

Docket No. A.26-01-022

Exhibit No. _____

Date August 12, 2026 (Errata, August 17, 2026)

Witness William A. Monsen

**DIRECT TESTIMONY OF WILLIAM A. MONSEN
REGARDING MARGINAL COSTS AND REVENUE ALLOCATION
ON BEHALF OF SNOW SUMMIT LLC
IN BEAR VALLEY ELECTRIC SERVICE'S GENERAL RATE CASE
APPLICATION 26-01-022**

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2 **REGARING MARGINAL COSTS AND REVENUE ALLOCATION**
3 **ON BEHALF OF SNOW SUMMIT LLC**
4 **IN BEAR VALLEY ELECTRIC SERVICE'S GENERAL RATE CASE**
5 **APPLICATION 26-01-022**
6

7 **I. Introduction and Summary of Testimony**
8

9 **Q. Please state your name, position and business address.**

10 A. My name is William A. Monsen. I am a Principal Consultant at MRW & Associates,
11 LLC (MRW). My business address is 1736 Franklin Street, Suite 700, Oakland
12 California.

13
14 **Q. Are you the same William A. Monsen that previously submitted testimony in this**
15 **proceeding?**

16 A. Yes. I submitted testimony on behalf of Snow Summit LLC on July 27, 2026.¹ My
17 qualifications are presented in that testimony.

18
19 **Q. What are Snow Summit's interests in this phase of the proceeding?**

20 A. As a major energy user and single largest customer² on the Bear Valley Electric Service,
21 Inc. (BVES) system, Snow Summit is concerned about how various incorrect
22 assumptions in BVES's marginal cost study have resulted in an incorrect revenue
23 allocation.

¹ "Direct Testimony of William A. Monsen Regarding Results of Operations on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application 26-01-022," July 27, 2026 (Snow Summit RO Testimony).

² Snow Summit LLC (Snow Summit) operates two ski resorts: Snow Summit resort and Big Bear Mountain resort. In total, Snow Summit is BVES's entire A5 TOU Primary customer class.

1
2 **Q. What is the purpose of your testimony in this phase of the proceeding?**

3 A. The purpose of my testimony in this phase of the proceeding is to discuss BVES's
4 proposals regarding marginal costs and revenue allocation in this General Rate Case
5 (GRC) proceeding.³
6

7 **Q. Please summarize your recommendations and conclusions regarding BVES's**
8 **marginal costs and revenue allocation.**

9 A. In this testimony, Snow Summit presents the impacts of Snow Summit's recommended
10 changes to input assumptions and modeling conventions used by BVES to derive BVES's
11 proposed marginal costs and revenue allocations. In addition, Snow Summit corrects
12 errors in BVES's Marginal Cost of Service model (which is the basis for BVES's
13 marginal costs and revenue allocations). Snow Summit also points out inconsistencies in
14 BVES's Marginal Cost of Service model relative to BVES's testimony.
15

16 Snow Summit's Results of Operations (RO) testimony recommended changes to BVES's
17 load forecast for the A5 TOU Primary customer class. In summary, Snow Summit's

³ BVES served Volumes 1-5 of its opening testimony (regarding Results of Operations and other matters) with its application (Application (A.) 26-01-022) on January 30, 2026. BVES served Volume 6 on March 13, 2026. Volume 6 addresses BVES's proposals regarding marginal costs, revenue allocation, and rate design. BVES revised its Results of Operations because it was unable to proceed with a solar generating project that BVES had planned to come online in 2027. BVES revised the calculation of its Results of Operations on July 15, 2026, but did not serve updated testimony consistent with its revised Results of Operation. BVES provided Snow Summit with updated models for its Results of Operation on July 15, 2026. BVES's change in its assumptions underlying its Results of Operations resulted in changes to BVES's marginal costs and revenue allocation. BVES provided Snow Summit with updated models and results for the changes to marginal costs and revenue allocation on July 16, 2026. In this testimony, Snow Summit presents results based on BVES's revised models. Pursuant to a ruling by Administrative Law Judge (ALJ) Van Dyken dated July 22, 2026, Snow Summit submits this testimony related to its concerns regarding BVES's proposed marginal costs, revenue allocation and rate design. Unless otherwise indicated, BVES's testimony is referred to as "BVES Testimony" with an associated volume number.

1 recommended reductions in the load forecast for the A5 TOU Primary customer class are
2 reasonable because they are based on (1) the fact that BVES projects a significant
3 increase in loads for 2025-2030 during the non-snowmaking months of April-October
4 despite the fact that there have been no changes in equipment or operations at the Snow
5 Summit resort during those months and (2) the clear over-forecasting of loads in 2026 for
6 the A5 TOU Primary class during snowmaking months relative to actual loads.⁴
7

8 Application of Snow Summit's load forecast for the A5 TOU Primary customer to
9 BVES's Supply Model reduces BVES's Supply revenue requirements. Applying Snow
10 Summit's recommended load forecast to BVES's Marginal Cost of Service model results
11 in changes to unit marginal costs for Generation (both capacity and energy) and
12 Distribution (both coincident demand and non-coincident demand) as well as changes to
13 how those revised marginal costs are converted into BVES's marginal cost-based cost of
14 service, which is the basis for BVES's revenue allocation based on the Equal Percent of
15 Marginal Cost (EPMC) modeling approach.
16

17 Snow Summit also recommends revising other assumptions related to the development of
18 unit marginal Distribution demand costs for both coincident and non-coincident demand.
19 BVES improperly includes the costs of new substation and distribution facilities that
20 were constructed at the request of Snow Summit (and are paid for entirely by Snow
21 Summit through an Added Facilities Agreement) in the development of the unit marginal
22 Distribution costs for coincident and non-coincident demand. Customers other than Snow

⁴ The basis for and level of changes are fully described in Snow Summit's RO testimony.

Summit do not bear the cost of those new facilities and, as a result, those customer do not incur any marginal costs associated with those facilities. Snow Summit recommends excluding the cost of the plant additions for the Snow Summit substation and associated equipment from the calculation of the unit marginal Distribution demand costs for coincident and non-coincident demands.

Snow Summit is the only customer on the BVES system that has an interruptible tariff, meaning that Snow Summit can have its loads curtailed by BVES in cases of supply shortages. Because of this, BVES does not apply marginal Generation capacity costs to customers in the A5 TOU Primary customer class in its Marginal Cost of Service calculations. An analogous situation exists regarding marginal increases in distribution equipment based on marginal increases in loads. If the expected loads for the A5 TOU Primary class increase resulting in the need for transmission or distribution equipment, BVES could curtail Snow Summit load and avoid the need for such equipment upgrades. This is well-understood by the Commission. Snow Summit recommends a modest decrease of 5% in the unit marginal Distribution cost for coincident demand for the A5 TOU Primary class to reflect this benefit. Snow Summit also recognizes that this issue has been discussed for years by the larger utilities and, as a result, recommends that BVES establish a stakeholder process to explore this issue further.

Snow Summit's recommended changes result in a more reasonable revenue requirement estimate for BVES. In addition, they provide superior estimates of unit marginal costs and marginal cost-based revenue requirements, which serve as the basis of BVES's

1 EPMC-based revenue allocation proposal. Even though BVES's revenue allocation
2 proposal relies on only 10% of the EPMC-based revenue allocation, correct marginal
3 costs and a proper marginal cost-based revenue allocations promote the efficient use of
4 electricity. The Commission has found this in countless other proceedings, including in
5 past BVES GRCs.

6
7 **Q. How is your testimony organized?**

8 A. After this introduction and summary section, Chapter II summarizes the key points of
9 BVES's marginal cost and revenue allocation proposals in this proceeding. Next, Chapter
10 III identifies and proposes corrections to BVES's marginal cost study. Chapter IV
11 presents Snow Summit's proposed revenue allocation based on its recommendations
12 regarding marginal costs. Chapter V provides summary recommendations and
13 conclusions. Following the text of the testimony, there are several attachments that
14 present materials referred to in this testimony.

15
16 **Q. Does your testimony provide recommended changes to BVES's marginal costs and**
17 **revenue allocation based on your recommendations?**

18 A. Snow Summit presents approximate changes to BVES's marginal costs and revenue
19 allocation in this testimony. In addition, Snow Summit presents approximate changes to
20 BVES's Supply revenue requirements.

21
22 Snow Summit had intended to provide revised calculations of marginal costs and revenue
23 allocation pursuant to its recommendations summarized above. Snow Summit attempted

1 through discovery and informal meetings to obtain copies of the complete, functional
2 models used by BVES in the development of its testimony and recommendations;
3 obtaining those models likely would have allowed Snow Summit to do such analysis.
4 However, despite Snow Summit's efforts, it became clear that Snow Summit had not
5 received complete copies of the models used by BVES to develop its testimony. When
6 Snow Summit ultimately concluded that it would not be able to perform a full analysis of
7 revenue allocation based on Snow Summit's revenue requirements recommendations
8 presented in its prior testimony in this proceeding, Snow Summit requested that BVES
9 evaluate the impact of certain changes to sales forecasts and marginal distribution costs.⁵
10 BVES provided responses to those requests but following additional discovery, Snow
11 Summit found that BVES had not analyzed ALL impacts of the scenarios requested by
12 Snow Summit.⁶ As a result, Snow Summit is unable to provide precise revenue
13 requirements based on Snow Summit's recommendations.

14
15 **Q. Can you provide an example of this issue?**

16 A. Yes. BVES's Supply model has numerous values that are likely tied to loads, but the
17 Supply model does not include formulae for those calculations. Instead, that model has
18 "hard-coded" values. Thus, Snow Summit cannot provide the updated revenue allocations
19 based on the revenue requirements and marginal costs consistent with Snow Summit's
20 recommendations. As a result, this testimony will provide Snow Summit's
21 recommendations for changes to factors affecting BVES's marginal costs and

⁵ Snow Summit Data Request Set 8.

⁶ BVES Response to Snow Summit Data Request Set 11, Request 6.

1 approximate estimates of the impacts of changed assumptions on BVES's marginal costs
2 and revenue allocation.

3 **II. BVES's Marginal Cost and Revenue Allocation Proposals**

4
5 **Q. At a high level, please describe BVES's approach for determination of marginal**
6 **costs and revenue allocation in this proceeding.**

7 A. In this proceeding, BVES uses a two-part weighted-average approach to develop its
8 revenue allocation. The first part (the EPMC method) uses marginal costs for each
9 customer class to develop marginal cost-based revenues for 2027 and then allocates the
10 2027 total revenue requirement based on the percent of marginal cost-based revenues for
11 each class. The second part (the System Average Percent (SAP) method) applies the same
12 percentage increase for each customer class's current class-average rate for 2026 to
13 derive new class-average rates for 2027 and then multiplies those rates by forecasted
14 sales in 2027 for each class to arrive at class revenue responsibility.

15
16 **Q. Does BVES use the above approach for its entire revenue requirement?**

17 A, No. BVES applies the above approach separately for its Base revenue requirements and
18 for its Supply revenue requirements.⁷

19
20 **Q. What costs are included in the Base revenue requirements?**

⁷ BVES allocates Other Operating Revenues (OOR) to customer classes in its RO models and adds this to the revenue allocation developed using the 90/10 approach.

1 A. BVES includes its distribution revenue requirements (i.e., distribution demand
2 (coincident), distribution demand (non-coincident), and distribution (customer)) as well
3 as certain capacity-related supply costs in its Base revenue requirements.⁸
4

5 **Q. What costs are included in the Supply revenue requirements?**

6 A. BVES assigns the variable costs from the Supply model to the Supply revenue
7 requirements.
8

9 **Q. How does BVES derive the EPMC-based revenue allocation for Base revenue**
10 **requirements?**

11 A. BVES describes the process as follows: “The EPMC method is applied by functional cost
12 category. For example, demand-related distribution costs are allocated based on demand-
13 related class marginal costs, and customer-related distribution costs are allocated based
14 on customer-related class marginal costs.”⁹ Based on this approach, BVES claims that it
15 develops unit marginal costs for Generation (energy), Generation (capacity), Distribution
16 demand (coincident), Distribution demand (non-coincident), and Distribution (customer)
17 in its marginal cost of service (MCS) model and applies different determinants to each of
18 these unit marginal costs to develop marginal cost-based revenue requirements for each
19 of these components of the revenue requirements. These marginal cost-based revenue
20 requirements are then reconciled to equal the actual revenue requirement for each
21 component of the revenue requirement.
22

⁸ BVES MCS Model, tab “RO Inputs,” cells J1:J30.

⁹ BVES Testimony, Chapter 6, p. 15.

1 **Q. Does BVES in fact use the approach it described in its testimony to develop its**
2 **EPMC-based revenue allocation?**

3 A. No. Rather than developing actual revenue requirements for each component of its
4 revenue requirements, BVES improperly combines portions of costs of different
5 components. In addition, BVES improperly combines marginal cost-based revenue
6 requirements before reconciliation. In other words, BVES's implementation of its EPMC-
7 based revenue allocation is at odds with BVES's theoretical description of its approach.

8
9 **Q. Please explain.**

10 A. To develop its total revenue requirements by "component" BVES does the following:

- 11 • Distribution (customer): BVES derives this component of its revenue requirement in
12 its RO model.
- 13 • Other Operating Revenues: BVES derives this component of its revenue requirement
14 in its RO model.
- 15 • Generation: BVES uses the revenue requirements calculated in its Supply model.
- 16 • Distribution (demand): BVES derives this by subtraction. It takes the total revenue
17 requirements from its RO model and subtracts the revenue requirements for
18 Distribution (customer), Other Operating Revenues, and Generation and calls this
19 Distribution (demand). In practice, this component of BVES's revenue requirements
20 consists of Distribution (coincident), Distribution (non-coincident), and the fixed
21 Generation costs not captured in the Supply model. Thus, this component combines
22 both Distribution and certain Generation costs.

1 The following figure¹⁰ presents BVES's approach to developing its components of its
2 revenue requirements:

3

¹⁰ In order to avoid confusion, any tables taken directly from BVES testimony or workpapers will be called a "figure".

Figure 1: BVES Development of Components of Revenue Requirements

Revenue Requirements	2027	Revenue Requirements	Total	Customer [1] [2]	Demand
Revenue Requirements (Generation)	16372131.64	Rate Base			
Revenue Requirements (Distribution) - Dem	\$ 51,301,726	Plant (\$000)	293134.5683	36787.0708	256347.4975
Revenue Requirements (Distribution) - Cust	7,168,714	CWIP (\$000)	3,031		3,031
Revenue Requirements (Other)	1,885,007	Accum. Depr (\$000)	(69,813)	-15538.87987	(54,274)
Total Revenue Requirements	76,727,578	Net Plant (\$000)	226,353	21,248	205,104
		Other Adjustments (\$000)	-19584.61177	-1838.44898	-17746.16279
		Rate Base (\$000)	206767.914	19409.74194	187358.172
		Return on Rate Base (\$)	\$ 18,919,264	\$ 1,775,991	\$ 17,143,273
		Expenses			
		Production, Transmission	17556581.72		17556581.72
		Distribution	\$ 7,475,857	268676.0693	7,207,181
		Customer Acc. + Uncoll	\$ 1,476,716	1,476,716	
		A&G	\$ 13,690,343	901,387	12,788,956
		Depreciation	\$ 7,202,703	1769099.65	5433603.802
		Other Taxes	\$ 4,447,821	417,526	4,030,295
		Income Taxes	\$ 5,958,292	559,317	5,398,974
		Revenue Requirements	76727578.23	\$ 7,168,714	\$ 69,558,865
		Other Revenues	-1885006.82		-1885006.82
		Supply	(16,372,132)		(16,372,132)
		Distribution	\$ 58,470,440	7168713.692	\$ 51,301,726
			\$	0	\$ 1
		[1] Plant includes Accounts 368-370 (Transformers, Meters, Services)			
		[2] Distribution O&M includes Accounts 586, 587, 595, 597			

Source: Derived from BVES MCS Model, Tab "RO Inputs."

1
2 **Q. Please explain the above figure.**

3 A. The upper left corner of the figure presents BVES's derived revenue requirements by
4 "component." The figure highlighted in yellow is the revenue requirements derived from
5 BVES's Supply model.¹¹ Also shown is BVES's Distribution (customer) revenue
6 requirements (developed in its own workpaper¹²) and the Other Operating Revenues
7 (derived in BVES's RO models). The revenue requirements for Distribution - Dem is
8 derived in the right half of the figure. The column labeled "Total" presents the derivation
9 of the total revenue requirements (\$76,727,578). The column labeled "Customer"
10 presents the total revenue requirements for Distribution (customer), which is equal to
11 \$7,168,714. The column labeled "Demand" is the residual revenue requirements
12 (\$69,558,865). As can be seen, this column includes expenses for Production,
13 Transmission, Distribution, A&G, Depreciation, Taxes, and other items. To arrive at the
14 value labeled as Distribution-dem, BVES subtracts Other Revenue and Supply revenue
15 requirements from the \$69,558,865 to arrive at the value of \$51,301,726.

