE's TO Tariff, ranging from a low of -$0.03 per MWh (i.e., a monthly credit) to a high of $1.43 per MWh. As of January 1, 2011 the RS Rate charged to BVES is $0.03 per MWh. The amount of the RS Rate charged to BVES depends on its metered energy. Based on the forecasted energy requirements for BVES for 2011 of 151,932 MWh, the RS Rate would result in an annual cost of $4,569.

6.C.4 SCE Bear Valley Project Distribution Facilities Agreement

When BVES was installing the Bear Valley Power Plant (BVPP), SCE determined that it needed to build certain discrete additional facilities on its system to accommodate the interconnected operation of the BVPP with the SCE distribution system. Under the Bear Valley Project Distribution Facilities Agreement, SCE recovers the actual costs of these facilities. The agreement provides for a monthly fixed charge of $111.31.

6.C.5 Total Monthly SCE Transmission Charges

The four different monthly charges for transmission and wholesale distribution services from SCE total approximately $112,811, or $1,353,732 annually.

6.D California Independent System Operator Charges

The CAISO charges BVES, through its Scheduling Coordinator APX, for ancillary services, grid management charges, imbalance energy, and CAISO uplifts.[71] Ancillary services are the services necessary to follow the moment-to-moment changes in load, such as regulation, load following, voltage support and operating reserve capacity. Grid management charges are the cost of operating the California transmission grid and include costs associated with running the CAISO markets. Imbalance energy charges apply to deviations between scheduled and metered energy.

The largest CAISO charges are Wheeling Access Charges for use of the CAISO-controlled transmission grid. The CAISO assesses Wheeling Access Charges for transmission (or "wheeling") on the CAISO-controlled grid by non-Participating Transmission Owners (non-PTOs) such as Bear Valley.[72] High Voltage (HV) Wheeling Access Charges are assessed for wheeling from transmission facilities with a voltage rating of 200 kV or higher. Wheeling from transmission facilities with a voltage rating of less than 200 kV will result in Low Voltage (LV) Wheeling Access Charges in

[71] CAISO uplift charges are collected from all customers to ensure market participants, including suppliers, are made whole. They reflect costs incurred to run the market for which there is no direct assignment to specific LSEs. They are collected from all customers to ensure the CAISO market is ultimately revenue neutral.
[72] PTOs themselves are assessed analogous Transmission Access Charges.

addition to the HV Wheeling Access Charge. These access charges are established by the CAISO Tariff filed with FERC.

The HV Wheeling Access Charge recovers the rolled-in HV transmission revenue requirements of the 12 PTOs. The CAISO Tariff also establishes a LV Wheeling Access Charge for some PTOs, including SCE. The LV Wheeling Access Charge is a utility-specific rate based on the utility's LV transmission facilities within the CAISO-controlled grid. SCE's LV Wheeling Access Charge is applied to BVES load served from SCE's Victor substation, from which SCE provides service to BVES at SCE's Goldhill substation.

The CAISO High Voltage Wheeling Access Charge is approximately \$6.4364/MWh for use of the 220/500/1,000 kV system, and the Low Voltage Wheeling Access Charge is \$0.4216/MWh for use of the SCE 69/115 kV lines that are part of the CAISO-controlled grid. BVES pays both charges at its energy take-out point at SCE's Victor Substation (from which BVES ultimately takes delivery at Goldhill), but pays only the High Voltage Wheeling Access Charge at its energy take-out point at SCE's Vista Substation (from which BVES ultimately takes delivery at Harnish). These charges may vary monthly as transmission rate filings are made by the various utilities (the PTOs) that have turned over transmission to the CAISO.

SCE files its base HV and LV transmission revenue requirements with FERC in amendments to its Transmission Owner (TO) Tariff.[73] In 2008 and 2009, SCE filed substantial increases in its base HV and LV transmission revenue requirement with FERC. In September 2009, FERC approved a settlement that resulted in a 29% increase in SCE's HV transmission revenue requirement and a 19% increase in SCE's LV Wheeling Access Charge. In February 2011, FERC approved a settlement that resulted in a further 8% increase in SCE's HV transmission revenue requirement and a 24% increase in SCE's LV Wheeling Access Charge. These SCE rate filings are reflected in the CAISO High Voltage Wheeling Access Charge and the SCE LV Wheeling Access Charge in effect as of June 1, 2011.

On June 3, 2011, SCE filed in FERC Docket No. ER11-3697-000 another amendment to TO Tariff, which would increase its HV transmission revenue requirement by 20%, and its LV Wheeling Access Charge by 43%, effective January 1, 2012. FERC has taken no action on this filing to date.

BVES paid approximately \$1,000,000 for CAISO transmission charges in 2010 and an additional \$92,000 annually for SC fees to the APX. Total CAISO charges are around \$1,600,000 annually for transmission, grid management and ancillary services. The monthly payments to the CAISO are dependent upon the total amount of energy used by BVES each month and how closely BVES schedules energy deliveries to match load.

[73] SCE separately files annual tariff amendments to change its separately stated Construction Work in Progress (CWIP) transmission revenue requirement.

BVES load will be charged for its energy consumption at the LMP at the Default Load Aggregation Point (DLAP)[74] of Southern California Edison (SCE) in the Day Ahead market. Any real time deviations from the Day Ahead schedule will be settled every 10 minutes at the real time LMP of DLAP SCE.

BVES will also have the option of making bilateral energy purchases and scheduling them in the CAISO market through inter-SC trades of energy in the Day Ahead market.

Table 6.3 summarizes BVES' charges from SCE and the CAISO for transmission and distribution services.

Type of Charge	Purpose	Cost per Month (Approximate)
SCE Wholesale Distribution Access Tariff (WDAT) Charges	Distribution service over non-CAISO portions of SCE's transmission grid from Victor Substation to Cottownwood Substation and from Vista Substation to Zanja Substation	$55,014
33 kV SCE Transmission Charges	Use of SCE 33 kV facilities from two WDAT delivery points to two BVES interconnections with SCE points	$16,246 $38,137 $2,922
Reliability Services Charges	Use of transmission service from SCE for grid reliability	$381
Bear Valley Project Distribution Facilities Agreement	SCE facilities required for interconnected operation of BVPP with SCE distribution system	$111
CAISO Charges	Use of the CAISO 115 kV and greater transmission lines	$110,000
	Total Monthly Cost **Total Annual Cost**	**$222,811** **$2,673,732**

Table 6.3: SCE and CAISO Transmission and Distribution Charges

6.E Congestion Costs

Congestion Costs are one of the two components (transmission losses being the other) of the cost to deliver energy from one point to another within the CAISO. The cost of congestion is the difference in the Marginal Congestion Cost (MCC) component of the Locational Marginal Price[75] (LMP) between the price nodes specified for energy delivery and takeout. For BVES supply contracts, the source from the CAISO

[74] LAP is defined in Appendix G.
[75] The CAISO's market design creates marginal nodal or locational prices in its Day Ahead market process. The Locational Marginal Price or LMP is the algebraic sum of the 1) Marginal Energy Cost (MCE), 2) Marginal Cost of Congestion (MCC), and 3) Marginal Loss Cost (MLC).

settlements perspective is the aggregated generation hub price for South of Path 15 (SP15_Gen Hub) area.[76] The sink, or takeout, point is the Southern California Edison Default Load Aggregation Price (SCE_DLAP). This price is the load weighted aggregation of all load nodes within the SCE area. The Congestion Cost is calculated using the Day Ahead Market Prices as follows:

Congestion Costs = Source Marginal Congestion Cost – Sink Marginal Congestion Costs
or Source MCC – Sink MCC

Congestion costs can be mitigated through the use of Congestion Revenue Rights (CRRs). As reflected in the 2010 IRP, the cost of congestion was relatively low for the first 9 months of MRTU.[77] For 2010, the cost of congestion was found to increase from 2009, but in general remained fairly low with the exception of a few instances of high cost of congestion. Table 6.4 shows the 2010 On- and Off-Peak Average MCC differences between the SP15 Generation Hub and SCE Default LAP as well as the maximum hourly difference per month. While there were some instances of negative delivery costs, resulting in a "payback" of the MCC differential earned by BVES in the Day Ahead market, on average the delivery costs have been positive. Overall, congestion between the Generation Hub and the Default LAP occurred primarily during peak hours with little to no congestion during off-peak hours. During on-peak hours, the average hourly congestion cost by month was found to range from a low of $0.00 per MWh in May to a high of $0.59 per MWh in January.

2010 On-Peak	Average Hourly MCC Differential ($/MWh)	Maximum Hourly MCC Differential ($/MWh)	Minimum Hourly MCC Differential ($/MWh)	2010 Off-Peak	Average Hourly MCC Differential ($/MWh)	Maximum Hourly MCC Differential ($/MWh)	Minimum Hourly MCC Differential ($/MWh)
January	0.5898	26.6913	0.0	January	0.0340	1.5361	0.0
February	0.3115	3.3222	0.0	February	0.0089	0.6295	0.0
March	0.1524	2.7570	0.0	March	0.0	0.0	0.0
April	0.1004	2.1908	-0.7953	April	0.0	0.0	0.0
May	0.0	0.0	0.0	May	0.0	0.0	0.0
June	0.0554	9.6507	0.0	June	0.0	0.0	0.0
July	0.1577	7.9113	0.0	July	0.0	0.0	0.0
August	0.0395	3.4771	-0.1320	August	0.0	0.0	0.0
September	0.0292	6.1468	0.0	September	0.0	0.0	0.0
October	0.0636	2.8133	-0.9166	October	0.0879	5.3588	0.0
November	0.0087	3.2103	-0.7695	November	0.0025	0.1304	-0.0018
December	0.0389	7.5581	-1.6767	December	0.0061	0.1421	0.0
Annual Average	0.1289			Annual Average	0.0116		

Note: Negative numbers indicate the Gen Hub is more Congested than the Default LAP. When this occurs the CRR is a liability and BVES must pay back the congestion revenue earned in the Day Ahead Market. Positive numbers indicate the Default LAP is more congested than the Gen Hub and BVES is paid back the congeston charges in the Day Ahead Market.

Table 6.4: 2010 Congestion Cost between SP15 Gen Hub and SCE_DLAP

The primary driver contributing to a relative increase in congestion costs for 2010 from the initial deployment of CRRs in April of 2009 is the tightening of constraints in the Day Ahead Market. In November 2009, the ISO implemented the Southern California

[76] The CAISO derives the aggregated generation hub price by calculating a weighted average for all generators within the SP15 area. Weights are pre-determined by the CAISO on an annual basis based on previous year output. Generator hub prices are calculated for NP15, ZP26 and SP16 areas. Generation scheduled to the aggregate generation hubs is paid/charged the weighted hub price as calculated in the Day Ahead market.
[77] MRTU was deployed in April of 2009 along with CRRs.

Edison Import Branch Group constraint.[78] This constraint impacts the total volume of imports as a percentage of loads in the SCE territory and was found heavily congested during the first quarter of 2010. When this constraint becomes binding (i.e., the limit is reached), the Default LAP becomes more congested, increasing the MCC. Additionally, as the MRTU has matured during the first year of operation, the CAISO has tightened other constraints in an effort to manage the majority of internal congestion in the Day Ahead market as opposed to the Real Time Market.

Looking forward, as the economic conditions within California improve and system load increases, the cost of congestion will increase corresponding to heavier system loading. Additionally, as more renewable generation is added within the CAISO area, it is expected that transmission use will increase and ultimately add to the overall cost of congestion. To mitigate this risk, BVES will continue to participate in the CAISO CRR process to secure the appropriate financial hedge to mitigate potentially increasing congestion costs or secure PPAs that deliver energy to the SCE_DLAP on behalf of BVES.

6.F Cost Impacts of AB 32 (GHG)

With CARB's development of AB 32 regulations, BVES has incurred direct costs and could incur indirect costs associated with compliance. However, because the BVPP has limited GHG emissions due to low amounts of annual generation, and because CARB's exemption thresholds for Regulation compliance are higher than BVES operation levels, overall direct costs have been limited.

6.F.1 Direct Costs

Current direct costs include: 1) GHG reporting under the Mandatory Reporting Regulation, 2) compliance with the SF_6 Regulation, and 3) compliance with the Fee Regulation.

As discussed in Section 4, overall Regulation compliance activities, and therefore administrative costs, are limited for BVES. With the 2010 revisions to the Mandatory Reporting Regulation, direct costs will be reduced further as a result of reduced requirements for reporting and verification for retail sellers. CARB's threshold for reporting as an electric generating facility was also revised in 2010 from 2,500 to 10,000 MT CO_2e; BVES is exempt from reporting in both scenarios until power generation increases.

Direct costs to BVES that are associated with the Fee Regulation are minimal, given that BVES is currently exempt from fee assessment, leaving only administrative reporting requirements as provided in the January 2011 amendments to the regulation. The Fee Regulation assesses fees for facilities that emit more than 2,500 metric tons of CO_2 from electricity generating activities during the reporting year.

[78] CAISO 2010 Market Issues & Performance Annual Report, section 5.3 Internal Congestion.

The SF_6 Regulation, implemented in January 2011, has the most direct costs associated with compliance. There is no numeric threshold for the SF_6 Regulation; the Regulation applies to all owners of GIS equipment,[79] which includes BVES since it owns four (4) 38 kV circuit breakers installed in the substation at the BVPP. Direct costs associated with SF_6 Regulation compliance are associated with: 1) development of SF_6 Inventory Measurement Procedures, 2) establishment and maintenance of GIS equipments inventory, including storage containers, and 3) annually reporting SF_6 emissions. With the exception of circuit breaker major maintenance activities, the small amount of SF_6 located at the BVPP and the historical emissions indicates that direct costs will be minimal. Even during the initial development of procedures/plans to demonstrate compliance, costs are anticipated to range between $5,000 and $10,000. However, in the later years of the SF_6 Regulation, costs will likely increase as BVES replaces circuit breakers due to excessive leakage.

6.F.2 Indirect Costs

The Scoping Plan outlines GHG reduction measures that reach across all sectors of California's economy, increasing compliance reporting and other costs to all sectors. As a result, BVES may incur indirect costs in the future, most notably a price increase of wholesale power and natural gas, resulting from the CARB Scoping Plan, future GHG emissions reduction measures, and related policies and programs implemented by the CPUC.

The GHG impacts extend beyond BVES' administrative and direct costs. Currently, CARB estimates that AB 32 will result in a cost to producers of approximately $30/ton of GHG emissions in excess of emission allowances. The method for allocating emission allowances to utilities has not yet been determined. The statewide GHG emission goals are to achieve GHG emissions equivalent to a gas-fired generator with a heat rate of 7,800 BTU/kWh, or about .25 tons of GHG emissions per MWh.

CPUC Final Resolution E-4298, which approved the 2009 Market Price Referent (MPR), also includes estimates of GHG Compliance Costs. In developing the MPR, CPUC staff used the "Synapse 2008 CO_2 Price Forecasts" mid-case cost data as the GHG environmental input to the MPR. For the years 2012, 2015, and 2020, the GHG Compliance Cost components for the MPR were calculated to be $11.51, $26.84, and $47.97 per MT CO_2e, respectively.

While BVES will not have to make payments to California or CARB for GHG emissions, it could see the price of energy purchases from gas-fired generation increase by approximately $15/MWh by 2014 if AB 32 is implemented. This equates to almost a $2,000,000 annual increase in power supply costs due to BVES' dependence on gas-fired generation.

[79] The SF_6 Regulation defines GIS as "all electrical power equipment insulated with SF_6 gas regardless of location. GIS includes: switches, stand-alone gas-insulated equipment, and any combination of electrical disconnects, fuses, electrical transmission lines, transformers and/or circuit breakers used to isolate gas insulated equipment (see SF_6 Regulation §95351)."

6.G Risk Management

As a small utility, BVES generally assumes a risk-averse posture. Rather than rely on the volatile spot market for supply, it prefers certainty in total power supply costs to the highest degree possible rather than risk upward price movements in the energy market. For the past few years, BVES has been able to fix the cost of a large percentage (80 to 90 percent) of its total power supply costs through long-term PPAs. With the signing of the Shell PPA, BVES managed to insulate itself from market price uncertainty but still faces other sources of risk.

BVES looks at its Value at Risk (VAR) when determining how much of its future energy supplies to purchase. The VAR is a measure of how much total costs change when underlying variables, such as natural gas prices, change.

BVES' year-ahead VAR is low in 2011 when the various Shell agreements meet almost all of BVES' power supply requirements. Beginning in 2012 when the Shell seasonal baseload purchase expires, BVES' VAR jumps to almost 20 percent. That is, power supply costs could increase by almost 20 percent if natural gas costs double, or an additional $2,500,000 annually. This cost impact can be mitigated by long-term PPAs, by hedging on-peak requirements with a strike price option on natural gas prices, or by entering into renewable contracts not tied to natural gas prices.

One of the ways BVES mitigates a high VAR is to stagger the lengths of various power supply purchase agreements so that only a portion of BVES resources need to be renewed at any one time. In its PPA with Shell Energy, BVES contracted for energy products under varying contract terms for baseload, peaking and intermediate resources, significantly reducing BVES' VAR. BVES will follow this same strategy with its planned annual and seasonal baseload contracts. If renewable resource purchases are later added to BVES' resource mix, BVES should be able to further reduce its year-ahead VAR.

BVES' exposure to risk comes in a number of ways. For example, BVES faces forecast risk, market-price risk, regulatory risk, supply risk, counterparty risk and other types of business risk.

Forecast risk is the cost associated with over or under-forecasting BVES' retail requirements and having either too much or too little energy, requiring that BVES either buy at higher than expected costs or sell from existing contracts at a loss.

Market-price risk is the risk associated with entering into long-term contracts with wholesale prices subsequently falling, such that BVES could have purchased the energy less expensively. Conversely, if BVES chooses not to enter into a contract at current prices and then prices rise, BVES' price of power could rise dramatically as compared to not locking in prices at lower rates.

Regulatory risk is the added cost of changes in regulations or new regulations that increase BVES' cost of doing business. The greatest fear of regulatory risk is that BVES takes actions to meet current regulations, and regulations are subsequently changed such that BVES incurs increased and unforeseen costs, (1) to undo earlier actions, and (2) to meet the new regulations.

Supply risk is the chance that contracted energy is not delivered for any reason, resulting in BVES incurring additional costs to replace the energy. This is especially applicable where BVES intends to dispatch the BVPP to avoid higher costs but the BVPP does not operate during the planned time period. Another example is SCE and/or CAISO grid reliability.

