Docket No.: A.12-02-013

Exhibit No.: ____________________

Date: July 27, 2012

Witness: William A. Monsen

TESTIMONY OF WILLIAM A. MONSEN ON BEHALF OF SNOW SUMMIT, INC. CONCERNING REVENUE REQUIREMENTS, MARGINAL COSTS, AND REVENUE ALLOCATION

Table of Contents

Table of Figures

Table of Tables

I. Introduction and Summary

Q. Please state your name and business address.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC. (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Please describe Snow Summit, Inc.

A. Snow Summit, Inc. operates two ski resorts in Big Bear Lake – Snow Summit and Bear Mountain. Both ski resorts are customers of Bear Valley Electric Service Division (BVES). Snow Summit, Inc. is the single largest customer of BVES. In total, Snow Summit, Inc. has 15 separate accounts with BVES. Three of these accounts are large power accounts that take service under BVES's Tariff Schedule A-5 TOU Primary.[1] BVES has no other customers that currently take service under this rate schedule. In addition, Snow Summit, Inc. has 12 accounts that take service under BVES's A-1, A-2, and A-3 commercial rate schedules.

Q. Briefly summarize Snow Summit's electric supply program.

A. Currently, BVES provides service to a portion of Snow Summit's loads through the Summit substation. In addition, Snow Summit generates its own power to serve the remainder of its load, including its snowmaking load. Snow Summit's

[1] Unless otherwise noted, any mention of Schedule A-5 or A-5 TOU refers to Schedule A-5 TOU Primary.

diesel-fired generation only supplies Snow Summit loads (i.e., Snow Summit does not deliver power to BVES).

Q. Has BVES ever provided service to the loads served by Snow Summit's diesel generation?

A. No. I understand that Snow Summit's load expanded significantly in 1979 when it installed a major snowmaking system. Prior to installing the snowmaking system, Snow Summit requested incremental service from BVES, but BVES could not satisfy this request on the grounds that it had inadequate supply resources. Since Snow Summit needed to install the snowmaking system to remain competitive, it installed its own diesel-fired generation system and a self-maintained distribution system to serve these new loads. Snow Summit repowered its generation system in stages from 2003 to 2006.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide analysis of aspects of BVES's revenue requirement, marginal costs, and revenue allocation proposals. In addition, I address BVES's novel proposal to serve incremental load at Snow Summit under a rate that is, by design, more expensive than a cost-based rate. Of particular concern is this incremental service ratemaking proposal and BVES's revenue allocation proposal, both of which would impose costs on Snow Summit, Inc. well beyond its cost of service. I also discuss aspects of BVES's revenue requirement proposal that overstate BVES's revenue needs and errors in BVES's marginal cost study that would affect Snow Summit, Inc. while providing *de minimis* benefit to BVES or to other customers.

Q. Please summarize your testimony.

A. My testimony is structured in the typical order of rate proceedings: I start by examining revenue requirements and then proceeding to marginal costs and revenue allocation. I conclude by addressing BVES's special request for a Snow Summit substation ratemaking proposal.

In Chapter II, I address an element of BVES's revenue requirement request, namely BVES's requested increase in return on equity (ROE). This request is unjustified given the significant reduction in the risk-free cost of capital since BVES's last ROE request, a reduction that has led every other California investor-owned utility to request an ROE reduction, not an increase. Furthermore, BVES has made no demonstration or claim of an increase in shareholder risk since its last ROE adjustment and, in fact, has made proposals in this proceeding to reduce such risk. The Commission should reduce BVES's ROE to 8.39% to take into account BVES's reduced cost of capital. This would reduce BVES's revenue requirement request by $871,000.

In Chapter III, I address four flaws in BVES's marginal cost study: (1) a market energy price forecast that is inconsistent with current market conditions and does not provide a reasonable projection of seasonal price differentiation, (2) a $3.1

million revenue credit that was inappropriately included in the marginal generation cost study, (3) the inappropriate omission of operations and maintenance (O&M) costs from the marginal generation cost study, and (4) an incorrect Renewable Energy Credit (REC) adder that overstates the marginal cost of power by including "make-up" costs from prior year REC obligations. I present an updated set of marginal costs that corrects for these errors.

In Chapter IV, I critique BVES's revenue allocation proposal, which makes only a slight movement toward marginal cost-based revenue allocation and, as a result, would essentially keep in place the utility's current inequitable revenue allocation. BVES's own marginal cost study demonstrates that the utility's rate structure is significantly askew from a marginal cost-based allocation. While acknowledging the primacy of marginal costs within Commission policy, BVES recommends only a 10% movement towards marginal cost-based rates. Such a small movement would unfairly require other customers to continue to provide permanent residential customers with substantial subsidies. For example, A-5 TOU Primary customers would be required to pay nearly 50% above their cost of service under BVES's proposal. Such an allocation structure is inconsistent with Commission policy, unduly discriminatory, and, on account of its substantial cost burden on commercial customers, harmful for the Big Bear Lake region. I therefore propose that BVES's revenue allocation be designed to bring class revenue responsibility 25% closer to a marginal cost-based revenue allocation on the effective date of the Commission's decision in this proceeding.

In Chapter V, I address BVES's novel proposal to serve incremental load at Snow Summit. Instead of offering a cost-based rate, BVES proposes a Supplemental Energy Rate (SER) that has a built-in subsidy to all other customers of at least $330,000 per year. The most surprising element of BVES's request is that there currently is no agreement between BVES and Snow Summit for such an expansion in service. For that reason, I recommend that the Commission defer consideration of this matter. However, if the Commission does decide to address the structure of how BVES should make supplemental sales to Snow Summit, then I recommend that the service be provided under the otherwise applicable tariff instead of the SER. BVES's proposed SER is untimely, is not cost-based, is counter to Commission and State ratemaking policy, and allows BVES to arbitrarily assign costs to specific customers. Aside from these policy concerns, the SER is overly complex, indexed improperly, and administratively burdensome for Snow Summit.

II. BVES's Revenue Requirement Request is Overstated

Q. What is BVES's revenue requirement request?

A. BVES is requesting a revenue requirement of $44.70 million, representing a $4.01 million (9.85%) increase over the currently authorized revenue requirement.[2]

Q. Have you examined this request in detail?

A. No. I have examined only BVES's requested Return on Equity (ROE) increase. As discussed below, I believe this proposal is unjustified. I have not examined BVES's other cost inputs and have no opinion at present as to the reasonableness of those requests.

A. BVES's ROE should be reduced to reflect reductions in BVES's cost of capital

Q. What level of ROE is BVES requesting?

A. BVES is requesting an increase in ROE from 10.5% to 12.0%.[3]

Q. How does BVES's ROE request compare to the ROE request of another small investor-owned electric utility (i.e., California Pacific Electric Company (CalPECO))?

[2] A. 12-02-013, Testimony of Bear Valley Electric Service (BVES Testimony), Volume 1, page 4.
[3] BVES Testimony, Volume 5, page 9.

A. Unlike BVES's request for an increase in ROE, CalPECO has requested a reduction in ROE from 10.75% to 10.5%.[4] BVES's proposed ROE is 14.3% greater than CalPECO's proposed ROE.[5]

Q. How does BVES's ROE request compare to the ROE requests of other California investor-owned utilities?

A. BVES's proposed ROE for 2013 is significantly higher than the ROE requested by PG&E (11.0%), SCE (11.1%), and SDG&E (11.0%) in their Cost of Capital Applications submitted for 2013.[6] Notably, along with CalPECO, each of the three large utilities is requesting a reduction in its ROE for 2013,[7] while BVES is requesting an increase.

Q. How does BVES's proposed increase in ROE affect BVES's revenue requirement?

A. If BVES's ROE were maintained at 10.5% and all other BVES proposals were granted, BVES's revenue request would be reduced by $286,000, reducing BVES's requested increase in revenue requirements by more than 7%[8] (to 9.15%).

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[4] Amended application of California Pacific Electric Company in A.12-02-014, February 29, 2012, page 6. See Attachment B.
[5] 14.3% = 12.0/10.5 - 1
[6] PG&E Testimony in A.12-04-018 page 1-1 (See Attachment C), SCE Testimony in A.12-04-015 page 3 (See Attachment D), and SDG&E Application in A.12-04-016 page 4 (See Attachment E).
[7] PG&E Testimony in A.12-04-018 page 1-1 (See Attachment C), SCE Testimony in A.12-04-015 page 3 (See Attachment D), and SDG&E Application in A.12-04-016 pages 1 and 4 (See Attachment E).
[8] -7.1% = 9.15%/9.85% - 1

Q. Do you recommend that BVES's ROE should remain at 10.5%?

A. No. As discussed below, BVES's ROE should not remain at 10.5% but should instead be reduced, which would further reduce BVES's revenue request.

Q. How is the appropriate level of ROE assessed?

A. The ROE can be assessed in a number of ways. Under the Capital Asset Pricing Model (CAPM), which is one of the models that BVES relied upon in developing its ROE proposal, the cost of equity is the sum of two components: a risk-free cost of capital and a risk adder.[9]

1. The risk-free cost of capital is the expected return on an asset that does not bear any risk. The rate is typically estimated on the basis of relatively low-risk assets such as long-term yields on Treasury bonds.[10]
2. The risk adder recognizes and compensates shareholders for specific risks that they bear.

Q. How do these two components interact?

A. The two components are independently evaluated and then summed together to form the recommended ROE. Accordingly, an increase or decrease in either component flows through directly to the ROE. For example, if the risk-free cost of capital decreases, the ROE will correspondingly decline unless the risk adder increases to fully offset this reduction.

[9] BVES Testimony, Volume 5, page 25.

[10] In their most recent applications, BVES, PG&E, SCE, and SDG&E have all estimated their risk-free rates of return based on 30-year Treasury bond rates. See BVES Testimony (Volume 5), page 27, PG&E testimony in A.12-04-018, page 2A-11 (See Attachment C), SCE testimony in A.12-04-015, page 5 (See Attachment D), and SDG&E testimony in A.12-04-016 (Morin) page 36 (See Attachment F).

Q. What is the recent history of BVES's ROE?

A. BVES requested an ROE of 11.7% in its last general rate case (GRC)[11] and in May 2009 agreed to a settlement with the Division of Ratepayer Advocates (DRA) for an ROE of 10.5%.[12] This settlement was adopted by the Commission in October 2009.[13] In the current application BVES is requesting a much higher ROE of 12%.[14]

Q. How has the risk-free component of BVES's ROE changed since its last GRC?

A. At the time BVES submitted its last GRC application, the 30-year Treasury bill rate was 4.69%.[15] The rate in June 2012 was 2.70%.[16] The risk-free cost of capital has therefore declined by 42% since BVES's last ROE request.[17]

Q. Has BVES's requested ROE increased even though its risk-free cost of capital has declined?

A. Yes. This can be seen in Table 1, which shows the 30-year Treasury bond rate in effect at the time of important BVES GRC milestones. As shown in the table, the

[11] BVES Testimony in A.08-06-034, Volume 5, page 1. See Attachment G.
[12] Settlement Agreement Between the Division of Ratepayer Advocates and Golden State Water Company, on Behalf of its Bear Valley Electric Service Division, A.08-06-034, page 11. See Attachment H.
[13] D.09-10-028 in A. 08-06-034
[14] BVES Testimony, Volume 5, page 9.
[15] Historical data for 30-year Treasury bill, June 2008. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.
[16] Historical data for 30-year Treasury bill, June 2012. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.
[17] (Treasury bill rate in 2012- Treasury bill rate at time of June 2008 application)/ Treasury bill rate in June 2012= (2.73-4.69)/4.19= -42%

bond rate at the time of BVES's 2013 GRC request was lower than the bond rates in effect during BVES's 2009 GRC case, but BVES's current ROE request is higher than the ROEs requested and agreed to in that case.

Table 1: BVES ROE Requests and Treasury-Bond Rates

	Date	Yield on 30-Year Treasury Bond[18]	ROE
BVES 2009 GRC Request	June 2008	4.69%	11.7%[19]
2009 GRC Settlement	May 2009	4.23%	10.5%[20]
2009 GRC Decision	October 2009	4.19%	10.5%[21]
BVES 2013 GRC Request	February 2012	3.11%	12.0%[22]

Q. Does BVES assume that the risk-free component will remain near current levels over this upcoming GRC cycle?

A. No. While BVES notes that interest rates dropped in 2009 and have been at 40-year lows in recent years,[23] BVES assumes in its ROE calculations a risk-free interest rate of 4.80%,[24] which is more than 75% greater[25] than the current risk-free rate of 2.70% [26]and is even higher than the risk-free rate that was in effect when BVES submitted its last GRC application in 2008.