16
17 **Q. Doesn't subtracting "Supply revenue" remove all Generation costs of Distribution –**
18 **Dem?**

19 A. No. "Supply" is only the expense portion of Generation costs calculated in the Supply
20 model. There are other costs (e.g., depreciation, taxes, return on rate base) plus the

¹¹ "CONFIDENTIAL BVES GRC Supply Forecast Model (NO SOLAR) 062426.xlsx." (BVES Supply Model) Calculations performed in tab "Input Loads & Resources." Summary of results in tab "TAB #E1 Supply Expense SUMRY."

¹² BVES MCS Model, tab "MDC-Derivation."

1 portion of Administrative and General (A&G) cost that is allocated to Generation that are
2 still included in Distribution-Dem.

3
4 **Q. What is the magnitude of Generation costs that remain in Distribution-Dem?**

5 A. Without additional information from BVES, it is not possible to develop precise values
6 for the amount of generation-related costs that are inappropriately assigned to the
7 Distribution revenue requirements. However, I estimate that approximately \$96,000 of
8 production expenses and about \$8.5 million of A&G are inappropriately assigned to the
9 Distribution revenue requirement.¹³ I cannot provide a precise value for the amount of
10 return, depreciation, and taxes that are incorrectly assigned to distribution demand.

11
12 **Q. Why do you say that BVES improperly combines marginal cost-based revenues?**

13 A. In the development of marginal cost-based revenues used to derive the EPMC-based
14 revenue allocation, BVES uses the sum of the marginal cost-based revenues for
15 Generation (capacity) and Generation (energy)¹⁴ as the basis for the marginal cost-based
16 revenue that is reconciled against the Supply revenue requirements. In addition, BVES
17 uses the sum of the marginal cost-based revenues for Distribution (coincident) and
18 Distribution (non-coincident)¹⁵ as the basis for the marginal cost-based revenues that is
19 reconciled against Distribution – Dem, which contains generation costs.

20

¹³ Production expense estimate derived from BVES Model “SEC 2-SOE.xlsm,” tab “RO Detail S2.” A&G estimate assumes that total A&G (after deduction for Distribution (customer)) is allocated based on % of expenses for Production: $\$16,372,132 / (\$17,556,582 + \$7,207,191) * \$12,788,956 = \$8,455,196$. See BVES MCS Model, tab “RO Inputs.”

¹⁴ BVES MCS Model, tab “Target Revenues”, cells C17:K17.

¹⁵ BVES MCS Model, tab “Target Revenues”, cells C25:K25.

1 **Q. How does BVES use these two methods to arrive at its recommended revenue**
2 **allocation?**

3 A. BVES applies a fixed percentage (10%) to the EPMC-based class revenue requirements
4 and the remainder (90%) to the SAP-based class revenue requirements to arrive at the
5 weighted-average revenue allocation for its Base revenue requirements and its Supply
6 revenue requirements for 2027.

7
8 **Q. What are BVES’s proposed revenue requirements and revenue allocation in this**
9 **proceeding?**

10 A. In its RO Testimony, Snow Summit presented BVES’s proposed revenue requirements
11 and revenue allocation by customer class and year.¹⁶ For convenience, that table is
12 reproduced here:

¹⁶ Snow Summit RO Testimony, p. 11.

Table 1: BVES's Proposed Revenue Allocation in Application Without Solar

	Current 2026	2027	2028	2029	2030
Residential Permanent Service	\$14,530,082	\$16,683,831	\$17,202,043	\$17,572,389	\$18,606,588
Residential Non-Permanent Service	25,141,698	30,598,713	33,100,712	35,657,329	39,386,988
General Service - Small (A1)	8,466,164	10,150,955	10,851,611	11,535,354	12,621,818
General Service - Medium (A2)	2,606,700	2,936,929	2,937,058	2,921,281	2,978,275
General Service - Large (A3)	3,644,683	4,329,442	4,353,646	4,459,051	4,816,464
General Service - Time-of-Use (A4-TOU)	2,280,931	2,845,254	3,230,671	3,262,681	3,209,807
Time-of-Use Service (A5 TOU Secondary)	629,322	784,681	820,068	850,371	914,986
Time-of-Use Service (A5 TOU Primary)	5,749,203	6,428,229	6,689,140	6,885,985	7,422,090
Street Lighting	64,529	84,537	89,204	93,984	100,746
Total Revenues excl. OOR	\$63,113,312	\$74,842,571	\$79,274,154	\$83,238,425	\$90,057,761
Year-over-Year Increase %		18.6%	5.9%	5.0%	8.2%
Other Operating Revenues (OOR)	1,884,921	1,885,007	1,885,093	1,885,178	1,885,264
Total Revenues w/ OOR	64,998,233	76,727,578	81,159,247	85,123,603	91,943,026

Source: Derived from BVES's Marginal Cost of Service (MCS) model, tab "Target Revenues."

As can be seen from the above table, BVES is proposing overall revenue requirements of \$76.728 million in Test Year 2027. This is an increase of \$11.729 million (i.e., 18.0%) compared to the revenue that BVES forecasts that it would collect in 2026 under rates that were in effect at the start of 2026.

The following table from Snow Summit's RO testimony¹⁷ presents the change in class-average rates by customer class and year as well as the compound average growth rate (CAGR) over the entire GRC cycle:

¹⁷ Snow Summit RO Testimony, p. 12.

Table 2: Percentage Rate Increases Proposed by BVES by Year and Customer Class

	2027	2028	2029	2030	CAGR over GRC Cycle
Residential Permanent Service	14.8%	3.1%	2.2%	5.9%	6.4%
Residential Non-Permanent Service	21.7%	8.2%	7.7%	10.5%	11.9%
General Service - Small (A1)	19.9%	6.9%	6.3%	9.4%	10.5%
General Service - Medium (A2)	12.7%	0.0%	-0.5%	2.0%	3.4%
General Service - Large (A3)	18.8%	0.6%	2.4%	8.0%	7.2%
General Service - Time-of-Use (A4-TOU)	24.7%	13.5%	1.0%	-1.6%	8.9%
Time-of-Use Service (A5 TOU Secondary)	24.7%	4.5%	3.7%	7.6%	9.8%
Time-of-Use Service (A5 TOU Primary)	11.8%	4.1%	2.9%	7.8%	6.6%
Street Lighting	31.0%	5.5%	5.4%	7.2%	11.8%
Total	18.6%	5.9%	5.0%	8.2%	9.3%

Source: Derived from MCS model, tab "Target Revenues."

As can be seen from the above table, BVES is proposing more than a 14.8% increase in class-average rates in 2027 for the Permanent Residential class. BVES is also proposing a compound average annual increases of between 3.4% and 11.9% for each year of the 4-year GRC cycle for all customer classes.

The following table from Snow Summit's RO testimony¹⁸ presents BVES's revenue fractions by customer class and year:

¹⁸ Snow Summit RO Testimony, p. 13.

Table 3: Revenue Allocation Fractions Proposed by BVES

	2026 At Present Rates	2027	2028	2029	2030
Residential Permanent Service	23.0%	22.3%	21.7%	21.1%	20.7%
Residential Non-Permanent Service	39.8%	40.9%	41.8%	42.8%	43.7%
General Service - Small (A1)	13.4%	13.6%	13.7%	13.9%	14.0%
General Service - Medium (A2)	4.1%	3.9%	3.7%	3.5%	3.3%
General Service - Large (A3)	5.8%	5.8%	5.5%	5.4%	5.3%
General Service - Time-of-Use (A4-TOU)	3.6%	3.8%	4.1%	3.9%	3.6%
Time-of-Use Service (A5 TOU Secondary)	1.0%	1.0%	1.0%	1.0%	1.0%
Time-of-Use Service (A5 TOU Primary)	9.1%	8.6%	8.4%	8.3%	8.2%
Street Lighting	0.1%	0.1%	0.1%	0.1%	0.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Derived from MCS model, tab "Target Revenues." These fractions are w/o OOR.

Revenue fractions are equal to the fraction of BVES's total revenue requirements (excluding Other Operating Revenues) assigned to each customer class by year. As can be seen from the above table, the revenue fractions for each customer class change from 2027 to 2030, with some fractions increasing (e.g., Residential Non-Permanent Service) and others decreasing (e.g., Residential Permanent Service, A-5 Primary).

Q. How does BVES propose to develop its revenue allocations in this proceeding?

A. For 2027, BVES proposes to use a weighted average revenue allocation, with 10% of the revenue allocation based on EPMC and 90% based on SAP.¹⁹ For the attrition years, BVES proposes to use SAP to determine revenue allocation.²⁰

¹⁹ BVES Testimony, Chapter 6, p. 16.

²⁰ BVES Testimony, Chapter 6, p. 17.

1 **Q. How did BVES develop its SAP proposal for the attrition years?**

2 A. As can be seen from Table 3 above, BVES’s revenue allocation proposal for the attrition
3 years of 2028-2030 does not apply an SAP change to class revenue allocation. This is
4 shown by the fact that the revenue fraction for each class changes by year. Instead, BVES
5 calculates an “SAP change” by comparing the revenue requirements for year “X” with
6 the sum of the class-specific forecasted revenues for year “X” based on assumed sales to
7 each class in year “X” and rates for each class from year “X-1.” BVES then applies that
8 same percentage change to the rates for each class from year “X-1” to derive the rates for
9 each class for year “X”. BVES then derives the revenue allocation for the year by
10 multiplying the derived class-specific rates for year “X” by the class-specific sales to that
11 class in year “X”. BVES uses this process separately for its Base revenue requirements
12 and its Supply costs.

13
14 **Q. Are there cross-subsidies within BVES’s proposed revenue allocation based on**
15 **BVES’s assumed marginal costs in this proceeding?**

16 A. Yes. Cross-subsidies exist when the revenue allocation for a particular class is different
17 from the EPMC-based revenue allocation for that class. Using BVES’s marginal costs,
18 the following table presents the cross-subsidies that exist in BVES’s proposed rates in
19 this proceeding and as proposed by BVES in its last GRC:

Table 4: Inter-Class Subsidies in BVES's Proposal Using BVES's Marginal Costs

	BVES 2027	Prior GRC
Residential Permanent Service	(2,584,702)	(3,347,865)
Residential Non-Permanent Service	996,278	1,236,548
General Service - Small (A1)	871,017	393,163
General Service - Medium (A2)	53,019	182,278
General Service - Large (A3)	1,298,030	384,813
General Service - Time-of-Use (A4-TOU)	725,373	499,329
Time-of-Use Service (A5 TOU Secondary)	(621,966)	66,812
Time-of-Use Service (A5 TOU Primary)	(684,447)	520,997
Street Lighting	(52,603)	63,925
Total	-	0

Sources: BVES 2027 derived from MCS model, tab "Target Revenues." Prior GRC derived from "Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case, Application 22-08,010," May 26, 2023, p. 16.

Q. Do you have any comments about the above table?

A. Yes. The above table presents BVES's own estimates of the cross-subsidies in its current rate proposal and compares those estimates with the cross-subsidies in BVES's prior GRC rate proposal. The most surprising result is that BVES now contends (based on BVES's own marginal costs) that the A5 TOU Primary class (A5-P) is being subsidized by other customer classes whereas in the prior GRC (and for at least the three GRCs prior to this proceeding) BVES's own analysis (relying on BVES's own marginal costs) showed that the A5-P class was subsidizing other customers (e.g., the Permanent Residential class).

Q. How can you explain such a change in the cross-subsidization for the A5-P class between the prior GRC and this GRC?

A. The only explanation is that the current GRC has hugely different estimates of marginal costs for the A5-P class relative to the prior GRC. The following table compares the fraction of marginal costs²¹ by function for the two GRCs:

Table 5: Percentage Change in Marginal Costs Between Prior and Current GRC

		Res. Perm.	Res. Non- Perm.	A1 Comm'l	A2 Comm'l	A3 Comm'l	A4 TOU	A5 Sec.	A5 Pri.	Street Lights	Total
Generation	2027 TY	27%	38%	13%	4%	4%	4%	2%	9%	0%	100%
	2023 TY	32%	38%	12%	5%	5%	3%	0%	6%	0%	100%
	Diff.	-5%	0%	1%	-1%	0%	1%	2%	3%	0%	
Distribution Demand	2027 TY	24%	37%	12%	4%	4%	3%	2%	14%	0%	100%
	2023 TY	32%	41%	12%	5%	4%	2%	0%	4%	0%	100%
	Diff.	-8%	-3%	0%	-1%	0%	1%	2%	10%	0%	
Distribution Customer	2027 TY	27%	50%	14%	3%	3%	0%	0%	1%	1%	100%
	2023 TY	26%	51%	13%	4%	4%	0%	0%	1%	1%	100%
	Diff.	1%	-1%	1%	-1%	-1%	0%	0%	0%	0%	
Other Operating Revenues	2027 TY	1%	2%	1%	0%	0%	0%	0%	96%	0%	100%
	2023 TY	32%	41%	12%	5%	4%	2%	0%	4%	0%	100%
	Diff.	-31%	-39%	-11%	-5%	-4%	-2%	0%	92%	0%	
Total	2027 TY	25%	39%	12%	4%	4%	3%	2%	12%	0%	100%
	2023 TY	32%	41%	12%	5%	4%	2%	0%	4%	0%	100%
	Diff.	-6%	-2%	0%	-1%	0%	1%	2%	8%	0%	

²¹ These fractions are based on the percentage of reconciled revenue requirements based on the percent of marginal cost allocated to each customer class.

1 The above table compares the percentage of marginal costs for each function (i.e.,
2 Generation, Distribution Demand, Distribution Customer, and Other Operating
3 Revenues) for BVES's estimates in this case and in the prior GRC. The highlighted cells
4 show where there are very large changes for the A5-P class. In each of the highlighted
5 cells, BVES's percentage of total marginal costs for the A5-P are greater than in the prior
6 GRC.

7
8 **Q. Does Snow Summit have concerns with BVES's proposed marginal costs and**
9 **revenue allocation?**

10 A. Yes. I address these concerns in the following chapters of this testimony.

11
12 **III. BVES Should Correct Errors in Its Marginal Cost Study**

13
14 **Q. What is the purpose of this chapter?**

15 A. This chapter addresses BVES's marginal cost study.²²

16
17 **Q. How did BVES use the marginal cost study?**

18 A. As discussed in the next chapter, BVES proposes to develop its Base and Supply revenue
19 allocations for 2027 partially on this marginal cost study.

20
21 **Q. Do you agree with BVES's marginal cost study?**

²² BVES Testimony, Volume 6, pp. 7-14. BVES develops its estimates of marginal costs in its MCS Model.

1 A. Not entirely. There are several errors in BVES's study. These errors result in incorrect
2 calculation and application of marginal costs, which skew the determination of a
3 marginal cost-based revenue allocation.
4

5 **Q. What are the impacts of BVES's flawed marginal cost study?**

6 A. As noted above, BVES's marginal cost study in this proceeding resulted in huge changes
7 in marginal cost fractions²³ relative to BVES's prior GRC. Using BVES's incorrect
8 marginal costs results in an incorrect EPMC-based revenue allocation. Since BVES bases
9 its proposed revenue allocation in part on its EPMC-based revenue allocation, the errors
10 in BVES's marginal cost study result in an incorrect revenue allocation.
11

12 **Q. Please summarize the errors you have identified in BVES's marginal cost study that**
13 **you address in this testimony.**

14 A. I address two errors that have notable impacts on the marginal cost results:

- 15 1. As noted in Snow Summit's RO testimony, BVES's sales and load forecasts for
16 the A5-P customer class are unreasonable. First, BVES's forecast for the
17 snowmaking months (November through March) is significantly higher for 2026
18 than actual loads for the A5-P class.²⁴ Second, BVES's forecast for the non-
19 snowmaking months of April-October inexplicably increased in 2025 (and that
20 increase persists in 2026-2030.)²⁵ By forecasting higher than reasonable sales and

²³ "Marginal cost fractions" are the fraction of total reconciled revenue requirements based on marginal costs. The marginal costs for each function and customer class are applied to the total revenue requirement for each function to arrive at the reconciled revenue requirements based on marginal costs. These reconciled revenue requirements are the basis for BVES's EPMC-based revenue requirements.

²⁴ Snow Summit RO Testimony, pp. 26 to 28.