Counterparty risk is the risk that a counterparty defaults on its obligations and BVES incurs a financial penalty attempting to replace energy contracted from the counterparty. As a small utility with a limited number of counterparties, BVES is exposed to this type of risk daily. To minimize this risk, BVES attempts to insure that its counterparties are financially sound and contractually bound to meet their supply obligations. BVES is currently developing a credit review methodology to further ensure counterparty financial viability.

BVES cannot avoid all risk; risk that cannot be avoided must be managed. Daily or hourly energy requirements cannot be forecast with a high degree of certainty weeks or even months in advance of need. BVES cannot control the grid delivery system nor the actions of its counterparties or regulators.

Regardless of its inability to control the actions of the market or other entities, BVES can design its resource acquisition strategy to minimize the financial impact of forecast and market risk. BVES has fixed the price of roughly 80 percent of its energy requirements for the next few years, attempting to minimize the impact of sudden price spikes in the power markets. BVES attempts to deal only with companies that have good credit ratings and periodically reviews their ratings.

An area of great concern to BVES is regulatory risk at both the federal and state levels. The change in federal administration has resulted in dramatically different energy and environmental goals than the previous administration. These proposed changes, if implemented, could result in significant additional costs to BVES and its customers.

This is especially true at the state level where MRTU implementation, RPS, energy efficiency requirements and proposed new environmental rules could add new complexity and costs to BVES' operations. These proposed changes, both at the federal and state level, will be taken into consideration by BVES in its integrated resource planning process.

6.H Financial Contracts

BVES' seasonal baseload purchase expires at the end of 2011. Beginning in 2012, BVES requires additional baseload capacity for the winter season. It can either purchase a physical contract where energy is generated and delivered to BVES through the CAISO or a financial contract where a counterparty assumes the financial risk and BVES takes energy from the CAISO market.

There are a number of different financial contracts available to BVES to consider, that may reduce its exposure to price spikes in the CAISO market.

6.H.1 Call Options

BVES currently uses heat rate options to set the price it pays for a portion of its energy. However, this is just one of the different options available to it. Other types of options are not tied to changes in daily gas prices and can help BVES reduce its exposure to changes in natural gas prices.

A call option allows the purchaser to buy the right to purchase a specific quantity of energy at a fixed price (called the strike price) regardless of the market price. For example, BVES may purchase a call option for up to 10 MW per hour at a price of $60/MWh. If energy prices are greater than $60/MWh, then BVES would exercise its right and pay the strike price. If prices were less than $60/MWh, BVES would not exercise its right and instead purchase in the market at the lower price.

The price that BVES has to pay for call options depends upon the time left to exercise an option and the strike price relative to the market.[80] The lower the strike price, the higher the option premium. Also, the further out in time the option is, the greater the price reflecting uncertainty about the future direction of the market.

BVES has to balance current and forward prices with options. In the best case, any option purchased by BVES would not be exercised, meaning that daily market natural gas prices were less than the strike price and BVES can purchase energy less expensively.

Options are used to cap energy costs. An option provides protection against the financial impact of high energy prices, but that protection comes with a cost.

Figure 6.5 illustrates how a call option works. In exchange for the option premium, the marketer guarantees that BVES will not pay more than the strike price. In the example shown, if the energy price is greater than $70, BVES' cost is capped at $70. If prices are less than $70, BVES pays the market price.

There are different measures of the market price. With one type of call option, the maximum BVES pays each hour is capped at $70/MWh. Figure 6.5 illustrates this type of call option. In this situation, BVES is protected against even an hourly spike in prices.

[80] Option prices have been studied extensively and depend upon the relationship of the price to the strike price, time to maturity, underlying price volatility and the interest rate.

With the other types of call options, a daily or monthly average price is used. In this situation, BVES is protected against prices rising above the strike price on average for the period but is still at risk for hourly price spikes.

Call options that protect against hourly spikes are more expensive than options that use daily or monthly averages.

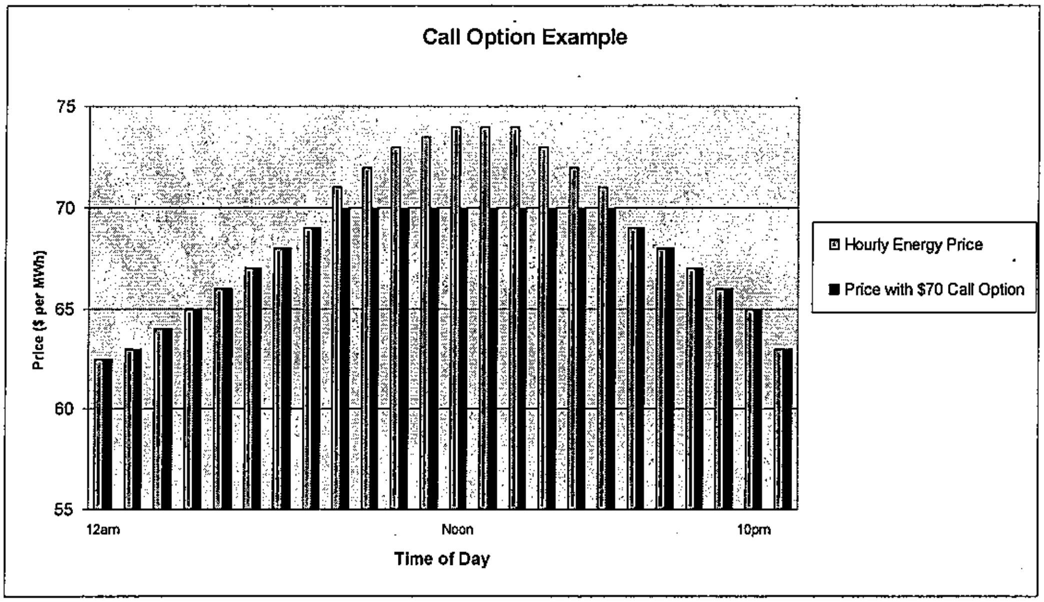


Figure 6.5: Example of Call Option Pricing

6.H.2 Collars

A way for BVES to avoid paying the high premium cost of options is to use costless collars. With a collar, the range of energy prices is fixed. A collar with a cap (via a call option) of $65/MWh and floor (via a put option) of $45/MWh means that for a portion of its energy BVES will not pay more than $65/MWh, regardless of how high the price of energy is during the delivery period. But, BVES would also not pay less than $45/MWh regardless of how low energy prices are.

The advantage of a costless collar is that, unlike a call option, BVES does not have to pay for price protection. The value of the implicit put option is used to offset the cost of the call. The disadvantage is that BVES would not be able to take advantage of prices lower than the floor.

Costless collars are generally asymmetric. If the future energy price is $50/MWh, the collar may be from $45/MWh to $65/MWh. If BVES wanted a symmetric collar (for example $40/MWh to $60/MWh) then it would likely have to pay the counterparty.

6.H.3 Financial Hedges

BVES has historically not made use of financial hedges, preferring instead to purchase with fixed price and options. However, primarily due to the MRTU market in which many counterparties participate, financial hedges have become much more common in the California wholesale gas and electric markets.

The simplest form of a financial hedge is a contract-for-differences. Two parties agree to a fixed, or strike, price based upon a daily index cost of energy and a specific quantity. On a daily basis, the difference between the spot price and the strike price is due one party. If the price is below the strike price, BVES would owe the counterparty, whereas if the spot price is above the strike price, the counterparty would owe BVES.

For example, if BVES took a daily hedge at $50/MWh for 10 MW per hour for the 16 on-peak hours, BVES is agreeing to pay $500 per hour for 10 MW of energy for 16 hours, or $8,000.

If the average price of energy in the CAISO market during the on-peak period was $40/MWh (below the strike price) then BVES would pay the CAISO for 160 MWh (10 MWh per hour for 16 hours) at $40/MWh or $6,400. It would also pay the counterparty $1,600 ($10 per MWh for 10 MWh each hour for 16 hours) for a total cost of $8,000.

If however, the average price of energy during the day were $75/MWh, BVES would pay the CAISO $12,000 ($75/MWh times 160 MWh) but receive a payment of $4,000 from the counterparty ($25/MWh times 160 MWh). As a result, BVES' net cost is still $8,000.

The purpose of a financial hedge is to lock in the price regardless of the source of supply. The financial hedge actually works as a fixed price purchase.

The advantage of a financial hedge is that it can be done with any financial counterparty so long as an index can be agreed upon. Energy supplies can then be purchased at spot prices from the CAISO and the financial hedge used to fix price. This allows entities the opportunity to enter into financial hedges with strong credit counterparties.

6.H.4 Financial Instruments Versus Physical Purchases

Prior to the beginning of MRTU in 2009, utilities had to purchase physical products to insure the availability of energy for retail requirements. However, the MRTU is a closed market where all physical energy deliveries are made to the CAISO and all LSEs receive their energy from the CAISO. As a result, the CAISO marketplace has become a financial market with purchasers deciding how to settle financial accounts, either directly with the CAISO or with the counterparty. From BVES' viewpoint, the net result is the same whether it chooses to purchase financial instruments or physical energy. The only difference is that BVES would have more potential counterparties with financial instruments than with physical instruments.

Regardless of how BVES chooses to meet future energy requirements, BVES must still purchase 12 MW of baseload resources and 5 to 7 MW of seasonal baseload resources plus up to 10 MW of intermediate/peaking resources during the winter months.

At current market prices, BVES' future total power supply costs are likely to decline from current levels. The greatest risk to BVES is an unforeseen price spike. BVES has a significant Value at Risk (VAR) due to its large net short position in 2012 and beyond that is anticipated to be addressed in 2011.

Since the CPUC has approved the use of RECs, BVES may also use financial instruments to purchase its necessary renewable energy. That is, RECs could be used to offset the actual physical purchase of renewable energy. RECs are a form of financial instrument, allowing renewable energy to be purchased in one area or time but counted as non-renewable energy until the REC is used to convert a corresponding amount of non-renewable energy to green energy. The use of RECs should make it much easier for BVES to meet its renewable requirements in the future.

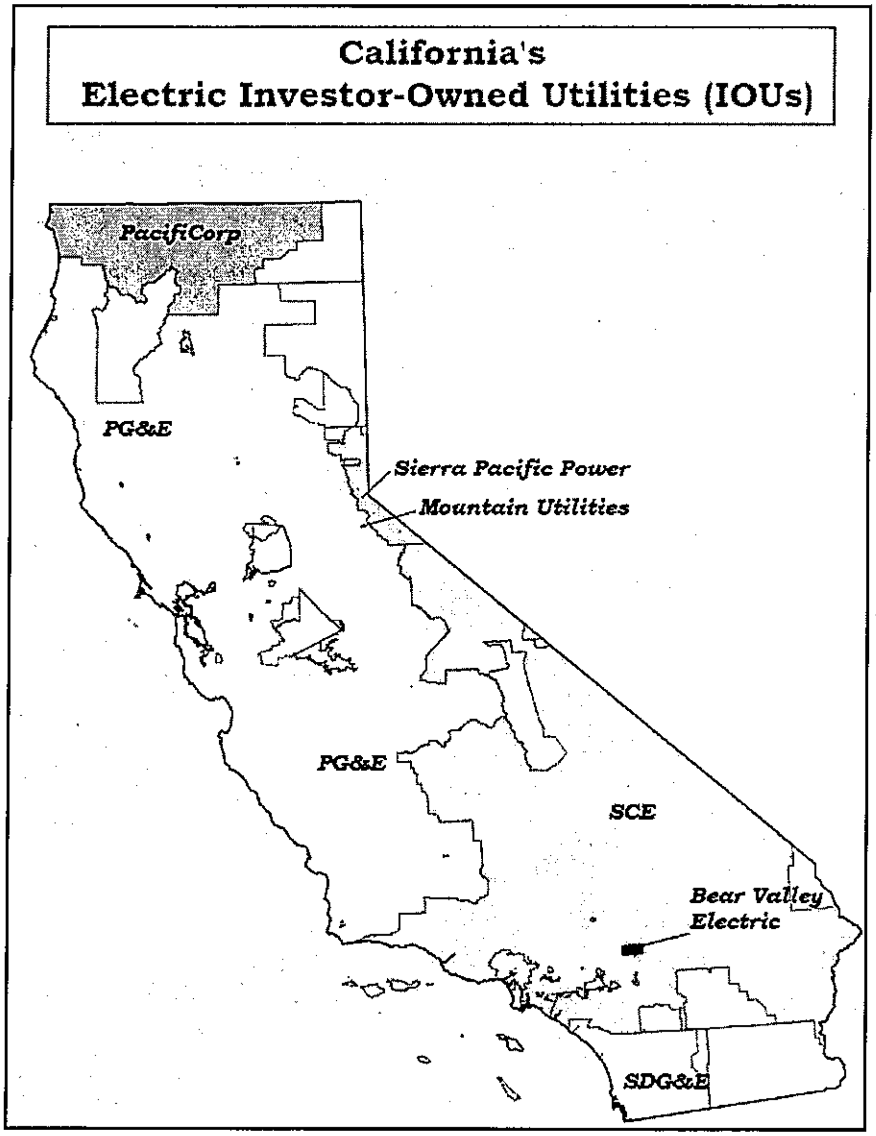
6. I Summary and Conclusions

BVES' power supply costs will be stable for 2011 and 2012 with little price risk, since so much of its energy requirements are hedged with fixed price contracts. The only event that is likely to cause a significant increase will be the requirement for renewable resources.

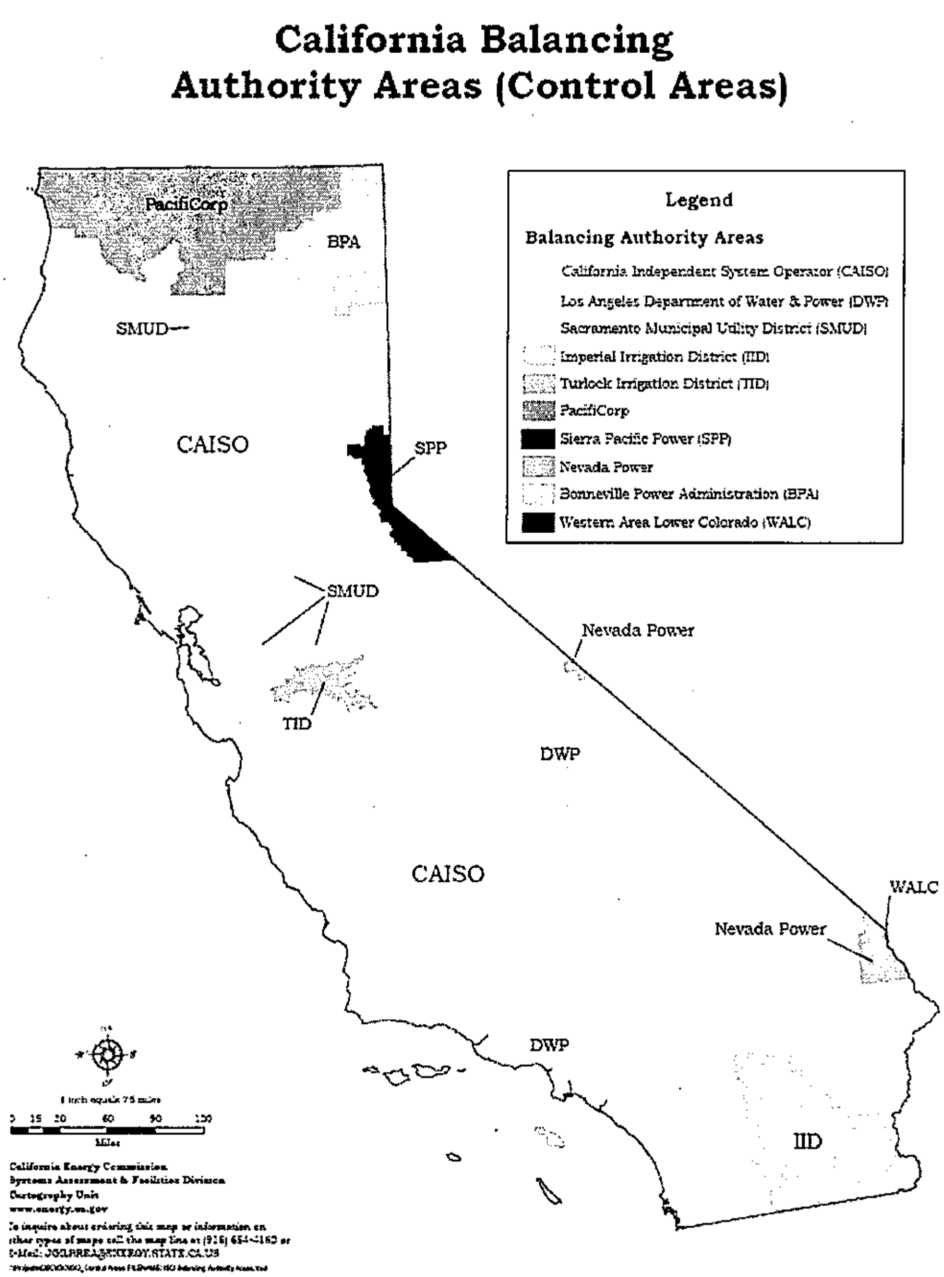
Since determining two top successful bidders from its RFP issued in January 2011, BVES is now in the process of negotiating power purchase agreements (PPAs) to replace its soon-to-expire seasonal baseload contract and its annual baseload contract expiring in November 2013. For its peaking/intermediate needs, BVES is considering strike price options to cap market price risk and, under a financial product, purchase from the MRTU market rather than enter into must-take products. This strategy could provide significant price protection while providing an opportunity for BVES to take advantage of declining energy prices and protect against daily forecast error.

Currently, future power supply costs are low in comparison to energy prices in the past few years. This presents an opportunity to fix future prices at or below current price levels.