[18] Historical data for 30-year Treasury bill. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.
[19] BVES Testimony in A.08-06-034, Volume 5, page 1. See Attachment G.
[20] Settlement Agreement Between the Division of Ratepayer Advocates and Golden State Water Company, on Behalf of its Bear Valley Electric Service Division, A.08-06-034, page 11. See Attachment H.
[21] D.09-10-028 in A. 08-06-034
[22] BVES Testimony, Volume 5, page 9
[23] BVES Testimony, Volume 5, page 18.
[24] BVES Testimony, Volume 5, page 42, Table 7
[25] 77.8% = 4.80%/2.70% - 1
[26] Historical data for 30-year Treasury bill, June 2012. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.

Q. Is BVES's approach for forecasting the risk-free interest rate consistent with BVES's methodology in its last rate case?

A. No. BVES's current ROE estimate is based on proprietary forecasts of 2013-2016 long-term Treasury bonds yields.[27] In its last GRC, BVES used projected Treasury rates for the first three quarters of the 2009 Test Year only,[28] not for the entire GRC period (i.e., 2009-2012).

Q. Does BVES's risk-free interest rate forecast seem consistent with interest rate developments since its proprietary forecasts were released?

A. No. The forecasts that BVES relied on were released in late November and early December 2011,[29] at which time the 30-year Treasury bond rate was around 3%.[30] The forecasts predicted that the 2013 rate would increase by 35%-40% to 4.15%.[31] However, instead of increasing, bond rates have fallen in recent months and are currently at 2.70%.[32] To achieve the predicted 2013 rate by the end of the year, bond yields would have to increase by more than 50% from their current levels.[33]

Q. Is it reasonable to use current bond rates in place of forecasted rates?

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[27] BVES Testimony, Volume 5, page 27.
[28] BVES Testimony in A.08-06-034, Volume 5, page 4-9. See Attachment G.
[29] BVES Testimony, Volume 5, page 42.
[30] The 30-year Treasury bond rate was 2.92% on November 25, 2011, the date of the Value Line forecast release, and 3.12% on December 1, 2011, the date of the Blue Chip forecast release. Historical data for 30-year Treasury bill. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.
[31] Average of the two forecast values of 4.10% (Value Line) and 4.20% (Blue Chip Consensus Forecasts), as presented in BVES Testimony, Volume 5, page 42.
[32] Historical data for 30-year Treasury bill, June 2012. http://www.federalreserve.gov/releases/h15/data.htm. See Attachment I.
[33] 4.15/2.70-1 = 54%

A. Given the uncertainty as to future interest rates and given the drawbacks of relying on proprietary forecasts, it is reasonable to consider current bond rates in place of proprietary forecasts of future bond rates as the benchmark interest rate. Since actual bond rates are readily available, this approach has the advantage of enabling a consistent comparison of the risk-free cost for the test year.

Q. Does BVES propose to introduce another factor into its calculation of ROE?

A. Yes. BVES proposes to add a "risk premium" in addition to the risk adder discussed above.

Q. What is the "risk premium"?

A. BVES's risk premium is the spread between bond costs and equity costs. BVES's testimony refers to literature that points to an inverse relationship between interest rates and these risk premiums, meaning that at lower interest rates there is a greater spread between the bond rate and the cost of equity.[34] Based on its assessment of its risk premium, BVES concludes that a given reduction in the interest rate on 30-year Treasury bonds should yield a smaller reduction in ROE.[35]

Q. Despite its proposed "risk premium," what does BVES conclude about the relationship between changes in risk-free interest rates and changes in ROE?

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[34] BVES Testimony, Volume 5, pages 18-19.
[35] BVES Testimony, Volume 5, pages 19-20.

A. Despite its assertions about the effect of risk premium on ROE, BVES agrees in principle that, all else equal, a lower interest rate should yield a lower ROE.[36]

Q. Is it reasonable then that BVES is requesting an ROE increase given the decline in the risk-free cost of capital?

A. BVES's request might be reasonable if the risk adder component has increased to more than offset the decline in the risk-free component.

Q. What would cause the risk adder to increase?

A. The risk adder is indicative of the particular risks faced by BVES's shareholders. An increase in the risk adder would imply that there has been an increase in the risks that BVES faces as a business since its last request to change its ROE.

Q. Do you believe that BVES's shareholders will be at greater risk in the future than during the recent past?

A. No. It appears that BVES has made proposals in this proceeding to reduce, rather than increase, its risks.

Q. What are those proposals?

A. BVES has introduced several new proposals in its 2012 GRC that would reduce risk to its shareholders. Three such proposals are summarized below:

[36] BVES Testimony, Volume 5, page 22.

- A new Post Test Year Attrition Mechanism (PTAM) for years 2014, 2015, and 2016 to adjust the revenue requirement for operations and maintenance (O&M) expenses, administrative and general expenses, tax rate changes, and carrying costs of capital additions.[37] This mechanism would eliminate the risk to BVES shareholders of reduced earnings on account of increases to these costs during the attrition years.
- A new Pension and Benefit (P&B) balancing account to track the difference between P&B costs recovered in rates and actual P&B costs.[38] This balancing account would eliminate risk to BVES shareholders of reduced earnings on account of higher-than-anticipated P&B costs.
- Modification to the Base Revenue Requirement Adjustment Mechanism (BRRAM) to track seasonally adjusted monthly sales in place of one-twelfth of the annual revenue requirement. As BVES explains, the current method "creates a distortion in the BRRAM account, which needlessly distorts BVES' quarterly financial statements."[39] The modification would reduce shareholder risks that arise from these distortions.

Q. Does BVES provide evidence to substantiate an increase in shareholder risk since its last GRC?

A. To my knowledge, BVES does not directly consider how shareholder risk has changed since the last GRC. In its CAPM analysis, BVES calculates the risk

[37] BVES Testimony, Volume 1, page 11.
[38] BVES Testimony, Volume 1, page 13.
[39] BVES Testimony, Volume 1, page 10.

premium based on a market risk premium, which estimates the incremental risk of equities relative to bonds, adjusted for the lower-than-average risk of electric utility equities relative to the market as a whole and the alleged increased risk of BVES equities relative to the average electric utility equity given the small size of the utility ("beta" adjustment).[40] BVES also adds an 80-basis-point adder to account for alleged incremental risk on account of BVES's size and company-specific risks,[41] which appears to overlap with the "beta" adjustment and double-count the alleged incremental risk from BVES's small size. BVES does not evaluate shareholder risk relative to the shareholder risk assumed in its last request to change its ROE in its last GRC. BVES also does not explain what incremental risk warrants the addition of the 80-basis-point adder, which was not applied in BVES's last GRC.[42]

Q. Do you object to particular assumptions used in BVES's analysis?

A. BVES's analysis is built of many assumptions, and, aside from those discussed above, I have not assessed these assumptions in detail. Instead, I have presented a high-level comparison to assess whether BVES's result is reasonable.

Q. What do you conclude regarding BVES's proposed ROE?

[40] BVES Testimony, Volume 5, pages 27-28.
[41] BVES Testimony, Volume 5, page 32.
[42] BVES Testimony in A.08-06-034, Volume 5, pages 4-8 through 4-12. See Attachment G.

A. I conclude that BVES's proposed ROE is too high, since the risk-free cost of capital has declined and BVES has not presented evidence of an increase in shareholder risk.

Q. What do you propose?

A. BVES's ROE should certainly be no higher than it is now. In fact, since the risk-free interest rate has fallen by 42% since BVES's last application,[43] the ROE should, at a minimum, be reduced by one-half to two-thirds of this 42% reduction in risk-free interest rates.[44] This would reduce the ROE to the range of 8.39%-9.22%.

Q. Why do you recommend a reduction in ROE based on the reduction in the risk-free interest rate?

A. In D.02-11-027, the Commission stated that its practice has been to adjust rates of return by one-half to two-thirds of the change in the benchmark interest rate in order to increase the stability of the ROE over time.[45] My recommended reduction in ROE is consistent with this prior Commission decision.

Q. From this range of potential ROE, what do you recommend for BVES's ROE in this proceeding?

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[43] (Treasury bill rate in 2012- Treasury bill rate at time of June 2008 application)/ Treasury bill rate in June 2012= (2.73-4.69)/4.19= -42%
[44] D.02-11-027, page 20.
[45] D.02-11-027, page 20.

A. Given BVES's proposals to reduce shareholder risks, I suggest that BVES's ROE should be set at the lower end of this range (i.e., 8.39%). Such a reduction is reasonable given the significant drop in the risk-free cost of capital and BVES's proposed reductions to shareholder risk. However, if the Commission does not adopt all of BVES's proposals that reduce shareholder risk, the Commission could consider a slightly higher ROE value in the range.

Q. What would be the revenue impacts from your proposal?

A. Adopting Snow Summit's proposal for an ROE of 8.39% would reduce BVES's proposed revenue requirement increase by 22% to $3.139 million. This would reduce BVES's revenue request by $871,000 million.

III. Errors in the Marginal Cost Study should be Corrected

Q. Did BVES present a marginal cost study to guide the allocation of revenue requirements?

A. In part. BVES did present a marginal cost study. However, as discussed in the next section, BVES proposes to base revenue allocations primarily on the *status quo* allocations, with just a 10 percent movement toward an allocation based on marginal costs.

Q. Do you agree with BVES's marginal cost study?

A. No. There are several errors in BVES's study. These errors result in incorrect marginal costs, which skew the determination of a marginal cost-based revenue allocation.

A. Marginal cost study errors

Q. Please summarize the errors you have identified in BVES's marginal cost study.

A. I have identified four errors that have notable impacts on the marginal cost results:

1. The forecast of market energy prices provided by ICF International is inconsistent with current market conditions;
2. The marginal generation cost study inappropriately includes a $3.1 million revenue credit associated with the added facilities charge;

3. O&M costs are inappropriately omitted from the marginal generation cost study; and
4. BVES used an incorrect Renewable Energy Credit (REC) adder that overstates the price of RECs.

In addition, it appears that BVES corrected errors in its marginal cost study prior to providing workpapers to parties but did not update its testimony to be consistent with these changes.[46] Even if the Commission were to reject my proposed corrections to BVES's marginal cost study described below, the Commission should at least require BVES to use its own updated marginal costs results in the derivation of its revenue allocation and rate design proposals.

i. BVES's market price forecast needs to be corrected

Q. In what way is the ICF market price forecast inconsistent with historic price patterns and current market conditions?

A. The ICF forecast that BVES used in its marginal cost study shows SP-15 electricity prices to be 7% higher in the winter (defined as December through February) than in the summer (defined as June through August).[47] This is inconsistent with historic price patterns, in which winter prices are generally lower than summer prices (Table 2). In addition, the ICF forecast incorporates

[46] BVES Workpaper, Vol 6 Chap 2_Marg Cost April 5 2012e.xls, tab Spreadsheet Guide, rows 9-12.
[47] 7% = $59.71 per MWh winter/$55.83 per MWh summer – 1. BVES Workpaper, Vol 6 Chap 2_Marg Cost April 5 2012e.xls, tab SP-15 Market Prices (Nominal $), cells E103:E104 and B85.

historical data only through 2010;[48] it does not therefore reflect the significant reduction in natural gas prices that occurred in 2011 and 2012.

Table 2: SP-15 Seasonal Price Differences: Historic Average versus ICF Forecast

	2003-2011 Average		2007-2010 Average		ICF Forecast[49]	
	$/MWh	Winter price as % of Summer	$/MWh	Winter price as % of Summer	$/MWh	Winter price as % of Summer
All hours		98%		101%		107%
Winter	54.91		53.18		59.71	
Summer	55.84		52.89		55.83	
On-Peak[50] hours		94%		94%		99%
Winter	61.32		58.75		63.42	
Summer	65.14		62.70		64.31	
Off-Peak hours		114%		114%		123%
Winter	48.88		47.73		54.77	
Summer	42.71		41.75		44.48	

Q. Did ICF's forecast of 2011 market prices match reasonably well with actual prices seen in 2011?

A. ICF's forecast of prices missed badly when compared to actual prices. In its forecast, ICF projected that winter prices would be 16% higher than summer prices. In fact, actual average winter prices were four percent below actual average summer prices (Table 3). Also, ICF's forecast overestimated actual market prices by 12% overall and overestimated winter prices by 29%. In summary, ICF's forecast therefore did not provide a reasonable projection of seasonal price differentiation.

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[48] "ICF Base Case Energy Price Projections for the SP-15 Power Market – Preliminary Draft," Attachment 1, pages 1-2. Provided as an attachment to BVES Response to Snow Summit discovery request 5 Q3a. (BVES reports that it did not receive a final version of the memo.) See Attachment J.

[49] BVES uses a 2013-2015 weighted average of energy prices in nominal dollars from ICF's forecast.

[50] Peak definition is 6x16, reflecting Monday through Saturday 7:00 AM to 11:00 PM; see BVES response to Snow Summit discovery request 5 Q3a, Attachment 1, page 1. See Attachment J.