²⁵ Snow Summit RO Testimony, pp. 20 to 23.

loads for the A5-P class, BVES not only overstates its Supply revenue requirements but it also uses unreasonable loads for the determination of marginal costs.²⁶

2. BVES improperly includes certain plant costs in its development of its unit marginal costs for transmission and distribution (T&D) (demand). BVES includes plant costs for substations and equipment that are paid for 100 percent by Snow Summit, meaning that there are no marginal costs to other ratepayers associated with those facilities. In addition, the T&D plant costs that BVES includes are not caused by changes in demand, meaning that they are not marginal, resulting in incorrect unit marginal Distribution (demand) costs.

Q. Are the errors you address in this testimony the only errors in its workpapers?

A. They may not be. However, my testimony focuses on the errors summarized above. This does not mean that there are not other errors in BVES's marginal cost study or that Snow Summit necessarily agrees with the remaining assumptions of (and results from) the Marginal Cost of Service study.

Q. What is the significance of the errors in BVES's marginal cost calculations that you address?

A. The development of reasonably accurate marginal costs is critical to establishing the degree to which a utility's rates are based on marginal costs in a manner consistent with longstanding Commission policy. If underlying assumptions and/or calculations within a

²⁶ Snow Summit's RO Testimony also noted that BVES uses two separate load forecasts in the development of its revenue requirements for supply and for developing marginal costs. Snow Summit RO Testimony, pp. 23 to 26.

1 utility's marginal cost analysis are unreasonable or simply incorrect, they can result in
2 errors in the marginal costs recommended by the marginal cost study. This would
3 unfairly bias the marginal cost-based revenue allocation as determined by the utility's
4 analysis in favor of one or more customer classes and against other customer classes. It
5 would also result in less efficient use of electricity by customers.

6 A. BVES's Load Forecasts For A5-P Customers Are Too High, Resulting In
7 Incorrect Unit Marginal Costs

8
9 **Q. How are BVES's load forecasts used in the determination of unit marginal costs,**
10 **revenues at marginal costs, and EPMC-based revenue allocation?**

11 A. BVES's Marginal Cost of Service model uses load forecasts in a number of different
12 ways:

- 13 • Hourly Marginal Energy Costs: BVES uses its load forecast as the basis for the
14 determination of its Supply revenue requirements. BVES's Supply model takes
15 hourly loads²⁷ and performs a deterministic "dispatch" of the resources BVES has
16 under its control to meet those loads.²⁸ The hourly "Total Net Expenditure per Net
17 MWh" from the Supply model is the value that BVES uses as its hourly marginal
18 energy costs in its MCS model. BVES uses the total costs and the total loads by time
19 of use period for the Test Year (2027) and the three attrition years (2028-2030) to
20 derive the unit marginal energy costs by time of use period.

²⁷ Note that the hourly loads used in the Supply model are capped at 47.4 MW, while the hourly loads used in parts of the MCS model are not capped at this level. Snow Summit has submitted numerous data requests regarding this apparent inconsistency to BVES but BVES claims that there is no inconsistency. See BVES Response to Snow Summit Data Request Set 9, Request 1, BVES Response to Snow Summit Data Request Set 10, Requests 1 and 2, BVES Response to Snow Summit Data Request Set 11, Request 1, BVES Response to Snow Summit Data Request Set 12, Request 1.

²⁸ The Supply model also calculates other costs, such as BVES's Resource Adequacy and CAISO costs.

- 1 • Long Run Unit Transmission and Distribution Marginal Costs: BVES uses a modified
2 version of the so-called “NERA” method for determining the long-run unit
3 transmission and distribution costs (on a \$/kW basis).²⁹ The NERA method uses
4 regressions of cumulative plant additions for transmission, distribution plant, and
5 substation costs against both maximum coincident and maximum non-coincident
6 demands to derive long-run unit transmission and distribution costs. Maximum
7 coincident demand is the maximum demand of all customers in a particular hour of a
8 year. Maximum non-coincident demand is the sum of the maximum hourly demands
9 for each customer class for a year.
- 10 • Allocation of Marginal Costs to Customer Classes: In addition to using load forecasts
11 for the determination of unit marginal costs, BVES uses load forecasts to calculate the
12 total costs for each customer class for each category of costs (e.g., generation
13 capacity, generation energy, distribution demand (coincident), distribution demand
14 (non-coincident)). This Marginal Cost of Service relies on different aggregations of
15 loads for different customer classes. These are:
 - 16 ○ Allocation of total marginal energy costs to time of use periods and customer
17 classes using the total loads disaggregated by customer class and time of use
18 periods for the Test Year.
 - 19 ○ Allocation of total marginal generation capacity costs to time of use periods
20 and customer classes using the fraction of total demands disaggregated by
21 time of use period and customer class for the top 100 hours of coincident
22 demand in the Test Year.

²⁹ BVES Response to Snow Summit Data Request Set 7, Request 7.

- Allocation of unit coincident marginal T&D fixed costs to time of use periods using the fraction of the top 100 hours of coincident demand in the Test Year in each time of use period.
- Allocation of total coincident marginal T&D fixed costs by time periods for each customer class based on the average load by time of use period for each customer class for the Test Year.
- Allocation of total coincident marginal T&D variable costs to customer classes based on annual customer loads for each class.
- Allocation of total non-coincident marginal T&D costs to customer classes based on annual non-coincident demand by customer class.

As can be seen from the above, loads by customer class are a critical part of the development of Marginal Cost of Service for each customer class, which is then used to develop the EPMC-based revenue allocation.

Q. What are your recommended changes to the forecasted loads for the A5-P class?

A. As discussed in Snow Summit's RO testimony, Snow Summit recommends (1) reducing forecasted loads in the snowmaking months by 12.5% for 2026-2030 and (2) to use the average of 2024 and 2025 loads during the non-snowmaking months for the forecasted corresponding monthly loads in 2026-2030. Based on those recommendations, Snow Summit recommends applying the following scalars to BVES's forecasted hourly loads for each month and year:

Table 6: Scalars for Hourly Loads for A5-P Class

Month	2025	2026	2027	2028	2029	2030
1	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
2	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
3	100.0%	87.5%	87.5%	87.5%	87.5%	87.5%
4	100.0%	78.5%	78.2%	78.9%	78.9%	78.9%
5	100.0%	88.7%	89.7%	89.6%	89.2%	88.3%
6	100.0%	81.4%	81.5%	80.5%	81.9%	81.9%
7	100.0%	82.9%	88.5%	87.7%	87.8%	82.1%
8	100.0%	82.9%	82.0%	80.1%	81.2%	83.3%
9	100.0%	79.2%	79.5%	82.7%	82.3%	81.6%
10	100.0%	118.9%	124.0%	114.1%	108.5%	107.7%
11	87.5%	87.5%	87.5%	87.5%	87.5%	87.5%
12	87.5%	87.5%	87.5%	87.5%	87.5%	87.5%

As can be seen from the above table, Snow Summit does not recommend reducing BVES's loads in January-October of 2025 since the two new substations serving the Snow Summit resort did not come online until the end of September 2025.

Q. Did you also examine the reasonableness of BVES's load forecasts for other customer classes?

A. No. Snow Summit requested hourly load data from BVES for 2024 to the present for all customer classes but BVES indicated that it "has raw metered reads for 2025 and 2026, but has not gone through class-load study yet. BVES will not be doing the class-load study until the next GRC."³⁰ Thus, Snow Summit was unable to review the reasonableness of BVES's load forecasts for other customer classes. However, there are

³⁰ BVES Response to Snow Summit Data Request Set 11, Request 2. See also BVES Response to Snow Summit Data Request Set 10, Request 2. Snow Summit even asked for aggregated monthly loads by customer class once BVES indicated that it hadn't completed its "class load study." BVES refused to provide loads in this aggregated form. BVES Response to Snow Summit Data Request Set 12, Request 3.

likely fewer huge errors in BVES’s forecasts for classes other than A5-P since none of the other classes had such significant changes in loads after 2024 (i.e., the installation of the new substations at Snow Summit resort in late September 2025 allowed Snow Summit to purchase significantly greater amounts of energy from BVES than before the substations were installed.)

Q. What are the impacts of your recommended changes in loads for the A5-P class on the various elements of BVES’s proposals?

A. The following table summarizes Snow Summit’s recommended load forecast for use in BVES’s Marginal Cost of Service model³¹ by customer class:

Table 7: Snow Summit Recommended Load Forecast (MWh)

	2025	2026	2027	2028	2029	2030
Perm Res	45,910	45,357	44,681	44,103	43,315	42,643
Seas Res	52,688	54,260	55,800	57,625	59,320	61,154
A1	21,801	22,276	22,775	23,186	23,507	23,956
A2	7,409	7,082	7,032	6,737	6,402	6,099
A3	7,442	7,546	7,854	7,475	7,254	7,293
A4	5,761	6,307	7,019	7,619	7,381	6,764
A5-S	2,301	2,295	2,287	2,294	2,294	2,306
A5-P	18,186	20,297	20,081	19,626	19,686	19,758
Street Lt	107	107	106	107	106	107
Total	161,605	165,525	167,635	168,772	169,267	170,078

The following table presents the change in load for the A5-P class resulting from Snow Summit’s recommendations:

³¹ Snow Summit also derived hourly loads for use in BVES’s Supply model based on the modified hourly loads discussed here. The modified hourly loads for the Supply model limited hourly loads for the BVES system to 47.4 MW.

Table 8: Comparison of BVES and Snow Summit Load Forecast for A5-P Class (MWh)

	2025	2026	2027	2028	2029	2030
BVES	19,334	23,271	22,985	22,489	22,568	22,676
Snow Summit	18,186	20,297	20,081	19,626	19,686	19,758
Change	(1,147)	(2,974)	(2,905)	(2,864)	(2,881)	(2,918)

The following table presents Snow Summit's forecast³² of coincident peak loads used in BVES's Marginal Cost of Service model³³ by customer class:

Table 9: Snow Summit Recommended Coincident Peak Demand Forecast (MW)

	2024	2025	2026	2027	2028	2029	2030
Perm Res	8,797	9,423	9,318	7,763	7,655	7,533	8,763
Seas Res	12,923	14,702	15,072	13,242	13,567	13,934	16,642
A1	4,225	1,796	1,829	1,632	1,662	1,691	1,965
A2	1,248	1,040	997	637	605	580	897
A3	984	771	861	851	818	904	932
A4	684	430	485	481	513	477	485
A5S	456	934	934	834	834	834	934
A5P	12,410	22,389	22,389	25,652	25,652	25,652	22,389
Street Lt	20	25	25	25	25	25	25
System	41,748	51,511	51,912	51,117	51,330	51,629	53,033

The following table compares the forecasts of coincident peak loads from BVES and Snow Summit for the A5-P class based on Snow Summit's revised forecast of hourly loads for the A5-P class:

³² BVES admitted that the coincident peak demands that it originally presented in its MCS model were incorrect. The coincident peak demands presented in this table have been corrected by Snow Summit (since BVES indicated that it would correct the erroneous coincident peak demands in its rebuttal testimony). See BVES Response to Snow Summit Data Request Set 9, Request 5.

³³ Snow Summit also derived hourly loads for use in BVES's Supply model based on the modified hourly loads discussed here. The modified hourly loads for the Supply model limited hourly loads for the BVES system to 47.4 MW.

Table 10: Comparison of Snow Summit and BVES Forecast of Coincident Peak Demand for A5-P Class (MW)

	2024	2025	2026	2027	2028	2029	2030
Snow Summit	12,410	22,389	22,389	25,652	25,652	25,652	22,389
BVES	12,410	25,588	25,588	29,316	29,316	29,316	25,588
Change	-	(3,198)	(3,198)	(3,665)	(3,665)	(3,665)	(3,198)

The following table presents Snow Summit's forecast of non-coincident maximum loads:

Table 11: Snow Summit Forecast of Maximum Non-Coincident Peak Loads (MW)

	2024	2025	2026	2027	2028	2029	2030
Perm Res	12,220	13,907	13,753	13,556	13,366	13,153	12,933
Seas Res	17,002	19,619	20,112	19,957	20,446	21,000	22,207
A1	6,208	6,905	7,033	7,163	7,293	7,419	7,557
A2	2,097	2,406	2,283	2,286	2,192	2,077	1,988
A3	1,657	1,900	2,122	2,288	2,200	2,431	2,295
A4	1,302	1,273	1,471	1,649	1,808	1,731	1,654
A5S	751	1,134	1,134	1,134	1,134	1,134	1,134
A5P	19,753	29,849	29,849	29,849	29,849	29,849	29,849
Street Lt	40	39	39	39	39	39	39
System	61,030	77,032	77,795	77,920	78,326	78,834	79,656

The following table compares the forecasts of non-coincident maximum loads from BVES and Snow Summit for the A5-P class based on Snow Summit's revised forecast of hourly loads for the A5-P class:

Table 12: Comparison of Snow Summit and BVES Maximum Non-Coincident Loads (MW)

	2024	2025	2026	2027	2028	2029	2030
Snow Summit	19,753	29,849	29,849	29,849	29,849	29,849	29,849
BVES	19,753	34,113	34,113	34,113	34,113	34,113	34,113
Change	-	(4,264)	(4,264)	(4,264)	(4,264)	(4,264)	(4,264)

The following table presents summary statistics about Snow Summit's forecast of the Top 100 maximum coincident peak demands for 2027 based on Snow Summit's revised forecast of hourly loads for the A5-P class:

Table 13: Snow Summit Forecast of Top 100 Maximum Coincident Loads (kW)

Top 100 Hours (Avg. Load)	# of Hours	Top 100 %	System Kw	Perm Res	Seas Res	A1	A2	A3	A4	A5S	A5P	Street Lt	BVES TOU Period
Winter TOU - Peak	41	41.00%	46,658	8,346	12,380	3,107	1,018	1,105	693	665	19,320	24	W-OnP
Winter TOU - Mid-Peak	25	25.00%	44,989	6,702	10,895	2,445	906	919	618	500	21,985	19	W-MP
Winter TOU - Off-Peak	34	34.00%	45,084	4,788	10,048	2,437	853	883	706	555	24,790	24	W-OfP
Summer TOU - Peak	-	0.00%	-	-	-	-	-	-	-	-	-	-	S-OnP
Summer TOU - Mid-Peak	-	0.00%	-	-	-	-	-	-	-	-	-	-	S-MP
Summer TOU - Off-Peak	-	0.00%	-	-	-	-	-	-	-	-	-	-	S-OfP

The following table presents the differences between the forecasts of Snow Summit and BVES:

Table 14: Comparison of Snow Summit and BVES Top 100 Loads

Top 100 Hours (Avg. Load)		# of Hours	Top 100 %	System Kw	Perm Res	Seas Res	A1	A2	A3	A4	A5S	A5P	Street Lt
Winter TOU - Peak		2	2.00%	(2,944)	69	128	91	23	24	25	(1)	(3,302)	0
Winter TOU - Mid-Peak		1	1.00%	(3,257)	70	295	112	38	(4)	(2)	1	(3,769)	0
Winter TOU - Off-Peak		(3)	-3.00%	(3,389)	(63)	144	(21)	(5)	(1)	(12)	3	(3,435)	0
Summer TOU - Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-
Summer TOU - Mid-Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-
Summer TOU - Off-Peak		-	0.00%	-	-	-	-	-	-	-	-	-	-

As can be seen from Table 14 above, Snow Summit's load forecast results in 2 more hours in the Winter TOU-Peak Period than BVES's forecast (41 vs. 39 hours). The Snow Summit forecast also results in lower average loads for the A5-P class in all Winter TOU periods (e.g., 3,302 kW lower in the Winter Peak period) but slightly higher values in the Winter TOU-Peak and Winter TOU-Mid-Peak periods for most of the other classes (e.g., 69 kW and 70 kW increases for Permanent Residential class in the Winter Peak and Winter Mid-Peak periods.)

Q. What is the impact of Snow Summit's proposed load forecast on the supply revenue requirements?

A. The following table presents Snow Summit's estimate of Supply revenue requirements by customer class for 2027:

Table 15: Impact of Snow Summit Load Forecast Recommendation on Supply Costs (\$)

	BVES	Snow Summit	Snow Summit - BVES
Residential Permanent	4,375,801	4,307,802	(67,999)
Residential Non-Permanent	5,464,204	5,381,906	(82,298)
A1 Commercial	2,050,344	2,019,038	(31,306)
A2 Commercial	536,427	528,357	(8,070)
A3 Commercial	779,769	767,510	(12,259)
A4 TOU	716,684	705,187	(11,497)
A5 Secondary	212,544	209,160	(3,384)
A5 Primary	2,227,803	2,175,630	(52,174)
Street Lighting	8,556	8,419	(137)
Total	16,372,132	16,103,009	(269,123)

As can be seen from the above table, using more reasonable load forecasts for the A5-P class results in a reduction in the supply revenue requirement of \$269,123.