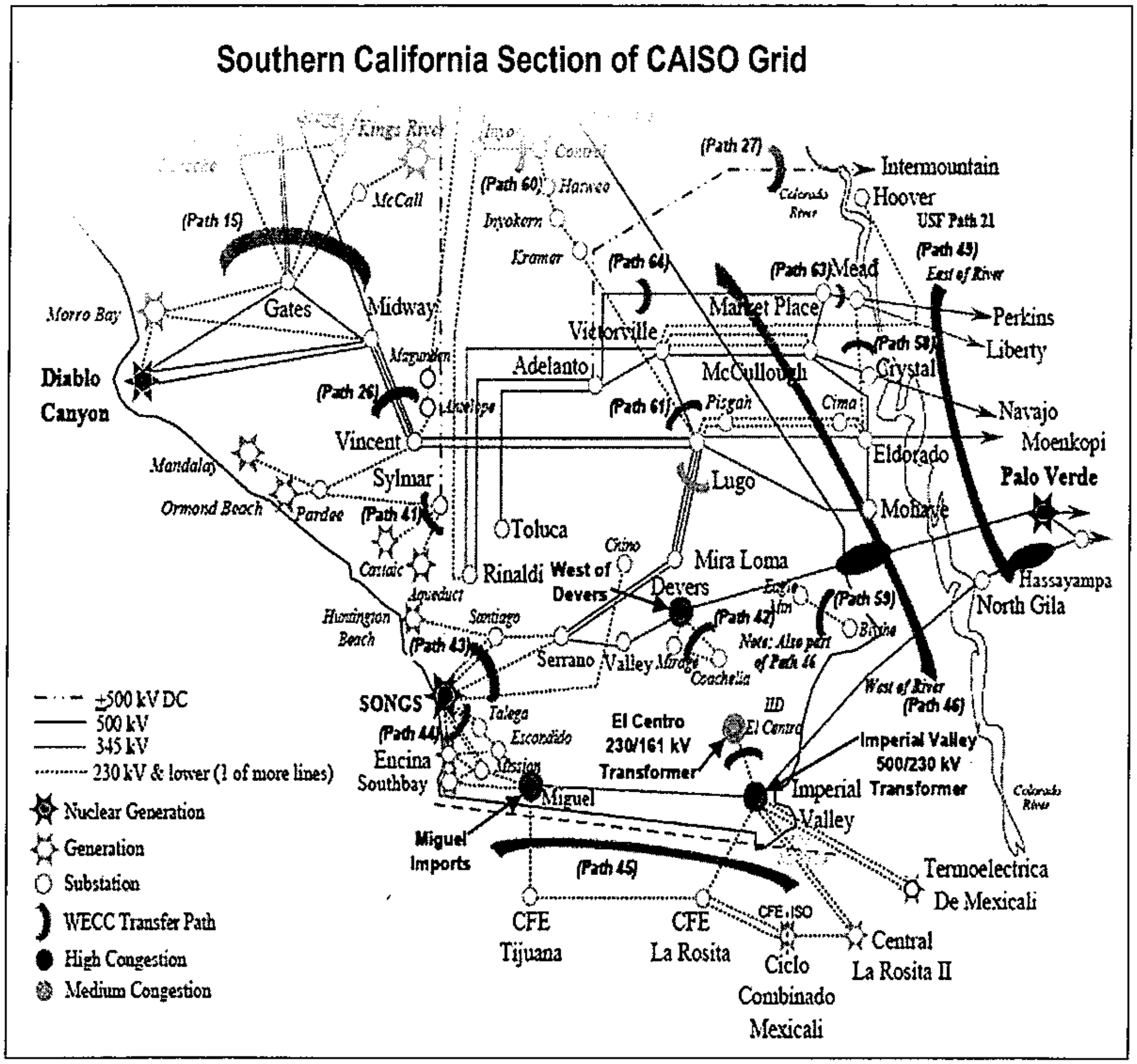
Appendix A: Map of California Investor-Owned Utilities



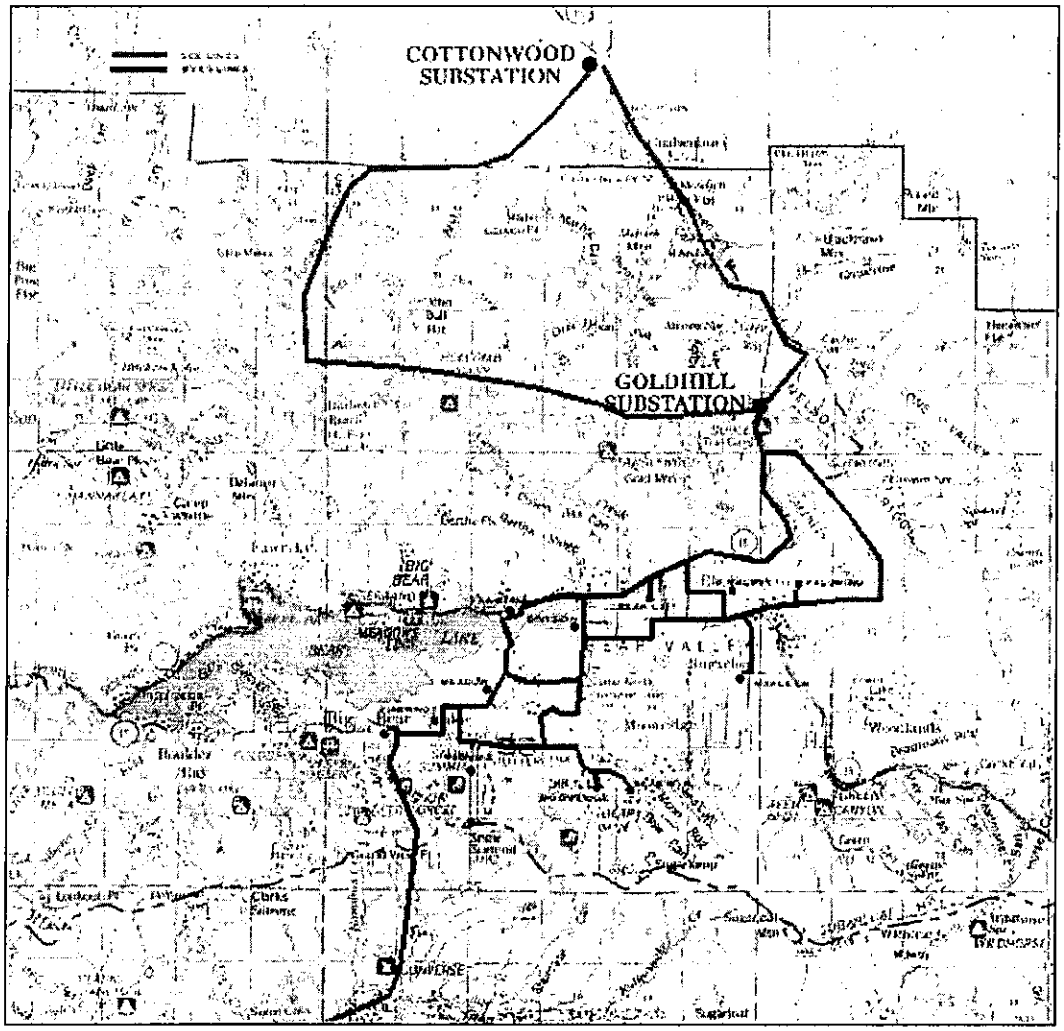
Appendix B: Map of California Balancing Authorities



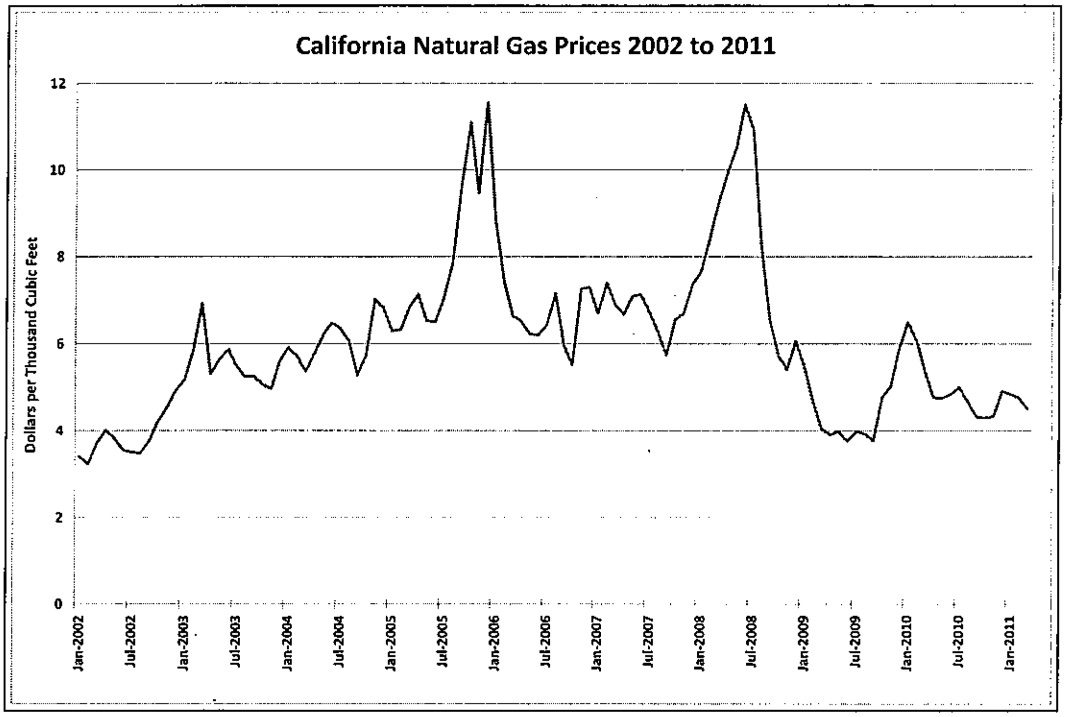
Appendix C: Map of Southern California Transmission System



Appendix D: Map of BVES Power and Interconnection with SCE Power Lines



Appendix E: Natural Gas Prices

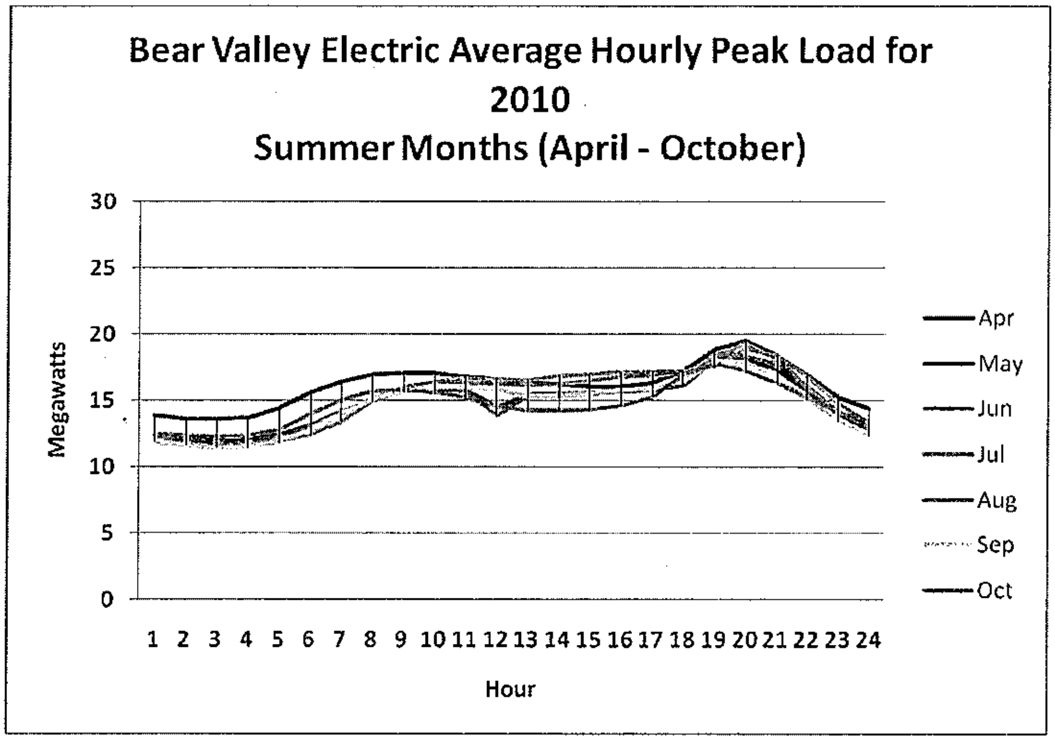


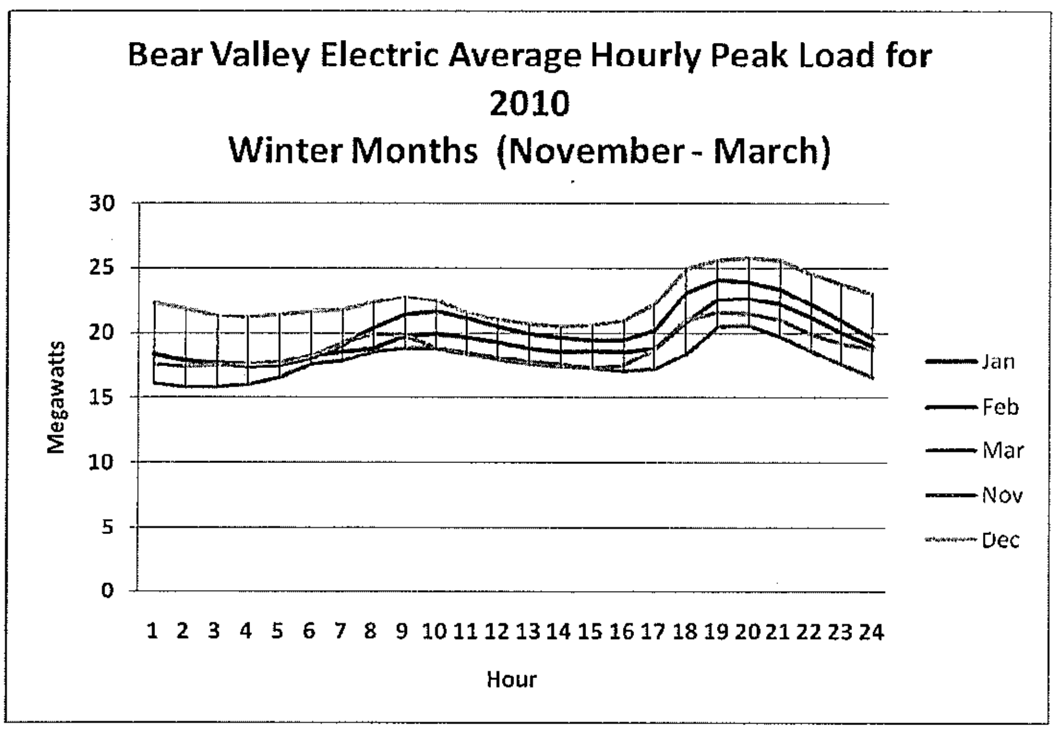
California Natural Gas Price Sold to Electric Power Consumers
(Dollars per Thousand Cubic Feet)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	3.42	3.23	3.71	4.01	3.84	3.55	3.51	3.48	3.75	4.22	4.52	4.93
2003	5.17	5.84	6.93	5.31	5.64	5.87	5.48	5.25	5.25	5.06	4.96	5.62
2004	5.91	5.71	5.36	5.78	6.19	6.47	6.36	6.05	5.28	5.73	7.01	6.82
2005	6.29	6.33	6.83	7.14	6.53	6.49	7.06	7.86	9.61	11.10	9.46	11.55
2006	8.78	7.42	6.63	6.53	6.23	6.20	6.44	7.16	5.97	5.52	7.26	7.30
2007	6.70	7.39	6.91	6.67	7.09	7.13	6.72	6.28	5.74	6.56	6.70	7.35
2008	7.66	8.40	9.23	9.91	10.47	11.50	10.92	8.25	6.55	5.73	5.41	6.06
2009	5.47	4.67	4.05	3.91	3.99	3.76	3.98	3.93	3.77	4.78	5.01	5.88
2010	6.50	6.07	5.37	4.76	4.75	4.84	5.00	4.67	4.32	4.30	4.33	4.91
2011	4.84	4.76	4.51									

Source: Energy Information Administration (www.eia.doe.gov)

Appendix F: Monthly Average Load Curves (Including Bear Valley Power Plant)





Appendix G: Glossary of Acronyms

APT	Annual Procurement Target	The amount of renewable generation an LSE must procure in order to meet the statutory requirement that it increase its renewable procurement by at least 1 percent of retail sales per year.
APX	APX, Inc.	The company that serves as the CAISO-certified Scheduling Coordinator (SC) for BVES.
BA	Balancing Authority	An entity that maintains load-resource balance within an area defined by a metered boundary. A balancing authority is the entity responsible for operating a control area. It matches generation with loads and maintains frequency within limits.
BVPP	Bear Valley Power Plant	The 8.4 MW natural gas-fired, peaking power plant owned and operated by Bear Valley Electric Service.
CAISO	California Independent System Operator Corporation	A not-for-profit public-benefit corporation charged with operating the majority of California's high-voltage wholesale power grid. The CAISO is the independent link between power plants and the utilities that serve the State's consumers, providing equal access to the grid for all qualified users and planning for transmission infrastructure.
CARB	California Air Resources Board	The "clean air agency" in the government of California, established in 1967 as a department within the cabinet-level California Environmental Protection Agency.
CO_2e	Carbon Dioxide Equivalency	A quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).
CRR	Congestion Revenue Rights	A financial mechanism designed to reduce the effect of congestion costs allocated to LSEs. A CRR is a uni-directional right to receive congestion charges from an entity causing transmission congestion.
DR	Demand Response	A set of programs offered by an LSE that provides its customers with financial incentives to reduce load in response to an event signal from the LSE.
DSM	Demand Side Management	Programs initiated by the LSE with its customers that include both EE and DR.
EE	Energy Efficiency	A set of programs offered by the LSE that provides its customers with financial incentives to install efficient electric equipment.
ENG	Electricity and Natural Gas	An industry sector covered by Greenhouse Gas legislation.
EPS	Emission Performance Standards	A facility-based emissions standard requiring all new long-term commitments for baseload generation to serve California consumers be entered into with power plants that have emissions no greater than a combined cycle gas turbine plant. That level is established at 1,100 pounds of CO2 per megawatt-hour.
GHG	Greenhouse Gas	A gas, such as water vapor, carbon dioxide, methane, chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), that absorbs and re-emits infrared radiation, warming the earth's surface and contributing to climate change.