Table 3: SP-15 Seasonal Price Differences: 2011 Actual versus ICF Forecast

	2011 Actual		ICF Forecast		ICF Forecast as % of Actual 2011 Prices
	$/MWh	**Winter as % of Summer**	**$/MWh**	**Winter as % of Summer**	
All hours	*31.41*		*35.30*		*112%*
Winter	30.75	96%	39.60	116%	129%
Summer	32.07		34.20		107%
On-Peak hours					
Winter	34.96	90%	42.30	103%	121%
Summer	38.86		40.90		105%
Off-Peak hours					
Winter	26.41	126%	36.10	143%	137%
Summer	21.02		25.20		120%

Q. Why is the seasonal price differentiation of concern?

A. A market price forecast that overestimates winter prices relative to summer prices exaggerates the cost of serving customers during the winter relative to the cost of serving customers during the summer. Snow Summit, Inc.'s electricity usage is highly weighted to the winter ski season months. BVES projects, for example, that two-thirds of the electricity usage on Snow Summit, Inc.'s A-5 TOU Primary accounts (which make up the vast majority of Snow Summit, Inc.'s usage) will be during the December-February period.[51] A forecast that exaggerates the cost of service during the winter months relative to the summer months therefore inappropriately shifts costs to Snow Summit, Inc. and other customer classes that have winter-peaking loads relative to customer classes whose loads are concentrated in other seasons or are more evenly distributed across the year.

[51] BVES workpaper, Vol 6 Chap 2 Marg Cost April 5 2012 e.xls, sheet Forecast 2008-2016(2), cells BE84:BE96.

Q. What is the source of the error in seasonal price differentiation in the ICF forecast?

A. The source of the error is unclear since ICF developed its forecast using a proprietary production cost simulation model[52] and ICF's memo to BVES describing the price forecast does not address the reason for forecasting winter rates that are so much higher than summer rates.[53]

Q. Have you developed an alternate forecast based on up-to-date natural gas prices?

A. Yes. I used the implied market heat rates for 2013 from ICF's forecast for each time-of-use period. I applied these implied market heat rates to natural gas prices based on futures prices for 2013 to develop a forecast of 2013 power prices in each period. Table 4 compares this forecast with the forecast that BVES used in its marginal cost study.

[52] Letter from ICF International to Joseph Phalen, BVES, March 29, 2011, Provided as an attachment to BVES Response to Snow Summit discovery request 2 Q48. See Attachment K.
[53] "ICF Base Case Energy Price Projections for the SP-15 Power Market – Preliminary Draft." See Attachment J.

Table 4: Snow Summit and BVES SP-15 Market Price Forecasts

	Snow Summit [$/MWh]	BVES [$/MWh]	BVES overestimate [%]
All Hours (Annual)	**36.85**	**55.96**	**52%**
Winter	34.99	59.71	71%
Summer	38.11	55.83	47%
Winter Shoulder	37.32	54.36	46%
Summer Shoulder	36.80	53.84	46%
Peak Hours (Annual)	**40.30**	**61.26**	**52%**
Winter	37.10	63.42	71%
Summer	43.73	64.31	47%
Winter Shoulder	39.57	57.69	46%
Summer Shoulder	41.38	60.62	46%
Off-Peak Hours (Annual)	**32.25**	**48.89**	**52%**
Winter	32.18	54.77	70%
Summer	30.58	44.48	45%
Winter Shoulder	34.28	49.87	45%
Summer Shoulder	30.76	44.90	46%

Q. Are there additional differences between your forecast and BVES's forecast?

A. Yes. BVES's forecast is based on an average of projected 2013-2015 market prices, whereas my forecast is based on projected 2013 market prices alone. I used the 2013 market price forecast because the test year for this rate case is 2013. BVES did not explain why it included 2014 and 2015 forecasted prices in its test year 2013 marginal cost analysis.

ii. The $3.1 million revenue credit should be removed

Q. What is the $3.1 million revenue credit?

A. BVES's marginal generation (demand) cost study is based on the capital cost of the Bear Valley Power Plant (BVPP) as if it were constructed to be in-service at the start of 2013.[54] BVES estimated this cost, subtracted a \$3.1 million credit,[55] and then used the adjusted cost to calculate marginal generation demand costs.

Q. What is the basis for this "credit"?

A. While this revenue credit is not explained in BVES's workpapers, BVES explained it in response to a Snow Summit data request:[56]

> This \$3.1 million revenue credit was developed in the context of the contribution to margin that would accrue if the [Snow Summit] added facilities contract was implemented. The estimate is a simple calculation of an added margin from use of the capacity of \$350,000 per year for 20 years at a current discount factor of 9.81% [(rate of return)] which yields a \$3.1 million revenue credit and a reduction in the marginal cost of the capacity of \$369/kw.
>
> It is important to note that this revenue credit is being used as an example of accounting for a revenue credit that can occur as a result of adding additional generating capacity on the [Bear Valley] system. That is, it is assumed, that the additional capacity will be used in a cost- effective manner for some portion of the year and credit for this capacity use is appropriately accounted, in marginal cost terms, in reducing the annualized capital cost of the facility.

BVES explained in response to follow-up data requests that the \$350,00 per year value is a rounded, estimated value of the annual added margin to ratepayers (i.e., revenues above cost of service) from the proposed Supplemental Energy Rate (SER)[57] beginning in 2014 (the first full year of substation operations).[58]

Q. Why is this credit unreasonable?

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[54] BVES workpaper, Vol 6 Chap 2 Marg Cost April 5 2012e.xls, tab BVPP 2013, cell F3.
[55] BVES workpaper, Vol 6 Chap 2 Marg Cost April 5 2012e.xls, tab BVPP 2013, cell F21.
[56] BVES response to Snow Summit discovery request 2 Q49. See Attachment K.
[57] See Chapter V for a complete assessment of BVES's proposed SER.
[58] BVES response to Snow Summit discovery request 5 Q4a. See Attachment L.

A. I have several objections to this credit. My primary objections are:

1. As discussed below, Snow Summit disagrees with BVES's proposal for an SER that includes a subsidy from Snow Summit to all other ratepayers, so the premise for the credit is unsound.[59]

2. The link between incremental power sales to Snow Summit under the SER and operations of the BVPP is tenuous at best, since the vast majority of BVES's supply that would serve Snow Summit's supplemental load would come from market purchases and not the BVPP. BVES's workpapers show only 44 MWh of energy usage from BVPP in 2014 (at a cost of just $3,849),[60] while the supplemental sales agreement is expected to lead to incremental sales of more than 10,000 MWh in that year.[61] It is unreasonable to apply a $350,000 per year revenue credit against BVPP costs on account of added margin from the supplemental energy sale when the supplemental sale is for the most part unrelated to BVPP operations.

3. BVES is projecting that the BVPP will not generate any power in the test year.[62] It is not reasonable to take a $350,000 credit based on BVPP sales if BVES assumes that the BVPP will not generate in the Test Year.

[59] The credit is based on the amount of the subsidy from Snow Summit to other customers.
[60] BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8c Supply Base+Sale, cells P259 and P281.
[61] BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8d SS Supplemental Sale, cell I10
[62] BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8c Supply Base+Sale, cell P181.

4. BVES based the revenue credit on anticipated margin from sales to Snow Summit under the SER beginning in 2014. Sales under the SER in 2013 (and, accordingly, margin from these sales) are projected at only about 36% of the sales expected in 2014.[63] Potential added margin in 2014 that is not anticipated in 2013 should not be incorporated into the test year forecast.

In summary, while there may be theoretical support for netting out energy value from a plant's capital costs to determine the capacity value for a plant, this is not what BVES is doing here. BVES will realize no added margin if BVES provides Snow Summit's incremental power requirements pursuant to a cost-based tariff. Further, the "energy value" that BVES nets out will not be realized at all in 2013 (since BVES does not expect the BVPP to run in that year) and is about 250 times greater than the energy value that BVES expects to be realized from BVPP in 2014.[64]

Q. What do you recommend?

A. The basis for this credit is severely flawed. The credit should therefore be removed in its entirety from the marginal cost calculation.

[63] BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8d Snow Summit Supplemental Sale, cells C12:D12.
[64] 249= 10,925 MWh of supplemental sales in 2014 / 43.66 MWh of BVPP generation in 2014 – 1.

iii. O&M Costs should be incorporated in the generation demand-related costs

Q. Why did BVES omit O&M costs from generation demand-related costs?

A. In response to a Snow Summit data request, BVES explained that "Zero demand-related O&M is included in the generation demand-related costs since it is assumed that any O&M costs are already incorporated into the $3.1 million revenue credit found in the BVPP 2013 tab."[65]

Q. If these O&M costs have already been incorporated into the analysis, why is it reasonable to add them in again?

A. Despite the data response cited above, in response to a follow-up data request asking how much O&M costs were incorporated in the $3.1 million revenue credit, BVES stated, "There are no O&M costs in the $3.1 million."[66] Thus, it appears that O&M costs were incorrectly omitted from the analysis.

Q. Have you estimated the amount of O&M costs to add in?

A. Yes. I calculated $30.44 per kW-year in demand-related generation O&M costs based on the marginal cost of generation O&M shown in BVES's workpapers.[67] This O&M cost should be added in to Table 2.5 of Volume 6 and the associated tab of BVES's marginal cost model.[68]

[65] BVES response to Snow Summit discovery request 2 Q50. See Attachment K.
[66] BVES response to data request Snow Summit discovery request 5 Q5. See Attachment L.
[67] BVES workpaper, Vol 6 Chap 2 Marg Cost April 5 2012e.xls, tab #21 Total O&M (3), rows 136-142.
[68] BVES workpaper, Vol 6 Chap 2 Marg Cost April 5 2012e.xls, tab T4 pg 2 (7), cell F24.

iv. **REC Adder Value Should be Corrected**

Q. What value did BVES use for a REC adder in its marginal cost study?

A. BVES used a REC adder of $0.00584 per kWh as part of its marginal energy cost study.

Q. Is this REC adder correct?

A. No. BVES's workpaper shows BVES's anticipated REC expense in 2013 to be $0.00301 per kWh.[69] This is the correct value to use in its marginal cost study.

Q. Why do you believe that the value BVES used is incorrect?

A. BVES included in its value $1.8 million in REC "make-up costs" associated with meeting past REC obligations from 2010 through 2012.[70]

Q. Why is it inappropriate to include make-up costs from 2010-2012 in the REC value?

A. The marginal energy cost study should evaluate the incremental cost to serve an additional unit of load.[71] New load coming onto BVES's system should not incur REC costs based on BVES's decision not to meet its RPS obligations in prior

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[69] BVES workpaper, Balancing Accounts 1-25-2012 4pm EWRIGHT with SS #5 annotations.xlsx, tab SUP BA 2013, cell Q43. Workpaper provided in response to Snow Summit discovery request 5 Q1. See Attachment L.

[70] BVES did not acquire sufficient renewable energy to meet its obligations in 2010-2012 under California's Renewable Portfolio Standard. BVES assumes that the cost of meeting its past obligations is $1.8 million. See BVES workpaper, Balancing Accounts 1-25-2012 4pm EWRIGHT with SS #5 annotations.xlsx, tab SUP BA 2012, row 37 (including comments). See also BVES response to Snow Summit discovery request 5 Q1b. See Attachment L.

[71] D.96-04-050, page 17 (*quoting* D.92549 and D.93887).

years. It is therefore inappropriate to include the make-up costs for past REC under-procurement in the marginal cost study. BVES's projected 2013 REC expense of $0.00301 per kWh should be used as the REC adder in place of the higher value that includes make-up costs.

B. Revised Marginal Costs

Q. Have you calculated marginal cost results correcting the four errors discussed above?

A. Yes. My forecast of revenues at marginal costs consistent with the discussion above is shown in Table 5. BVES's results are also provided for comparison.

Table 5: Revenue at Marginal Costs (Excluding Supplemental Sales Agreement)

	Snow Summit Results		**BVES Results**	
	Total Marginal Cost	Share of Total	Total Marginal Cost	Share of Total
Res Perm	$14,441,455	36.6%	$13,732,214	36.0%
Res Seas	$10,679,699	27.1%	$10,263,226	26.9%
Residential Total	**$25,121,154**	**63.7%**	**$23,995,440**	**62.9%**
A-1	$4,707,018	11.9%	$4,512,752	11.8%
A-2	$3,082,307	7.8%	$2,961,920	7.8%
A-3	$3,079,849	7.8%	$2,952,535	7.7%
A-4 TOU	$1,957,833	5.0%	$1,869,134	4.9%
Total Commercial	**$12,827,008**	**32.5%**	**$12,296,340**	**32.3%**
A-5 TOU Secondary	$203,891	0.5%	$226,503	0.6%
A-5 TOU Primary	$1,186,984	3.0%	$1,503,186	3.9%
Total Large Power	**$1,390,875**	**3.5%**	**$1,729,689**	**4.5%**
Streetlights	**$107,892**	**0.3%**	**$105,564**	**0.3%**
TOTAL SYSTEM	$38,855,080	100.0%	$38,127,033	100.0%

IV. BVES Should Move More Substantially Towards a Marginal Cost-Based Revenue Allocation

Q. Please describe BVES's revenue allocation proposal.

A. BVES requests an overall 2013 revenue requirement increase of $4.01 million (9.85%), with $860,000 of this increase coming from sources other than regular electric bills.[72] Removing these non-rate components yields an average rate increase of 7.79%.[73] BVES anticipates a subsequent 5.5% reduction in average rates in September 2014 when the Purchased Power Adjustment Clause (PPAC) under-collection has been paid off,[74] reducing the increase relative to current rates to 1.9%.[75] To allocate these revenue increases among customer classes, BVES performed a marginal cost study and calculated the Equal Percentage of Marginal Cost ("EPMC") for each customer class. BVES proposes to allocate the requested rate increase based primarily on the current revenue allocation structure with a movement of 10% toward revenue allocation based on Equal Percentage of Marginal Cost (EPMC).[76] BVES proposes to allocate the projected September 2014 rate decrease on an equal cent per kWh basis.[77]

Q. Why has BVES proposed to use marginal costs to derive its revenue allocation in this proceeding?

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[72] BVES Testimony Volume 1, page 4.
[73] BVES Testimony Volume 1, page 4.
[74] BVES Testimony Volume 1, page 5.
[75] (1+0.0779)*(1-.055)-1=1.9%.
[76] BVES Testimony Volume 1-Supplement, page 3.
[77] BVES response to Snow Summit discovery request 4 Q9. See Attachment M.