Q. How did you derive the change in supply revenue requirements?

A. I input Snow Summit's recommended hourly loads into BVES's supply model (capping loads at 47.4 MW). I did not change any of BVES's assumptions regarding the cost or availability of different supply options.

Q. Do you have any concerns about Snow Summit's estimate of Supply revenue requirements?

A. Yes. BVES's Supply model has several assumptions that are "hard-wired" but that likely change with changes to load forecasts. These include:

- Quantity and price of Renewable Energy Credits (RECs) that BVES must purchase
- The Resource Adequacy (RA) capacity charge paid by BVES
- Fees paid to the California Independent System Operator (CAISO)
- Charges paid by BVES for transmission access and options

- The amount of energy either supplied or consumed each hour by BVES's proposed battery project

Because these charges did not vary in BVES's Supply model with revised loads, they are likely incorrect in Snow Summit's estimate of supply revenue requirements. However, since Snow Summit's load forecast is lower than BVES's forecast for the A5-P class and for the BVES system, I would expect that the Supply revenue requirements would be slightly less than presented in Table 15 above.

Q. What are the impacts of Snow Summit's revised load forecast for the A5-P class on marginal costs?

A. The following table compares the unit generation marginal costs by TOU period for Snow Summit and BVES:

Table 16: Comparison of Generation Unit Marginal Costs (\$/kW-yr)

Snow Summit				BVES				Change (SS - BVES)		
Generation MC (\$/kW)	312.38	% Top 100 Hrs		Generation MC (\$/kW)	312.38	% Top 100 Hrs	Generation MC (\$/kW)	-	% Top 100 Hrs	
Winter Peak	128.08	41%		Winter Peak	121.83	39%	Winter Peak	6.25	2%	
Winter Mid-Peak	78.10	25%		Winter Mid-Peak	74.97	24%	Winter Mid-Peak	3.12	1%	
Winter Off-Peak	106.21	34%		Winter Off-Peak	115.58	37%	Winter Off-Peak	(9.37)	-3%	
Summer Peak	-	0%		Summer Peak	-	0%	Summer Peak	-	0%	
Summer Mid-Peak	-	0%		Summer Mid-Peak	-	0%	Summer Mid-Peak	-	0%	
Summer Off-Peak	-	0%		Summer Off-Peak	-	0%	Summer Off-Peak	-	0%	

As seen from the above table, a greater percentage of the unit generation marginal costs are assigned to the winter peak (41% vs. 39%) and the winter mid-peak (25% v. 24%) periods using Snow Summit's load forecast.

The following table compares the unit marginal energy costs by TOU period for Snow Summit and BVES:

Table 17: Comparison of Snow Summit and BVES Unit Marginal Energy Costs (\$/MWh)

Generation Marginal Energy Costs	Based on 2027-2030 Supply Forecast		
	Snow Summit	BVES	Change
Winter Peak	56.42	57.31	(0.89)
Winter Mid-Peak	67.69	68.21	(0.51)
Winter Off-Peak	66.67	68.46	(1.79)
Summer Peak	47.51	47.50	0.01
Summer Mid-Peak	68.90	68.76	0.14
Summer Off-Peak	62.57	62.54	0.03

As can be seen from the above table, the unit marginal energy costs for the winter TOU periods are slightly lower based on Snow Summit's load forecast than BVES's estimates (e.g., \$56.42/MWh vs. \$57.31/MWh in the Winter Peak period.) In addition, the unit marginal energy costs for the summer TOU periods are slightly higher using Snow Summit's load forecast.

Q. Does Snow Summit's revised load forecast affect BVES's estimate of unit customer-related marginal distribution costs?

A. No.

1 **Q. Does Snow Summit’s load forecast affect the unit marginal costs for Distribution**
2 **(coincident and non-coincident)?**

3 A. Yes. The revised load forecast changes these unit marginal costs as well. However, as
4 discussed below, Snow Summit has other recommended changes to the determination of
5 the unit marginal costs for coincident and non-coincident demand-based Distribution.
6 Therefore, Snow Summit will present those revised marginal costs in the next section.

8 B. BVES Improperly Calculates Marginal Distribution Demand Costs

9
10 **Q. How did BVES develop unit marginal Distribution demand costs?**

11 A. BVES performed several regressions where the independent variables are system
12 coincident peak demand or system non-coincident peak demand and the dependent
13 variables are cumulative (1) net “transmission” additions, (2) net “distribution” additions,
14 and (3) net “distribution” substation additions. These linear regressions used five years of
15 historic data and five years of forecast data. The resulting “slope” for each regression is
16 used to develop marginal Distribution demand costs for customers taking service on A-5
17 Primary as well as the rest of BVES’s customers.³⁴

18
19 **Q. What is the basis of this approach for determination of unit marginal costs for**
20 **Distribution demand?**

21 A. This method was originally developed by the National Economic Research Associates in
22 the 1970s when marginal cost-based ratemaking was in its infancy.

23

³⁴ BVES MCS Model, tabs “MDD-Plant_Inv” and “MDD-A5P.”

1 **Q. What period of data is used with the NERA method for estimating unit marginal**
2 **Distribution demand costs?**

3 A. 15 years of time-series data is used with this method. NERA’s method uses 10 years of
4 historic data and 5 years of forecast data.

5
6 **Q. How many years of data did BVES use in the development of these unit marginal**
7 **cost estimates?**

8 A. BVES used 10 years of costs: 5 years of historic data (2021-2025) and 5 years of forecast
9 data (2026-2030).³⁵

10
11 **Q. Does BVES make any adjustments to the regression results to arrive at its final**
12 **estimates of unit marginal Distribution demand costs?**

13 A. Yes. BVES applies an arbitrary 50% reduction to the regression results developed using
14 BVES’s implementation of the NERA method to arrive at its final unit marginal
15 Distribution demand costs for T&D and for substations.³⁶

16 1. BVES Improperly Assigns Marginal Distribution Demand Costs to A5-P
17 Customers Despite Those Customers Being Interruptible Pursuant to BVES’s Tariff
18

19 **Q. Does BVES assign marginal Distribution demand costs to customers in the A5-P**
20 **class?**

21 A. Yes.

22
23 **Q. Is this appropriate?**

³⁵ BVES MCR model, tabs “MDD-Plant_Inv” and “MDD-A5P.”

³⁶ BVES Response to Snow Summit Data Request Set 9, Request 2.

1 A. No. Customers in the A5-P class can have their loads interrupted if needed by BVES.
2 There does not appear to be a limit on the number of times that BVES can interrupt these
3 customers but BVES can only interrupt A5-P customer load to respond to situations
4 where it would not have sufficient generation capacity to meet all loads. Thus, if
5 customers in the A5-P class wish to increase their usage by a small amount and, as a
6 result, cause the need for additional transmission or distribution facilities to deliver that
7 incremental demand, BVES could choose to curtail the incremental load, thereby
8 avoiding the need for some of those incremental facilities.
9

10 **Q. Have other utilities used this sort of approach to avoid construction of new**
11 **facilities?**

12 A. Yes. Utilities implement demand-side management programs to avoid construction of
13 new generation facilities. Demand-side resources are used to allow utilities to avoid the
14 construction of new distribution facilities.³⁷ The Commission has a long-term and
15 extensive effort to properly value the costs avoided as a result of demand-side
16 resources.³⁸
17

18 **Q. Does BVES value the ability of A5-P customers to avoid construction of new**
19 **facilities in its ratemaking process?**

³⁷ See Rulemaking (R.) 21-06-017, the Distribution Planning Process Improvements and the Distribution Investment Deferral Framework, which is “an ongoing annual process to identify, review, and select opportunities for competitively sourced distributed energy resources to defer or avoid utility traditional distribution capital investments. DERs as alternatives to traditional grid investments are commonly referred to as non-wires alternatives.” <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning>

³⁸ See R.22-11-013. See also the Commission’s website related to the development and enhancement of the Avoided Cost Calculator: <https://www.cpuc.ca.gov/dercosteffectiveness>

1 A. Yes. BVES does not assign unit marginal Generation capacity costs to customers in the
2 A5-P customer class in the development of its EPMC-based revenue allocation. It
3 appears that BVES does this since a small increase in demand by customers in the A5-P
4 class will not trigger the need for new generation supplies.

5
6 **Q. How is this analogous to avoiding construction of new distribution substations?**

7 A. BVES has two sources of electric supply: generation within its service territory and
8 imported energy from Southern California Edison Company (SCE) through substations
9 that interconnect BVES's system to SCE. While BVES is attempting to construct new in-
10 area generation, this has proven difficult (e.g., the failed solar project that caused BVES
11 to revise its revenue requirements, marginal cost, and revenue allocation proposals in this
12 proceeding). Absent additional in-area generation, the only way for BVES to increase
13 supply for its customers is through increased distribution substation capacity between
14 BVES and SCE. By using additional curtailment of load to the A5-P class, BVES could
15 defer such distribution substation expansion projects.

16
17 **Q. How might the ability of BVES to curtail load for A5-P customers change the**
18 **assignment of marginal Distribution demand costs to the A5-P class?**

19 A. BVES's "unit marginal Distribution demand cost" for the A5-P class is based on two sets
20 of costs: (1) transmission plant excluding substations and (2) distribution plant
21 categorized as substations.³⁹ It is possible that BVES could rely on curtailment to avoid a
22 portion of new distribution substation capacity.

³⁹ BVES MCS Model, tab "MDD-A5P."

1
2 **Q. Have you estimated the fraction of capital additions to distribution substations that**
3 **might be avoided through curtailment of A5-P customer load?**

4 A. No. This analysis would require an in-depth understanding of BVES's distribution
5 planning process. It would also require discussions with stakeholders (e.g., Snow
6 Summit, BVES, ratepayer advocates) to balance the amount of additional curtailment that
7 might occur against the benefits of that additional curtailment.

8
9 **Q. Would the avoidance of distribution costs apply to marginal T&D costs for both**
10 **coincident and non-coincident demands?**

11 A. No. This is only applicable to coincident distribution demand costs. Since customers in
12 the A5-P class would consume some amount of power throughout the year, their marginal
13 non-coincident distribution demand costs are non-zero.

14
15 **Q. What do you recommend?**

16 A. There is clearly a benefit that the A5-P class provides to BVES in terms of avoidance of
17 additional distribution substation investments. However, the magnitude of that benefit is
18 uncertain. Snow Summit recommends that the marginal Distribution capacity costs for
19 coincident demand be reduced in this proceeding by a nominal amount (e.g., 5%) to
20 account for that benefit.⁴⁰ Snow Summit also recommends that the Commission order
21 BVES to convene a stakeholder group to determine the avoided Distribution demand
22 costs provided by the A5-P class.

⁴⁰ Snow Summit did not include this recommended reduction in the unit marginal Distribution demand (coincident) costs that it presents in this testimony.

1 2. BVES Improperly Includes Non-Marginal Costs in the Development of Its
2 Unit Marginal Distribution Demand Costs
3

4 **Q. What are marginal Distribution demand costs?**

5 A. BVES states: “Marginal distribution demand costs represent the incremental cost in
6 transmission and distribution facilities to serve incremental peak demands. The
7 incremental cost includes transmission, distribution, and substation investments.”⁴¹
8

9 **Q. How does BVES calculate its unit marginal costs for Distribution demand?**

10 A. BVES uses several steps to calculate marginal costs for Distribution demand:

- 11 • It calculates the change in total investment in its sub-transmission system (i.e.,
12 34.5 kV) and its other distribution facilities (except for final line transformers)
13 relative to changes in its total coincident and non-coincident demand for 10 years
14 (five historical and five forecast years). These steps yield the unit marginal costs
15 of sub-transmission and distribution caused by both coincident and non-
16 coincident peak demands.
- 17 • It uses 100% of the unit marginal cost of sub-transmission and 50% of the unit
18 marginal cost of distribution driven by coincident peak demands as caused by
19 customers’ coincident demands; it also uses 50% of the unit marginal cost of
20 distribution caused by non-coincident demands as being caused by customers’
21 non-coincident demands.
- 22 • For the A-5 Primary customers, BVES uses a slightly different approach: it
23 determines the unit marginal cost of sub-transmission lines and distribution

⁴¹ BVES Testimony, Chapter 6, p. 10.

1 substations based on the coincident peak demands on the system to develop the
2 unit marginal Distribution cost (coincident) and assigns those to A-5 P's
3 coincident demands; it then assumes that 50% of the marginal cost of distribution
4 substations based on non-coincident demands are caused by A-5 Primary
5 customers and assigns those unit marginal Distribution costs (non-coincident) to
6 A5-P's non-coincident demands.

7
8 **Q. What is the basis of BVES's assumed transmission and distribution investments for**
9 **these calculations?**

10 A. Snow Summit understands that BVES uses its historic and forecast net plant additions
11 plus Construction Work in Progress (CWIP) to arrive at the annual investments.⁴² These
12 investments include both conventional investments in T&D facilities (e.g., substations,
13 poles, wire) resulting from increases in demand as well as investments made as part of
14 BVES's wildfire mitigation efforts.

15
16 **Q. Does this series of investments include the substations and other distribution**
17 **facilities for which Snow Summit pays 100 percent of the costs pursuant to an**
18 **Added Facilities Agreement?**

19 A. Yes. As discussed elsewhere, Snow Summit pays 100% of the costs of substations and
20 distribution equipment that were constructed by BVES pursuant to Snow Summit's
21 Added Facilities Agreement with BVES.

⁴² BVES MCS Model, tab "Plant."

a) BVES Improperly Includes Costs of Substations and Other Distribution Equipment For Which Snow Summit Pays 100 Percent of the Costs

Q. What are the costs associated with the substations and other distribution equipment for which Snow Summit pays 100 percent of the costs pursuant to an Added Facilities Agreement?

A. These projects are covered under BVES’s Project C-023: Snow Summit Project. The following table summarizes the costs associated with this project:

Table 18: Plant Additions for Snow Summit Project

Project ID	Project Name	Recurring Projects Flag =1	In Service Year	FERC Account	Percentage of Cost	Actual Spend End of 2024	Plant Additions					
							2025	2026	2027	2028	2029	2030
C-023	Snow Summit Project	0	2025	362	75%	4,809,911	8,707,673	-	-	-	-	-
C-023	Snow Summit Project	0	2025	366	15%	961,982	1,741,535	-	-	-	-	-
C-023	Snow Summit Project	0	2025	367	10%	641,322	1,161,023	-	-	-	-	-

Source: Excerpt from BVES Model “SEC7-8-9-UPIS Reserve RB_Filing.xlsx,” tab “Forecasted Additions by Pro WS4”

As can be seen from the above table, BVES has plant additions of approximately \$8.7 million, \$1.7 million, and \$1.2 million in 2025 for FERC Accounts 362, 366, and 367, respectively.⁴³ These costs were recorded as plant additions in 2025 when the Snow Summit project came online.

Q. Are these the values that BVES includes in the development of its distribution demand costs?

⁴³ FERC Account 362 is the FERC account for substation costs.

1 A. These are approximately equal to the values used by BVES in its regression analysis.
2 BVES modifies its plant additions to account for retirements and other adjustments.
3 However, BVES does not perform those modifications on a per-project basis, so it is not
4 possible for me to develop precise estimates of those adjustments. Snow Summit expects
5 that the adjustments are small.

6
7 **Q. Why is it inappropriate for BVES to include these costs in its assessment of the**
8 **marginal Distribution demand costs?**

9 A. The costs for the Snow Summit Project are not costs borne by any ratepayer except for
10 Snow Summit pursuant to the Added Facilities Agreement.⁴⁴ Stated differently, the
11 *marginal* Distribution demand cost of the Snow Summit Project for other ratepayers is
12 \$0. Because other customers bear no net costs for those facilities, it is improper to include
13 those costs in the development of unit marginal Distribution demand costs.

14
15 **Q. What do you recommend?**

16 A. BVES should remove the costs of the Snow Summit Project from the data used in its
17 regression analysis to determine unit marginal Distribution demand costs.

18
19 **Q. Should BVES remove these costs from its rate base?**

20 A. BVES models the Snow Summit Project in its RO model as any other T&D addition. In
21 addition, BVES includes the payments made by Snow Summit in its calculation of
22 revenue requirements and deducts the costs paid by Snow Summit from costs that are

⁴⁴ Even though the Added Facilities Agreement is between BVES and the Snow Summit resort, Snow Summit is the only customer in the A5-P class.

assigned to all customer classes under BVES's normal ratemaking treatment of capital projects. Because of this netting, it is appropriate to include the costs of the Snow Summit Project in BVES's revenue requirements calculation since it is ultimately netted out of revenue requirements.