Appendix G: Glossary of Acronyms		
GIS	Gas Insulated Switchgear	A term used to designate gas insulated, metal-clad electrical switchgear, such as circuit breakers.
GRC	General Rate Case	A process used by a utility to request recovery of its forecast revenue requirement including all operating and investment related costs. It establishes or changes the rate design and price levels to customers. It is a public process in which customers may participate.
HASP	Hour Ahead Scheduling Process	The Hour Ahead market for the pre-dispatch of non-dynamic intertie energy. In addition to pre-dispatching energy imports and exports, HASP also includes Ancillary Service imports to the CAISO from external Balancing Authority Areas.
IBPA	Initial Baseline Procurement Amount	The target level of renewables procurement for a utility in its first year of mandated RPS compliance, as set by the Commission. For BVES, the IBPA has been calculated as: 2003 IBPA = [(2001 RPS-eligible procurement ÷ 2001 total retail sales) x 2003 total retail sales] + 1 percent of 2001 retail sales
ICPM	Interim Capacity Procurement Mechanism	A tariff which became effective on March 31, 2009 at the start of the new ISO market, enabling the ISO to acquire generation capacity to maintain grid reliability if (1) load serving entities fail to meet resource adequacy requirements; (2) procured resource adequacy resources are insufficient or (3) unexpected conditions create the need for additional capacity.
IOU	Investor Owned Utility	A privately-owned electric utility whose stock is publicly traded that is rate regulated and authorized to achieve an allowed rate of return for its shareholders.
IPT	Incremental Procurement Target	The amount of RPS-eligible renewable procurement that must be procured in the current year, over and above what is already in an LSE's portfolio.
IRP	Integrated Resource Plan	A document for planning, evaluating and acquiring generation resources to meet forecasted energy requirements. The goal of the IRP is to identify a mix of firm generation resources that provides reliable, least-cost energy to serve the needs of electric customers.
IRRP	Interim Reliability Requirements Program	A program which implements Resource Adequacy established by State authorities, including the CPUC and other local regulatory authorities, intended to remain effective until implementation of Market Redesign and Technology Upgrade.
LAP	Load Aggregation Point	A set of physical or theoretical Pricing Nodes as specified in the CAISO Tariff that are used for the submission of Bids and Settlement of Demand.
LMP	Locational Marginal Pricing	A market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid. Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity - the one that balances supply and demand - to market.
LSE	Load Serving Entity	An entity that provides electric power service to end-use customers. LSEs include but are not limited to IOUs, Energy Service Providers, Community Aggregation Groups and publicly-owned utilities.

Appendix G: Glossary of Acronyms		
MCC	Marginal Congestion Cost	The component of LMP at a node that accounts for the costs of congestion, as measured between that node and a reference bus.
MPR	Market Price Referent	The price of electricity a utility would need to purchase to meet its capacity and energy needs from conventional fossil fuel resources to be used in comparison with the purchase of renewable resources under the RPS bidding process.
MRTU	Market Redesign and Technology Upgrade	CAISO market redesign process implemented on April 1, 2009, intended to improve the reliability of energy supply and transmission grid management.
NPTO	Non-Participating Transmission Owner	An entity with contractual rights to transmission service through another entity's transmission system, even though the owning entity has turned over control of its system to the CAISO.
PPA	Power Purchase Agreement	Power contract between an LSE and an electricity generator.
RA	Resource Adequacy	CPUC mandated level of capacity and reserves that each LSE must have to meet their customers' demand that is coincident with CAISO's peak load.
RES	Renewable Energy Standard	A standard proposed by the California Air Resources Board which would require load serving entities to increase the amount of renewable power in their portfolios to 33 percent by the year 2020.
RFP	Request For Proposals	A document that an organization posts to elicit competitive bids from potential suppliers of a product or service.
RPS	Renewables Portfolio Standard	CPUC/Legislature requirement that all LSEs must obtain a specific percentage of the energy they sell to their retail customers through renewable generation sources.
RUC	Residual Unit Commitment	The process conducted by the CAISO in the Day-Ahead Market after the Integrated Forward Market has been executed to ensure sufficient Generating Units, System Units, System Resources and Participating Loads are committed to meet the CAISO Forecast of CAISO Demand.
SC	Scheduling Coordinator	An entity certified and authorized by the CAISO to schedule load and generation resources in the CAISO market.
SENA	Shell Energy North America	An energy provider with which BVES has contracted for multiple energy products to be delivered over the period 2009 through 2013.
SMJU	Small and Multi-Jurisdictional Utilities	CPUC-regulated utilities other than Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric, which serve retail customers in California.
TREC	Tradable Renewable Energy Credit	A tradable certificate of proof that one kWh of electricity has been generated by a renewable-fueled source. Credits are denominated in kilowatt-hours (kWh) and identified as a separate commodity from the power itself.
VAR	Value at Risk	A technique used to estimate the probability of portfolio losses based on the statistical analysis of historical price trends and volatilities.
WDAT	Wholesale Distribution Access Tariff	A fee levied by a transmission owner to an LSE with no transmission ownership for use of their transmission equipment.

Appendix H: Power Supply Cost Model

NOTE: The costs calculated by the BVES Power Supply Cost Model and shown in this appendix do <u>not</u> include the cost of renewables purchases. Refer to Table 6.2 in Chapter 6 for a breakdown of those projected costs by year, using RECs as the basis for a cost calculation.

Power Supply Cost Model

	2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		34	30	27	22	21	21	21	22	21	21	32	37	37
Monthly Energy (MWh)		16,755	13,408	13,689	11,091	10,943	10,625	11,588	11,540	10,819	11,109	13,159	17,206	151,932
Capacity Requirements														
Monthly Peak Less BVPP		25.31	21.66	18.45	13.40	12.62	12.62	12.34	13.29	12.26	13.07	23.45	28.42	
Reserve Requirements		3.80	3.25	2.77	2.01	1.89	1.89	1.85	1.99	1.84	1.96	3.52	4.26	
Total Capacity Requirements		29.10	24.91	21.21	15.41	14.52	14.51	14.19	15.28	14.10	15.03	26.97	32.68	
Resource Adequacy Capacity		35	35	28	18	18	18	18	18	18	18	33	35	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Net RA Capacity Position		15	19	8	3	4	4	5	4	5	4	7	11	
RA Capacity Cost ($/kw-month)		$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	
Total Capacity Cost		$87,500	$87,500	$70,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$82,500	$87,500	$ 730,000
Net Capacity Position Load versus Resources														
Energy Purchases														
Annual Baseload Energy (MWh)		9,672	8,723	9,672	9,347	9,672	9,347	9,672	9,672	9,347	9,672	9,360	9,672	113,828
Seasonal Baseload Energy (MWh)		5,208	4,697	0	0	0	0	0	0	0	0	3,600	5,208	18,713
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	0
Bear Valley Power Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
Imbalance Energy		710	1,276	0	63	172	161	153	141	183	114	1,495	730	
Total Purchases		15,590	14,696	9,672	9,410	9,844	9,508	9,825	9,813	9,530	9,786	14,455	15,610	
Cost/MWh														
Annual Baseload Energy ($MWh)		$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	$67.75	
Seasonal Baseload Energy ($MWh)		$68.25	$68.25									$68.25	$68.25	
Renewable Energy ($/MWh)														
On-peak Energy Option ($MWh)		$44.68	$41.61	$30.56	$23.26	$20.54	$20.03	$22.08	$24.78	$25.50	$26.74	$33.01	$41.96	
Off-peak Energy Purchases ($MWh)		$34.04	$31.70	$23.28	$17.72	$15.65	$15.26	$16.82	$18.88	$19.43	$20.37	$25.15	$31.97	
BVPP ($/MWh) plus $4/MWh O&M		$57.19	$53.53	$40.38	$31.69	$28.45	$27.84	$30.28	$33.50	$34.36	$35.83	$43.30	$53.95	
Imbalance Energy ($/MWh)		$42.55	$39.63	$29.10	$22.15	$19.56	$19.07	$21.02	$23.60	$24.28	$25.46	$31.44	$39.96	
Total Cost														
Annual Baseload Energy		$655,278.00	$590,983.25	$655,278.00	$633,259.25	$655,278.00	$633,259.25	$655,278.00	$655,278.00	$633,259.25	$655,278.00	$634,140.00	$655,278.00	
Seasonal Baseload Energy		$355,446.00	$320,570.25	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$245,700.00	$355,446.00	$1,277,162.25
On-peak Energy Option		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Off-peak Energy Purchases		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Bear Valley Power Plant		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Imbalance Energy (see attached worksheet)		$125,280	($3,599)	$153,611	$60,116	$51,767	$51,830	$77,439	$76,228	$61,464	$50,614	$2,826	$82,645	$790,222
TOTAL Purchased Power/Generation Cost		$1,136,004	$907,955	$808,889	$693,376	$707,045	$685,090	$732,717	$731,506	$694,723	$705,892	$882,666	$1,093,369	$9,779,232
Transmission/Shell Option Premium														
W-DAT		$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$660,168
33 kV Transmission Charges		$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$194,947
Revised/Amended Transmission Agreement		$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$457,644
Reliability		$1,173	$939	$958	$776	$766	$744	$811	$808	$757	$778	$921	$1,204	$10,635
Shell Option Premium		$42,000	$42,000	$42,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$42,000	$42,000	$42,000
TOTAL COST		$152,569	$152,335	$152,355	$124,173	$124,163	$124,140	$124,208	$124,204	$124,154	$124,174	$152,318	$152,601	$1,365,394
TOTAL COST		$1,288,573	$1,060,290	$961,244	$817,549	$831,208	$809,230	$856,925	$855,710	$818,877	$830,066	$1,034,984	$1,245,970	$11,144,626
OTHER COSTS														
Ancillary Services		$117,285	$93,858	$95,823	$77,639	$76,602	$74,372	$81,119	$80,777	$75,732	$77,765	$92,113	$120,441	$1,063,526
Grid Management		$109,913	$87,958	$89,800	$72,759	$71,787	$69,697	$76,020	$75,699	$70,972	$72,877	$86,323	$112,870	$996,676
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
Total		$234,699	$189,317	$193,123	$157,897	$155,889	$151,569	$164,639	$163,976	$154,204	$158,141	$185,936	$240,811	$2,150,201
TOTAL POWER SUPPLY COSTS		$1,610,772	$1,337,107	$1,224,367	$1,020,446	$1,032,096	$1,005,799	$1,066,564	$1,064,686	$1,018,081	$1,033,208	$1,303,420	$1,574,281	$14,290,827
Cost/MWh		$96.14	$99.72	$89.44	$92.00	$94.31	$94.67	$92.04	$92.26	$94.10	$93.00	$99.05	$91.50	$94.06
Energy Cost		$1,136,004	$907,955	$808,889	$693,376	$707,045	$685,090	$732,717	$731,506	$694,723	$705,892	$882,666	$1,093,369	$9,779,232
Cost/MWh		67.80	67.72	59.09	62.52	64.61	64.48	63.23	63.39	64.21	63.54	67.08	63.55	$ 64.37

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Power Supply Cost Model

	2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		34	30	27	22	21	21	21	22	21	22	33	37	37
Monthly Energy (MWh)		17,180	13,588	13,940	11,244	11,066	10,862	11,788	11,829	11,127	11,468	13,263	17,662	155,038
Capacity Requirements														
Monthly Peak Less BVPP		25.98	22.03	18.85	13.76	12.98	13.01	12.73	13.78	12.80	13.64	24.31	29.10	
Reserve Requirements		3.90	3.31	2.83	2.06	1.95	1.95	1.91	2.07	1.92	2.05	3.65	4.36	
Total Capacity Requirements		29.87	25.34	21.67	15.83	14.93	14.97	14.64	15.85	14.72	15.69	27.96	33.46	
Resource Adequacy Capacity		28	28	28	18	18	18	18	18	18	18	28	28	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Net RA Capacity Position		7	12	7	3	4	4	4	3	4	3	1	3	
RA Capacity Cost ($/kw-month)		$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	
Total Capacity Cost		$70,000	$70,000	$70,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$70,000	$70,000	$ 665,000
Energy Purchases														
Annual Baseload Energy (MWh)		9,672	8,736	9,672	9,347	9,672	9,347	9,672	9,672	9,347	9,672	9,360	9,672	113,841
Seasonal Baseload Energy (MWh)		5,208	4,704	0	0	0	0	0	0	0	0	3,600	5,208	18,720
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Bear Valley Power Plant		0	0	0	0	0	0	0	0	0	0	0	0	
Imbalance Energy		625	1,207	0	46	144	118	117	96	125	74	1,327	641	4,522
Total Purchases		15,505	14,647	9,672	9,393	9,816	9,465	9,789	9,768	9,472	9,746	14,287	15,521	
Cost/MWh														
Annual Baseload Energy ($MWh)		$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	$67.90	
Seasonal Baseload Energy ($MWh)		$51.50	$51.50									$51.50	$51.50	
Renewable Energy ($/MWh)														
On-peak Energy Option ($MWh)		$50.32	$49.11	$45.38	$44.30	$48.13	$49.22	$50.55	$50.05	$44.10	$44.37	$56.32	$58.73	
Off-peak Energy Purchases ($MWh)		$38.34	$37.42	$34.58	$33.76	$36.67	$37.50	$38.51	$38.14	$33.60	$33.81	$42.91	$44.75	
BVPP ($/MWh) plus $4/MWh O&M		$63.90	$62.46	$58.03	$56.74	$61.30	$62.60	$64.17	$63.59	$56.50	$56.82	$71.05	$73.92	
Imbalance Energy ($/MWh)		$47.92	$46.77	$43.22	$42.19	$45.84	$46.88	$48.14	$47.67	$42.00	$42.26	$53.64	$55.94	
Total Cost														
Annual Baseload Energy		656,729	593,174	656,729	634,661	656,729	634,661	656,729	656,729	634,661	656,729	635,544	656,729	
Seasonal Baseload Energy		268,212	242,256	-	-	-	-	-	-	-	-	185,400	268,212	964,080
On-peak Energy Option		-	-	-	-	-	-	-	-	-	-	-	-	
Off-peak Energy Purchases		-	-	-	-	-	-	-	-	-	-	-	-	
Bear Valley Power Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance Energy		$116,734	$3,717	$217,474	$90,745	$76,479	$81,142	$114,204	$117,003	$98,286	$85,668	$9,433	$132,685	$1,143,570
TOTAL Purchased Power/Generation Cost		$1,041,675	$839,148	$874,202	$725,407	$733,208	$715,803	$770,933	$773,731	$732,948	$742,397	$830,377	$1,057,625	$9,837,454
Transmission/Shell Option Premium														
W-DAT		$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$660,168
33 kV Transmission Charges		$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$194,947
Revised/Amended Transmission Agreement		$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$457,644
Reliability		$1,203	$951	$976	$787	$776	$760	$825	$828	$779	$803	$928	$1,236	$10,853
Shell Option Premium		$42,750	$42,750	$42,750	$14,250	$14,250	$14,250	$14,250	$14,250	$14,250	$14,250	$42,750	$42,750	$313,500
TOTAL COST		$153,349	$153,098	$153,122	$124,434	$124,423	$124,407	$124,472	$124,475	$124,426	$124,449	$153,075	$153,383	$1,637,112
TOTAL COST		$1,195,024	$992,246	$1,027,325	$849,840	$857,630	$840,210	$895,404	$898,206	$857,373	$866,847	$983,452	$1,211,008	$11,474,565
OTHER COSTS														
Ancillary Services		$120,261	$95,114	$97,581	$78,711	$77,603	$76,035	$82,515	$82,806	$77,892	$80,275	$92,842	$123,633	$1,085,268
Grid Management		$112,702	$89,135	$91,447	$73,764	$72,725	$71,255	$77,328	$77,601	$72,996	$75,229	$87,006	$115,862	$1,017,051
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
Total		$240,464	$191,749	$196,529	$159,975	$157,828	$154,790	$167,343	$167,906	$158,388	$163,004	$187,348	$246,996	$2,192,319
TOTAL POWER SUPPLY COSTS		$1,505,487	$1,253,995	$1,293,853	$1,054,815	$1,060,458	$1,040,001	$1,107,747	$1,111,112	$1,060,761	$1,074,851	$1,240,801	$1,528,004	$14,331,885
Cost/MWh		$87.63	$92.29	$92.81	$93.81	$95.66	$95.75	$93.97	$93.93	$95.33	$93.73	$93.55	$86.51	92.44
Energy Cost		$1,041,675	$839,148	$874,202	$725,407	$733,208	$715,803	$770,933	$773,731	$732,948	$742,397	$830,377	$1,057,625	$9,837,454
Cost/MWh		60.63	61.76	62.71	64.51	66.14	65.90	65.40	65.41	65.87	64.74	62.61	59.88	63.45