A. In its last GRC, BVES's testimony showed that many different customer classes, including A-5 TOU Primary customers (i.e., Snow Summit and Bear Mountain) had been providing a sizable subsidy to permanent residential customers.[78] While Snow Summit, Inc. argued that this level of subsidy was inequitable and that BVES should begin a substantial movement towards a marginal cost-based revenue allocation, a settlement between BVES and DRA in that case maintained the *status quo* revenue allocation structure, and BVES continued to subsidize permanent residential customers (e.g., A-5 TOU Primary accounts continued to pay 37% above their cost of service to fund their share of this subsidy.)[79] However, in approving the settlement, the Commission noted that it expected movement toward marginal cost-based revenue allocation in the instant proceeding.[80]

Q. Did the Commission make other findings in that decision that bear on this issue?

A. Yes. While approving an 18% revenue increase in the Test Year, the Commission was unwilling to approve Snow Summit, Inc.'s revenue allocation proposal that would have increased rates slightly more for permanent residential customers because "revenue allocations under the EPMC that result in increases above 20% for certain customers '[do] not represent a reasonable balancing of our ratemaking

[78] BVES Testimony in A.08-06-034, Volume 6 Part I, Table 3-1, page 18. See Attachment N.
[79] Overcharge calculated based on BVES's marginal cost results in BVES's last GRC. BVES Testimony in A.08-06-034, Volume 6 Part I, Table 3-1, page 18, and D.09-10-028, pages 1 and 6. See Attachment N.
[80] D.09-10-028, page 7, FN 13.

goals.'"[81] Thus, in the last BVES GRC, the Commission held that more than a 20% increase in rates would be unreasonable.

Q. Why has BVES proposed a movement of only 10% towards full EPMC?

A. In the current application, BVES states that the Commission "has made use of EMPC a primary goal,"[82] albeit a goal that cannot always be fully attained in a single proceeding given large rate impacts to certain customer classes. BVES believes that its proposed 10% movement toward EPMC-based revenue allocation "provides a reasonable balance of fairness and rate stability."[83]

Q. Do you agree with BVES that a 10% movement towards EPMC-based revenue allocation provides a reasonable balance of fairness and rate stability?

A. No. Such a small movement towards EPMC unfairly requires other customers to continue to provide permanent residential customers with substantial subsidies.

Q. Did BVES use the Commission's 20% rate increase benchmark from the decision in its last GRC in determining the appropriate movement towards EPMC in this case?

A. It does not appear that BVES did. BVES presented in its testimony a revenue allocation scenario representing 25% movement toward EPMC. According to

[81] BVES Testimony, Volume 6, page 2, citing D.09-10-028, pages 6-9.
[82] D.09-10-028, October 15, 2009, page 6.
[83] BVES Testimony, Volume 6, page 4.

BVES's calculations, this scenario would result in a 16% increase for residential customers and an 18% increase for A-5 TOU Secondary customers, with smaller increases for all other customer classes.[84] Even though these increases are below the 20% benchmark, BVES rejected this scenario in favor of its proposed 10% movement towards EPMC.

Q. Under BVES's proposal, what is the impact on Snow Summit, Inc.?

A. BVES's proposal in this case would charge A-5 TOU Primary accounts 26% above their cost of service according to BVES's own calculations (i.e., about $550,000 per year).[85] However, I believe that this significantly understates the impact on Snow Summit, Inc.'s accounts taking service under Schedule A-5 TOU Primary.

Q. What is your estimate of the subsidy that Snow Summit, Inc. provides to other customers?

A. As noted above, there are several major errors in BVES's marginal cost study. Correcting for the errors reveals that A-5 TOU Primary customers are subsidizing residential customers to a much greater extent than BVES has acknowledged. Using BVES's proposed 10% movement towards marginal cost-based revenue allocation, I estimate that A-5 TOU Primary customers would still be paying nearly 50% about their cost of service, even after BVES's proposed movement

[84] BVES Testimony, Chapter 6, page 5.
[85] BVES Workpaper A5 Rate Design 3-20-2012.xlsx. Tab #2 EPMC, cells (N44+G44)/(K44+G44) – 1 and cells N44-K44.

toward EPMC-based allocation. This extraordinary and continuing subsidy would cost Snow Summit, Inc. nearly $900,000 in 2013 alone.

Q. Does this $900,000 payment above Snow Summit, Inc.'s cost-of-service incorporate the share-the-savings component of BVES's proposed SER proposal?

A. No. BVES has also proposed that Snow Summit, Inc. should provide $331,000 in subsidies to other customers under its SER proposal for supplemental power sales.[86] When combined with the $900,000 in subsidies resulting from BVES's revenue allocation proposal, Snow Summit, Inc. would pay a subsidy of $1.23 million to all other customers.

Q. Why should the Commission modify BVES's revenue allocation proposal?

A. There are several reasons for modifying BVES's revenue allocation proposal:

1. The proposal is inconsistent with Commission policy, as it is unduly discriminatory to certain customer classes and would continue the substantial subsidization of the permanent residential customer class.
2. The proposal would have severe economic impacts on commercial customers and the Big Bear Lake region.
3. The proposal fails to take advantage of the special opportunity available during this GRC period to make substantial movement towards marginal

[86] BVES response to Snow Summit discovery request 5 Q4a. See Attachment L.

cost-based rates at much reduced impact to permanent residential customers.

I discuss each of these points in more detail below.

A. BVES's revenue allocation proposal is inconsistent with Commission policy

Q. Is BVES's revenue allocation proposal consistent with Commission policy?

A. No. Commission policy has consistently supported the allocation of revenues among customer classes on the basis of EPMC. For instance in Decision 96-04-050, the Commission stated:

> Rates which promote the most conservation, efficiency and equity must ultimately be based on marginal costs. The result of basing rates on marginal costs is that the rate equals the cost of producing one more unit, or the savings from producing one less unit. In this way each consumer pays the resource cost (additional cost of the added quantity) of additional consumption, or saves the resource cost when consumption is reduced.
>
> Conservation is achieved since consumption is made only when the benefits of consumption are greater than or equal to the cost (i.e., there is no 'wasteful' use). Efficiency is achieved since the least cost combination of resource neither overuses the good (which would occur if its price is below marginal cost) nor under-uses the good (which would occur if the price is over the marginal cost).
>
> Finally, equity is achieved since no customer underpays or overpays relative to the resource cost (e.g., consumers choosing solar or insulation are not treated inequitably since they save the resource cost from their lack of consumption and the non-solar or non-insulation electric customers pay the resource cost for their choice to consume).[87]

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[87] D.96-04-050, page 17-18 (*quoting* D.92549 and D.93887).

The Commission has reinforced this policy repeatedly. For example, the State's Energy Action Plan made the goal of adopting rates "based on clear cost-causation principles" the first of its Key Actions pertaining to Electricity Market Structure.[88] A 2008 decision reiterates:

> Promoting economically efficient decision-making is the primary policy objective that can be achieved through rate design. A rate that promotes economic efficiency is one that charges a customer based on the marginal cost of providing the customer one more or one less unit of energy—in other words, a rate based on marginal cost. The Commission has had a long standing policy of adopting marginal cost-based rates.[89]

This decision further notes that "rates based on marginal cost will simultaneously achieve economic efficiency and equity by ensuring that customers' rates are commensurate with the costs they cause."[90]

In the recently-issued order instituting a new rulemaking on residential rate design issues, the Commission again emphasized that "developing equitable rates based on the principle of cost causation is one of the underlying goals of the Commission's rate making process" and noted that "avoiding cross-subsidies and supporting cost-causation principles 'achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.'"[91]

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[88] Energy Action Plan II, adopted October 2005, page 9. See Attachment O.
[89] D.08-07-045, pages 43-44.
[90] D.08-07-045, page 46.
[91] Order Instituting Rulemaking On The Commission's Own Motion To Conduct A Comprehensive Examination Of Investor Owned Electric Utilities' Residential Rate Structures, The Transition To Time Varying And Dynamic Rates, And Other Statutory Obligations, R.12-06-013, June 21, 2012, page 13. See Attachment P.

Q. Isn't mitigation of overly burdensome rate increases also Commission policy?

A. Yes. In cases where the application of an EPMC-based revenue allocation would be "unduly detrimental" to a particular customer class, the Commission has approved modified allocation measures that mitigate large rate increases.[92] However, in taking such action the Commission has stated that it does "not subjugate [its] primary ratemaking goal [of use of marginal costs for ratemaking] in order to address these issues."[93]

Q. What do you conclude from this?

A. Because BVES's revenue allocation proposal would allocate revenue requirements based 90% on the current allocation ("system average percent" or "SAP") and 10% based on marginal costs, BVES's revenue allocation proposal is inconsistent with Commission policy.

Q. Would BVES's proposed revenue allocation discriminate among customer classes?

A. Yes, as demonstrated in BVES's marginal cost study, residential customers[94] are currently being subsidized by all other customer classes, and this subsidy would

[92] D.96-04-050, page 19.
[93] D.96-04-050, page 21.
[94] Further, permanent residential customers are being subsidized while seasonal residential customers are not.

continue under BVES's proposed revenue allocation.[95] Given the magnitude of this subsidy, BVES's proposed revenue allocation does not fairly allocate costs among different customers but instead would continue undue discrimination between customer classes in rate relationships.

Q. What is the impact on each customer class of using your proposed approach for revenue allocation and your recommended marginal costs?

A. Table 6 shows the percentage change in revenue responsibility for each customer class in test year 2013 under both BVES's proposed approach and a 100% EPMC-based revenue allocation approach, based on my recommended marginal costs (excluding the Supplemental Sales Agreement). As Table 6 demonstrates, under the 100% EPMC revenue allocation approach, seasonal residential customers, large commercial customers, A-5 TOU Primary customers, and streetlighting customers would be entitled to a <u>decrease</u> in their revenue responsibility relative to their cost responsibility under present rates. In contrast, BVES's proposed 90%-SAP approach would <u>increase</u> the revenue responsibility for each of these customer classes.

These results show that, if adopted by the Commission, BVES's proposed approach would result in nearly all of BVES's customer classes continuing to

[95] BVES Workpaper A5 Rate Design 3-20-2012.xlsx. Tab #2 EPMC. Under BVES's marginal cost results, the unsubsidized revenue increase for permanent residential customers would be $4.7 M (cell K35); under BVES's proposal, the revenue increase would be just $1.2 M (cell N35). Other customers would support this $3.5 M subsidy via a revenue increase of $2.0 M (N48-N35) in place of a revenue decrease of $1.5 M (K48-K35).

provide a significant subsidy to the permanent residential customer class. BVES's approach would also create a subsidy for the A-5 TOU Secondary customer class, which consists of a single customer, the Big Bear Area Regional Wastewater Agency (BBARWA).

Table 6: Rate Changes Under BVES Proposal and Under Marginal Cost Revenue Allocation Approach (Snow Summit Marginal Cost Study)

	BVES Proposed Rate Increase (90% SAP Allocation)[96]	Rate Increase with Marginal Cost (100% EPMC) Allocation[97]
Residential (Perm.)	13%	47%
Residential (Seas.)	9%	(3%)
Total Residential	**11%**	**21%**
A-1 (Small Com.)	9%	7%
A-2 (Med. Com.)	9%	4%
A-3 (Large Com.)	7%	(12%)
A-4 (Large Com.)	8%	(7%)
Total Commercial	**8%**	**(1%)**
A-5 TOU Secondary	11%	36%
A-5 TOU Primary	5%	(30%)
Total Large Power	**5%**	**(26%)**
Streetlights	**9%**	**(6%)**
TOTAL SYSTEM	9%	9%

Source: Snow Summit calculation

Q. Have you been able to quantify the magnitude of these subsidies?

A. Based on the Snow Summit marginal cost results, under a 100%-EPMC approach, permanent residential customers would be responsible for $15.9 million of

[96] Cells O35:O48.
[97] Cells K35:K48 divided by cells G35:G48.