3. Impacts of Snow Summit Assumptions on Marginal Distribution Demand Costs

Q. Do Snow Summit's recommended changes to BVES's load forecast for the A5-P class and the removal of the Snow Summit substation have an impact on unit marginal Distribution demand costs?

A. Yes. The following sections present those impacts.

a) Marginal Distribution Demand (Coincident)

Q. What are the impacts on marginal Distribution demand costs (for coincident demands) associated with Snow Summit's proposed changes to load forecast and removing the Snow Summit substation from the calculation of marginal costs?

A. As noted above, Snow Summit recommends changes in the load forecast for the A5-P class. Those changes result in a change in coincident and non-coincident demands. Both coincident and non-coincident demands affect the calculation of the unit marginal cost for Distribution demand (coincident and non-coincident). Removing the costs of the Snow Summit distribution substation and other facilities paid for entirely by Snow Summit also changes the unit marginal costs. Thus, there are three separate cases: (1) changing the load forecast and including the Snow Summit facilities in the calculation of unit marginal

1 Distribution demand costs, (2) removing the Snow Summit facilities from the calculation
2 of unit marginal Distribution demand costs and using BVES's load forecast, and (3)
3 changing the load forecast and removing the Snow Summit facilities from the calculation
4 of unit marginal Distribution demand costs. Each is presented below:

Table 19: Comparison of Unit Marginal Distribution (Coincident) Values Including Snow Summit Substations and Using Snow Summit Loads (\$/kW)

Snow Summit				BVES					Change (SS - BVES)			
	System	A-5P			System	A-5P				System	A-5P	
Coincident Distribution MC (\$/kW)	972.06	190.49	% Top 100 Hrs	Coincident Distribution MC (\$/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC (\$/kW)	212.01	41.25	% Top 100 Hrs
Winter Peak	398.54	78.10	41.00%	Winter Peak	296.42	58.20	39.00%		Winter Peak	102.12	19.90	2.00%
Winter Mid-Peak	243.01	47.62	25.00%	Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	60.60	11.81	1.00%
Winter Off-Peak	330.50	64.77	34.00%	Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	49.28	9.55	-3.00%
Summer Peak	-	-	0.00%	Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%	Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%	Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

Table 20: Comparison of Unit Marginal Distribution (Coincident) Values Removing Snow Summit Substations and Using BVES Loads (\$/kW)

Snow Summit				BVES					Change (SS - BVES)			
	System	A-5P			System	A-5P				System	A-5P	
Coincident Distribution MC (\$/kW)	707.78	104.44	% Top 100 Hrs	Coincident Distribution MC (\$/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC (\$/kW)	(52.27)	(44.80)	% Top 100 Hrs
Winter Peak	276.04	40.73	39.00%	Winter Peak	296.42	58.20	39.00%		Winter Peak	(20.38)	(17.47)	0.00%
Winter Mid-Peak	169.87	25.07	24.00%	Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	(12.54)	(10.75)	0.00%
Winter Off-Peak	261.88	38.64	37.00%	Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	(19.34)	(16.58)	0.00%
Summer Peak	-	-	0.00%	Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%	Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%	Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

Table 21: Comparison of Unit Marginal Distribution (Coincident) Values Removing Snow Summit Substations and Using Snow Summit Loads (\$/kW)

Snow Summit					BVES					Change (SS - BVES)			
	System	A-5P				System	A-5P				System	A-5P	
Coincident Distribution MC (\$/kW)	904.49	133.51	% Top 100 Hrs		Coincident Distribution MC (\$/kW)	760.05	149.24	% Top 100 Hrs		Coincident Distribution MC (\$/kW)	144.44	(15.73)	% Top 100 Hrs
Winter Peak	370.84	54.74	41.00%		Winter Peak	296.42	58.20	39.00%		Winter Peak	74.42	(3.46)	2.00%
Winter Mid-Peak	226.12	33.38	25.00%		Winter Mid-Peak	182.41	35.82	24.00%		Winter Mid-Peak	43.71	(2.44)	1.00%
Winter Off-Peak	307.53	45.39	34.00%		Winter Off-Peak	281.22	55.22	37.00%		Winter Off-Peak	26.31	(9.82)	-3.00%
Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%		Summer Peak	-	-	0.00%
Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%		Summer Mid-Peak	-	-	0.00%
Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%		Summer Off-Peak	-	-	0.00%

1 The following is seen from the above tables:

- 2 • Using Snow Summit Load Only: As seen in Table 19, using the Snow Summit load
3 forecast alone results in a significant increase in the unit marginal cost for
4 Distribution (coincident): for system, this increases from \$760/kW to \$962/kW and
5 for A5-P, this increases from \$149/kW to \$190/kW. This also increases the allocation
6 of cost in the winter on-peak and mid-peak period by 2% and 1%, respectively, while
7 decreasing the allocation to the winter off-peak period by 3%.
- 8 • Removing Snow Summit Substation Only: As seen in Table 20, removing the Snow
9 Summit substation while using the BVES load forecast results in a decrease in the
10 unit marginal cost for Distribution (coincident): for system, this decreases from
11 \$760/kW to \$708/kW and for A5-P, this decreases from \$149/kW to \$104/kW. This
12 keeps the allocation of costs based on the Top 100 hours the same as assumed by
13 BVES.
- 14 • Use Snow Summit Loads and Remove Snow Summit Substation: As seen in Table
15 21, using the Snow Summit load forecast and removing the Snow Summit substation
16 results in a significant increase in the unit marginal cost for Distribution (coincident)
17 for system (from \$760/kW to \$904/kW) and a decrease for A5-P (from \$149/kW to
18 \$134/kW.) This also increases the allocation of cost in the winter on-peak and mid-
19 peak period by 2% and 1%, respectively, while decreasing the allocation to the winter
20 off-peak period by 3%.

b) Marginal Distribution Demand (non-coincident)

Q. What are the impacts of Snow Summit's assumptions on unit marginal Distribution demand costs based on non-coincident loads?

A. As with the impacts of Snow Summit's assumptions on unit marginal Distribution demand cost based on coincident loads, there are three scenarios to examine: (1) changing load forecast as recommended by Snow Summit and including the new Snow Summit facilities in the calculation of unit marginal Distribution demand costs, (2) removing the Snow Summit facilities from the calculation of unit marginal Distribution demand costs and using BVES's load forecast, and (3) using Snow Summit's load forecast and removing the Snow Summit facilities. Each is presented below:

Table 22: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Including Snow Summit Substations and Using Snow Summit Loads (\$/kW)

	Non-Coincident (\$/kW)	
	System	A-5P
Snow Summit	577.30	106.70
BVES	473.56	87.59
Change	103.74	19.11

As seen from the above table, using the Snow Summit load forecast results in significant increases in the unit marginal costs: from \$473.57/kW to \$577.30/kW for system and from \$87.59/kW to \$106.70/kW for the A5-P class.

Table 23: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Removing Snow Summit Substations and Using BVES Loads (\$/kW)

	Non-Coincident (\$/kW)	
	System	A-5P
Snow Summit	439.10	58.39
BVES	473.56	87.59
Change	(34.46)	(29.20)

As seen from the above table, removing the Snow Summit substations and using the BVES load forecast for A5-P results in a decrease in the unit marginal Distribution costs: from \$473.57/kW to \$439.10/kW for system and from \$87.59/kW to \$58.39/kW for the A5-P class.

Table 24: Comparison of Unit Marginal Distribution Costs (Non-Coincident) Removing Snow Summit Substations and Using Snow Summit Loads (\$/kW)

	Non-Coincident (\$/kW)	
	System	A-5P
Snow Summit	534.86	71.15
BVES	473.56	87.59
Change	61.30	(16.43)

As seen from the above table, removing the Snow Summit substations and using the Snow Summit load forecast results in an increases in the unit marginal costs for system: from \$473.57/kW to \$534.86/kW. It also results in a decrease in the unit marginal costs for the A5-P class from \$87.59/kW to \$71.15/kW.

IV. BVES Should Revise Its Revenue Allocation to Incorporate More Appropriate Marginal Costs and Other

Assumptions Recommended by Snow Summit

Q. What is the purpose of this chapter of your testimony?

A. This chapter present the impacts of Snow Summit’s recommended marginal costs and other assumptions on BVES’s revenue allocation.

A. BVES’s Revenue Allocation Proposal

Q. Please describe BVES’s revenue allocation proposal.

A. In its revenue allocation proposal for 2027, BVES takes a small step in the direction of marginal cost-based revenue allocation. BVES proposes to use a hybrid approach to revenue allocation for the Test Year, where it will use a weighted-average revenue allocation based 10% on EPMC and 90% on SAP.⁴⁵

For years 2028-2030, BVES proposes to use a completely different revenue allocation scheme than it uses for 2027. Instead of basing the revenue allocation in 2028-2030 on marginal costs at all, BVES uses SAP to allocate the change in revenue requirements in 2028-2030 relative to the revenue requirements in 2027.⁴⁶ By doing this, BVES effectively locks in any cross-subsidies that would exist in the 2027 revenue allocation for the remaining three years of the GRC cycle.⁴⁷

⁴⁵ BVES Testimony, Volume 6, p. 16.

⁴⁶ BVES Testimony, Volume 6, p. 17.

⁴⁷ To develop its “SAP” proposal, BVES uses the formula: rates in year X = rates in year X-1 * [revenue requirement in year X / (rates in year X-1 * sales in year X)].

The following table presents BVES’s proposed revenue allocation fractions for each customer class and year:

Table 25: BVES's Revenue Allocation Proposal (Percent of Total Excluding OOR)

Revenue Allocation Fractions by Year and Customer Class					
	Current	Proposed	Proposed	Proposed	Proposed
	2026	2027	2028	2029	2030
Residential Permanent Service	23.0%	22.3%	21.7%	21.1%	20.7%
Residential Non-Permanent Service	39.8%	40.9%	41.8%	42.8%	43.7%
General Service - Small (A1)	13.4%	13.5%	13.7%	13.8%	14.0%
General Service - Medium (A2)	4.1%	3.9%	3.7%	3.5%	3.3%
General Service - Large (A3)	5.8%	5.8%	5.5%	5.4%	5.3%
General Service - Time-of-Use (A4-TOU)	3.6%	3.8%	4.1%	3.9%	3.6%
Time-of-Use Service (A5 TOU Secondary)	1.0%	1.0%	1.0%	1.0%	1.0%
Time-of-Use Service (A5 TOU Primary)	9.1%	8.6%	8.5%	8.3%	8.3%
Street Lighting	0.1%	0.1%	0.1%	0.1%	0.1%
Total less OOR	100.0%	100.0%	100.0%	100.0%	100.0%

Source: Derived from BVES MCS Model, tab “Target Revenues”

Q. Why does BVES recommend its hybrid approach for revenue allocation in 2023?

A. BVES states that “The Company’s proposal strikes an appropriate balance of the rate design principles.”⁴⁸

Q. What does BVES say about its recommendation to use its SAP approach for revenue allocation in 2028-2030?

⁴⁸ BVES Testimony, Volume 6, p. 16.

1 A. BVES states that “The Company proposes to establish revenue targets in 2028-2030
2 based on the SAP method. The SAP method would be applied independently to Base and
3 Supply revenues.”⁴⁹

4
5 B. Snow Summit Revenue Allocation Proposal
6

7 **Q. Please describe how Snow Summit developed its revenue allocation proposal.**

8 A. As described previously, Snow Summit examined and proposed modifications to specific
9 assumptions used by BVES in the development of its marginal costs. The modified
10 assumptions resulted in changes to BVES’s unit marginal costs as well as certain factors
11 used to determine the Marginal Cost of Service. Snow Summit then applied the modified
12 assumptions to the MCS model used by BVES to develop its revenue allocation proposal.
13

14 **Q. Did Snow Summit make any changes to BVES’s assumptions that were in the MCS
15 model prior to applying its changed assumptions?**

16 A. Yes. As mentioned previously, in response to a Snow Summit data request, BVES
17 admitted that it had used incorrect values for its coincident peak demands.⁵⁰ Since BVES
18 did not plan to send out a modified MCS model correcting this error prior to when BVES
19 submits its rebuttal testimony, Snow Summit revised the base assumptions used to
20 properly calculate annual coincident peak demands. This correction to BVES’s modeling
21 resulted in a change in BVES’s proposed revenue allocation.
22

⁴⁹ BVES Testimony, Volume 6, p. 17.

⁵⁰ BVES Response to Snow Summit Data Request Set 9, Request 5.

1 **Q. Did you revise BVES's revenue requirements consistent with your recommendation**
2 **in Snow Summit's prior testimony regarding revenue requirements?**

3 A. I did calculate new Supply revenue requirements based on Snow Summit's proposed
4 changes to loads for the A5-P class. As noted above, Snow Summit's Supply revenue
5 requirements is likely high because BVES's Supply model had certain values that should
6 have changed with changes in loads but did not because BVES had hard-coded those
7 values in its model.

8
9 **Q. In Snow Summit's RO testimony, Snow Summit recommended changing BVES's**
10 **capital structure and return on equity. Did you reflect that recommendation in the**
11 **updated revenue requirements or calculation of marginal costs in this testimony?**

12 A. No. I did not calculate new revenue requirements assuming Snow Summit's
13 recommended capital structure and return on equity.⁵¹ In addition, I did not use Snow
14 Summit's recommended values for capital structure or return on equity in the
15 development of marginal costs.⁵²

16
17 **Q. Please present your revised revenue allocation.**

18 A. The following tables presents Snow Summit's proposed revenue allocation for 2027:
19

⁵¹ Snow Summit RO Testimony, pp. 18-19.

⁵² BVES's cost of capital is used in the development of its Real Economic Carrying Charge (RECC) and other assumptions in BVES's MCS model. See BVES MCS Model, tab "Common_Inputs."

1

Table 26: Snow Summit Revenue Allocation (\$)

	Supply Revenue Requirements			Base Revenue Requirements			Total Revenue Requirements		
	BVES	Snow Summit	Change	BVES	Snow Summit	Change	BVES	Snow Summit	Change
Residential Permanent	4,375,801	4,307,802	(67,999)	12,301,375	12,424,945	123,569	16,677,176	16,732,747	55,570
Residential Non-Permanent	5,464,204	5,381,906	(82,298)	25,141,413	25,369,356	227,943	30,605,617	30,751,262	145,645
A1 Commercial	2,050,344	2,019,038	(31,306)	8,086,240	8,153,939	67,698	10,136,584	10,172,976	36,392
A2 Commercial	536,427	528,357	(8,070)	2,396,826	2,417,972	21,146	2,933,253	2,946,329	13,076
A3 Commercial	779,769	767,510	(12,259)	3,546,647	3,572,623	25,976	4,326,416	4,340,133	13,717
A4 TOU	716,684	705,187	(11,497)	2,125,992	2,142,118	16,127	2,842,676	2,847,305	4,630
A5 Secondary	212,544	209,160	(3,384)	572,070	580,088	8,018	784,614	789,248	4,634
A5 Primary	2,227,803	2,175,630	(52,174)	4,223,864	4,002,006	(221,859)	6,451,668	6,177,636	(274,032)
Street Lighting	8,556	8,419	(137)	76,012	76,516	504	84,568	84,935	368
Total	16,372,132	16,103,009	(269,123)	58,470,440	58,739,563	269,123	74,842,571	74,842,571	-

Note: Does not include Other Operating Revenues

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4

5

Table 27: Snow Summit Changes in Revenue Allocation from Revenue at Present Rates (%)

	Supply Revenue Requirements			Base Revenue Requirements			Total Revenue Requirements		
	BVES	Snow Summit	Change	BVES	Snow Summit	Change	BVES	Snow Summit	Change
Residential Permanent	-10.1%	-11.5%	-1.4%	30.2%	31.5%	1.3%	18.2%	18.7%	0.6%
Residential Non-Permanent	-8.8%	-10.2%	-1.4%	26.3%	27.4%	1.1%	16.2%	16.6%	0.4%
A1 Commercial	-10.1%	-11.5%	-1.4%	25.5%	26.5%	1.1%	18.1%	18.6%	0.5%
A2 Commercial	-7.8%	-9.2%	-1.4%	26.0%	27.1%	1.1%	14.6%	15.0%	0.4%
A3 Commercial	-10.8%	-12.2%	-1.4%	22.3%	23.2%	0.9%	12.0%	12.2%	0.2%
A4 TOU	-11.8%	-13.2%	-1.4%	23.1%	24.1%	0.9%	24.7%	25.4%	0.7%
A5 Secondary	-6.6%	-8.0%	-1.5%	42.4%	44.4%	2.0%	12.0%	7.3%	-4.8%
A5 Primary	-13.6%	-15.6%	-2.0%	32.8%	25.8%	-7.0%	31.1%	31.6%	0.6%
Street Lighting	-5.7%	-7.2%	-1.5%	37.1%	38.0%	0.9%	16.6%	16.6%	0.0%
Total	-10.2%	-11.6%	-1.5%	27.2%	27.8%	0.6%	18.2%	18.7%	0.6%

Note: Does not reflect changes in Other Operating Revenues

6

7

Q. What assumptions did you use in the development of Snow Summit's revenue allocation?

A. I used Snow Summit's revised forecast of loads for the A5-P customer class. In addition, I excluded the Snow Summit substation and associated distribution equipment from the net plant additions used in the calculations of unit marginal Distribution demand costs. As noted above, using the revised forecast for the loads for the A5-P customer class affects the calculation of BVES's unit marginal costs as well as the Supply revenue requirement.