Power Supply Cost Model

	2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		35	31	28	23	22	22	22	23	22	23	34	39	39
Monthly Energy (MWh)		17,352	13,961	14,366	11,646	11,541	11,359	12,315	12,388	11,627	12,030	13,858	18,196	160,638
Capacity Requirements														
Monthly Peak Less BVPP		26.71	22.90	19.65	14.56	13.84	14.00	13.68	14.76	13.80	14.61	25.53	30.29	
Reserve Requirements		4.01	3.44	2.95	2.18	2.08	2.10	2.05	2.21	2.07	2.19	3.83	4.54	
Total Capacity Requirements		30.72	26.34	22.60	16.75	15.91	16.10	15.73	16.97	15.87	16.80	29.36	34.83	
Resource Adequacy Capacity		28	28	28	18	18	18	18	18	18	18	28	28	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Net RA Capacity Position		6	11	6	2	3	3	3	2	3	2	-1	2	
RA Capacity Cost ($/kw-month)		$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	
Total Capacity Cost		$70,000	$70,000	$70,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000	$70,000	$70,000	$ 665,000
Energy Purchases														
Annual Baseload Energy (MWh)		9,672	8,723	9,672	9,347	9,672	9,347	9,672	9,672	9,347	9,672	9,347	9,672	113,815
Seasonal Baseload Energy (MWh)		5,208	4,697	0	0	0	0	0	0	0	0	3,595	5,208	18,708
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Bear Valley Power Plant		0	0	0	0	0	0	0	0	0	0	0	0	
Imbalance Energy		523	1,035	0	23	72	40	45	29	50	30	1,086	523	
Total Purchases		15,403	14,455	9,672	9,370	9,744	9,387	9,717	9,701	9,397	9,702	14,028	15,403	
Cost/MWh														
Annual Baseload Energy ($MWh)		$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	$68.50	
Seasonal Baseload Energy ($MWh)		$51.50	$51.50									$51.50	$51.50	
Renewable Energy ($/MWh)														
On-peak Energy Option ($MWh)		$59.15	$58.09	$48.50	$41.04	$39.27	$33.85	$36.55	$38.55	$41.09	$44.30	$55.43	$58.95	
Off-peak Energy Purchases ($MWh)		$45.07	$42.73	$36.95	$31.27	$29.92	$25.79	$27.84	$29.37	$31.31	$33.75	$42.23	$44.91	
BVPP ($/MWh) plus $4/MWh O&M		$74.42	$70.77	$61.74	$52.86	$50.75	$44.29	$47.51	$49.90	$52.91	$56.74	$69.99	$74.18	
Imbalance Energy ($/MWh)		$56.34	$53.42	$46.19	$39.09	$37.40	$32.23	$34.81	$36.72	$39.13	$42.19	$52.79	$56.14	$526
Total Cost														
Annual Baseload Energy		$662,532.00	$597,525.50	$662,532.00	$640,269.50	$662,532.00	$640,269.50	$662,532.00	$662,532.00	$640,269.50	$662,532.00	$640,269.50	$662,532.00	
Seasonal Baseload Energy		$268,212.00	$241,895.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$185,142.50	$268,212.00	
On-peak Energy Option		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Off-peak Energy Purchases		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Bear Valley Power Plant		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Imbalance Energy		$132,684	$26,140	$257,625	$118,361	$105,030	$112,269	$152,312	$157,000	$133,908	$120,654	$39,970	$155,656	$1,511,610
TOTAL Purchased Power/Generation Cost		$1,063,428	$865,561	$920,157	$758,631	$767,562	$752,538	$814,844	$819,532	$774,177	$783,186	$865,382	$1,086,400	$10,271,399
Transmission/Shell Option Premium														
W-DAT		$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$55,014	$660,168
33 kV Transmission Charges		$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$16,246	$194,947
Revised/Amended Transmission Agreement		$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$38,137	$457,644
Reliability		$1,215	$977	$1,006	$815	$808	$795	$862	$867	$814	$842	$970	$1,274	$11,245
Shell Option Premium		$43,500	$43,500	$43,500	$14,500	$14,500	$14,500	$14,500	$14,500	$14,500	$14,500	$43,500	$43,500	$319,000
TOTAL COST		$154,111	$153,874	$153,902	$124,712	$124,704	$124,692	$124,759	$124,764	$124,710	$124,739	$153,867	$154,170	$1,643,004
TOTAL COST		$1,217,539	$1,019,435	$1,074,059	$883,342	$892,267	$877,230	$939,602	$944,296	$898,888	$907,925	$1,019,249	$1,240,570	$11,914,403
OTHER COSTS														
Ancillary Services		$121,461	$97,725	$100,563	$81,520	$80,786	$79,516	$86,205	$86,716	$81,390	$84,208	$97,007	$127,372	$1,124,469
Grid Management		$113,826	$91,583	$94,242	$76,396	$75,708	$74,518	$80,786	$81,265	$76,274	$78,915	$90,910	$119,365	$1,053,788
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
Total		$242,787	$196,808	$202,305	$165,415	$163,995	$161,534	$174,491	$175,481	$165,165	$170,623	$195,417	$254,237	$2,268,257
TOTAL POWER SUPPLY COSTS		$1,530,326	$1,286,243	$1,346,364	$1,093,758	$1,101,261	$1,083,763	$1,159,093	$1,164,777	$1,109,053	$1,123,547	$1,284,666	$1,564,807	$14,847,659
Cost/MWh		$88.20	$92.13	$93.72	$93.92	$95.42	$95.41	$94.12	$94.02	$95.38	$93.40	$92.70	$86.00	92.43
Energy Cost		$1,063,428	$865,561	$920,157	$758,631	$767,562	$752,538	$814,844	$819,532	$774,177	$783,186	$865,382	$1,086,400	$10,271,399
Cost/MWh		61.29	62.00	64.05	65.14	66.51	66.25	66.17	66.16	66.58	65.10	62.45	59.71	63.94

Power Supply Cost Model

	2014	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		35	32	28	24	23	23	23	24	23	24	35	40	40
Monthly Energy (MWh)		17,765	14,480	14,924	12,193	12,096	11,844	12,818	12,909	12,092	12,471	14,569	18,561	166,722
Capacity Requirements														
Monthly Peak Less BVPP		27.8	23.5	19.6	15.6	14.9	14.9	14.6	15.7	14.7	15.4	26.6	31.3	
Reserve Requirements		4.2	3.52	2.94	2.34	2.23	2.24	2.19	2.36	2.20	2.32	3.99	4.69	
Total Capacity Requirements		32.0	27.0	22.6	18.0	17.1	17.2	16.8	18.1	16.9	17.8	30.6	35.9	
Resource Adequacy Capacity		23.2	18.1	21.7	17.1	16.2	16.3	15.9	17.2	16.1	16.9	29.7	27.1	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Baseload		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	
Seasonal Baseload		-	-	-	-	-	-	-	-	-	-	-	-	
Renewable		-	-	-	-	-	-	-	-	-	-	-	-	
Peaking		-	-	-	-	-	-	-	-	-	-	-	-	
Total		32.0	27.0	22.6	18.0	17.1	17.2	16.8	18.1	16.9	17.8	30.6	35.9	270
Capacity Position		23	18	22	17	16	16	16	17	16	17	30	27	
RA Capacity Cost ($/kW-month)		$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	
Total RA Capacity Cost		$ 69,514	$ 54,359	$ 65,172	$ 51,334	$ 48,733	$ 49,015	$ 47,799	$ 51,637	$ 48,161	$ 50,706	$ 89,152	$ 81,295	$ 706,878
Energy Purchases														
Annual Baseload Energy (MWh)		8,928	8,064	8,928	8,640	8,928	8,640	8,928	8,928	8,640	8,928	8,640	8,928	105,120
Seasonal Baseload Energy (MWh)		5,208	4,704	0	0	0	0	0	0	0	0	3,600	5,208	18,720
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Bear Valley Power Plant		-	-	-	-	-	-	-	-	-	-	-	-	
Short Energy		3,866	2,281	5,996	3,553	3,168	3,204	3,890	3,981	3,452	3,547	2,882	4,696	
Long Energy		-237	-569	0	0	0	0	0	0	0	-4	-553	-271	
Total Energy		18,239	15,618	14,924	12,193	12,096	11,844	12,818	12,909	12,092	12,479	15,675	19,103	
Cost/MWh														
Annual Baseload Energy ($MWh)		$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	
Seasonal Baseload Energy ($MWh)		$51.50	$51.50									$51.50	$51.50	
Renewable Energy ($/MWh)		$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	$105.60	
On-peak Energy Option ($MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Off-peak Energy Purchases ($MWh)		$45.29	$42.12	$37.80	$31.93	$50.17	$45.07	$41.88	$43.42	$49.37	$49.90	$55.31	$56.43	
BVPP ($/MWh) plus $4/MWh O&M		$74.77	$69.82	$63.06	$53.88	$82.38	$74.43	$69.43	$71.85	$81.14	$81.97	$90.42	$92.17	
Imbalance Energy ($/MWh)		$56.62	$52.65	$47.25	$39.91	$62.71	$56.34	$52.35	$54.28	$61.71	$62.38	$69.14	$70.54	
Total Cost														
Annual Baseload Energy		$ 508,450	$ 459,245	$ 508,450	$ 492,048	$ 508,450	$ 492,048	$ 508,450	$ 508,450	$ 492,048	$ 508,450	$ 492,048	$ 508,450	$ 5,986,584
Seasonal Baseload Energy		$ 268,212	$ 242,256	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 185,400	$ 268,212	
On-peak Energy Option		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Off-peak Energy Purchases		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bear Valley Power Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance Energy		$ 213,403	$ 102,095	$ 353,267	$ 195,279	$ 182,049	$ 183,779	$ 236,683	$ 243,110	$ 212,047	$ 194,248	$ 120,758	$ 229,745	$ 2,466,463
TOTAL Purchased Power/Generation Cost		$ 990,064	$ 803,596	$ 861,716	$ 687,327	$ 690,498	$ 675,827	$ 745,133	$ 751,559	$ 704,095	$ 702,698	$ 798,206	$ 1,006,407	$ 9,417,127
SCE Transmission Costs														
W-Dat		$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 660,168
33 Kv		$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 194,947
Revised/Amended Transmission Agreement		$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 457,644
Reliability		$ 12,436	$ 10,136	$ 10,447	$ 8,535	$ 8,467	$ 8,291	$ 8,973	$ 9,037	$ 8,464	$ 8,729	$ 10,198	$ 12,993	$ 116,705
Shell Option Premium														
TOTAL COST		$ 121,832	$ 119,533	$ 119,843	$ 117,932	$ 117,864	$ 117,687	$ 118,359	$ 118,433	$ 117,861	$ 118,126	$ 119,595	$ 122,389	$ 1,429,464
OTHER COSTS														
Ancillary Services		$124,355	$101,360	$104,468	$85,354	$84,670	$82,906	$89,726	$90,366	$84,643	$87,294	$101,983	$129,927	$1,167,051
Grid Management		$119,914	$97,740	$100,737	$82,306	$81,646	$79,945	$86,521	$87,139	$81,621	$84,176	$98,341	$125,286	$1,125,370
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
TOTAL Cost		$251,769	$206,599	$212,705	$175,160	$173,817	$170,350	$183,747	$185,004	$173,764	$178,969	$207,824	$262,713	$2,382,421
TOTAL POWER SUPPLY COSTS		$1,433,179	$1,184,087	$1,259,437	$1,031,752	$1,030,912	$1,012,879	$1,095,048	$1,106,634	$1,043,881	$1,050,499	$1,214,777	$1,472,805	$13,935,890
Cost/MWh		$80.67	$81.77	$84.39	$84.62	$85.23	$85.52	$85.43	$85.72	$86.33	$84.24	$83.38	$79.35	$83.59
Energy Cost		$990,064	$803,596	$861,716	$687,327	$690,498	$675,827	$745,133	$751,559	$704,095	$702,698	$798,206	$1,006,407	$9,417,127
Energy Cost/MWh		55.73	55.50	57.74	56.37	57.09	57.06	58.13	58.22	58.23	56.35	54.79	54.22	56.48

Power Supply Cost Model

	2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		37	33	30	25	24	24	23	25	24	24	36	40	40
Monthly Energy (MWh)		18,128	14,895	15,257	12,493	12,409	12,129	13,095	13,148	12,306	12,624	14,807	18,662	169,953
Capacity Requirements														
Monthly Peak Less BVPP		28.7	25.0	21.5	16.2	15.5	15.5	15.1	16.2	15.1	15.8	27.1	31.7	
Reserve Requirements		4.3	3.74	3.23	2.43	2.32	2.33	2.26	2.43	2.27	2.37	4.07	4.75	
Total Capacity Requirements		33.0	28.7	24.7	18.7	17.8	17.9	17.3	18.6	17.4	18.2	31.2	36.4	
Resource Adequacy Capacity		24.2	19.9	23.9	17.8	16.9	17.0	16.5	17.8	16.5	17.3	30.3	27.6	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Baseload		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	
Seasonal Baseload		-	-	-	-	-	-	-	-	-	-	-	-	
Renewable		-	-	-	-	-	-	-	-	-	-	-	-	
Peaking		-	-	-	-	-	-	-	-	-	-	-	-	
Total		33.0	28.7	24.7	18.7	17.8	17.9	17.3	18.6	17.4	18.2	31.2	36.4	280
Capacity Position		24	20	24	18	17	17	16	18	17	17	30	28	
RA Capacity Cost ($/kW-month)		$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	
Total RA Capacity Cost		$ 72,533	$ 59,574	$ 71,677	$ 53,437	$ 50,780	$ 51,001	$ 49,494	$ 53,314	$ 49,628	$ 52,000	$ 91,033	$ 82,669	$ 737,140
Energy Purchases														
Annual Baseload Energy (MWh)		8,928	8,064	8,928	8,640	8,928	8,640	8,928	8,928	8,640	8,928	8,640	8,928	
Seasonal Baseload Energy (MWh)		5,208	4,704	0	0	0	0	0	0	0	0	3,600	5,208	
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Bear Valley Power Plant		-	-	-	-	-	-	-	-	-	-	-	-	
Short Energy		4,182	2,587	6,329	3,853	3,481	3,489	4,167	4,220	3,666	3,699	3,049	4,771	
Long Energy		-190	-459	0	0	0	0	0	0	0	-3	-482	-244	
Total Energy		18,508	15,814	15,257	12,493	12,409	12,129	13,095	13,148	12,306	12,629	15,770	19,151	
Cost/MWh														
Annual Baseload Energy ($MWh)		$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	
Seasonal Baseload Energy ($MWh)		$51.50	$51.50									$51.50	$51.50	
Renewable Energy ($/MWh)		$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	$107.18	
On-peak Energy Option ($MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Off-peak Energy Purchases ($MWh)		$58.02	$46.76	$41.22	$28.28	$33.13	$43.89	$40.89	$41.88	$44.01	$37.66	$48.90	$52.03	
BVPP ($/MWh) plus $4/MWh O&M		$94.65	$77.06	$68.40	$48.19	$55.77	$72.58	$67.90	$69.45	$72.77	$62.84	$80.40	$85.30	
Imbalance Energy ($/MWh)		$72.52	$58.45	$51.52	$35.35	$41.42	$54.86	$51.12	$52.36	$55.01	$47.07	$61.12	$65.04	
Total Cost														
Annual Baseload Energy		$ 508,450	$ 459,245	$ 508,450	$ 492,048	$ 508,450	$ 492,048	$ 508,450	$ 508,450	$ 492,048	$ 508,450	$ 492,048	$ 508,450	
Seasonal Baseload Energy		$ 268,212	$ 242,256	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 185,400	$ 268,212	
On-peak Energy Option		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Off-peak Energy Purchases		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bear Valley Power Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance Energy		$ 249,491	$ 129,850	$ 395,993	$ 225,334	$ 212,292	$ 212,407	$ 271,810	$ 276,640	$ 241,329	$ 216,488	$ 142,930	$ 250,604	$2,825,169
TOTAL Purchased Power/Generation Cost		$ 1,026,153	$ 831,351	$ 904,443	$ 717,382	$ 720,741	$ 704,455	$ 780,260	$ 785,090	$ 733,377	$ 724,938	$ 820,378	$ 1,027,266	$9,775,833
SCE Transmission Costs														
W-Dat		$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 660,168
33 Kv		$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 194,947
Revised/Amended Transmission Agreement		$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 457,644
Reliability		$ 12,689	$ 10,427	$ 10,680	$ 8,745	$ 8,686	$ 8,490	$ 9,166	$ 9,204	$ 8,614	$ 8,837	$ 10,365	$ 13,064	$ 118,967
Shell Option Premium														
TOTAL COST		$ 122,086	$ 119,823	$ 120,076	$ 118,142	$ 118,083	$ 117,887	$ 118,563	$ 118,600	$ 118,011	$ 118,234	$ 119,761	$ 122,460	$ 1,431,726
OTHER COSTS														
Ancillary Services		$126,893	$104,268	$106,796	$87,452	$86,860	$84,904	$91,665	$92,038	$86,141	$88,371	$103,649	$130,636	$1,189,674
Grid Management		$118,917	$97,714	$100,083	$81,955	$81,401	$79,568	$85,903	$86,253	$80,726	$82,816	$97,134	$122,424	$1,114,895
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
TOTAL Cost		$253,310	$209,483	$214,379	$176,907	$175,761	$171,972	$185,068	$185,792	$174,367	$178,688	$208,283	$260,560	$2,394,569
TOTAL POWER SUPPLY COSTS		$1,474,081	$1,220,232	$1,310,575	$1,065,868	$1,065,365	$1,045,315	$1,133,385	$1,142,796	$1,075,383	$1,073,859	$1,239,455	$1,492,955	$14,339,269
Cost/MWh		$81.32	$81.92	$85.90	$85.32	$85.86	$86.18	$86.55	$86.92	$87.39	$85.06	$83.71	$80.00	$84.37
Energy Cost		$1,026,153	$831,351	$904,443	$717,382	$720,741	$704,455	$780,260	$785,090	$733,377	$724,938	$820,378	$1,027,266	$9,775,833
Energy Cost/MWh		56.61	55.81	59.28	57.42	58.08	58.08	59.58	59.71	59.60	57.42	55.40	55.05	57.52