BVES's proposed revenue requirement, and BBARWA would be responsible for $230,000. In contrast, under a 90%-SAP approach, permanent residential customers would be responsible for only $12.2 million, and BBARWA would be responsible for only $188,000 (see Table 7). In other words, under BVES's proposal permanent residential customers would pay $3.7 million (23%) less than their marginal cost-based revenue responsibility, and BBARWA would pay $42,000 (18%) less than its marginal cost-based responsibility. On the other hand, large commercial customers would be responsible for 20% more than their marginal cost allocations, A5 TOU Primary customers would be responsible for 49% more than their marginal cost allocations, and streetlight accounts would be responsible for 16% more than their marginal cost allocations.

Table 7: Cross-Subsidization in BVES's Proposed 90%-SAP Revenue Allocation

	100% Marginal Cost (EPMC) Allocation	BVES Allocation Proposal [90% SAP]	Difference between BVES and EPMC Allocations	BVES Proposal as a percent of EPMC Allocation
	[A]	[B]	[B]-[A]	[B]/[A]
Residential (Perm.)	$15,931	$12,191	($3,741)	77%
Residential (Seas.)	$11,592	$13,015	$1,422	112%
Total Residential	**$27,523**	**$25,205**	**($2,318)**	**92%**
A-1 (Small Com.)	$5,285	$5,413	$128	102%
A-2 (Med. Com.)	$3,506	$3,659	$152	104%
A-3 (Large Com.)	$3,563	$4,369	$806	123%
A-4 (Lrg. Com.)	$2,245	$2,612	$367	116%
Total Commercial	**$14,599**	**$16,052**	**$1,453**	**110%**
A-5 TOU Secondary	$230	$188	($42)	82%
A-5 TOU Primary	$1,810	$2,700	$889	149%
Total Large Power	**$2,040**	**$2,888**	**$847**	**142%**
Streetlights	**$110**	**$128**	**$18**	**116%**
TOTAL SYSTEM	$44,273	$44,273	$0	100%

Source: Snow Summit calculation

B. BVES's revenue allocation proposal would have significant adverse impacts on the regional economy

Q. How would BVES's proposed revenue allocation impact the regional Big Bear Lake economy?

A. BVES's proposed revenue allocation would place a large burden on the economy of the Big Bear Lake region, since many businesses would likely be forced to pass along increased electricity costs to their customers. This would discourage economic activity in the area, and the resulting revenue loss would also result in a loss of local taxes paid by these businesses.

Q. How would an increase in electricity costs for Snow Summit and Bear Mountain affect the regional Big Bear Lake economy?

A. The rate increase proposed by BVES would increase Snow Summit, Inc.'s electricity costs by about $120,000 annually.[98] This increase, which comes on top of a $500,000 per year increase from BVES's last GRC,[99] would further reduce the funds available for infrastructure development at the resort, which in time would reduce the ability of Bear Mountain and Snow Summit to compete against other ski resorts.

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98 BVES Workpaper A5 Rate Design 3-20-2012.xlsx. Tab #2 EPMC, cell N44.

99 BVES Testimony in A.08-06-034, Volume 6 Part 1, Table 3-1 on page 18 ($2.76 million for A5 Primary in Current Rate Revenue Plus SAP, which was adopted by the Commission in D.09-10-028, compared with $2.25 million Revenue Current Rates). See Attachment N.

Essentially, Snow Summit, Inc. would have two main alternatives to avoid this consequence. First, it could reduce its electricity usage in order to offset the large rate increase. However, this would be detrimental to the resorts, since the bulk of the resorts' electricity usage is for snowmaking, which is a critical necessity for Snow Summit, Bear Mountain, and many other ski resorts. Any significant reduction in electricity usage would come at a cost of reduced snowmaking and quality of product. Second, Snow Summit, Inc. could try to pass on the electric cost increase to customers. However, as prices are currently set at their market value, a price increase would likely result in a loss of business volume that could have a serious financial impact on the company. Under either option, a large electric rate increase for Bear Mountain and Snow Summit would likely result in the loss of visitors to the resorts.

The impact of a loss of visitors to the resorts would be felt throughout the Big Bear Lake area because Snow Summit and Bear Mountain are significant sources of economic activity in the region. The resorts directly pump millions of dollars a year into the regional economy. For example, in fiscal year 2008 alone, the resorts paid $14.1 million in payroll, purchased $5.5 million in local services and supplies, and paid $1.2 million in county and local fees and taxes.[100]

Reduced skier visits at Snow Summit and Bear Mountain would likely have an even greater indirect impact on the tourist-based winter economy of the Big Bear

[100] Data provided by Snow Summit, Inc. See Attachment Q.

Lake region. All of the area's businesses that depend upon winter visitations, such as lodges, restaurants, shops, and gas stations, would feel the effects of a decline in the skier visit volume at the resorts. The lost income of these businesses would in turn negatively affect the non-tourist portions of the local economy, such as professional services, hardware stores, retail, and government services.

C. Solution: Phase in greater movement toward marginal cost-based revenue allocation

Q. What is Snow Summit's recommendation?

A. Snow Summit recommends that the Commission adopt a revenue allocation that moves BVES substantially closer to a marginal cost-based revenue allocation while at the same time mitigates significant rate increases to the degree possible. The following section discusses this proposal.

Q. Do you believe revenue allocation should be based solely on EPMC considerations in this case?

A. Not in this particular case. As seen in Table 6 above, an EPMC-based revenue allocation would result in more than a 40% increase in revenue responsibility for permanent residential customers in 2013. Notwithstanding the clear efficiency and equity benefits of an EPMC approach, I recognize that such a large rate increase would be problematic. Accordingly, I agree that it is appropriate to phase in movement toward an EPMC-based revenue allocation for BVES to avoid rate shock. This phase-in would move BVES substantially closer to an EPMC-based revenue allocation over a series of years.

Q. Why do you believe that the phase-in should begin with this GRC?

A. This phase-in should begin as soon as possible given the inequity of continuing to require Snow Summit, Inc. and other customers to pay costs significantly in excess of their cost of service in order to provide subsidies to permanent residential customers. In addition, this GRC presents an unusual opportunity for making substantial progress towards an EPMC-based revenue allocation at a reduced bill impact to permanent residential customers.

Q. Please describe the opportunity.

A. As noted above, BVES anticipates a 5.5% reduction in average rates in September 2014 when the PPAC under-collection has been paid off.[101] At this point, the Supply Adjustment rate will be set to zero.[102] BVES proposes to reduce rates on an equal cents per kWh basis, which, under BVES's proposal, would reduce rates for most customers by $0.01729 per kWh.[103] This would result in a rate reduction for permanent residential customers of more than 6%.[104]

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[101] BVES Testimony Volume 1, page 4.
[102] BVES response to Snow Summit discovery request 4 Q9. See Attachment M.
[103] Based on BVES's proposed tariffs. The proposed Supply Adjustment rate for low-income residents and for BVES employees is lower than for other customers, BVES Testimony Volume 6, pages 45-47.
[104] Calculated based on BVES's proposed Supply Adjustment rates for permanent residential customers, for permanent residential low-income customers, and for BVES employees in 2013 and the respective load forecasts for these customer groups. This result holds true under both the BVES and Snow Summit marginal results.

Instead of reducing residential rates that are already well below their cost of service, the Commission could use this reduction in revenue requirement as an opportunity to make substantial progress towards establishing EPMC-based rates for BVES with little bill impact on the permanent residential customers.

Q. What is your revenue allocation proposal?

A. I propose a two-step process. First, on the effective date of the decision in this proceeding, I propose a revenue allocation that is based 25% on EPMC and 75% on SAP. Second, on the date that BVES fully amortizes the Supply Adjustment charge (anticipated in September 2014), the Commission should bring revenue responsibility an additional 25% closer to an EPMC-based revenue allocation by moving to a revenue allocation based 50% on EPMC and 50% on SAP.[105] Together, these changes would bring revenue allocation 50% closer to an EPMC-based revenue allocation.

Q. How would your proposal affect revenue responsibility for the various customer classes in 2013?

A. Under my proposed allocation, if BVES were granted its requested revenue increase, revenue responsibility in 2013 would increase for all customer classes (see Table 8). Revenue responsibility would increase most for permanent residential customers (18%) and for BBARWA (16%); however, these increases would be much lower than their increases under the 100% EPMC approach (i.e.,

[105] This additional 25% shift is calculated with respect to current rates (not proposed 2013 rates).

47% for permanent residential customers and 36% for BBARWA). In other words, the permanent residential customer class and BBARWA would continue to be heavily subsidized by other customer classes.

Table 8: Maximum 2013 Rate Increase under Proposed Allocation Scenarios[106]

	Rate Increase with Marginal Cost Allocation [100% EPMC]	Rate Increase Under BVES Proposal [10% EPMC]	Rate Increase Under Snow Summit Proposal [25% EPMC]
Residential (Perm.)	47%	13%	18%
Residential (Seas.)	-3%	9%	7%
Total Residential	**21%**	**11%**	**12%**
A-1 (Small Com.)	7%	9%	9%
A-2 (Med. Com.)	4%	9%	8%
A-3 (Large Com.)	-12%	7%	4%
A-4 (Lrg. Com.)	-7%	8%	5%
Total Commercial	**-1%**	**8%**	**7%**
A-5 TOU Secondary	36%	11%	16%
A-5 TOU Primary	-30%	5%	-1%
Total Large Power	**-26%**	**5%**	**0%**
Streetlights	**-6%**	**9%**	**6%**
TOTAL SYSTEM	*9%*	*9%*	*9%*

However, if the Commission granted BVES less than its requested revenue requirement increase in this proceeding, the 2013 rate increase for residential customers and for BBARWA would be proportionately lower. For example, under

[106] Based on Snow Summit's marginal cost results. Using BVES's marginal cost results, the 2013 increase for permanent residential customers would be 16% and for BBARWA would be 18%.

a system-wide average rate increase of 5%, the 2013 rate increase under my proposal would be 10% for permanent residential customers and 8% for BBARWA.

Q. How would your proposal affect revenue responsibility for the various customer classes after BVES eliminates its Supply Adjustment charge in 2014?

A. Table 9 presents these results. This table also presents BVES's proposed rate changes at the time of the Supply Adjustment rate elimination.

Table 9: Rate Change under Proposed Allocation Scenarios upon Elimination of the Supply Adjustment Rate (around September 2014)

	Rate Change Under BVES Proposal [10% EPMC for entire GRC period]	Rate Change Under Snow Summit Proposal [25% EPMC in 2013; 50% EPMC in Sept. 2014]
Residential (Perm.)	-6%	2%
Residential (Seas.)	-4%	-7%
Total Residential	**-5%**	**-3%**
A-1 (Small Com.)	-5%	-6%
A-2 (Med. Com.)	-5%	-7%
A-3 (Large Com.)	-5%	-10%
A-4 (Lrg. Com.)	-5%	-9%
Total Commercial	**-5%**	**-8%**
A-5 TOU Secondary	-7%	0%
A-5 TOU Primary	-8%	-18%
Total Large Power	**-8%**	**-17%**
Streetlights	**-3%**	**-7%**
TOTAL SYSTEM	*-5%*	*-5%*

As shown in the table, under BVES's proposal, permanent residential customers and BBARWA would receive rate reductions of 6% and 7%, respectively at the time of the elimination of the Supply Adjustment charge. Given that these customers are being heavily subsidized by other customer classes, these large rate reductions (which come at the cost of reduced rate reductions for the subsidizing customers) are inappropriate. Under my proposal, permanent residential customers would see a modest 2% rate increase, and BBARWA would receive a reduction of 0.5%.

Q. Is your proposal consistent with the 20% rate increase benchmark the Commission imposed in the last BVES GRC?

A. I believe so. As shown in Table 8, no customer class would be given a rate increase above 20% in 2013 under my proposal, even if BVES were granted its entire proposed increase in its revenue requirements. Midway through the GRC period, there would be further rate increases for permanent residential customers. If BVES were granted its entire revenue increase, the cumulative increase for these customers (compared to present rates) would be 21% for permanent residential customers and 15% for BBARWA. However, with a reduction to BVES's revenue requirement proposal, it is likely that the overall increase for both customer classes would remain below 20%. For example, adopting Snow Summit's ROE proposal would reduce the cumulative increase to permanent residential customers to 18%.

Q. Why is this allocation preferable to BVES's proposed revenue allocation?

A. Snow Summit's proposal balances the Commission's goals of relying on marginal costs for ratemaking and avoiding rate shock. This compromise begins the movement toward a marginal cost-based revenue allocation for BVES. Also, this proposal would help the fragile Big Bear Lake economy.

Q. Under your proposal for substation costs to be recovered from A-5 TOU Primary customers on a cost-of-service basis, how would these costs be incorporated into the revenue allocation?