Q. Please present Snow Summit's proposed revenue allocation for the Test Year and attrition years.

A. The following table presents Snow Summit's proposed revenue allocation for 2026-2030:

Table 28: Snow Summit Revenue Allocation for 2027-2030 (\$)

Base and Supply Revenue Targets	2026	2027	2028	2029	2030
Residential Permanent Service	14,530,082	16,732,747	17,269,719	17,642,727	18,681,888
Residential Non-Permanent Service	25,141,698	30,751,262	33,239,774	35,808,465	39,555,602
General Service - Small (A1)	8,466,164	10,172,976	10,871,901	11,556,975	12,646,139
General Service - Medium (A2)	2,606,700	2,946,329	2,944,380	2,928,591	2,985,875
General Service - Large (A3)	3,644,683	4,340,133	4,361,082	4,466,700	4,824,964
General Service - Time-of-Use (A4-TOU)	2,280,931	2,847,305	3,235,460	3,267,581	3,214,802
Time-of-Use Service (A5 TOU Secondary)	629,322	789,248	825,844	856,497	921,599
Time-of-Use Service (A5 TOU Primary)	5,749,203	6,177,636	6,436,587	6,616,690	7,125,912
Street Lighting	64,529	84,935	89,407	94,199	100,980
Total Revenues excl. OOR	63,113,312	74,842,571	79,274,154	83,238,425	90,057,761
Year-over-Year Increase %		18.6%	5.9%	5.0%	8.2%
Other Operating Revenues (OOR)	1,884,921	1,885,007	1,885,093	1,885,178	1,885,264
Total Revenues w/ OOR	64,998,233	76,727,578	81,159,247	85,123,603	91,943,026

Q. What are the average revenue requirements per kWh sales for each class and year?

A. The following table presents the average revenue requirements per kWh sales:⁵³

Table 29: Snow Summit Revenue Requirements per kWh Sales (\$/kWh)

Average Revenue per kWh Sales	2026	2027	2028	2029	2030
Residential Permanent Service	0.377	0.441	0.462	0.479	0.515
Residential Non-Permanent Service	0.537	0.638	0.670	0.701	0.752
General Service - Small (A1)	0.446	0.520	0.545	0.569	0.611
General Service - Medium (A2)	0.435	0.515	0.541	0.566	0.607
General Service - Large (A3)	0.498	0.573	0.601	0.629	0.675
General Service - Time-of-Use (A4-TOU)	0.411	0.461	0.483	0.501	0.539
Time-of-Use Service (A5 TOU Secondary)	0.290	0.363	0.380	0.394	0.424
Time-of-Use Service (A5 TOU Primary)	0.310	0.333	0.347	0.357	0.385
Street Lighting	0.691	0.910	0.958	1.009	1.082

The following table presents the annual change in revenue requirements per kWh sales based on the above table:

Table 30: Snow Summit Annual Change in Revenue Requirements per kWh Sales (%)

Average Revenue per kWh Sales	2027	2028	2029	2030
Residential Permanent Service	16.9%	4.7%	3.8%	7.6%
Residential Non-Permanent Service	18.7%	5.0%	4.6%	7.4%
General Service - Small (A1)	16.6%	4.9%	4.4%	7.4%
General Service - Medium (A2)	18.6%	5.0%	4.6%	7.4%
General Service - Large (A3)	15.0%	5.0%	4.6%	7.4%
General Service - Time-of-Use (A4-TOU)	12.2%	4.7%	3.9%	7.6%
Time-of-Use Service (A5 TOU Secondary)	25.4%	4.6%	3.7%	7.6%
Time-of-Use Service (A5 TOU Primary)	7.3%	4.3%	2.8%	7.8%
Street Lighting	31.6%	5.3%	5.4%	7.2%

Q. Why should the Commission adopt Snow Summit's recommended revenue allocation?

⁵³ BVES's MCS model has hard-coded sales values for 2027-2030. Snow Summit estimated sales for each customer class based on its proposed load forecast and the implied loss factors in BVES's sales and load forecasts for each class.

1 A. As discussed above, BVES's forecast of loads for the A5-P customer class is
2 unreasonable. Snow Summit revised that forecast to reflect the likely loads during the
3 non-snowmaking months, which BVES forecast to inexplicably increase in 2025 relative
4 to 2024 (and which remain unreasonably high in 2026-2030). To correct this error, Snow
5 Summit recommended using the average of loads for 2024 (based on actual data) and
6 2025 (based on BVES's forecast) as the basis for loads during the non-snowmaking
7 months for 2026-2030. This is a reasonable adjustment since Snow Summit has not
8 installed new equipment or changed operations during its non-snowmaking months.⁵⁴
9
10 Snow Summit also adjusted BVES's forecasted loads for the A5-P class during
11 snowmaking months. Snow Summit examined the actual loads in the snowmaking
12 months for the A5-P class in 2026 and found that BVES's forecast for 2026 was
13 approximately 25% higher than actual loads. To correct this error, Snow Summit
14 conservatively adjusted BVES's loads in the snowmaking months downward by 12.5%
15 (i.e., only half of the forecast error seen in 2026). This is also a conservative and
16 reasonable adjustment.⁵⁵
17
18 Snow Summit had planned to examine the BVES load forecasts for other customer
19 classes as well but BVES did not provide monthly loads for 2025 or 2026 for other
20 customer classes, as Snow Summit requested. The Commission should be less concerned
21 about the potential for huge forecasting errors in the loads for other customer classes

⁵⁴ Snow Summit RO Testimony, p. 7.

⁵⁵ Snow Summit RO Testimony, pp. 26-28.

1 since there were not the same type of major changes in loads for those classes between
2 2024 and the forecast years of 2025-2030 as were seen for the A5-P class.

3
4 The Commission should also adopt Snow Summit's recommended changes to the
5 calculation of unit marginal Distribution demand cost. Snow Summit is paying 100% of
6 the costs for the substations and distribution equipment associated with the new Snow
7 Summit Substations, meaning that the marginal cost of that equipment is zero for other
8 customer classes.

9
10 Snow Summit's recommended changes result in a more reasonable revenue requirement
11 estimate for BVES. In addition, they provide superior estimates of unit marginal costs
12 and marginal cost-based revenue requirements, which serve as the basis of BVES's
13 EPMC-based revenue allocation proposal. Even though BVES's revenue allocation
14 proposal relies on only 10% of the EPMC-based revenue allocation, correct marginal
15 costs and a proper marginal cost-based revenue allocations promote the efficient use of
16 electricity. The Commission has found this in countless other proceedings, including in
17 past BVES GRCs.

19 **V. Recommendations and Conclusion**

21 **Q. What is your overall recommendation?**

22 A. The Commission should adopt Snow Summit's recommendations regarding revisions to
23 BVES's revenue requirements, marginal costs and revenue allocation. In addition, the

1 Commission should order BVES to undertake a stakeholder process to examine the
2 distribution capacity costs avoided by interruptible customers.

3

4 **Q. Does this conclude your opening testimony?**

5 A. Yes, at this time.

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ATTACHMENT 1

6

RESUME FOR WILLIAM A. MONSEN

RESUME FOR WILLIAM ALAN MONSEN

PROFESSIONAL EXPERIENCE

Principal Consultant MRW & Associates, LLC (1989 - Present)

Specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options. Typical assignments include: analysis, testimony preparation and strategy development in large, complex regulatory intervention efforts regarding the economic benefits of utility mergers and QF participation in California's biennial resource acquisition process, analysis of markets for non-utility generator power in the western US, China, and Korea, evaluate the cost-effectiveness of onsite power generation options, sponsor testimony regarding the value of a major new transmission project in California, analyze the value of incentives and regulatory mechanisms in encouraging utility-sponsored DSM, negotiating non-utility generator power sales contract terms with utilities, and utility ratemaking.

Energy Economist Pacific Gas & Electric Company (1981 - 1989)

Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff University of Wisconsin-Madison Solar Energy Laboratory (1980 - 1981)

Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of Department of Energy's System Simulation and Economic Analysis working group.

EDUCATION

M.S., Mechanical Engineering, University of Wisconsin-Madison, 1980.

B.S., Engineering Physics, University of California, Berkeley, 1977.

Prepared Testimony and Expert Reports

1. California Public Utilities Commission (CPUC) Applications 90-08-066, 90-08-067, 90-09-001
Prepared Testimony with Aldyn W. Hoekstra regarding the California-Oregon Transmission Project for Toward Utility Rate Normalization (TURN). November 29, 1990.
2. CPUC Application 90-10-003
Prepared Testimony with Mark A. Bachels regarding the Value of Qualifying Facilities and the Determination of Avoided Costs for the San Diego Gas & Electric Company for the Kelco Division of Merck & Company, Inc. December 21, 1990.
3. California Energy Commission Docket No. 93-ER-94
Rebuttal Testimony regarding the Preparation of the 1994 Electricity Report for the Independent Energy Producers Association. December 10, 1993.
4. CPUC Rulemaking 94-04-031 and Investigation 94-04-032
Prepared Testimony Regarding Transition Costs for The Independent Energy Producers. December 5, 1994.
5. Massachusetts Department of Telecommunications and Energy DTE 97-120
Direct Testimony regarding Nuclear Cost Recovery for The Commonwealth of Massachusetts Division of Energy Resources. October 23, 1998.
6. CPUC Application 97-12-039
Prepared Direct Testimony Evaluating an Auction Proposal by SDG&E on Behalf of The California Cogeneration Council. June 15, 1999.
7. CPUC Application 99-09-053
Prepared Direct Testimony of William A. Monsen on Behalf of The Independent Energy Producers Association. March 2, 2000.
8. CPUC Application 99-09-053
Prepared Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association. March 16, 2000.
9. CPUC Rulemaking 99-10-025
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. July 3, 2000.

10. CPUC Application 99-03-014
Joint Testimony Regarding Auxiliary Load Power and Stand-By Metering on Behalf of Duke Energy North America. September 29, 2000.
11. CPUC Rulemaking 99-11-022
Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 7, 2001.
12. CPUC Rulemaking 99-11-022
Rebuttal Testimony of the Independent Energy Producers Association Regarding Short-Run Avoided Costs. May 30, 2001.
13. CPUC Application 01-08-020
Direct Testimony on Behalf of Bear Mountain, Inc. in the Matter of Southern California Water Company's Application to Increase Rates for Electric Service in the Bear Valley Electric Customer Service Area. December 20, 2001.
14. CPUC Application 00-10-045; 01-01-044
Direct Testimony on Behalf of the City of San Diego. May 29, 2002.
15. CPUC Rulemaking 01-10-024
Prepared Direct Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. May 31, 2002.
16. CPUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of Independent Energy Producers and Western Power Trading Forum. June 5, 2002.
17. Arizona Corporation Commission Docket Numbers E-00000A-02-0051, E-01345A-01-0822, E-0000A-01-0630, E-01933A-98-0471, E01933A-02-0069
Rebuttal Testimony on Behalf of AES NewEnergy, Inc. and Strategic Energy L.L.C.: Track A Issues. June 11, 2002.
18. CPUC Application 00-11-038
Testimony on Behalf of the Alliance for Retail Energy Markets in the Bond Charge Phase of the Rate Stabilization Proceeding. July 17, 2002.
19. CPUC Rulemaking 01-10-024
Prepared Testimony in the Renewable Portfolio Standard Phase on Behalf of Center for Energy Efficiency and Renewable Technologies. April 1, 2003.
20. CPUC Rulemaking 01-10-024
Direct Testimony of William A. Monsen Regarding Long-Term Resource Planning

Issues on Behalf of the City of San Diego. June 23, 2003.

21. CPUC Application 03-03-029
Testimony of William A. Monsen Regarding Auxiliary Load Power Metering Policy and Standby Rates on Behalf of Duke Energy North America. October 3, 2003.
22. CPUC Rulemaking 03-10-003
Opening Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of the Local Government Commission Coalition. April 15, 2004.
23. CPUC Rulemaking 03-10-003
Reply Testimony of William A. Monsen Regarding Phase One Issues Related to Implementation of Community Choice Aggregation on Behalf of Local Government Commission. May 7, 2004.
24. CPUC Rulemaking 04-04-003
Direct Testimony of William A. Monsen Regarding the 2004 Long-Term Resource Plan of San Diego Gas & Electric Company on Behalf of the City of San Diego. August 6, 2004.
25. Sonoma County Assessment Appeals Board
Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.
26. Sonoma County Assessment Appeals Board
Presentation of Results from Expert Witness Report of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. September 10, 2004.
27. Sonoma County Assessment Appeals Board
Presentation of Rebuttal Testimony and Results of William A. Monsen Regarding the Market Price of Electricity in the Matter of the Application for Reduction of Assessment of Geysers Power Company, LLC, Sonoma County Assessment Appeals Board, Application Nos.: 01/01-137 through 157. October 18, 2004.
28. CPUC Rulemaking 04-03-017
Testimony of William A. Monsen Regarding the Itron Report on Behalf of the City of San Diego. April 13, 2005.
29. CPUC Rulemaking 04-03-017
Rebuttal Testimony of William A. Monsen Regarding the Cost-Effectiveness of

- Distributed Energy Resources on Behalf of the City of San Diego. April 28, 2005.
30. CPUC Application 05-02-019
Testimony of William A. Monsen SDG&E's 2005 Rate Design Window Application on Behalf of the City of San Diego. June 24, 2005.
 31. CPUC Rulemaking 04-01-025, Phase II
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 18, 2005.
 32. CPUC Application 04-12-004, Phase I
Direct Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. July 29, 2005.
 33. CPUC Application 04-12-004, Phase I
Rebuttal Testimony of William A. Monsen on Behalf of Crystal Energy, LLC. August 26, 2005.
 34. CPUC Rulemakings 04-04-003 and 04-04-025
Prepared Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. August 31, 2005.
 35. CPUC Application 05-01-016 et al.
Prepared Testimony of William A. Monsen Regarding SDG&E's Critical Peak Pricing Proposal on Behalf of the City of San Diego. October 5, 2005.
 36. CPUC Rulemakings 04-04-003 and 04-04-025
Prepared Rebuttal Testimony of William A. Monsen Regarding Avoided Costs on Behalf of the Independent Energy Producers. October 28, 2005.
 37. Public Utilities Commission of the State of Colorado Docket No. 05A-543E
Answer Testimony of William A. Monsen on Behalf of AES Corporation and the Colorado Independent Energy Association. April 18, 2006.
 38. CPUC Application 04-12-004
Prepared Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 14, 2006.
 39. CPUC Application 04-12-004
Prepared Rebuttal Testimony of William A. Monsen Regarding Firm Access Rights on Behalf of Clearwater Port, LLC. July 31, 2006.

40. Public Utilities Commission of Nevada Dockets 06-06051 and 06-07010
Testimony of William A. Monsen on Behalf of the Nevada Resort Association
Regarding Integrated Resource Planning. September 13, 2006.
41. CPUC Application 07-01-047
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning
the Application of San Diego Gas & Electric Company for Authority to Update
Marginal Costs, Cost Allocation, and Electric Rate Design. August 10, 2007.
42. Public Utilities Commission of the State of Colorado Docket No. 07A-447E
Answer Testimony of William A. Monsen on Behalf of the Colorado Independent
Energy Association. April 28, 2008.
43. CPUC Application 08-02-001
Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil
Department Concerning the Application of San Diego Gas & Electric Company and
Southern California Gas Company for Authority to Revise Their Rates Effective
January 1, 2009 In Their Biennial Cost Allocation Proceeding. June 18, 2008.
44. CPUC Application 08-02-001
Rebuttal Testimony of William A. Monsen On Behalf of the City of Long Beach Gas
& Oil Department Concerning the Application of San Diego Gas & Electric Company
and Southern California Gas Company for Authority to Revise Their Rates Effective
January 1, 2009 In Their Biennial Cost Allocation Proceeding. July 10, 2008.
45. CPUC Application 08-06-001 et al.
Prepared Testimony of William A. Monsen On Behalf of the California Demand
Response Coalition Concerning Demand Response Cost-Effectiveness and Baseline
Issues. November 24, 2008.
46. CPUC Application 08-02-001
Testimony of William A. Monsen On Behalf of the City of Long Beach Gas & Oil
Department Concerning Revenue Allocation and Rate Design Issues in The San
Diego Gas & Electric Company and Southern California Gas Company Biennial Cost
Allocation Proceeding. December 23, 2008.
47. CPUC Application 08-06-034
Testimony of William A. Monsen On Behalf of Snow Summit, Inc. Concerning Cost
Allocation and Rate Design. January 9, 2009.
48. CPUC Application 08-02-001
Rebuttal Testimony of William A. Monsen on Behalf of the City of Long Beach Gas
& Oil Department Concerning Revenue Allocation and Rate Design Issues in The
San Diego Gas & Electric Company and Southern California Gas Company Biennial
Cost Allocation Proceeding. January 27, 2009.