Power Supply Cost Model

	2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Monthly Peak (MW)		38	34	30	25	24	24	24	25	24	25	36	40	40
Monthly Energy (MWh)		18,401	15,059	15,416	12,709	12,542	12,232	13,268	13,222	12,455	12,707	14,808	18,876	171,695
Capacity Requirements														
Monthly Peak Less BVPP		29.1	25.3	21.8	16.6	15.7	15.8	15.3	16.5	15.4	16.2	27.4	32.0	
Reserve Requirements		4.4	3.80	3.27	2.48	2.35	2.37	2.30	2.47	2.30	2.42	4.12	4.80	
Total Capacity Requirements		33.5	29.1	25.1	19.0	18.0	18.1	17.6	18.9	17.7	18.6	31.6	36.8	
Resource Adequacy Capacity		24.7	20.3	24.3	18.2	17.2	17.3	16.8	18.1	16.8	17.7	30.7	27.9	
Dispatchable DSM		8.85	8.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	8.85	
Baseload		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	
Seasonal Baseload		-	-	-	-	-	-	-	-	-	-	-	-	
Renewable		-	-	-	-	-	-	-	-	-	-	-	-	
Peaking		-	-	-	-	-	-	-	-	-	-	-	-	
Total		33.5	29.1	25.1	19.0	18.0	18.1	17.6	18.9	17.7	18.6	31.6	36.8	284
Capacity Position		25	20	24	18	17	17	17	18	17	18	31	28	
RA Capacity Cost ($/kW-month)		$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	
Total RA Capacity Cost		$ 73,981	$ 60,840	$ 72,771	$ 54,560	$ 51,597	$ 51,851	$ 50,389	$ 54,205	$ 50,428	$ 53,187	$ 92,130	$ 83,820	$ 749,757
Energy Purchases														
Annual Baseload Energy (MWh)		8,928	8,064	8,928	8,640	8,928	8,640	8,928	8,928	8,640	8,928	8,640	8,928	
Seasonal Baseload Energy (MWh)		5,208	4,704	0	0	0	0	0	0	0	0	3,600	5,208	
Renewable Energy (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
On-peak Energy Option (MWh)		0	0	0	0	0	0	0	0	0	0	0	0	
Off-peak Energy Purchases (MWh)		0	0	0	0	0	0	0	756	0	0	0	0	
Bear Valley Power Plant		-	-	-	-	-	-	-	-	-	-	-	-	
Short Energy		4,436	2,711	6,488	4,069	3,614	3,592	4,340	3,667	3,815	3,780	3,011	4,963	
Long Energy		-171	-419	0	0	0	0	0	-129	0	-1	-443	-223	
Total Energy		18,401	15,059	15,416	12,709	12,542	12,232	13,268	13,222	12,455	12,707	14,808	18,876	
		0	0	0	0	0	0	0	0	0	0	0	0	
Cost/MWh														
Annual Baseload Energy ($MWh)		$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	$56.95	
Seasonal Baseload Energy ($MWh)		$51.50	$51.50									$51.50	$51.50	
Renewable Energy ($/MWh)		$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	$108.79	
On-peak Energy Option ($MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Off-peak Energy Purchases ($MWh)		$52.06	$49.21	$44.68	$38.92	$53.95	$51.58	$50.38	$53.70	$56.02	$54.35	$62.17	$65.28	
BVPP ($/MWh) plus $4/MWh O&M		$85.34	$80.89	$73.81	$64.81	$88.29	$84.59	$82.72	$87.90	$91.53	$88.92	$101.14	$105.99	
Imbalance Energy ($/MWh)		$65.07	$61.52	$55.85	$48.65	$67.43	$64.47	$62.98	$67.12	$70.03	$67.94	$77.72	$81.60	
Total Cost														
Annual Baseload Energy		$508,450	$459,245	$508,450	$492,048	$508,450	$492,048	$508,450	$508,450	$492,048	$508,450	$492,048	$508,450	
Seasonal Baseload Energy		$268,212	$242,256	$0	$0	$0	$0	$0	$0	$0	$0	$185,400	$268,212	
On-peak Energy Option		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Off-peak Energy Purchases		$0	$0	$0	$0	$0	$0	$0	$40,595	$0	$0	$0	$0	$ 40,595
Bear Valley Power Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Renewable Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance Energy		$284,841	$149,133	$431,858	$253,532	$234,535	$232,771	$281,796	$252,276	$249,752	$236,643	$150,375	$277,591	$3,035,102
TOTAL Purchased Power/Generation Cost		$1,061,502	$850,634	$940,307	$745,580	$742,985	$724,819	$790,246	$801,320	$741,800	$745,092	$827,823	$1,054,253	$10,026,361
SCE Transmission Costs														
W-Dat		$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 55,014	$ 660,168
33 Kv		$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 16,246	$ 194,947
Revised/Amended Transmission Agreement		$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 38,137	$ 457,644
Reliability		$ 12,881	$ 10,541	$ 10,791	$ 8,896	$ 8,779	$ 8,563	$ 9,288	$ 9,255	$ 8,718	$ 8,895	$ 10,365	$ 13,213	$ 120,187
Shell Option Premium														
TOTAL COST		$ 122,277	$ 119,938	$ 120,188	$ 118,293	$ 118,176	$ 117,959	$ 118,684	$ 118,652	$ 118,115	$ 118,292	$ 119,762	$ 122,610	$ 1,432,945
OTHER COSTS														
Ancillary Services		$128,806	$105,415	$107,909	$88,964	$87,793	$85,627	$92,877	$92,554	$87,183	$88,950	$103,654	$132,132	$1,201,865
Grid Management		$120,710	$98,789	$101,127	$83,372	$82,274	$80,245	$87,039	$86,737	$81,703	$83,359	$97,139	$123,827	$1,126,319
Schedule/Dispatch		$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$90,000
TOTAL Cost		$257,016	$211,703	$216,536	$179,836	$177,567	$173,371	$187,417	$186,791	$176,386	$179,810	$208,293	$263,459	$2,418,184
TOTAL POWER SUPPLY COSTS		$1,514,776	$1,243,115	$1,349,802	$1,098,269	$1,090,325	$1,068,000	$1,146,736	$1,160,968	$1,086,728	$1,096,380	$1,248,007	$1,524,141	$14,627,248
Cost/MWh		$82.32	$82.55	$87.56	$86.42	$86.94	$87.31	$86.43	$87.81	$87.25	$86.28	$84.28	$80.74	$85.19
Energy Cost		$1,061,502	$850,634	$940,307	$745,580	$742,985	$724,819	$790,246	$801,320	$741,800	$745,092	$827,823	$1,054,253	$10,026,361
Energy Cost/MWh		57.69	56.49	61.00	58.66	59.24	59.25	59.56	60.60	59.56	58.64	55.90	55.85	58.40

APPENDIX A

CONSISTENCY WITH COMMISSION DECISIONS

AND RULES

AND PROJECT DEVELOPMENT STATUS

PUBLIC VERSION

APPENDIX A

CONSISTENCY WITH COMMISSION DECISIONS

AND RULES

AND PROJECT DEVELOPMENT STATUS

According to the 2009 RPS Solicitation Advice Letter Template, Appendix A is a supplement to Part I of the Advice Letter Template under "Consistency with Commission Decisions and Rules" and "Project Development Status." Appendix A is intended to provide a place for confidential information to fully answer Part I of the Advice Letter Template.

BVES has reviewed the questions and requested information contained in Confidential Appendix A. Many of the questions or requested information in Confidential Appendix A are not applicable to a contract to acquire unbundled RECs. Except for one area of inquiry, all of the questions or requests for information in Appendix A have been addressed in the public version of this Advice Letter.

Part C(1) and (5) request information as to why the subject contract was preferred relative to other bids or other procurement options.

Execution of Confirmation No. 2 for the purchase of in-state unbundled RECs was the culmination of negotiations to resolve a dispute between LACSD and BVES regarding a Master Power Purchase and Sale Agreement ("Master Agreement") and Confirmation No. 1 for bundled RPS-energy. The Master Agreement and Confirmation No. 1 were executed in September 2009 and amended in May 2010. In Application 10-06-003 filed June 2, 2010, BVES requested Commission approval of the Master Agreement and Confirmation No. 1.

In the fall of 2010, LACSD sought to change the notice provisions for closing LACSD's RPS-eligible generating facility under Confirmation No. 1. BVES could not take RPS bundled energy from LACSD until the Commission approved the Master Agreement and Confirmation No. 1. LACSD began suggesting to BVES that the parties simply walk away from the Master Agreement and Confirmation No. 1 that had not yet been approved by the Commission. BVES indicated it had no interest in abandoning the agreement with LACSD for bundled RPS energy.

On February 9, 2011, the Board of Directors of LACSD sought unilaterally to cancel the Master Agreement and Confirmation No. 1. GSWC objected, claiming that the Master Agreement and Confirmation No. 1 were still in effect, and only the obligations of BVES were subject to the condition precedent of Commission approval.

The Commission approved the Master Agreement and Confirmation No. 1 in D.11-06-030 on June 23, 2011. As part of a settlement of the dispute between the parties under Confirmation No. 1 (*i.e.*, bundled RPS energy from the LACSD's landfill Generating Facility), the parties reached agreement in early July and executed Confirmation No. 2 as of August 1, 2011 for the purchase and sale of in-state RECs from LACSD's Generating Facility.

Prior to and during the period of negotiations related to Confirmation No. 2 (Fall of 2010 through early July 2011), several significant developments occurred with respect to RECs. At the beginning of the negotiations (Fall of 2010) to resolve the dispute, RECs were not authorized to be used to meet RPS obligations in California. Section 399.16 of the Public Utilities Code[41] authorized the Commission to allow the use of RECs for RPS compliance. In D.10-03-021 (March 11, 2010), the Commission used its statutory authority and authorized the use of REC-only transactions. But D.10-03-021 was suspended on May 6, 2010 in D.10-05-018, and the Commission placed a moratorium on submission or approval of REC-only contracts. The Commission issued D.11-01-025[42] (effective January 13, 2011) lifting the stay of D.10-03-021 authorizing the use of RECs. It also authorized the filing of REC contracts by no earlier than April 1, 2010.

Although D.11-01-025 effectively allowed RECs to be used to comply with RPS requirements, unbundled RECs (*i.e.*, RECs without any associated energy) from out-of-state facilities still required matching energy to count towards RPS compliance, as discussed in more detail below.[43] RECs from in-state facilities meet the requirements of energy being "delivered" to California residents, however.

[41] All statutory references herein are to the Public Utilities Code, unless otherwise indicated.
[42] Several parties filed applications for rehearing of D.11-01-025. These rehearing applications were dismissed by the Commission on September 8, 2011 in D.11-09-019.
[43] Under Section 399.13(c), the California Energy Commission's ("CEC") is required to undertake certain measures, including the establishment of a system for tracking and verifying RECs and to verify the generation and delivery of

In the spring of 2011, the Legislature passed a new RPS law (Senate Bill 1X 2, hereinafter referred to as "SB 1X 2" or "the New RPS Law") and the Governor signed it on April 12, 2011. The New RPS Law deletes, in its entirety, Section 25741(a) of the Public Resources Code, which is the definition of "delivery" of RPS energy.[44] In addition, the provision in existing Section 399.13(c) which provides for the CEC to verify the generation "and delivery" of electricity with respect to RECs is modified by the provisions of the New RPS Law by deleting the words "and delivery" from the CEC's responsibilities.[45] Moreover, in D.11-09-019, the Commission stated: "SB 2 (1X) requires implementation of higher RPS targets and modifies other aspects of RPS program implementation, including rules for TRECs. Among other things, this legislation modifies: the definition of a REC to *eliminate the delivery requirements* . . ."[46]

However, California law requires that any legislation enacted during a special session of the Legislature will not be in full or force or effect until 91 days following the adjournment of such special session. Although SB 1X 2 was signed by the Governor in April 2011, no one (including BVES) knew then when the new RPS law would take effect or how key provisions would be implemented by the Commission.

The subject contract price of $30.00 per REC for in-state RECs compares favorably with bids received by BVES in February 2011 as a result of BVES' 2011 RFP. In fact, BVES received no bids for in-state RECs as a result of the 2011 RFP. BVES did receive bids from several bidders for out-of-state RECs ranging from a low of [redacted] to a high of [redacted] per out-of-state REC.[47] However, at the time the bids were received (February 2011), RPS law required that out-of-state RECs be matched with energy. The requirement to "match" out-of-state RECs with power delivered to BVES made offers for out-of-state RECs much less attractive to BVES than truly unbundled, in-state RECs, such as those in Confirmation No. 2. BVES purchases

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electricity associated with each REC. Section 25741(a) of the Public Resources Code contains a statutory definition of "delivered" and "delivery" with respect to energy generated by an eligible renewable energy resource, including RECs.

[44] Section 6 of SB 1X 2.

[45] The new Section 399.12(h)(1), however, still contains the concept of "delivery" of energy in the definition of "renewable energy credit." This, most likely, was an oversight by the draftspersons of SB 1X 2. It is not anticipated that this apparent oversight will prevent the effective elimination of the concept of delivery energy with respect to an unbundled REC transaction.

[46] D.11-09-019 at p. 3 (emphasis supplied).

[47] For a detailed description of the bids received from the 2011 RFP as well as other RPS procurement options, see Appendix B, 2011 Solicitation Overview.

power from energy suppliers and the spot market; adding out-of-state energy purchases would be administratively burdensome and could result in BVES having to sell surplus energy into the market at a loss. Therefore, the total cost of any of the out-of-state REC offers received in February 2011, coupled with the cost of "matching" energy, substantially exceeded the price of the unbundled, in-state RECs of $30.00 per REC pursuant to Confirmation No. 2.

During the period of negotiation leading up to the execution of Confirmation No. 2 on July 27, 2011,[48] BVES received a bilateral offer for in-state RECs from [redacted]. The May 9, 2011 [redacted] offer consisted of [redacted] per REC for [redacted] in-state 2009 RECs, [redacted] per REC for [redacted] 2010 in-state RECs and [redacted] per REC for [redacted] 2011 in-state RECs (a total of [redacted] in-state RECs). The parties engaged in preliminary contract negotiations to prepare definitive contracts for the purchase and sale of these in-state RECs. Although [redacted] offer for in-state RECs were [redacted] than the $30.00 per in-state REC price under Confirmation No. 2, BVES urgently needed far more RECs than [redacted] was offering.[49]

Except for the [redacted] offer to sell [redacted] in-state RECs to BVES at the time BVES executed Confirmation No. 2, BVES had no other viable offers for RPS-eligible resources and, in particular, in-state RECs other than the proposed settlement with LACSD reflected in Confirmation No. 2. In addition, if BVES failed to reach an agreement for the purchase of RECs from LACSD to resolve the dispute with LACSD, BVES might have received no bundled RPS energy from LACSD under Confirmation No. 1 and been involved in costly litigation. In summary, $30.00 for in-state RECs under Confirmation No. 2 were the best option available at that time, over-and-above the [redacted] REC offers. And no offer for out-of-state RECs with matching energy as a result of the 2011 RFP was competitive with the cost of unbundled, in-state RECs under Confirmation No. 2.

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[48] Golden State Water Company, on behalf of BVES, executed Confirmation No. 2 on July 13, 2011.

[49] BVES' annual RPS requirements are approximately 30,000 MWh. In addition, until LACSD began delivering bundled RPS energy on August 1, 2011 pursuant to the Master Agreement and Confirmation No. 1, BVES had been unable to procure any RPS-eligible energy. This inability to obtain any RPS-eligible energy until August 1, 2011 results in BVES having a substantial deficiency in RPS-eligible energy to acquire over-and-above its current and future RPS requirements.

Thus, at the time of execution of Confirmation No. 2, the offer of 20,793 of 2010 in-state RECs and approximately 15,650 of 2011 in-state RECs, all at the price of $30.00 per REC, was a least-cost, best-fit offer for BVES for urgently needed RPS-compliant resources.

In its continuing effort to locate additional RPS-eligible resources, in August 2011 (approximately one month after reaching an agreement with LACSD for Confirmation No. 2) BVES contacted several of the bidders to the 2011 RFP that had responded in February 2011 and requested updated bids. BVES received and analyzed the updated bids. Among other bids, [redacted] submitted a bid for [redacted] out-of-state RECs per year for a [redacted] contract at [redacted] per REC.

Although elimination of the delivery of energy with respect to out-of-state RECs under Section 25741(a) of the Public Resources Code and Section 399.13(c) of the Public Utilities Code had not yet taken effect under SB 1X 2,[50] BVES concluded that by the time negotiations on any updated bids were completed, REC-only contracts were executed, and advice letter filings were prepared, SB 1X 2 would become effective. Once SB 1X 2 is effective, out-of-state unbundled RECs become a very good fit for BVES due to no matching energy requirement. BVES concluded that it should pursue the bid from [redacted] for [redacted] out-of-state RECs per year (with no matching energy) for a [redacted] contract (total of [redacted] RECs) at [redacted] per REC. On September 15, 2011 BVES notified [redacted] that it would not be pursuing negotiations with [redacted] to purchase its [redacted] of in-state RECs.

BVES notes that [redacted] updated bid described immediately above was received after LACSD and BVES had reached agreement on Confirmation No. 2. Moreover, there are no assurances that BVES and [redacted] will reach agreement and sign a definitive agreement for the sale of [redacted] out-of-state RECs at a price of [redacted] per REC. BVES urgently needs RPS-compliant resources. Approval of Confirmation No. 2 will help BVES meet some of its RPS requirements.

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[50] SB 1X 2 will go into effect December 10, 2011.

APPENDIX B

2011 SOLICITATIONS OVERVIEW

PUBLIC VERSION

JANUARY 2011 and SEPTEMBER 2011

SOLICITATIONS OVERVIEW

JANUARY 2011 RFP

The January 14, 2011 RFP ("January 2011 RFP") by BVES requested bids to acquire one or a combination of the following: RECs; bundled renewable energy; non-renewable resources; and financial instruments to control CAISO energy costs. Out of over 140 potential bidders, BVES received only eleven bids, all of which included some sort of renewable product ranging from out-of-state RECs to in-state bundled renewable energy, utility owned generation and PPAs. The bids were received on February 15, 2011 and are described below in detail.

While RECs became available for RPS compliance through the Commission's Decision 11-01-025 issued January 13, 2011, the requirement to "match" out-of-state RECs with power delivered to BVES made out-of-state RECs much less attractive to BVES than truly unbundled, in-state RECs. BVES purchases power from energy suppliers and the spot market; adding out-of-state energy purchases would be administratively burdensome and could result in BVES having to sell surplus energy into the market at a loss.

Bundled RPS Energy Offers

[redacted] offered [redacted] MWh of RPS energy per year for a [redacted] term ([redacted]) at [redacted] per MWh derived from the conversion of landfill gas to RPS-eligible energy using in-state resources. The price was competitive or superior to other bundled energy offers and the resource "fit" with BVES' resources/load was favorable. BVES deemed [redacted] the successful bidder in its 2011 RFP and entered into negotiations. In July 2011, [redacted] withdrew its offer and negotiations ceased. [redacted] indicated that it intended to sell the landfill gas directly to unregulated customers that owned generation.

[redacted] offered solar PV at an estimated price of approximately [redacted], or [redacted] per month [redacted], both with a [redacted] annual escalator. This offer was not pursued by BVES due to [redacted].

[redacted] offered to sell to BVES a [redacted] solar PV plant estimated to produce [redacted] MWh per year. The purchase price was [redacted]. This offer was not pursued due to [redacted].

[redacted] offered a [redacted] MW solar array at a price of [redacted] with a [redacted] annual escalator. This offer was not pursued by BVES due to [redacted].

Out-of-State REC Offers with Matching Energy

[redacted] submitted a bid for [redacted] out-of-state RECs per year for [redacted] years ([redacted]) at [redacted]/REC coupled with an offer of matching energy at [redacted]. As reflected in its power procurement guidelines, BVES normally seeks [redacted], BVES did not pursue this bid.

[redacted] submitted a bid for [redacted] out-of-state RECs per year for [redacted] years ([redacted]) at [redacted] per REC, plus an additional amount for "matching" energy based upon [redacted]. As noted above, BVES normally seeks [redacted]. Accordingly, this bid was not pursued by BVES.

[redacted] submitted a bid for [redacted] out-of-state RECs per year for [redacted] years ([redacted]) at [redacted] per REC, plus an additional amount for "matching" energy priced [redacted]. This bid was not pursued because of the [redacted].

[redacted] offered [redacted] MWh per year for [redacted] years beginning [redacted] at an all-in price (RECs plus matching energy) of [redacted]/MWh. The offer was contingent upon obtaining CPUC approval [redacted] after the contract was signed. If approval was not obtained within that time frame, [redacted] would have no liability. This offer [redacted]. BVES also was concerned with the [redacted]. [redacted] BVES determined not to pursue [redacted] bid.

[redacted] submitted a bid for a [redacted] contract for out-of-state RECs at [redacted] per REC and matching energy at a price range of [redacted]. With a Standard & Poor's rating of [redacted], BVES determined not to pursue this offer.