A. I recommend that these costs be directly assigned to A-5 TOU Primary customers separate from the overall revenue allocation. This is a standard method for addressing costs that are directly attributable only to a specific customer class, as Southern California Edison explained in its most recent GRC Phase II application:[107]

> Whereas allocated distribution revenues are spread to all customer groups based on distribution marginal cost, non-allocated revenues are assigned directly to particular rate groups and are intended to recover the cost of equipment or services that are incurred solely for the benefit of that rate group. Non-allocated revenues consist primarily of street lighting facilities' costs and power factor adjustment revenues. SCE assigns these revenues directly to the specific rate groups responsible for incurring the costs.

The costs associated with the substation should similarly be considered non-allocated costs and assigned directly to A-5 TOU Primary customers.

Q. When should these costs be first assigned?

[107] Southern California Edison. SCE-03 in A.11-06-007, June 6, 2007, page 18. See Attachment R.

A. The costs should first be assigned on January 1 of the year following the substation's in-service date.

Q. Are there any precedents for incorporating a conditional future revenue requirement increase into a rate case?

A. Yes. This was done, for instance, in PG&E's Gas Accord V settlement. The settling parties identified eight "Adder projects" and set a capital expenditure cap on each one. The settlement explains, "An Adder project is a capital project that will be included in rates only if the project is actually built and only starting on the January 1 following the project's in-service date."[108] I recommend that this structure be used also in this case: if the substation is completed during this rate case cycle, the actual costs associated with the substation should be incorporated into A-5 TOU Primary rates on January 1 of the year following the project's in-service date (consistent with the standard ratemaking treatment for capital additions).

Q. Would you oppose incorporating project costs into the Test Year revenue requirement on a *pro rata* basis by assuming the substation goes into service on October 2013?

A. Yes. Significant steps remain before the proposed project could become a reality, including an agreement between Snow Summit and BVES, Commission approval of this agreement, and project construction. The project completion date cannot be

[108] Gas Accord V Settlement Agreement in the Pacific Gas & Electric Company 2011 Gas Transmission & Storage Rate Case, A.09-09-013, August 20, 2010, page 8. See Attachment S.

well-estimated at this time, nor can it be predicted with reasonable certainty whether or not the project will even be completed. Based on BVES's projections, the revenue requirement associated with this project (if charged on a cost-of service basis) could add more than $400,000 per year to the A-5 TOU Primary revenue requirement, which is a 16% increase in costs compared to the current A-5 TOU Primary revenue requirement. It would not be appropriate to impose on ratepayers such a significant rate increase for a project that may not be completed or may not be completed for a number of years. It would also not be reasonable to assess A-5 TOU Primary customers for the cost of facilities that are not used and useful. For those reasons, I recommend that the Commission only allow BVES to include substation costs in rates after the project is completed.

V. The Commission Should Not Adopt BVES's Non-Cost-Based Proposal to Increase Service To Snow Summit or, In the Alternative, Order BVES to Provide Cost-Based Service

A. BVES's Proposal

Q. Please describe BVES's substation and Supplemental Energy Rate (SER) proposal.

A. BVES describes its proposal as follows:

> BVES requests authority to provide…supplemental service to [Snow Summit] only under a new share-the-savings tariff referred to as the Supplemental Energy Rate (SER), combined with a new Added Facilities rate and new Added Facilities Agreement….The SER is designed to generate sufficient revenue to cover all of BVES' costs and provide savings to [Snow Summit] by avoiding the current practice of operating onsite diesel generators to operate its snowmaking equipment. In addition, BVES designed the SER to provide a financial benefit to BVES' other customers. Since the SER is indexed to the price of natural gas it is designed to recover all the marginal costs of providing this enhanced service.[109]

The "financial benefit" that BVES intends to provide for customers other than Snow Summit would be derived from "an additional margin that would reduce the amount of revenue increase needed in the test year from all other customers." [110]

Q. Please describe BVES's proposed Added Facilities Charge (AFC) as it applies to Snow Summit.

A. Under BVES's proposed AFC, BVES would install the agreed-upon substation allowing it to serve supplemental load at Snow Summit. Snow Summit would be

[109] BVES Testimony, Volume 3A, page 1.
[110] BVES Testimony, Volume 3A, page 4.

responsible for paying monthly costs for the facility in perpetuity in order to cover operations and maintenance costs, administrative and general costs, franchise fees and uncollectibles, ad valorem tax, and other expenses associated with the facility.[111] Charges under the AFC would also cover capital costs, rate of return, and depreciation.[112]

Q. Why has BVES argued that the new SER and AFC are necessary for it to provide supplemental service to Snow Summit?

A. BVES claims that "[u]se of the A-5 TOU rate for supplemental sales would result in unwarranted benefits to [Snow Summit] and unreasonable cost shifts to residential and other BVES customers."[113] In other words, BVES claims that the SER rate is necessary to avoid other customers subsidizing Snow Summit's electric service.

BVES further claims that its proposed AFC "is necessary because this new higher and customized level of supplemental service being requested was never contemplated when the existing A-5 TOU rate was developed" and that the projected 9% load factor would make it impossible to recover the costs of the expanded substation under the existing A-5 TOU rates.[114]

Q. Is the SER a cost-based rate?

[111] BVES Testimony, Volume 6, pages 99-100.
[112] BVES Testimony, Volume 6, page 100.
[113] BVES Testimony, Volume 3A, page 1.
[114] BVES Testimony, Volume 3A, page 4.

A. No. BVES specifically designed the rate to provide a subsidy of at least $331,000 from Snow Summit to other customers. In fact, the proposal not only provides an explicit subsidy, it also has provisions to ensure that the subsidy is no less than expected. In other words, the $331,000 subsidy from Snow Summit to other customers is possibly understated by BVES in its application.

Q. Has BVES explored any cost-based alternatives to the SER?

A. BVES states that it has considered the SER and a vaguely defined "A-5 TOU variant." BVES claims it is open to alternative methods that provide similar benefits to Snow Summit and non-participating customers but does not discuss any other attempts at developing a cost-based rate for new Snow Summit load.[115]

Q. Please describe how BVES would determine the price of energy under its proposed SER.

A. BVES would set a daily energy price, which would normally be its initial electricity price of $0.115 per kWh multiplied by its daily gas index, which would be set at 1.00 as of November 1, 2013.[116] This rate would be subject to price floors under "exceptional" conditions, including 1) high load conditions, 2) the unavailability of the Bear Valley Power Plant, and 3) volatile grid pricing where BVES must acquire power from the market to serve SER load.[117] Under certain conditions, the price floor would be as high as 150% of the maximum California

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[115] BVES Testimony, Volume 3A, page 6.
[116] BVES Testimony Volume 6, pages 50-51.
[117] BVES Testimony Volume 6, page 50.

Independent System Operator (CAISO) Locational Marginal Price (LMP) at the Southern California Edison default load aggregation point (DLAP) for the previous 24 hours.[118]

Q. Please describe Snow Summit's obligations under the SER.

A. Each day from November through March, Snow Summit would be required to notify BVES of its forecasted daily use by 7:30 AM. Prior to this, at 7:00 AM, BVES would notify Snow Summit of the amount of usage allowed under normal and exceptional pricing conditions, along with the energy prices themselves.[119] Thus, Snow Summit would have thirty minutes each morning to determine its operations for the next 24-hour period, subject to the pricing set by BVES.

B. Consideration of the SER is premature because BVES and Snow Summit have no agreement regarding supplemental service

Q. Have Snow Summit and BVES engaged in discussions about the possibility that BVES might serve the load currently served by Snow Summit's generation?

A. Yes. Without violating client confidence, I can say that Snow Summit and BVES have discussed having BVES expand the existing Summit substation to provide service for all of Snow Summit's loads.

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[118] BVES Testimony Volume 6, pages 54-55 and BVES response to Snow Summit discovery request 2 Q37 See Attachment K.

[119] BVES Testimony Volume 6, page 59.

Q. If BVES were to serve Snow Summit's snowmaking loads, would Snow Summit retire its generating system?

A. I understand that Snow Summit would continue to own and maintain its diesel-fired generating facilities. Snow Summit would also continue to own and maintain its electric distribution system.

Q. Do BVES and Snow Summit have any agreement regarding BVES providing incremental service to Snow Summit's snowmaking loads?

A. As far as I know, there is no such agreement. However, it is clear that BVES has not presented such an agreement to the Commission as part of this GRC.

Q. Given that there is no agreement for BVES to provide service to Snow Summit's snowmaking loads, what do you recommend?

A. The Commission should not adopt BVES's proposal regarding the Supplemental Energy Rate and Added Facilities Charge as it relates to Snow Summit. Consideration of BVES's proposal is premature. If Snow Summit and BVES are able to reach an agreement to have BVES supply Snow Summit's snowmaking loads, then BVES <u>may</u> need to file an application with the Commission for approval of that agreement. On the other hand, an application to the Commission may not be needed if BVES serves Snow Summit's load pursuant to BVES's existing tariffs (e.g., the A-5-TOU tariff).

C. Service under the A-5 TOU Primary tariff would not harm other ratepayers or subsidize Snow Summit

Q. Have you evaluated BVES's claim that using the A-5 TOU tariff for the supplemental sales in place of the SER would results in "unwarranted benefits to Snow Summit and unreasonable costs shifts to residential and other BVES customers"?[120]

A. Yes. I have evaluated BVES's claim and have found it to be unfounded.

Q. Would serving the supplemental sales under the A-5 TOU Primary tariff provide unwarranted benefits to Snow Summit?

A. No. Snow Summit, Inc.'s accounts are the only accounts taking service under BVES's A-5 TOU Primary tariff. By serving the supplemental sales under the A-5 TOU Primary tariff, Snow Summit, Inc. would be paying for the entire cost of the substation as well as all costs incurred to provide energy for these supplemental sales. These charges would be assessed on a cost-of-service basis, consistent with Commission ratemaking practices. Snow Summit, Inc. would not be benefiting from any sort of special deal; it would be paying for its full cost of service.

Q. Would serving the supplemental sales under the A-5 TOU Primary tariff result in unreasonable costs shifts to residential and other BVES customers?

[120] BVES Testimony, Volume 3A, page 1.

A. No. If the full substation revenue requirement were charged directly to A-5 TOU Primary customers (as I proposed above), no other customer would be harmed by these incremental costs. Snow Summit, Inc. would pay for them in full. In fact, other customers would benefit from the new substation because the increased Snow Summit load would reduce their share of fixed costs for other generation and distribution facilities.

D. BVES's proposed SER is inconsistent with State policy and hopelessly flawed

Q. Do you have other concerns about BVES's proposal?

A. Yes. The proposed rate is inconsistent with existing Commission and State policy, it provides unfair and unnecessary subsidies to other customers, and it establishes a dangerous precedent by allowing a utility to arbitrarily assign costs to individual customers. Finally, the proposal itself is ill-conceived, unduly burdensome on Snow Summit, and overly complex. If the Commission does choose to address the supplemental sales issue in this proceeding, using existing tariffs (e.g., A-5 TOU Primary) is the superior approach for establishing a rate for BVES's supplemental sales to Snow Summit. I discuss each of these topics below.

i. The SER is inconsistent with Commission and State policy

Q. Are you aware of any rates with other utilities similar to BVES's proposed SER?

A. No.

Q. Has BVES provided any Commission precedent to justify its proposed SER?

A. BVES stated that it "does not possess any examples of 'share-the-savings' agreements similar to the Supplemental Energy Rate…" BVES added that it is "generally aware of alternative rates approved by the Commission" and referenced Southern California Edison (SCE) Rate Schedule TOU-8-CR-1, an SCE Spot Pricing Amendment to its Contract for Services, and an SCE Incremental Sales Rate Agreement.[121]

Q. Are the SCE tariff and agreements cited by BVES in its discovery response substantially similar to BVES's proposed SER?

A. No. Based on my review of these documents, they do not appear to incorporate an explicit subsidy to all other SCE customers, as BVES is proposing to do in its SER. Furthermore, BVES itself acknowledges that these alternative rate examples are not similar to BVES's proposed SER.[122]

Q. Does Commission or other State policy support BVES's proposed SER?

A. No. As discussed in the marginal cost section above, Commission precedent and other State policy documents specifically support marginal cost-based ratemaking. The Commission has stated:

[121] BVES response to Snow Summit discovery request 2 Q1. See Attachment K.
[122] BVES response to Snow Summit discovery request 2 Q1. See Attachment K.