49. CPUC Application 08-11-014
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Cost Allocation and Electric Rate Design. April 17, 2009.
50. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. – Notice of Confidentiality: A Portion of Document Has Been Filed Under Seal. October 2, 2009.
51. Public Utilities Commission of the State of Colorado Docket No. 09-AL-299E
Supplemental Answer Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. October 8, 2009.
52. Public Utilities Commission of the State of Colorado Docket No. 09AL-299E
Surrebuttal Testimony of William A. Monsen on Behalf of Copper Mountain, Inc. and Vail Summit Resorts, Inc. December 18, 2009.
53. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, “Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana,” September 15, 2010.
54. United States District Court for the District of Montana, Billings Division, Rocky Mountain Power, LLC v. Prolec GE, S De RL De CV Case No. CV-08-112-BLG-RFC, “Supplemental Findings and Conclusions Regarding Evaluation of Business Interruption Loss Associated with a Fault on December 15, 2007, of a Generator Step-Up (GSU) Transformer at the Hardin Generating Station, Located in Hardin, Montana,” November 2, 2010.
55. CPUC Application 10-05-006
Testimony of William Monsen on Behalf of the Independent Energy Producers Association in Track III of the Long-Term Procurement Planning Proceeding Concerning Bid Evaluation. August 4, 2011.
56. Public Utilities Commission of the State of Colorado Docket No. 11A-869E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association, Colorado Energy Consumers and Thermo Power & Electric LLC. June 4, 2012.
57. CPUC Application 11-10-002
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocations, and Electric Rate Design. June 12, 2012.

58. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Cross Answer Testimony of William A. Monsen on Behalf of Colorado
Independent Energy Association, Colorado Energy Consumers and Thermo Power
& Electric LLC. July 16, 2012.
59. CPUC Rulemaking 12-03-014
Reply Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Concerning Track One of the Long-Term Procurement
Proceeding. July 23, 2012.
60. CPUC Application 12-03-026
Testimony of William A. Monsen on Behalf of the Independent Energy Producers
Association concerning Pacific Gas and Electric Company's Proposed Acquisition
of the Oakley Project. July 23, 2012.
61. CPUC Application 12-02-013
Testimony of William A. Monsen on Behalf of Snow Summit, Inc. Concerning
Revenue Requirement, Marginal Costs, and Revenue Allocation. July 27, 2012.
62. CPUC Application 12-03-026
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Concerning Pacific Gas and Electric Company's Proposed
Acquisition of the Oakley Project. August 3, 2012.
63. CPUC Application 12-02-013
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit, Inc. in
Response to the Division of Ratepayer Advocates' Opening Testimony. August 27,
2012.
64. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Answer Testimony of William A. Monsen on Behalf of Colorado
Independent Energy Association, Colorado Energy Consumers and Thermo Power &
Electric LLC. September 14, 2012.
65. Public Utilities Commission of the State of Colorado Docket No 11A-869E
Supplemental Cross Answer Testimony of William A. Monsen on Behalf of
Colorado Independent Energy Association, Colorado Energy Consumers and
Thermo Power & Electric LLC. October 5, 2012.
66. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Direct Testimony of
William A. Monsen. November 16, 2012.

67. Public Utilities Commission of the State Oregon Docket No UM 1182
Northwest and Intermountain Power Producers Coalition Exhibit 300 Witness
Reply Testimony of William A. Monsen. January 14, 2013.
68. CPUC Rulemaking 12-03-014
Testimony of William A. Monsen on Behalf of the Independent Energy Producers
Association Concerning Track 4 of the Long-Term Procurement Plan Proceeding.
September 30, 2013.
69. CPUC Rulemaking 12-03-014
Rebuttal Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Concerning Track 4 of the Long-Term Procurement Plan
Proceeding. October 14, 2013.
70. CPUC Application 13-07-021
Response Testimony of William A. Monsen on Behalf of Interwest Energy Alliance
Regarding the Proposed Merger of NV Energy, Inc. with Midamerican Energy
Holdings Company. October 24, 2013.
71. CPUC Application 13-12-012
Testimony of William A. Monsen on Behalf of Commercial Energy Concerning
SDG&E's 2015 Gas Transmission and Storage Rate Application. August 11, 2014.
72. Public Utilities Commission of Nevada Docket No. 14-05003
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. August
25, 2014.
73. CPUC Application 13-12-012/I.14-06-016
Rebuttal Testimony of William A. Monsen on Behalf of Commercial Energy
Concerning SDG&E's 2015 Gas Transmission & Storage Application. September
15, 2014.
74. CPUC Rulemaking 12-06-013
Testimony of William A. Monsen on Behalf of Vote Solar Concerning Residential
Electric Rate Design Reform. September 15, 2014.
75. CPUC Rulemaking 13-12-010
Opening Testimony of William A. Monsen on Behalf of the Independent Energy
Producers Association Regarding Phase1A of the 2014 Long-Term Procurement
Planning Proceeding. September 24, 2014.
76. CPUC Application 14-01-027
Testimony of William A. Monsen on Behalf of the City of San Diego Concerning
the Application of SDG&E for Authority to Update Electric Rate Design.
November 14, 2014.

77. CPUC Application 14-01-027
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Concerning the Application of SDG&E for Authority to Update Electric Rate Design. December 12, 2014.
78. CPUC Rulemaking 13-12-010
Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Supplemental Testimony in Phase 1A of the 2014 Long-Term Procurement Planning Proceeding. December 18, 2014.
79. CPUC Application 14-06-014
Opening Testimony of William A. Monsen on Behalf of the Independent Energy Producers Association Regarding Standby Rates in Phase 2 of SCE's 2015 Test Year General Rate Case. March 13, 2015.
80. CPUC Application 14-04-014
Opening Testimony of William A. Monsen on Behalf of ChargePoint, Inc. Regarding SDG&E's Vehicle Grid Integration Pilot Program. March 16, 2015.
81. Public Utilities Commission of the State of Hawaii Docket No. 2015-0022
Direct Testimony on Behalf of AES Hawaii, Inc. July 20, 2015.
82. Federal Energy Regulatory Commission Docket Nos. EL02-60-007 and EL02-62-006 (Consolidated)
Prepared Answering Testimony of William A. Monsen on Behalf of Iberdrola Renewables Regarding Rate Impacts of the Iberdrola Contract. July 21, 2015.
83. Public Utilities Commission of Nevada Docket Nos. 15-07041 and 15-07042
Prepared Direct Testimony of William A. Monsen on Behalf of the Alliance for Solar Choice (TASC). October 27, 2015.
84. Arizona Corporation Commission Docket No. E-00000J-14-0023
Rebuttal Testimony of William A. Monsen on Behalf of the Alliance for Solar Choice (TASC). April 7, 2016.
85. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A. Monsen. June 1, 2016.
86. Public Utilities Commission of the State of Colorado Proceeding No. 16AL-0048-E
Answer Testimony of William A. Monsen on Behalf of Vail Summit Resorts, Inc. June 6, 2016.
87. CPUC Application 15-04-012
Direct Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. July 5, 2016.

88. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Direct Testimony of William A. Monsen and Patrick J. Quinn. July 29, 2016.
89. Arizona Corporation Commission Docket No. E-01461A-15-0363
The Energy Freedom Coalition of America's (EFCA) Rebuttal Testimony of William A. Monsen. August 15, 2016.
90. CPUC Application 15-04-012
Rebuttal Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. October 14, 2016.
91. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027
Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. November 10, 2016.
92. CPUC Application 15-04-012
Joint Supplemental Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, R. Thomas Beach on Behalf of The Solar Energy Industries Association, Maurice Brubaker on Behalf of The Federal Executive Agencies, And William A. Monsen on Behalf of the City of San Diego. November 14, 2016.
93. CPUC Application 15-04-012
Joint Supplemental Testimony of Cynthia Fang on Behalf of San Diego Gas & Electric Company, Nathan Chau on Behalf of The Office of Ratepayer Advocates, William Monsen on Behalf of the City of San Diego and Alison M. Lechowicz on Behalf of the California City-County Street Light Association. November 16, 2016.
94. Public Utilities Commission of Nevada Docket No. 16-07001 and 16-08027
Supplemental Direct Testimony of William A. Monsen on Behalf of Ormat Nevada Inc. November 17, 2016.
95. Public Utilities Commission of the State of Colorado Proceeding No. 16A-0396E
Answer Testimony of William A. Monsen on Behalf of Colorado Independent Energy Association. December 9, 2016.
96. JAMS Arbitration Case No: 1220049998
Declaration of William A. Monsen on Behalf of Watson Cogeneration Company and Camino Energy, LLC. January 11, 2017.
97. CPUC Application A.16-06-013
Direct Testimony of William A. Monsen and Anna Casas on Behalf of South San Joaquin Irrigation District. March 15, 2017.

98. CPUC Application A.16-09-003
Direct Testimony of William A. Monsen on Behalf of the California Solar Energy Industries Association in Southern California Edison's Rate Design Window Application. April 28, 2017.
99. American Arbitration Association Case No. 01-16-0002-2121
Claimant Buena Vista Biomass Power, LLC's Expert Witness Disclosure. August 18, 2017.
100. American Arbitration Association Case No. 01-16-0005-1073
Expert Report of William A. Monsen on Behalf of Saguaro Power Company. September 15, 2017.
101. CPUC Application A.17-05-004
Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application. September 29, 2017.
102. CPUC Application A.17-05-004
Rebuttal to Testimony by the Office of Ratepayer Advocates by William A. Monsen on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case Application. October 27, 2017.
103. Superior Court of California, County of San Diego Case No. 37-2015-00014540-CU-MC-CTL
Declaration in Support of Defendant's Motion for Summary Judgement, or in the Alternative, Motion for Summary Adjudication. February 3, 2018.
104. CPUC Application 17-06-030
Testimony of William A. Monsen on Behalf of the Coalition for Affordable Street Lights Concerning Street Light Rates and LED Conversions. March 23, 2018.
105. CPUC Application 17-09-006
Direct Testimony of William A. Monsen on Behalf of The Western Manufactured Housing Communities Association in Pacific Gas & Electric's 2018 Gas Cost Allocation and Rate Design Proceeding. June 20, 2018.
106. JAMS Arbitration No. 1100088728
Expert Report by William A. Monsen for Aera Energy, LLC. July 24, 2018.
107. JAMS Arbitration No. 1100088728
Conclusions and Summary of Opinions of William A. Monsen for Aera Energy, LLC. July 24, 2018.
108. CPUC Application 18-03-003
Prepared Joint Testimony of Brandon Charles on Behalf of the California Farm

- Bureau Federation, William A. Monsen on Behalf of the City of San Diego and Cynthia Fang on Behalf of San Diego Gas and Electric Company. August 20, 2018.
109. CPUC Application 18-03-003
Prepared Supplemental Testimony of Brandon Charles on Behalf of the California Farm Bureau Federation, William A. Monsen on Behalf of the City of San Diego and Cynthia Fang on Behalf of San Diego Gas and Electric Company. September 27, 2018.
 110. CPUC Application 19-03-002
Direct Testimony of William A. Monsen on Behalf of the City of San Diego Regarding Marginal Costs, Revenue Allocation, and Rate Design. April 6, 2020.
 111. CPUC Application 19-11-019
Direct Testimony of William A. Monsen and Carlo Bencomo-Jasso on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. November 20, 2020.
 112. Rachel Kropp et al vs Southern California Edison Company Case No. BC698926
Declaration of William A. Monsen on Behalf of Brent & Foil, LLP. December 24, 2020.
 113. CPUC Application 19-11-019
Reply Testimony of William A. Monsen and Carlo Bencomo-Jasso on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. February 26, 2021.
 114. CPUC Application 20-10-012
Direct Testimony of William A. Monsen on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design. July 26, 2021.
 115. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E
Hearing Exhibit No. 1000 Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. October 11, 2021.
 116. Kern County Assessment Appeals Board
Testimony of William A. Monsen on Behalf of Clearway Energy Regarding Differences Between Standard Offer Contracts and Modern PPAs. October 19, 2021.
 117. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E
Hearing Exhibit No. 1001 Cross-Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. November 12, 2021.

118. Public Utilities Commission of the State of Colorado Docket No. 21A-0141E
Hearing Exhibit No. 1002 Testimony and Attachments in Opposition to the Non-
Unanimous Partial Settlement Agreement of William A. Monsen on Behalf of the
Colorado Independent Energy Association. December 6, 2021.
119. CPUC Application 21-06-021
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on
Behalf of The Utility Reform Network (TURN). June 13, 2022
120. CPUC Application 22-05-016
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on
Behalf of The Utility Reform Network. March 27, 2023.
121. CPUC Application 22-08-010
Direct Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear
Valley Electric Services General Rate Case. May 26, 2023.
122. CPUC Application 22-08-010
Rebuttal Testimony of William A. Monsen on Behalf of Snow Summit LLC in Bear
Valley Electric Services General Rate Case. June 16, 2023.
123. CPUC Rulemaking 23-01-007
Prepared Testimony of William A. Monsen Addressing Costs of the Diablo Canyon
Power Plant on Behalf of The Utility Reform Network. June 30, 2023.
124. CPUC Application 23-01-008
Direct Testimony of William A. Monsen on Behalf of The City of San Diego
Regarding Marginal Costs, Revenue Allocation, and Rate Design in Application 23-
01-008. January 8, 2024.
125. CPUC Application 23-01-008
Rebuttal Testimony of William A. Monsen on Behalf of The City of San Diego
Regarding Marginal Costs, Revenue Allocation, and Rate Design in Application 23-
01-008. February 7, 2024.
126. CPUC Application 23-05-010
Prepared Direct Testimony of William A. Monsen Addressing Generation Supply
Costs on Behalf of the Utility Reform Network. February 29, 2024.
127. CPUC Application 24-03-018
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's
2025 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform
Network. July 29, 2024.
128. CPUC Application 23-12-014

Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's Proposal to Uprate Capacity at Helms Creek Pumped Storage Project on Behalf of the Utility Reform Network. November 22, 2024.

129. Public Utilities Commission of the State of Colorado Docket No. 24A-0442E Hearing Exhibit No. 700, Rev 2 Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. May 30, 2025.
130. Public Utilities Commission of the State of Colorado Docket No. 24A-0442E Hearing Exhibit No. 701 Cross-Answer Testimony and Attachments of William A. Monsen on Behalf of the Colorado Independent Energy Association. May 23, 2025.
131. CPUC Application 25-03-015
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's 2026 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. July 24, 2025.
132. CPUC Application 25-03-015
Supplemental Testimony of William A. Monsen Addressing Escalators For Fixed Management Fees in Pacific Gas & Electric's 2026 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. October 20, 2025.
133. CPUC Application 25-05-009
Prepared Testimony of William A. Monsen Addressing Generation Supply Costs on Behalf of The Utility Reform Network. February 13, 2026.
134. CPUC Application 24-09-014
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's Proposals Regarding Marginal Costs on Behalf of The Utility Reform Network. March 9, 2026.
135. CPUC Application 26-03-031
Prepared Testimony of William A. Monsen Addressing Pacific Gas & Electric's 2027 Cost Recovery Forecast for Diablo Canyon on Behalf of the Utility Reform Network. July 17, 2026.
136. CPUC Application 26-01-022
Direct Testimony of William A. Monsen Regarding Results of Operations on Behalf of Snow Summit LLC in Bear Valley Electric Services General Rate Case, Application 26-010-022. July 27, 2026.

ATTACHMENT 2

DATA REQUEST RESPONSES REFERENCED IN TESTIMONY

Application 26-01-022
Seventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 1, 2026

7. Refer to BVES's development of marginal distribution costs and marginal substation costs in its MCS model. Please provide the following information regarding BVES's development of those marginal costs:
- a. The theoretical basis upon which BVES relies for using this approach.