<u>Out-of-State REC Offers Without Matching Energy</u>

BVES received three REC-only (no matching energy) offers, all of which were out-of-state RECs. One bid was from [redacted] for [redacted] RECs per year for either a [redacted] year term for [redacted] per REC and [redacted] per REC, respectively. [redacted] also submitted a bid for [redacted] out-of-state RECs per year at [redacted] per REC for a [redacted] term contract ([redacted]), or [redacted] out-of-state RECs at [redacted] per REC for a [redacted] year term contract ([redacted]). [redacted] bid was for [redacted] per year [redacted] RECs for a [redacted] year term at price of [redacted] per REC. Since the California RPS law in effect at the time the bids were received (February 15, 2011) required "matching" energy, these bids were not pursued by BVES.

TABLE OF BIDS FROM JANUARY 2011 RFP

Developer/ Bidder	Project Capacity Generation	Technology	Contract Term	Price
[redacted]	[redacted]	Landfill gas	[redacted]	$[redacted]/MWh
[redacted]	[redacted]	Solar PV	[redacted]	$[redacted]/MWh or $[redacted]Kw/month with [redacted]/yr escalator
[redacted]	[redacted]	Solar PV	[redacted]	[redacted] Million
[redacted]	[redacted]	Solar PV [redacted]	[redacted]	$[redacted]/MWh [redacted] annual escalator
[redacted]	[redacted]	Out-of-state wind RECs w/matching energy	[redacted]	$[redacted]/REC plus energy @ [redacted]

Developer/ Bidder	Project Capacity/ Generation	Technology	Contract Term	Price
[redacted]	[redacted]	Out-of-state RECs w/ matching energy	[redacted]	$[redacted]/MWh
[redacted]	[redacted]	Out of state RECs w/ matching energy	[redacted]	$[redacted] matching energy
[redacted]	[redacted]	[redacted] wind RECs	[redacted]	$[redacted]REC ([redacted]) [redacted]/REC ([redacted])
[redacted]	[redacted]	[redacted] wind RECs w/ matching energy option	[redacted]	$[redacted]/REC ([redacted]) $[redacted]/REC ([redacted]) $[redacted]/REC w/energy at [redacted] ([redacted])
[redacted]	[redacted]	[redacted] wind RECs	[redacted]	$[redacted]/REC w/ offer to add matching energy- price to be [redacted]

<u>Bilateral REC Offers</u>

On May 9, 2011, a bilateral offer for in-state RECs was received from [redacted]. The offer consisted of $[redacted] per REC for [redacted] 2009 in-state RECs, $[redacted] per REC for [redacted] 2010 in-state RECs and $[redacted] per REC for [redacted] 2011 in-state RECs (a total of [redacted] in-state RECs). The parties engaged in preliminary contract negotiations to prepare definitive contracts for the purchase and sale of these in-state RECs. BVES advised [redacted] on September 15, 2011, that BVES did not intend to pursue the in-state REC deal further in light of [redacted].

BVES also received unsolicited bilateral offers for out-of-state RECs. [redacted] offered out-of-state RECs under contracts with terms from [redacted] years, with volumes varying from [redacted] RECs per year. Prices ranged from [redacted] to [redacted] per REC. BVES contacted [redacted] and requested [redacted] provide more definitive information in writing regarding its unsolicited offer. [redacted] responded [redacted].

An unsolicited bilateral offer for RECs also was received from [redacted]. Although the offered prices were attractive ([redacted] for various "vintages" of RECs), [redacted] did not [redacted]. BVES was unfamiliar with [redacted]. Based upon information which appeared reliable, BVES concluded that [redacted]. Given these circumstances, BVES concluded [redacted].

A representative of [redacted] submitted an unsolicited bid of [redacted] for RECs from [redacted] located in California. BVES had concerns about [redacted]. No assurances as to [redacted] in its unsolicited bid. For these reasons, and the preference of BVES to [redacted], BVES determined not to pursue the unsolicited bid for [redacted].

TABLE OF BILATERAL UNSOLICITED REC OFFERS

Developer/ Bidder	Amounts	Technology	Contract Term	Price
[redacted]	[redacted]	In-state RECs	Single Transaction Contract	$[redacted]/REC for [redacted] 2009 RECs $[redacted] for [redacted] 2010 RECS $[redacted] for [redacted] 2011 RECs
[redacted]	[redacted]	Out-of-state wind or solar Pacific Northwest RECs	[redacted] years term	$[redacted]/ REC w/ no matching energy
[redacted]		Out-of-state RECs		2011 RECs -- [redacted] w/ no matching energy 2011-2013 RECs [redacted] w/no matching energy; 2011-2016 RECS [redacted] w/ no matching energy

<u>REC Bids Received After Confirmation No. 2 Executed</u>

On August 11, 2011, BVES requested [redacted] to update their February 2011 bids from the 2011 RFP. All [redacted] responded.

In its updated bid, [redacted] offered to sell BVES [redacted] out-of-state unbundled RECs per year in a [redacted] year contract at [redacted] per REC. It also offered to sell BVES [redacted] out-of-state RECs per year in a [redacted] year contract ([redacted]) at [redacted] per REC.

[redacted] also offered a [redacted]year bundled REC package of [redacted] per year out-of-state RECs at [redacted] per REC, plus an additional amount for "matching" energy priced at [redacted]. [redacted] further offered a [redacted]year bundled REC package of [redacted] per year out-of-state RECs at [redacted] per REC, plus an additional amount for "matching" energy priced at [redacted]. These bids were not pursued because of BVES' [redacted].

[redacted] offered [redacted] per out-of-state 2011 RECs, 2012 RECs and 2013 RECs, respectively. The term of the agreement would end [redacted] and the amount would be [redacted] RECs per year. Assuming negotiation and execution of a contract with [redacted] and approval of the contract by the CPUC by [redacted], the resulting amounts would be [redacted] 2012 RECs at [redacted] per REC and [redacted] 2013 RECs at a price of [redacted] per REC. Due to BVES' preference for [redacted] out-of-state RECs at [redacted] per REC, BVES did not pursue [redacted] out-of-state REC offer.

[redacted] revised its original prices for [redacted] wind RECs from [redacted] and [redacted] for [redacted] and [redacted] year terms, respectively, to [redacted] for [redacted] wind RECs per year for a [redacted] year term of [redacted] and [redacted] for [redacted] RECs per year for an [redacted] year term of [redacted]. Given that [redacted] updated bid had [redacted], BVES did not pursue [redacted] offers.

[redacted] updated its bids to a [redacted]year REC contract with a price of [redacted] to [redacted] per REC for [redacted] out-of-state RECs per year. Given that [redacted] updated bids had [redacted], BVES did not pursue [redacted] updated bids.

Since [redacted], the original successful bidder of the 2011 RFP, withdrew its offer, BVES identified [redacted] as the successful bidder for the RPS component of BVES' 2011 RFP and began pursuing negotiations for [redacted] updated bid of a [redacted]year contract for [redacted] per year of out-of-state RECs at [redacted] per REC.

TABLE OF UPDATED (AUGUST) BIDS FROM 2011 RFP

Developer/ Bidder	Project Capacity Generation	Technology	Contract Term	Price
[redacted]	[redacted]	Out-of-state wind RECs	Term ending [redacted]	$[redacted]/REC 2011 RECs $[redacted]/REC 2012 RECs $[redacted]/REC 2013 RECs
[redacted]	[redacted]	[redacted] wind RECs	[redacted] term	$[redacted]/REC ([redacted] term) $[redacted]/REC ([redacted] term)
[redacted]	[redacted]	[redacted] RECs w/option for matching energy	[redacted] term	$[redacted]/REC ([redacted] term) $[redacted]/REC ([redacted] term) $[redacted]/REC ([redacted] term) w/ energy at [redacted] $[redacted]/REC ([redacted] term) w/ energy at [redacted]
[redacted]	[redacted]	[redacted] RECs	[redacted] year term	$[redacted]/REC w/ offer to add matching energy- price to be [redacted]

SEPTEMBER 2011 RFP

In its continuing efforts to acquire the most cost effective RPS-eligible resources, BVES issued an RFP for unbundled RECs on September 15, 2011 ("September 2011 RFP"). Bidders were allowed to submit offers for bundled RPS-eligible energy , but BVES indicated it preferred unbundled RECs. BVES sought bids for a ten-year period (2011 – 2020) for the following amounts of RECs: 2011 – 26,442 RECs; 2012 – 26,930 RECs; 2013 – 27,881 RECs; 2014 – 36,174 RECs; 2015 – 36,972; 2016 – 37,370 RECs; 2017 – 49,950 RECs; 2018 – 50,579 RECs; 2019 – 51,216 RECs; and 2020 – 51,862 RECs. (these respective amounts and years hereinafter referred to as "Requested Number of RECs"). Out of over 155 potential bidders, BVES received sixteen bids for unbundled RECs. The bids were received on October 13, 2011 and have been evaluated. All bids are briefly described below. The bids are listed in the general order of evaluation, with the highest evaluated bids at the top. The first four bids listed below are the short-listed bidders.

[redacted] submitted two bids. One bid for the Requested Number of RECs, except for [redacted], for which it only offered [redacted] RECs. The source is an [redacted] facility and the term of the agreement offered is [redacted] with a price of [redacted] per REC. The second bid was for the Requested Number of RECs. The generation source is a [redacted] facility located in [redacted] and the term of the agreement offered is [redacted], with a price of [redacted] per REC. The second bid is the bid BVES selected for the short-list of bidders.

[redacted] submitted a bid for the Requested Number of RECs for the years [redacted] at the following prices: [redacted] respectively. The generation sources are [redacted] [redacted].

I[redacted] submitted two bids. One bid offered lump sum purchases for each compliance period at differing prices: [redacted] RECs for [redacted] per REC in [redacted], [redacted] RECs for [redacted] per REC in [redacted], [redacted] RECs for [redacted] per REC in 2017. In addition, [redacted] offered [redacted] RECs per year for [redacted] per REC from 2020-2030. The [redacted] volumes [redacted], while the [redacted] while the remaining volumes appear to be firm. The second bid was for [redacted] RECs for [redacted] per REC in [redacted], and [redacted] RECs in each of the years [redacted] at [redacted] per REC, respectively, and [redacted] RECs in each of the years [redacted] at [redacted] per REC, respectively. In addition, the offer included [redacted] RECs per year from 2020 to 2030 at [redacted] per REC. The [redacted] volume is [redacted], while the [redacted] volumes are [redacted]. The remaining appear to be firm. The generation sources are various [redacted].

[redacted] submitted a bid for the Requested Number of RECs and corresponding price per REC of [redacted] for each of the years [redacted], respectively. The generating source was not identified.

[redacted] submitted a bid for a four-year term contract for [redacted] RECs in [redacted], [redacted] RECs in [redacted] RECs in [redacted], and [redacted] RECs in [redacted]. The offered price is [redacted] per REC. The generation sources are [redacted] located in [redacted].

[redacted]. submitted a bid for the Requested Number of RECs at the following respective prices per REC: [redacted]. The term of the agreement would be [redacted]. There was no generation source identified in the bid.

[redacted] submitted a bid for a contract with a term of [redacted] for up to [redacted] RECs per year at the following prices: [redacted] The source of generation are [redacted].

[redacted] submitted a bid for the Requested Number of RECs at a non-binding price of [redacted] REC for years [redacted] and [redacted] per REC for years [redacted]. The generation source was not identified.

[redacted]. submitted a bid for a [redacted] contract for the Requested Number of RECs at a price of [redacted] per REC. The generation sources are [redacted]

[redacted] submitted a bid for [redacted] of [redacted] RECs at a price of [redacted] per REC. It offered for the years [redacted] the Requested Number of RECs for those years at a price of [redacted] per REC. BVES is required to [redacted] following execution of a definitive agreement. The generation source was not identified.

[redacted] submitted a bid for the Requested Number of RECs, and corresponding price per REC of [redacted] for each of the years [redacted], respectively. The generation source is the [redacted].

[redacted] submitted a bid for a [redacted] contract for [redacted] RECs per year at [redacted] per REC price. The offer is unit contingent, not firm. The generation source is a [redacted].

[redacted] submitted two bids. Both bids are for [redacted] RECs firm in [redacted], with additional amounts of RECs being unit contingent, and for years [redacted] RECs firm with additional amounts of RECs being unit contingent. The pricing differed between the two bids. The first bid offered prices of [redacted] per REC were for the period [redacted], respectively. The second bid was offered at the price of [redacted] per REC for years [redacted]. The generation source was [redacted]

[redacted] submitted a bid for [redacted] RECs per year for a [redacted] year term commencing [redacted] at a price of [redacted] per REC. The generating sources are various [redacted].

[redacted] submitted a bid for [redacted] RECs, [redacted] RECs and [redacted] RECs over a [redacted] period ([redacted]). The price is [redacted] per REC. The generation source is the [redacted], both located in [redacted].

BVES 2011 REC Only RFP--Bid Price and Volume Summary - Public Version

Company	Offer Summary	Option	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Weighted AVG Price
[redacted]													

APPENDIX C

FINAL RPS PROJECT-SPECIFIC

INDEPENDENT EVALUATOR REPORT

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APPENDIX D

CONTRACT SUMMARY

CONFIRMATION NO. 2 –LACSD RECs

PUBLIC VERSION

Contract Summary for

Confirmation No. 2 – LACSD RECs

I. Contract Summary

A. **Site**: 25706 Hawthorne Boulevard, Rolling Hills Estates, California

Contribution to BVES' RPS procurement targets: BVES is entitled to purchase 20,793 CEC-certified RPS-eligible renewable energy credits ("RECs") generated in 2010 and all of the CEC-certified RPS-eligible RECs generated in 2011 from the Generating Facility, which LACSD estimates to equal 15,652 RECs. BVES' RPS annual procurement target ("APT") for 2010 was 26,433 and for 2011 is 26,769. If all of the 2010 RECs (20,793) and a portion of the 2011 RECs (5,640) are applied to BVES' 2010 APT and the remainder of the 2011 RECs (10,012, assuming BVES purchases 15,652 2011 RECs from LACSD) are applied to BVES' 2011 APT, then the RECs purchased under Confirmation No. 2 would meet 100% of BVES' 2010 APT and 37.4% of BVES' 2011 APT. However, BVES does not commit to applying the RECs in this manner. BVES reserves the right to apply the RECs towards BVES' RPS requirements in a manner that most benefits BVES and its customers.

B. **Terms and Conditions of Delivery**: The date the contract delivery term begins is the first business day following the date of CPUC approval of Confirmation No. 2. The date upon which the RECs will be sold by LACSD and purchased by GSWC is a date no later than 60 days from the effective date of Confirmation No. 2, unless a longer period of time is required to complete the transaction.

C. **Major Contract Provisions:**

Term/Condition	RPS Contract
Type of Purchase	Renewable Energy Credits (RECs)
Utility Ownership Option	N/A
Conditions Precedent and	In the event CPUC approval of Confirmation No.

Date Triggers	2 does not occur before June 30, 2012, Confirmation No. 2 shall be of no force or effect regarding the 20,793 2010 RECs. In the event CPUC approval of Confirmation No. 2 does not occur prior to October 1, 2012, neither Party is liable to the other Party for any obligations under Confirmation No. 2.
Actual Price	$30.00 per REC
Product Type	In-state RECs
Key Contract Dates	In the event CPUC approval of Confirmation No. 2 does not occur before June 30, 2012, Confirmation No. 2 shall be of no force or effect regarding the 20,793 2010 RECs. In the event CPUC approval of Confirmation No. 2 does not occur prior to October 1, 2012, neither Party is liable to the other Party for any obligations under Confirmation No. 2.
Firming/Shaping Requirement	N/A
Expected Payments	Assuming purchase and delivery of a total of 36,445 @ $30.00/REC, expected total payment of $1,093,350.
Scheduling Coordinator	N/A
Allocation of CAISO charges	N/A
Allocation of Congestion Risk	N/A
Project Development Security	N/A
Daily Delay Damages	N/A
Seller-Required Performance	Sell 20,793 2010 RECs and all 2011 RECs available from Generating Facility (estimated to be 15,652 RECs) to BVES.
Seller Performance Assurances	N/A
Availability Guarantees	N/A
Energy Delivery	N/A

Requirements	
Liquidated Damages/Penalties for Failure to Perform	Coverage provisions under default provisions.
Force Majeure Provisions	N/A
No Fault Termination	None
Seller's Termination Rights	In the event CPUC approval of Confirmation No. 2 does not occur before June 30, 2012, Confirmation No. 2 shall be of no force or effect regarding the 20,793 2010 RECs. In the event CPUC approval of Confirmation No. 2 does not occur prior to October 1, 2012, neither Party is liable to the other Party for any obligations under Confirmation No. 2.
Utility's Termination Rights	See immediately above.
Right of First Refusal or Rights of First Offer	None.

D. Contract Price

1. **Levelized Contract Price.** $30.00/REC

2. **Individual Components of Pricing Structure**: None.

3. **Modifications of Contract Price**: None.

4. **Requested Price Adjustments/Modifications**: None.

5. **Project Characteristics Affecting Price**: None.

6. **Biomas Projects**: N/A

7. **Direct and Indirect Contract Costs**: None.

8. **Indirect Costs Built Into Contract Prices**: None.

9. **Out-of-State Energy Contracts**: N/A

10. **AMF Information:** N/A – there is no MPR for RECs and no AMFs are available for bilateral contracts.

11. **MPR Used for AMF Calculation**: N/A

12. **Generate Graphs Using RPS Workpapers**: Energy Division granted an exemption to BVES regarding the preparation of the various graphs, provided that a description of the bids received from the latest RFP are included. See Appendix B, 2011 Solicitation Overview.

13. **Describe How Contract Price Compares with the following cohorts**:

    a. **Other bids in the 2011 Solicitation**: The subject contract price of $30.00 per REC for in-state RECs compares favorably with bids received in February 2011 as a result of BVES' January 2011 RFP. [redacted]

    b. **Other bids in the 2011 Solicitations using the same technology**: N/A

c. **Recently Executed REC Contracts**: BVES has not previously executed a REC-only contracts.

d. **Other Procurement Options**: Execution of Confirmation No. 2 was the culmination of negotiations to resolve a dispute between LACSD and BVES regarding a Master Power Purchase and Sale Agreement ("Master Agreement") and Confirmation No. 1 for bundled RPS-energy. The Master Agreement and Confirmation No. 1 were executed in September 2009 and amended in May 2010. In Application 10-06-003 filed June 2, 2010, BVES requested Commission approval of the Master Agreement and Confirmation No. 1. In the fall of 2010, LACSD sought to change the notice provisions for closing the RPS-eligible generating facility under Confirmation No. 1. [redacted].