> [R]ates which promote the most conservation, efficiency and equity must ultimately be based on marginal costs. The result of basing rates on marginal costs is that the rate equals the cost of producing one more unit, or the savings from producing one less unit. In this way each consumer pays the resource cost (additional cost of the added quantity) of additional consumption, or saves the resource cost when consumption is reduced.[123]

In addition, California's Energy Action Plan made the goal of adopting rates "based on clear cost-causation principles" the first of its Key Actions pertaining to Electricity Market Structure.[124]

Q. Is there adequate policy precedent for the Commission to rely on to support the SER proposal?

A. No. The tariffs that BVES cites are not similar enough to the SER proposal to provide precedential support, and the proposal is in direct contradiction to State policy as outlined in the Energy Action Plan.

ii. The SER is not cost-based and provides explicit subsidies to other customers

Q. What is the "share-the-savings" concept proposed by BVES?

A. In addition to paying its full cost of service associated with serving Snow Summit's supplemental load, BVES is proposing that Snow Summit subsidize other customers' electric service.[125] BVES has stated clearly that the added "margin" (i.e., the subsidy built into the SER) it has proposed including in the

[123] D.96-04-050, pages 17-18 (*quoting* D.92549 and D.93887).
[124] Energy Action Plan II, adopted October 2005, page 9. See Attachment O.
[125] BVES Testimony, Volume 3A, page 4.

SER is above and beyond anything related to BVES's cost to serve Snow Summit's supplemental load.[126]

Q. Why does BVES claim it is necessary for Snow Summit to subsidize other customers through the SER rate?

A. BVES states that "[t]he SER is designed to exceed the marginal cost of providing the energy required in snow making by a margin over cost. The margin is designed to provide benefits for all other customers providing an assurance that other customers will not subsidize Snow Summit's incremental usage."[127]

Q. Is this consistent with cost-of-service ratemaking?

A. No. BVES's proposal flies in the face of cost-of-service ratemaking as supported by this Commission. To obtain service, BVES is requiring Snow Summit to pay an amount that is substantially greater than the full cost of its electricity supply.

Q. How much is this overcharge?

A. BVES forecasts that Snow Summit would pay an average of $331,000 per year above BVES's costs to provide the supplemental energy service in the years 2013-2016.[128] BVES states that this added margin would result in an additional

[126] BVES Testimony, Volume 3A, page 7.
[127] BVES Testimony, Volume 3A, page 7.
[128] BVES Testimony, Volume 3A, page 5, Table 6.1.

charge of $27 per MWh, resulting in a 34% increase relative to BVES's estimated delivered cost of grid power of $80 per MWh.[129]

Q. Does BVES provide any rationale for why the expected overcharge of $331,000 per year is the "right" amount?

A. No. The amount appears to be completely arbitrary.

Q. BVES states that the $331,000 expected overcharge will "offset the revenue requirement required to support the investment and operation proposed in this Special Request."[130] Is this characterization accurate?

A. No. In addition to the SER, BVES has proposed that Snow Summit pay for the full substation investment and operations costs through the AFC. Requiring Snow Summit to pay for these costs again through the SER would be a duplicative charge. Moreover, BVES does not tie the $331,000 amount to any valid portion of BVES's costs associated with serving Snow Summit's supplemental load. This overcharge is simply the difference between BVES's estimated revenues from Snow Summit under the SER and BVES's cost of providing service under the SER.[131]

Q. If the $331,000 overcharge is not paying for the cost of Snow Summit's added facilities or supplemental energy purchases, what is it paying for?

[129] BVES Testimony, Volume 3A, page 10.
[130] BVES Testimony, Volume 3A, page 6.
[131] BVES Testimony, Volume 3A, page 5, Table 6.1.

A. BVES states that "other customers will benefit from this added margin through a reduced revenue requirement."[132] In other words, this money will offset (i.e., subsidize) the revenue requirements associated with other customers' cost of service.

Q. Aside from the direct subsidy they would receive from Snow Summit, would BVES customers derive other benefits if Snow Summit purchases power from BVES for its snowmaking activities?

A. Yes. BVES states that the proposed additional service to Snow Summit would benefit all BVES customers by improving air quality for everyone in the Big Bear area as a result of burning less diesel fuel in Snow Summit's existing diesel generators.[133] Also, additional sales to Snow Summit would allow BVES's fixed costs to be amortized over a greater sales base, which should reduce rates for all customers. This benefit would be captured in cost-of-service ratemaking. In addition, as discussed above, the Big Bear Lake region could benefit economically if Snow Summit can reduce its operating costs and offer its services at lower prices.

Q. Is BVES providing Snow Summit with equal treatment relative to other customers under its proposed SER?

A. No. BVES's SER proposal goes to great lengths to protect other customers, but is content to overcharge Snow Summit for its electric service. BVES makes its

[132] BVES Testimony, Volume 3A, page 10.
[133] BVES Testimony, Volume 3A, page 1.

intentions clear in attempting to justify its use of a price floor in the SER, stating that it needs "the price security of the price floor being set by the maximum price from the previous day to assure that the cost of providing the service would be recovered and also the margin in the SER designed to benefit the other rate payers in the share the savings concept would need to be sustained."[134] BVES seeks to provide every assurance that customers other than Snow Summit receive a subsidy, while asserting that it is reasonable for Snow Summit to pay much more than the cost BVES incurs when it serves Snow Summit's supplemental load.

iii. If adopted, BVES's proposal could establish a dangerous precedent for ratemaking at the Commission

Q. What would be an outcome if the Commission adopts BVES's proposal?

A. In adopting BVES's proposal, the Commission would be endorsing rates based on the unilateral assignment of costs by a utility to a particular customer (or set of customers) above that customer's cost of service.

Q. Is this reasonable policy?

A. No. If adopted by the Commission, this would endorse BVES's approach of picking specific winners and losers in ratemaking.

Q. Why do you say that BVES's SER proposal picks winners and losers?

[134] BVES response to Snow Summit discovery request 2 Q39. See Attachment K.

A. BVES is very clear in stating that Snow Summit should pay more than its cost of service in order to subsidize the service of other customers.[135] Thus, Snow Summit's loss is a gain for all other customers.

Q. What do you recommend?

A. While the Commission has to make decisions that can result in certain customers benefiting and other customers being harmed, those decisions are rightfully made based on ratemaking policy and principles, not on the utility's selection of winners and losers. For this reason, the Commission should not adopt BVES's arbitrary allocation of revenues through its SER proposal.

iv. The SER is inconsistent with past practices, ill-conceived, unduly burdensome on Snow Summit, and overly complex

Q. Aside from your policy concerns with BVES's SER proposal, are there other problems with the proposal?

A. Yes. BVES's proposal is contrary to past actions by BVES in similar circumstances, is based on outdated assumptions, places extraordinary burdens on Snow Summit and transfers significant market risk to Snow Summit (which is less able to bear the risk than BVES). I discuss each of these concerns below.

a) BVES did not propose a SER-type rate under similar circumstances in the past

[135] BVES Testimony, Volume 3A, page 10.

Q. Has BVES faced a similar request for a significant increase in load in the past?

A. Yes. In 1989, Bear Mountain installed a snowmaking system.[136] That snowmaking system increased the connected load at Bear Mountain significantly.

Q. What was BVES's response to Bear Mountain's proposed increase in connected load?

A. BVES took several steps to accommodate Bear Mountain's request. Most significantly, BVES constructed the Bear Mountain substation, which allowed Bear Mountain to install its snowmaking facilities, resulting in a significant increase in Bear Mountain's load served by BVES.

Q. What kind of ratemaking treatment did BVES propose related to this service upgrade?

A. BVES proposed to recover the costs of this service upgrade through its general rates under a cost-of-service based rate. BVES did not propose a SER, an AFC, or any of the measures that BVES has proposed for the analogous increase in Snow Summit's demand on the BVES system. Notably, BVES did not propose that Bear Mountain provide explicit subsidies to all other BVES customers.

Q. Did BVES claim that providing service to Bear Mountain would result in a subsidy from other ratepayers to Bear Mountain?

[136] At the time that Bear Mountain installed its snowmaking facilities, it was not affiliated with Snow Summit.

A. No.

Q. Is Snow Summit's current request similar to that made in the past by Bear Mountain?

A. Yes. Both ski resorts were being served by BVES prior to their request for an increase in connected load. Both resorts were taking service under existing standard BVES tariffs. The only significant difference between the two cases is that BVES might be in a better position to serve the Snow Summit supplemental load than it was to serve Bear Mountain's load.

Q. Why might BVES be in a better position to serve Snow Summit's load?

A. Since Bear Mountain made its request for increased service, BVES has increased its supply options by (1) increasing its transfer capability with Southern California Edison and (2) building the Bear Valley Power Plant.

Q. What do you conclude?

A. BVES has extensive seller's market power over customers in the BVES service territory, and BVES appears to be trying to exert this market power over Snow Summit through the SER. Under completely analogous circumstances for service to Bear Mountain, BVES did not request such rate treatment. Therefore, in this situation, Snow Summit should receive incremental service under cost-based rates.

b) The power price forecasts used in calculating costs under BVES's proposed SER are based on outdated data and faulty assumptions

Q. What does BVES use as its electricity and natural gas price forecasts in calculating costs under the proposed SER?

A. BVES uses natural gas and electricity price forecasts developed by ICF International. These forecasts incorporate historical data only through 2010.[137] Given the significant reduction in natural gas and electricity prices since 2010, these forecasts no longer reflect current market conditions.[138]

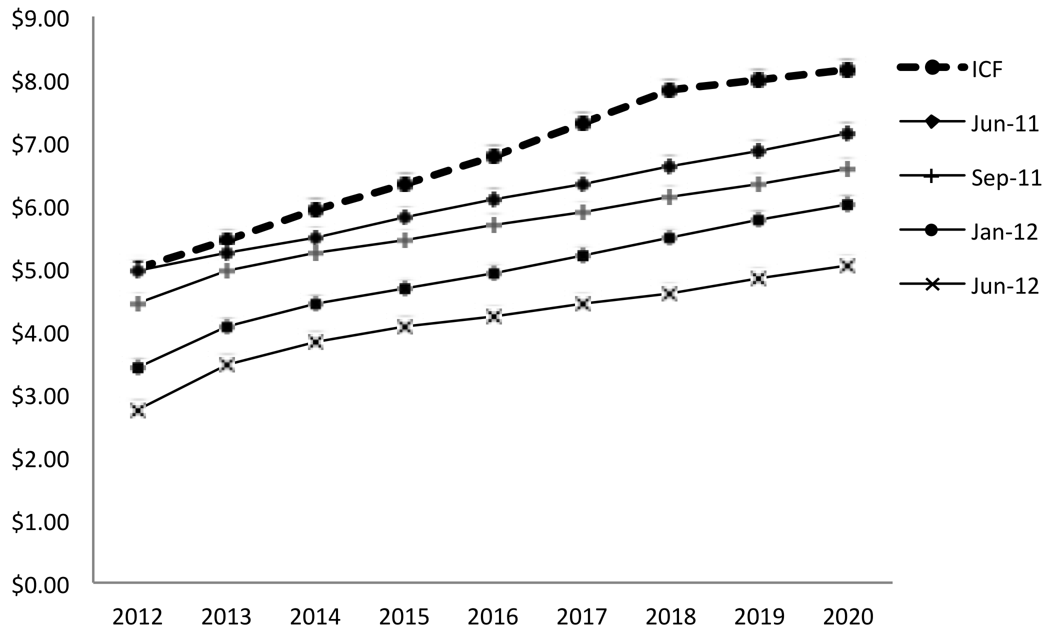
Q. What is the current outlook for natural gas futures and how have futures price changed over the last year?

A. NYMEX Henry Hub natural gas futures prices have declined considerably over the last year. This is seen in Figure 1, which presents the current and historic futures prices as well as ICF International's price forecast.

[137] "ICF Base Case Energy Price Projections for the SP-15 Power Market – Preliminary Draft," Attachment 1, pages 1-2. Provided as an attachment to BVES Response to Snow Summit discovery request 5 Q3. (BVES reports that it did not receive a final version of the memo.) See Attachment J.

[138] I provide further discussion of ICF's forecast in Chapter III of this testimony regarding marginal costs.

Figure 1: NYMEX Henry Hub Natural Gas Futures Prices, $ per MMBtu



Q. Are BVES's forecasts reasonable?

A. No. As seen in Figure 1, ICF's natural gas prices (which are used by BVES in its power price forecast) are significantly higher than current market expectations. Given that natural gas prices are a key driver of power prices, this calls into question the reasonableness of the entire BVES forecast. Indeed, BVES's power price forecast overestimated prices in the first forecast year (i.e., 2011) by 12%. Market prices have continued to fall since 2011, so the forecast error is likely to be even greater going forward.

Q. What is the result of BVES's reliance on ICF's forecast?

A. BVES has likely overestimated its procurement costs for the SER by a large amount by using these outdated forecasts. This, in turn, would result in under-estimating the amount of the subsidy paid by Snow Summit under the SER.

Q. Have you developed a revised power price forecast?

A. Yes. As described above in Chapter III of this testimony regarding marginal costs, I provide a new power price forecast based on updated natural gas futures prices.

Q. What do you recommend?

A. If the Commission chooses to take action on the substation proposal and adopts an energy rate for the supplemental sales to Snow Summit agreement that is different than the A-5 TOU Primary tariff, the SER should at the very least be based on a reasonable forecast of power prices, such as those presented in my marginal cost testimony.

c) BVES's proposed daily load and rate determination process for the SER would be onerous and burdensome for Snow Summit

Q. What steps would Snow Summit be required to perform each morning in order to take service under BVES's proposed SER?

A. As described above, Snow Summit would have no more than 30 minutes each morning to forecast its operations for the subsequent 24-hour period. Given this limited decision-making time, Snow Summit would have to expend considerable effort preparing operational contingencies for potential exceptional pricing situations and would have less flexibility in operating its business than if it took service under the A-5 TOU Primary tariff.