RESPONSE: BVES relies on a variation of the NERA Regression method to estimate the marginal distribution and marginal substation cost in its MCS model.

- b. All citations to documents explaining the theoretical basis for BVES using this approach for determination of marginal distribution and marginal distribution substation costs.

RESPONSE: The NERA Regression method has been utilized in the industry for determination of marginal distribution costs, including by other California Investor-Owned Utilities. For example, Southern California Edison and San Diego Gas & Electric utilized the NERA Regression method in A. 20-10-012 and A. 23-01-008 respectively. In addition, BVES utilized the method in its past two rate case applications.

- c. Is BVES aware of the so-called "NERA method" for determining marginal distribution costs? If so, please explain BVES's understanding of the NERA method for determining marginal distribution costs. Does BVES contend that it is using the "NERA method" in this proceeding? If so, where is BVES using it and how.

RESPONSE: Yes. Please refer to responses to parts 7(a) and 7(b). BVES has utilized a variation of the NERA Regression method for determining marginal distribution capacity costs.

BVES' understanding of the NERA method is as follows. The NERA method is a regression-based approach for estimating marginal distribution demand costs by measuring the relationship between cumulative incremental distribution investments and cumulative system load growth. The regression analysis treats load growth as the independent variable and distribution investments as the dependent variable. The analysis produces an estimated marginal cost of distribution capacity, expressed in dollars per kW.

Application 26-01-022
Eighth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 9, 2026

1. Please run BVES's Results of Operations and MCR models in this proceeding using the inputs as described in the following SCENARIOS and provide the results for each SCENARIO:
 - a. SCENARIO 1: Cap hourly sales and loads such that hourly loads do not exceed 47.658 MW. To achieve this reduction in hourly sales and loads, assume that customers in the A5-P class have their loads curtailed.
 - b. SCENARIO 2: Revise sales and loads to customers in the A5-P customer class such that each month's sales and loads during the months of April-October in 2025-2030 are equal to each month's sales and loads during the corresponding months of April-October in 2024. That is, do not assume the increase in sales and loads to A5-P customers that BVES assumes between 2025 and 2026 during non-snowmaking months.
 - c. SCENARIO 3: Exclude the following distribution projects from BVES's assumptions used for the development of marginal distribution demand costs for ALL CUSTOMER CLASSES:
 - i. B-001, B-002, B-003, B-004, C-001, C-002, C-003, C-004, C-005, C-006, C-007, C-011, C-012, C-021, C-024, C-025, C-028, C-029, C-030, C-031, C-034, C-037, C-038, C-039, C-041 & C-042.
 - d. SCENARIO 4: Exclude project C-023 from the assumed plant additions for determination of marginal distribution demand costs for ALL CUSTOMER CLASSES.

If BVES has any uncertainty about the scope and assumptions for the above requests, please let Snow Summit know so that Snow Summit can provide clarification to BVES.

For each SCENARIO, please provide copies of all inputs and models used to produce the results for the SCENARIO. Please provide the models in Excel in the format used by BVES to analyze each SCENARIO. Please ensure that all models have all formulae live and all links intact.

Application 26-01-022
Ninth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 10, 2026

1. Refer to file “BVES MCS Rate Design_vFinal (CONFIDENTIAL) (With Links).xlsx.” Please respond to the following requests:
 - a. Please provide the source and all workpapers for the hourly loads in tab “MGE-Derivation.” If there are models that provide inputs to the requested workpapers, please provide those as well.
 - b. Please explain why the hourly loads in tab “Hourly kWh” are not equal to the hourly loads in tab “MGE-Derivation.”
 - c. Please provide the source and all workpapers supporting the development of the “Total Net Energy Expenditures (\$ /MWh)” in cells F16:F35075 in tab “MGE-Derivation.”

Response:

- a. Please refer to ‘BVES GRC Supply Forecast Model MAIN FILE.xlsx’, Tab: ‘Input Loads & Resources’, Column E. Note that this file was submitted as part of the response to Snow Summit’s DR 004.
- b. The 2027-2030 hourly loads in Tab: ‘MGE-Derivation’, Column E are equal to system hourly loads in Tab: ‘Hourly kWh’, Column E, except for 1) the hours where total system load exceeds 47.40 MW and 2) for the hours where daylight saving time begins or ends.

The hourly loads in Tab: ‘MGE Derivation’, Column E, are capped at 47.40 MW. For an explanation of the 47.40 MW cap, please refer to Company’s response to Tenth Set of Data Requests of Snow Summit, Question 1(b).

- c. Please refer to ‘BVES GRC Supply Forecast Model MAIN FILE.xlsx’, Tab: ‘Input Loads & Resources’, Column AV.
2. Please explain the basis for the “50%” factor used to determine the Total CP Demand Driven and Total NCP Demand Driven Long Run Unit Investment in tab MDD-Plant_Inv in BVES’s MCR model (for example, see cells D47 and G52). Please provide all workpapers and documents supporting the development of those factors.

Response:

The 50.0 percent factor represents the Company’s judgement that approximately 50.00 percent of distribution plant investments recorded under Accounts 360-367 are due to an increase in CP system demands and 50.00 percent are due to an increase in NCP demands. The 50.0 percent factor is consistent with the marginal cost of service studies filed in the

Company's prior two applications (Application No. 22-08-010 and Application No. 17-05-004).

5. Please explain why the coincident peak demand values for "System_Kw" for 2027, 2028, and 2029 in tab "CP kW" in BVES's MCR model do not match the maximum values found for "System Kw" for 2027, 2028, and 2029 in tab "Hourly kWh." Also, please explain why the two highest values for "System Kw" in tab "Top_100" do not match the coincident peak demand for System found in tab "CP kW" for 2027.

Response:

In preparation of this discovery response, the Company has discovered that system coincident peak (CP) demands for 2020-2024 and 2027-2029 were inadvertently derived from hours other than the annual system maximum demand hours. This explains the referenced differences in CP demands.

The Company will correct the system CP demands as part of its Rebuttal testimony filing. A comparison of filed and corrected demands is provided below.

System Coincident Peak Demands (kW)			
Year	Filed	Corrected	Difference
2016	42,795	42,795	0
2017	40,217	40,217	0
2018	40,330	40,330	(0)
2019	42,970	42,970	0
2020	37,050	39,177	2,127
2021	36,391	38,287	1,896
2022	33,788	41,670	7,882
2023	32,850	42,059	9,209
2024	41,658	41,748	50
2025	54,709	54,709	0
2026	55,110	55,110	0
2027	54,649	54,781	133
2028	54,888	54,994	106
2029	55,228	55,294	66
2030	56,231	56,231	(0)

Application 26-01-022
Tenth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 13, 2026

1. Refer to “BVES GRC Supply Forecast Model MAIN FILE CONFIDENTIAL.xlsx” tab “Load Forecast Input” and please respond to the following questions:

- a. Confirm that the maximum value in the Load Forecasts for 2027-2030 is 47.4 MW.

Response: Yes. The maximum load forecast for 2027–2030 in the Supply Model is 47.4 MW, reflecting BVES’s contractual transmission capacity (39 MW) plus 8.4 MW from the Bear Valley Power Plant. The forecast does not include the BESS project’s additional 5 MW of peak capacity. Physical system limits may exceed contractual limits but vary depending on operating conditions and system configuration.

- b. Please explain how the load forecasts in this model are consistent with the values in tab “Hourly kWh” in BVES’s MCR model. If these load forecasts are not consistent, please explain why BVES uses a load forecast for development of its marginal costs and a different forecast for the development of its power supply costs.

Response: The supply forecast model reflects hourly operational constraints and resources used for day-ahead energy balancing and imbalance energy, while the MCR model uses load forecasts developed specifically to calculate marginal costs. As mentioned in response to question 1a, the Supply Model caps load at 47.4 MW, while load forecasts in the MCR do not have this constraint at corresponding hours. Moreover, hourly load forecasts in the MCR model do not factor in the impacts of daylight savings time.

Accordingly, differences reflect each model’s intended use and assumptions. See 1.a above for additional details.

2. Please provide the actual hourly loads for each customer class for 2024 to present. Please also provide BVES’s forecast of those hourly loads for each customer class for 2024 to present. Please provide this Excel. Please also provide a citation to BVES’s workpapers if these data were taken from the workpapers. Please also indicate if these hourly loads include losses.

Response: Attached is Excel spreadsheet, “snow summit dr10”, containing rate class hourly loads. There are two tabs in the spreadsheet, 2024 hourly rate class load study results and 2025-2030 forecast. All class values include losses.

Application 26-01-022
Eleventh Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 24, 2026

1. Refer to “BVES GRC Supply Forecast Model MAIN FILE CONFIDENTIAL.xlsx” tab “Load Forecast Input” and please respond to the following questions:

- a. Confirm that the maximum value in the Load Forecasts for 2027-2030 is 47.4 MW.

RESPONSE: Refer to DR 9 question 1 and DR 10 question 1a.

- b. Please provide the reason that the maximum value is 47.4 MW.

RESPONSE: Refer to DR 9 question 1, as well as response to question 1b of Snow Summit data request, (DR) 010.

- c. Please explain how the load forecasts in this model are consistent with the values in tab “Hourly kWh” in BVES’s MCR model. If these load forecasts are not consistent, please explain why BVES uses a load forecast for development of its marginal costs and a different forecast for the development of its power supply costs.

RESPONSE: Refer to DR 9 question 1, as well as response to question 1b of Snow Summit data request, (DR) 010.

2. Please provide the actual hourly loads for each customer class for 2024 to present. Please also provide BVES’s forecast of those hourly loads for each customer class for 2024 to present. Please provide this Excel. Please also provide a citation to BVES’s workpapers if these data were taken from the workpapers. Please also indicate if these hourly loads include losses.

RESPONSE: Please see response to DR 010 question 2. Currently, BVES has raw metered reads for 2025 and 2026, but has not gone through class-load study yet. BVES will not be doing the class-load study until the next GRC.

6. Refer to BVES Response to Snow Summit Set 8, Request 1. Please respond to the following questions:
- In the development of its response to Request 1b, did BVES revise its Supply model to account for lower assumed sales to customers in the A5-P class? If so, please explain why the revenue requirements for generation was unchanged in this scenario. If not, please rerun the scenario to include the supply costs and please provide updated results in the format similar to those provided in BVES response to Snow Summit Set 8, Request 1b.

RESPONSE: Refer to BVES's responses to Snow Summit Set 9, Question 1, for additional details. At the request of Snow Summit, BVES modeled the assumptions specified in Request 1b. BVES did not revise its underlying sales forecast or Supply Model to reflect the modeled assumptions requested by Snow Summit. Revising the sales forecast would require a much broader forecasting analysis beyond the requested scenario and would require BVES to invest an unduly burdensome amount of time, cost, and resources to accomplish. Accordingly, the generation revenue requirement remained unchanged.

The requested analysis requires the update of sales forecasts and outputs from BVES's GRC Supply Forecast Model. Note that BVES submitted the "BVES GRC Supply Forecast Model MAIN FILE CONFIDENTIAL.xlsx" for the analysis on June 08, 2026 for Snow Summit's use in modeling assumptions. BVES also submitted the updated Supply Model after the appeal to re-zone the solar project site was rejected, "CONFIDENTIAL BVES GRC Supply Forecast Model (NO SOLAR) 062426.xlsx," on July 14, 2026.

In conformance with Rules 10.3 and 10.4 of the Commission's Rules of Practice and Procedure, BVES has provided to Snow Summit the necessary computer models for Snow Summit to run the scenarios and analyses Snow Summit has requested in Question 6a.

- b. Some of the links to the MCS models provided in responses to this set of questions refer to files located on the ScottMadden server. Please revise your response to refer to files provided to Snow Summit in your responses.

RESPONSE: Please refer to supplemental response to Snow Summit Set 8.

- c. Please confirm that BVES ran ALL MODELS that could affect marginal costs or revenue requirements in the development of BVES's responses to these requests. If BVES did not do so, please identify the responses for which BVES did not run ALL MODELS that could affect marginal costs or revenue allocations and provide updated responses to these requests that are based on BVES running ALL MODELS that could affect marginal costs or revenue requirements.

RESPONSE: BVES ran Scenarios A, C, and D as described in Snow Summit Set 8, Request 1. Please refer to response to Question 6(a) above for further explanation of Scenario B.

Application 26-01-022
Twelfth Set of Data Requests of Snow Summit to
Bear Valley Electric Service
July 31, 2026

1. Refer to BVES Response to Snow Summit Data Request #10, Question 1. Please respond to the following questions:
 - a. BVES response to question 1a indicates that “The supply forecast model reflects hourly operational constraints and resources used for day-ahead energy balancing and imbalance energy, while the MCR model uses load forecasts developed specifically to calculate marginal costs.” Please respond to the following questions:
 - i. Please provide the theoretical justification for using a load forecast for calculation of marginal costs that exceeds the ability of the BVES system to serve those loads. As part of this justification, please provide citations to literature and other material that BVES relied on and that support your justification and provide copies of such literature and other materials.
 - ii. Has BVES’s witness regarding marginal costs ever used such an approach for calculation of marginal costs (i.e., where the load forecast that is the basis for the marginal costs has loads that exceed the delivery capability of the system) in previous testimony? If so, please provide copies of all such testimony and workpapers supporting such testimony. If not, please so state.
 - iii. Is BVES or its consultants aware of any other utilities that use different load forecasts for calculation of marginal costs that exceed the delivery capability of the utility? If so, please identify each such utility and the proceeding in which different load forecasts were used.

RESPONSE:

- i. The forecasted loads utilized for development of marginal costs do not exceed BVES system’s load-serving capability.
 - ii. Please refer to response to Question (a)(i).
 - iii. Please refer to response to Question (a)(i).
- b. Regarding BVES’s use of load forecasts for calculation of marginal costs that exceed the ability of BVES to meet those loads due to “hourly operational constraints and resources used for day-ahead energy balancing and imbalance energy” please respond to the following questions:

- i. Did BVES adjust the historic loads used in the development of marginal costs (i.e., loads for 2024 and before) to be consistent with BVES's approach for its forecasted loads in this proceeding? That is, do the historic loads prior to 2025 in tab "Hourly kWh" in BVES's MCS model ever exceed the ability of BVES to serve those loads at that time? If so, please explain how BVES made these adjustments. If not, please so state and explain why BVES did not make such adjustments.

RESPONSE:

- i. Please refer to response to Question (a)(i).
- c. Refer to BVES's statement in response to Snow Summit-10 question 1a that says "Physical system limits may exceed contractual limits but vary depending on operating conditions and system configuration." Please respond to the following questions:
 - i. Please identify the "operating conditions and system configuration" that allow physical system limits to exceed contractual limits. Please provide any operating standard practices, operator instructions, or other material in BVES's possession that address why and how BVES's physical system limits may "exceed contractual limits."

RESPONSE: The statement in BVES's response to Snow Summit Set 10, Question 1(a) recognizes the distinction between contractual transmission capability used for planning purposes and the physical capability of the electric system under actual operating conditions. For purposes of the GRC Supply Model, BVES uses its contracted import capability of 34 MW at Goldhill and 5 MW at Radford, together with the 8.4 MW Bear Valley Power Plant, resulting in a planning capability of 47.4 MW. This planning assumption does not include the 5 MW/20 MWh Battery Energy Storage System currently under construction.

Physical operating capability is evaluated in real time based on prevailing system conditions, including equipment availability, transmission configuration, feeder loading, apparent power (MVA) limitations, power factor, and applicable reliability criteria. Consequently, planning assumptions used to develop revenue requirements are not intended to represent a fixed operating limit under all system conditions.

BVES does not maintain materials that address why and how BVES's physical system limits may exceed contractual limits.

- ii. In 2024, how many times did “operating conditions and system configuration” allow physical system limits to exceed contractual limits? Please provide a listing of each such event, the date and time of the event, the duration of the event, the reason for exceeding contractual limits, and any notes, logs, memoranda, or other material that relates to these events.

RESPONSE: Please refer to response to question 12f of Snow Summit’s DR 007.

3. Please provide BVES’s total loads by customer class for each month of 2024, 2025, and all months of 2026 for which BVES has such data available. If the data provided by BVES in response to this question are class-specific sales instead of loads, please indicate the appropriate loss factors to use to adjust the monthly sales numbers to loads, such that they are consistent with the hourly loads used by BVES in the development of its marginal costs. Please provide your responses in Excel.

RESPONSE: Please refer to response to question 2 of Snow Summit’s DR 010. Also, please refer to response to question 2 of Snow Summit’s DR 011.