On February 9, 2011, the Board of Directors of LACSD sought unilaterally to cancel the Master Agreement and Confirmation No. 1. GSWC objected, claiming that the Master Agreement and Confirmation No. 1 were still in effect, and only the obligations of BVES were subject to the condition precedent that the Commission approve the Master Agreement and Confirmation No. 1.

The Commission approved the Master Agreement and Confirmation No. 1 in D.11-06-030 on June 23, 2011. As part of a settlement of the dispute between the Parties under Confirmation No. 1 (*i.e.*, bundled RPS energy from the LACSD's landfill Generating Facility), the parties executed Confirmation No. 2 as of August 1, 2011 for the purchase and sale of in-state RECs from the Generating Facility.

Offers Available to BVES During Negotiation Period with LACSD for Confirmation No. 2. During the period of negotiation leading up to the execution of Confirmation No. 2 on July 27, 2011,[51] BVES received a bilateral offer for in-state RECs from [redacted]. The May 9, 2011 [redacted] offer consisted of [redacted] per REC for [redacted] in-state 2009 RECs, [redacted] per REC for [redacted] 2010 in-state RECs and [redacted] per REC for [redacted] 2011 in-state RECs (a total of [redacted] in-state RECs). The parties engaged in preliminary contract negotiations to prepare definitive contracts for the purchase and sale of these in-state RECs. Although the [redacted] offering price for in-state RECs [redacted], BVES needed far more RECs than [redacted] was offering[52]. Except for the [redacted] offer to sell [redacted] in-state RECs to BVES, [redacted]. In addition, if BVES failed to reach an agreement for the purchase of RECs from LACSD to resolve the dispute with LACSD, [redacted].

Thus, at the time of execution of Confirmation No. 2, the offer of [redacted] of 2010 in-state RECs and approximately [redacted] of 2011 in-state RECs, all at the price of [redacted] per REC, was a least cost best fit offer for BVES for urgently needed RPS-compliant resources. And no offer for out-of-state RECs with matching energy as a result of the 2011 RFP was competitive with the cost of unbundled, in-state RECs under Confirmation No. 2.

Offers Available to BVES Following Execution of Confirmation No. 2 with LACSD.

In its continuing effort to locate additional RPS-eligible resources, in August 2011 (nearly one month after reaching an agreement with LACSD for

[51] GSWC executed Confirmation No. 2 on July 13, 2011.

[52] BVES' annual RPS requirements are approximately 30,000 MWh. In addition, until LACSD began delivering bundled RPS energy on August 1, 2011 pursuant to the Master Agreement and Confirmation No. 1, BVES had been unable to procure any RPS-eligible energy. This inability to obtain any RPS-eligible energy until August 2, 2011 results in BVES having a substantial deficiency in RPS-eligible energy to acquire over-and-above its current and future RPS requirements.

Confirmation No. 2) BVES contacted several of the bidders to the 2011 RFP that had responded in February 2011 and requested updated bids. BVES received and analyzed the updated bids. Among other bids, [redacted] submitted a bid for [redacted] out-of-state RECs per year for a [redacted] year contract at [redacted] per REC.

Although elimination of the delivery of energy with respect to out-of-state RECs under Section 25741(a) of the Public Resources Code and Section 399.13(c) of the Public Utilities Code had not yet taken effect under SB 1X 2,[53] BVES concluded that [redacted]. [redacted], out-of-state unbundled RECs become a good fit for BVES due to no matching energy requirement. BVES concluded that it should pursue the bid from [redacted] for [redacted] out-of-state RECs per year (with no matching energy) for a [redacted] year contract (total of [redacted] RECs) at [redacted] per REC. That process is ongoing.

See also the bids received from the September 2011 RPS for RECs described in Appendix B, Solicitations Overview.

BVES notes that [redacted] updated bid described immediately above and the bids from the September 2011 RPS for RECs described in Appendix B were received after LACSD and BVES had reached agreement on Confirmation No. 2. Moreover, there are no assurances that BVES and any bidder will reach agreement and sign a definitive agreement for the sale of RECs at prices included in a bid. BVES urgently needs RPS-compliant resources. Approval of Confirmation No. 2 will help BVES meet some of its RPS requirements.

14. Provide the rate impact of Confirmation No. 2 (cents/kw): Approval of Confirmation No. 2 and recovery of the $1,093,350 in payments made thereunder would result in $1,093,350 being booked in BVES' Purchased Power Adjustment Clause ("PPAC"). Without further action, which BVES is not requesting at this time, the

[53] SB 1X 2 will go into effect December 10, 2011.

booking of such costs in the PPAC account will have no immediate effect on customer rates. BVES has calculated that the $1,093,350 would be equivalent to a 2.93% increase in the 2012 revenue requirement and also the equivalent of a charge of $0.0071/kWh in 2012.

APPENDIX E

COMPARISON OF CONTRACT WITH

BVES PRO FORMA POWER PURCHASE AGREEMENT

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APPENDIX F

CONFIRMATION NO. 2

<u>Attachment A</u>

CONFIRMATION NO. 2

(RENEWABLE ENERGY CREDITS)

"CONFIDENTIALITY NOTICE: This information is intended only for the use of the individual or entity named below. If you are not the intended recipient, you are hereby notified that any disclosure, copying, distribution, or taking of any action in reliance on the contents of this information is strictly prohibited. If you have received this transmission in error, please immediately notify us by telephone to arrange for return of the documents."

Date:	August 1, 2011
To:	Energy Resource Department
Attention:	Tracey Drabant, Energy Resource Manager Fax No. 909-866-5056, Sanitation Districts of Los Angeles County
Re:	Deal Number: 2 Confirmation No. 2

The purpose of this Confirmation No. 2 (references in the STC non-modifiable provisions to "Agreement" and "the contract" are intended to refer to this Confirmation No. 2) is to confirm the terms and conditions of the transaction (Transaction) agreed upon by Buyer and Seller as of the Effective Date specified below. This Confirmation No. 2 is being provided pursuant to, in accordance with, and is subject to the applicable provisions of the EEI Master Power and Purchase Sale Agreement dated as of its Effective Date by and between Golden State Water Company DBA Bear Valley Electric Service (Party A – GSWC) and County Sanitation District No. 2 of Los Angeles County, a county sanitation district organized and existing under the provisions of the County Sanitation District Act, California Health & Safety Code section 4700 *et seq*. (Party B – District) (together, the Master Agreement). Notwithstanding any contrary provisions in the Master Agreement, any conflict between this Confirmation No. 2 and the Master Agreement will be resolved in favor of this Confirmation No. 2. Terms used but not defined in this Confirmation No. 2 will have the meanings ascribed to them in the Master Agreement.

We confirm the following terms of this Transaction:

PARTIES' ADDRESSES AND DEFINITIONS:

Buyer:	Golden State Water Company, 42020 Garstin Dr., PO Box 1547, Big Bear Lake, California 92315.
Seller:	County Sanitation District No. 2 of Los Angeles County, Attention: Solid Waste Management Department, 1955 Workman Mill Road, Whittier, California.
Generating Facility:	The landfill gas electric generation facilities owned by Seller at the Palos Verdes Landfill Gas-to-Energy Facility, in Rolling Hills, California.
Effective Date:	This Confirmation No. 2 takes effect on the first business day following the date on which the CPUC Approval of this Confirmation No. 2 becomes final as described in the Additional Terms below. Neither party shall be liable or obligated to the other party under this Confirmation No. 2 if such CPUC Approval is not obtained prior to October 1, 2012.
Delivery Term:	From and after the Effective Date for at least 60 days or such longer period of time that may be required to complete the Transaction.
Price:	$30.00 per Renewable Energy Credit.
Commodity:	CEC-certified RPS-eligible Renewable Energy Credits generated in 2010 and 2011 from the Generating Facility.
Quantity:	20,793 CEC-certified RPS-eligible Renewable Energy Credits generated in 2010 from the Generating Facility, and all of the CEC-certified RPS-eligible Renewable Energy Credits generated in 2011 from the Generating Facility, which Seller estimates to equal 15,652 Renewable Energy Credits.
Delivery Date:	A date mutually agreeable to both parties, that is within the time period of the Delivery Term, in which (i) Seller transfers the Quantity of the Commodity from Seller's WREGIS account to the Buyer's WREGIS account and (ii) Buyer pays to Seller an amount equal to the Price per Renewable Energy Credit multiplied by the Quantity of Commodity transferred to Buyer's WREGIS account.

TRANSACTION:

On the Delivery Date of this Confirmation No. 2, Seller shall sell and deliver to Buyer, and Buyer shall purchase at the Price and receive from Seller, the Quantity of the Commodity in accordance with the provisions of the Delivery Date.

ADDITIONAL TERMS

i) STC REC-1. Transfer of Renewable Energy Credits. Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(ii) STC REC-2. Tracking of RECs in WREGIS. Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(iii) STC REC-3. CPUC Approval. "CPUC Approval" means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement of Renewable Energy Credits that conform to the definition and attributes required for required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation, for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

(iv) STC 17 Applicable Law is set forth in Article Ten – Miscellaneous, Section 10.6 of the ADDITIONAL PROVISIONS section of the Cover Sheet to the Master Power Purchase and Sale Agreement.

(v) The parties, without further consideration, agree to execute and deliver additional documents and take such additional actions as may be necessary to consummate the Transaction as provided for in this Confirmation No. 2.

(vi) In the event CPUC Approval of Confirmation No. 2 does not occur before June 30, 2012, this Confirmation No. 2 will be of no force or effect regarding the 20,793 2010 RECs and LACSD may sell the 20,793 2010 RECs to other buyers without restriction. In the event CPUC approval of Confirmation No. 2 does not occur before October 1, 2012, this Confirmation No. 2 will be of no force or effect and LACSD may sell the 2011 RECs to other buyers without restriction.

Please confirm that the foregoing correctly sets forth the terms of our agreement by executing the copy of this Confirmation No. 2 and returning it to us for signature. We will deliver a fully-executed original back to you.

SELLER

COUNTY SANITATION DISTRICT NO. 2 OF LOS ANGELES COUNTY

By: ________________
Name: J. Greg Nordbak
Title: Chairperson, Board of Directors
Date: JUL 27 2011

ATTEST: Kimberly S. Compton
Secretary to the Board

APPROVED AS TO FORM:
LEWIS, BRISBOIS, BISGAARD & SMITH LLP

By: Daniel V. Hyde
District Counsel

BUYER:

GOLDEN STATE WATER COMPANY

By: Robert J. Sprowls
Name: ROBERT J. SPROWLS
Title: PRESIDENT & CEO
Date: JULY 13, 2011

86075717.1

APPENDIX G

PROJECT'S CONTRIBUTION TOWARDS RPS GOALS

CONFIRMATION NO. 2 RECs

CONTRIBUTION TO RPS GOALS

Project Name:	2010/2011 in-state RECs from RPS Generating Facility (Palos Verdes Landfill gas-to energy facility located in Rolling Hills, California) owned and operated by County Sanitation District No. 2 of Los Angeles County ("LACSD").
Technology:	Land fill gas to energy.
COD:	Commercially operational.
Location:	Rolling Hills, California.
Amount of RECs:	20,793 CEC-certified RPS-eligible renewable energy credits ("RECs") generated in 2010; and All of the CEC-certified RPS-eligible RECs generated in 2011 from the Generating Facility, which LACSD estimates to equal 15,652 RECs.
Delivery of RECs:	The date the contract delivery term begins is the first business day following the date of CPUC approval of Confirmation No. 2. The date upon which the RECs will be sold by LACSD and purchased by GSWC is a date no later than 60 days from the effective date of Confirmation No. 2, unless a longer period of time is required to complete the transaction.
Contribution of RECs:	If all of the 2010 RECs (20,793) and a portion of the 2011 RECs (5,640) are applied to BVES' 2010 APT and the remainder of the 2011 RECs (10,012, assuming BVES purchases 15,652 2011 RECs from LACSD) are applied to BVES' 2011 APT, then the RECs purchased under Confirmation No. 2 would meet **100% of BVES' 2010 APT** and **37.4% of BVES' 2011 APT**. However, BVES does not commit to apply the RECs in this manner. BVES reserves the right to apply the RECs towards BVES' RPS requirements in a manner that most benefits BVES and its customers.
Contribution of other RPS contracts:	BVES has one executed and approved contract with LACSD for delivery of RPS bundled energy from the Generating

Facility (*i.e.*, Confirmation No. 1). The Generating Facility produces approximately 2.4 MW of RPS-eligible energy per hour. Confirmation No. 1 requires all energy from the Generating Facility, up to 3 MW per hour, is to be sold to GSWC/BVES. Deliveries of bundled RPS energy began August 1, 2011. LACSD has ceased operations of the Generating Facility, as permitted under the settlement agreement between the two parties. It is estimated that BVES has received approximately 3,000 MWh of bundled RPS energy from the Generating Facility as of September, 30 2011. Assuming that is correct, it represents approximately 10% of BVES' 2011 APT.

% Goal Including RECs

If the anticipated amounts of 2010 RECs and 2011 RECs under Confirmation No. 2 are received and the estimate of 3,000 MWh of RPS energy under Confirmation No. 1 is correct, the total percentage of BVES' APT goals for 2010 and 2011 are 100% and 54%, respectively. However, BVES does not commit to apply the RECs in this manner. BVES reserves the right to apply the RECs towards BVES' RPS requirements in a manner that most benefits BVES and its customers.

APPENDIX H

ADDITIONAL INFORMATION FOR APPROVAL OF REC-ONLY CONTRACTS

ADDITIONAL INFORMATION FOR APPROVAL OF REC-ONLY CONTRACTS

In accordance with D.10-03-021, as modified by D.11-01-025, Ordering Paragraph 12, the following requested information is provided.

Request for Additional Information No. 1 – State whether the generation facility or facilities producing the energy eligible for the California renewables portfolio standard that is associated with the renewable energy credits to be procured entered commercial operation prior to January 1, 2005, or after January 1, 2005, or was not in commercial operation at the time the contract was signed;

Response: The Palos Verdes Landfill gas-to energy facility ("Generating Facility") located in Rolling Hills, California, which is the generating facility producing the RECs to be purchased by BVES in accordance with Confirmation No. 2, entered into commercial operation prior to January 1, 2005.

Request for Additional Information No. 2 -- Provide the sum of all delivered and expected tradable renewable energy credits purchased through contracts executed by the utility to date and how this compares to any applicable annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard;

Response: BVES has not executed any REC-only contracts to date, other than Confirmation No. 2, which is the subject of this Advice Letter filing.

Request for Additional Information No. 3 – Provide the sum of all delivered and expected tradable renewable energy credits purchased by that utility through contracts for the procurement of renewable energy credits only with facilities that are or were already online as of the execution date of their associated contract for procurement of tradable renewable energy credits, and how this compares to the applicable annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard;

Response: BVES has not executed any REC-only contracts to date, other than Confirmation No. 2, which is the subject of this Advice Letter filing. In addition, there are no limitations on BVES as to the amount of RECs that it may use to meet its RPS obligations. In D.10-03-021, the Commission specifically exempted BVES from the 25% of APT limitation on the use of TRECs for the larger investor-owned utilities.[54] In Senate Bill X1 2 ("SB X1 2"), BVES is authorized to use 100% RECs to meet its RPS obligations.[55]

Request for Additional Information No. 4 — Provide the sum of all delivered and expected tradable renewable energy credits purchased by that utility through contracts for the

[54] D.10-03-021 at p. 47.
[55] Section 25, SB X1 2, new Section 399.18(b).

procurement of renewable energy credits only with facilities that are not or were not online as of the execution dates of their associated contracts, and how this compares to the applicable annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard;

Response: BVES has not executed any REC-only contracts to date, other than Confirmation No. 2, which is the subject of this Advice Letter filing. In addition, there are no limitations on BVES as to the amount of RECs that it may use to meet its RPS obligations.

Request for Additional Information No. 5 — Provide a comparison of the price of the renewable energy credits in the contract that is the subject of the advice letter and the price of renewable energy credits from all contracts for the procurement of renewable energy credits only with facilities that were online as of the execution date of their associated contracts.

Response: BVES has no knowledge of the price of RECs from contracts for procurement of RECs from facilities that were online as of the execution of Confirmation No. 2.

Request for Additional Information No. 6 — Provide a comparison of the price of the renewable energy credits in the contract that is the subject of the advice letter and the price of renewable energy credits from all contracts for the procurement of renewable energy credits only with facilities that were not yet online as of the execution date of their associated contracts.

Response: BVES has no knowledge of the price of RECs from contracts for procurement of RECs from facilities that were not yet online as of the execution of Confirmation No. 2.

CERTIFICATE OF SERVICE

I certify that I have by electronic mail, or by U.S. Mail where no electronic address has been provided, this day served a true copy of the attached **NOTICE OF AVAILABILITY** on all parties listed in the attached Service Lists for R.11-05-005, R.06-02-012 and the Bear Valley Electric Service Distribution for Advice Letter Filings.

Dated November 23, 2011 at Los Angeles, California

/s/ Diana L. Cardenas
Diana L. Cardenas

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

NOTICE OF AVAILABILITY

An advice letter filing for a **Purchase and Sale Agreement for Renewable Energy Credits Between Golden State Water Company and County Sanitation District No. 2 of Los Angeles** ("Advice Letter") has been filed with the California Public Utilities Commission.

The Advice Letter includes a request for approval of a renewable energy credit contract ("Confirmation No. 2") between Golden State Water Company (on behalf of its Bear Valley Electric Service division) and County Sanitation District No. 2 of Los Angeles ("LACSD"). The subject project is the Palos Verdes Landfill gas-to-energy facility owned and operated by LACSD (the "Generating Facility"). The proposed Confirmation No. 2 is for the purchase by Golden State Water Company ("GSWC") of 20,793 2010 renewable energy credits ("RECs") and approximately 15,650 2011 RECs from the Generating Facility. If Confirmation No. 2 is approved by the Commission, GSWC is also seeking authority to book all Confirmation No. 2 payments to LACSD into Bear Valley Electric Service's Purchased Power Adjustment Clause for recovery in rates.

If anyone receiving this Notice of Availability wishes to receive a copy of the Advice Letter, please contact Diane Cardenas at dcardenas@fulbright.com or call (213) 892-9241 or send a written request to her at 555 South Flower Street, 41st Floor, Los Angeles, California 90071.

/s/ Fred G. Yanney

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