Q. Are exceptional pricing conditions expected to arise frequently?

A. Yes. BVES states that exceptional pricing "may occur as often as 40% of the time during the winter snow-making season."[139] Snow Summit, therefore, would face considerable uncertainty regarding the pricing and capacity availability to serve its loads on any given day during its peak operating season.

Q. What are the factors that influence the ability of Snow Summit to make snow?

A. The main factor (aside from the price of electricity) is ambient temperature. I understand that if ambient temperature is too high, then it is not possible to make snow.

Q. Since the SER is meant to supply energy for Snow Summit's snowmaking operations, how would Snow Summit plan its snowmaking operations under BVES's proposed SER?

A. Snow Summit would need to obtain a temperature forecast as close to 7 a.m. as possible and then base its estimated snowmaking activities on that forecast. It is important to note that much of the snowmaking occurs in the late afternoon or night, meaning that there would be significant uncertainty in Snow Summit's ability to make snow, given the uncertainty in temperatures 12-15 hours later in the day when the snowmaking activity would typically start.

[139] BVES Testimony, Volume 6, page 55.

Q. Under the SER, what would happen if Snow Summit committed to making snow in the morning but found that it was not possible to make snow in the afternoon or evening?

A. Snow Summit would likely be charged a penalty if it was unable to make snow.

Q. What might be the penalties?

A. The penalties under the SER would be $0.04 per kWh for all usage that deviated from the forecast usage by 10 MWh or more.[140] For example, in the event that Snow Summit planned to use its entire supplemental service capacity of 11 MW for four hours of snowmaking, it could be charged a penalty of $1,360 for the energy that it was unable to use during that time period.[141]

Q. Would there be similar risks if Snow Summit were to decide to make snow on a day when it had not planned to do so?

A. Yes. Snow Summit has a limited number of days in which it can make snow. If the actual ambient temperatures are lower than expected but Snow Summit forecasted that it would not be able to make snow, then Snow Summit would pay significant penalties to BVES for using more power than planned.

Q. How might the risks associated with the SER affect Snow Summit?

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[140] BVES Testimony, Volume 6, page 53.
[141] Assuming 11 MW planned snowmaking demand for 4 hours of the day (11 MW * 4 hours = 44 MWh); 44 MWh less 10 MWh penalty threshold equals 34 MWh, and the $0.04/kWh penalty charge applied to 34 MWh equals $1,360 ($0.04*34*1000 = $1,360).

A. At a minimum, Snow Summit would need to develop new risk management procedures to manage these potentially large costs of using more or less energy than anticipated due to daily weather fluctuations. I expect that Snow Summit would find itself with decreased flexibility in snowmaking operations, increased costs of operations, and/or lost revenue as a result of the SER's penalty charge structure.

Q. What do you conclude?

A. BVES's proposal would likely impose significant risks and costs on Snow Summit that are not faced by its competitors. These risks include both price risks related to the variable nature of the energy charges under BVES's proposal and risks related to BVES's proposed penalty charges. In addition, Snow Summit could face substantial direct and indirect costs as a result of the SER. Employee time and effort would be required simply to comply with the daily procedures BVES has proposed as part of the SER, and further employee time and effort may be required to modify Snow Summit's operations and internal decision making as a result of the proposed SER's structure and penalty provisions.

d) BVES's proposed SER forces Snow Summit to assume nearly all of the short-term price risk associated with BVES's procurement, and it does so through an inappropriate mechanism

Q. How does BVES propose to procure resources to serve any additional Snow Summit load?

A. BVES states that it "has two options for obtaining energy to service [Snow Summit's] load, namely it can buy from the CAISO or generate the power itself. BVES's first priority is to use the least-expense source, which is normally purchased power over the transmission grid as opposed to [Bear Valley Power Plant] power."[142]

Q. Why does BVES claim that the SER should be indexed to natural gas prices?

A. BVES makes two arguments. First, BVES states that "the SER supply charge should move consistently with energy costs at the margin."[143] More specifically, BVES states that "[t]his expectation that the SER will be equal to the gas-indexed price is due to the fact that gas prices directly affect the price of electricity purchased in the day-ahead market and even the LMP market; therefore, both gas and electric prices tend to move concomitantly."[144]

Second, BVES argues that the SER should be indexed to natural gas prices because the marginal source of energy for the SER "will be the BVPP most of the time," and the BVPP marginal cost is driven by the cost of natural gas.[145] BVES then states that the BVPP "is required to some degree to supply the SER."[146]

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[142] BVES Testimony, Volume 3A, page 8.
[143] BVES Testimony, Volume 3A, page 7.
[144] BVES Testimony, Volume 6, page 55.
[145] BVES response to Snow Summit discovery request 2 Q26. See Attachment K.
[146] BVES response to Snow Summit discovery request 2 Q26. See Attachment K.

Q. Is it reasonable to assume that the SER should be indexed to natural gas prices because the BVPP will serve load under the SER?

A. No. First, BVES's statement in response to Snow Summit's data request regarding the use of the BVPP to serve SER load directly conflicts with BVES's other testimony. BVES's testimony refers to the need to index the SER to the cost of market electricity, while its data request response refers to the need to index the SER to the marginal cost of the BVPP.

Second, BVES has not justified its assumption that the BVPP would be required to serve SER load or indicated how much of the SER load the BVPP would serve. BVES states that the BVPP would serve the SER load both "most of the time" and "to some degree." BVES has not explained why the BVPP would provide energy service at all when market power is cheaper, and why, if the BVPP must operate for reasons related to system reliability, those costs should not be allocated in part to other customers.[147]

Third, BVES's Results of Operations (RO) model indicates that BVES expects to run the BVPP only minimally even after Snow Summit starts to take service under the SER, with a total production of just 44 MWh in all of 2014.[148] This represents just 0.4% of the expected incremental sales from the substation in that

[147] The SER is an interruptible tariff (see BVES Testimony Volume 6, pages 56 and 61). Thus, it should have little or no impact on the ability to serve other customers' loads and, as a result, should not affect system reliability.
[148] BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8c Supply Base+Sale, cell P259.

year,[149] implying that 99.6% of the power for the incremental sales will come from market purchases. It is unreasonable to structure the SER based on assumed power production from BVPP when nearly all of the power is expected to originate from market purchases.

Q. Is BVES's proposed natural gas price index likely to cause the SER to move consistently with the market price of electricity?

A. No. BVES's proposed SER tariff states that its natural gas price index will be based on a 30-day rolling average of spot natural gas prices at SoCal Citygates plus transportation costs charged by Southwest Gas, which yields the delivered cost of gas to the BVPP.[150] Thus BVES is attempting to index the SER to the cost of natural gas delivered to its own power plant, when it clearly states that purchasing power from the Southern California wholesale electric market is likely to be its least-cost and therefore preferred electricity supply option.

Market data from recent years indicates that factors other than natural gas prices are important in determining wholesale power prices. For example, in the months in which the SER would be in effect,[151] average SP-15 power prices in 2010 increased by 5% while average Southern California natural gas prices increased by 16%. During these same months in 2011, SP-15 prices decreased by 24%

[149] 0.4% = 44 MWh from BVPP / Expected 10,925.3 MWh in 2014 generation supply under the supplemental sale. BVES Workpaper, MASTER RO MODEL 2013 GRC 2-6-2012, Tab#8d SS Supplemental Sale, cell I9

[150] BVES Testimony, Volume 6, pages 60-61.

[151] BVES states that the SER would be used "to provide service during the winter months of November through March…." BVES Testimony, Volume 6, page 49.

while natural gas prices decreased by only 19%.[152] The variability in the relationship between power and natural gas prices observed even over this two-year period indicates that additional factors beyond natural gas price movements are important in determining power prices (e.g., hydroelectric power conditions, electric demand.)[153] Given the day-to-day accuracy BVES is seeking with regard to its energy prices by implementing a daily price index, it is unreasonable to overlook the shortcomings of an index tied exclusively to natural gas prices in considering short-term power market price movements.

Q. How would BVES's proposed natural gas price index affect Snow Summit?

A. Under recent market conditions, an index based exclusively on natural gas prices would unfairly harm Snow Summit. As illustrated above, in each of the last two years, SP-15 power prices decreased at a faster rate than natural gas prices during the months that the SER would be in effect. Since there is no mechanism in BVES's daily price calculation to adjust for an accelerated price decrease, Snow Summit would have paid an excessive price that did not reflect BVES's cost for power purchased from the market.

Q. Does BVES propose any other mechanisms to manage the SER rate?

[152] Based on Platts SP-15 power and SoCal Gas natural gas daily spot market prices.

[153] Both relatively high hydro production and relatively low market demand could result in less gas-fired production being sold into the market. In either case, the implied market heat rate for the marginal generating unit would be lower than if all power sold in the market were gas-fired, thus resulting in a lower power price at the same gas price.

A. Yes. BVES has proposed allowing for its gas-indexed "normal pricing" to become the floor in the SER rate "to help ensure that the SER rate covers costs."[154] This would occur under BVES's proposed exceptional conditions pricing mechanism, which would result in the SER being set based on the higher of the normal SER energy price or the previous day's CAISO LMP.[155]

Q. BVES's exceptional pricing mechanism includes a second, high price volatility condition under which a 150% factor would be applied to the previous day's CAISO LMP for purposes of determining the daily energy rate. Why does BVES claim that this is necessary?

A. BVES states that "[t]he SER rate does not have a balancing account to offset the price spikes with the price drops as is the case for the other rates" and that "[t]he risk of the price going up…leaves Bear Valley Electric Service uncomfortable with stating an SER rate for the following day based only on the previous day prices with out any risk protection."[156]

Q. How does BVES propose to mitigate this alleged risk?

A. BVES adds a 50% surcharge on top of the prior day's price under these conditions.

[154] BVES Testimony, Volume 3A, page 7.
[155] BVES Testimony, Volume 6, page 60.
[156] BVES response to Snow Summit discovery request 2 Q45. See Attachment K.

Q. What are Snow Summit's options for purchasing energy under the SER when this second exceptional pricing condition is in effect?

A. According to BVES "[t]he customer can choose not to take service that day or Bear Valley Electric can require the 150% premium on the previous day's price…."[157]

Q. What is the net effect of BVES's proposed SER pricing mechanisms?

A. Under BVES's proposal, Snow Summit would bear nearly all of the risk associated with unexpectedly high prices and would be limited in how much it would benefit from unexpectedly low prices. Snow Summit could potentially benefit from declining natural gas prices, but would not benefit from other market conditions resulting in low power prices. Even if wholesale power prices fell well below the level that BVES charged Snow Summit, Snow Summit would have no opportunity for refund.

In addition, the second exceptional pricing condition in particular would force Snow Summit to accept considerable risk, given the fact that it would face a choice between not operating or paying a large premium to do so when this pricing condition is in effect. However, there would once again be no potential benefit to Snow Summit for accepting this risk in place of BVES.

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[157] BVES response to Snow Summit discovery request 2 Q45. See Attachment K.

As a result, under both "normal" and "exceptional" pricing conditions, the SER would require Snow Summit to bear a disproportionate and unreasonable amount of the market price risk associated with its energy purchases.

E. Recommendation: Allow Snow Summit to take service under its otherwise applicable tariff

Q. Given the problems you have identified with BVES's proposed SER, what do you recommend?

A. If the Commission chooses to address in this proceeding the potential sale of power to Snow Summit to serve its snowmaking loads, then I recommend that the Commission allow Snow Summit to take this supplemental service under its otherwise applicable tariff (A-5 TOU Primary). This is consistent with the approach that BVES used when Bear Mountain installed snowmaking and would not harm other BVES customers. It would provide a cost-based rate for Snow Summit's snowmaking, which is consistent with State and Commission policy. It would assign risks of power procurement to the entity best able to bear that risk (i.e., BVES). And it would not open the door to other potentially abusive cost shifting proposals by utilities.

VI. Conclusion

Q. Please summarize your recommendations.

A. My primary recommendations are as follows:

- BVES's Return on Equity should be set at 8.39%.

- The Commission should order BVES to correct errors in its marginal cost study and to use the corrected marginal costs in its ratemaking proposals.
- The Commission should adopt my proposals regarding revenue allocation, including:
  - Revenue allocation should move 25% towards a marginal cost-based allocation on the effective date of the Commission's decision in this proceeding, and
  - Revenue allocation should move an additional 25% towards a marginal cost-based allocation when BVES's rates are reduced to reflect the final payoff of the Purchased Power Adjustment Clause undercollection.
- The Commission should reject BVES's non-cost-based proposal to increase service to Snow Summit.

Q. Does this conclude your testimony?

A. Yes.