**Application No.**

**Exhibit No. BVES-**

**Date:**

**Witness:**

**BEFORE THE**

**PUBLIC UTILITIES COMMISSION**

**OF THE STATE OF CALIFORNIA**

**BEAR VALLEY ELECTRIC SERVICE, INC.**

**VOLUME 4**

**DIRECT TESTIMONY**

**SUPPLY COSTS HISTORICAL AND FORECAST**

**Prepared by:**

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1. INTRODUCTION and SUMMARY
   1. PURPOSE

The purpose of this testimony is to describe amounts recorded into the Supply Adjustment Balancing Account (“Supply Adjustment Account”) with respect to the historical costs of purchasing and producing energy, the costs of transmission, and other power-related costs incurred to provide energy to BVES’ customers during the period September 1, 2017 through October 31, 2022 (“Review Period”) as well as forecast costs for the period 2023 through 2026.

This testimony will also describe historical revenues recorded into the Supply Adjustment Account during the Review Period and forecasted revenues for the period 2023 through 2026.

* 1. ORGANIZATION

This volume has 5 chapters:

Chapter 1: Introduction and Summary.

Chapter 2: Supply Adjustment Balancing Account Costs: September 1, 2017 through October 31, 2022, sponsored by Julie Roberts.

Chapter 3: Supply Adjustment Balancing Account Revenues: September 1, 2017 through October 31, 2022, sponsored by Julie Roberts.

Chapter 4: Supply Adjustment Balancing Account Cumulative Net Balances September 1, 2017 through October 31, 2022, sponsored by Julie Roberts.

Chapter 5: Forecast of Power Supply Costs 2023 through 2026, sponsored by Sean Matlock.

1. SUPPLY ADJUSTMENT BALANCING ACCOUNT COSTS  
   SEPTEMBER 1, 2017 TO OCTOBER 31, 2022
   1. PURPOSE

The purpose of this testimony is to describe costs recorded into the Supply Adjustment Balancing Account (“Supply Adjustment Account”) during the period September 1, 2017 through October 31, 2022 (“Review Period”). BVES’ Supply Adjustment Account tracks the costs incurred for purchasing and producing energy, the costs of transmission, and other power-related costs incurred to provide energy to BVES’ customers. This testimony will provide the basis for the Commission to conclude that the costs recorded into the Supply Adjustment Account are proper and may be recovered in rates.

The revenues from the Supply Adjustment Account Charges (described below) that were recorded into the Supply Adjustment Account are addressed in Chapter 3 of this Volume.

* 1. BACKGROUND

BVES has a Supply Adjustment Account to track the power supply and delivery-related costs and the revenues generated from certain charges: the “Supply Charge” (formerly known as the “Energy Charge for Purchases”), the “Transmission Charge” (formerly known as the “Power System Delivery Charge”), and the “Supply Adjustment Charge” (formerly known as the “Amortization Charge”). The various charges recorded into the Supply Adjustment Account are collectively referred to as the “Supply Adjustment Account Charges.” Amounts recorded into the Supply Adjustment Account were last reviewed by the Commission in Application 17-05-004.

* 1. SUMMARY AND INTRODUCTION
     1. Supply Adjustment Account Last Reviewed In Application 17-05-004 and Approved in D. 19-08-027.

In BVES’ last general rate case (“GRC”) application, BVES addressed all Supply Adjustment Account[[1]](#footnote-1)-related costs for the period of September 1, 2011 through October 31, 2016. Those costs were approved in D.19-08-027 for recovery in rates. This testimony will address all Supply Adjustment Account-related costs for the period September 1, 2017 through October 31, 2022 (the “Review Period”).

* + 1. Summary of Supply Adjustment Account Costs.

Costs relating to energy supplies, as discussed below, are tracked and recorded into the Supply Adjustment Account. Revenues derived from the Supply Charge and Transmission Charge rates, as described in Chapter 4, are also tracked and recorded into the Supply Adjustment Account.

Long-term and monthly energy contract costs, which are recorded in the Supply Adjustment Account, comprise about 53 percent of the total; day-ahead and imbalance purchases and sales comprise about 8 percent of the total; capacity costs comprise about 7 percent of the total; transmission service on both the SCE and CAISO grids comprise about 8 percent of the total; costs associated with retired renewable energy credits (RECs) to satisfy the state’s Renewables Portfolio Standard comprise about 4 percent of the total; and CAISO costs comprise about 20 percent of the total. Natural gas costs for the Bear Valley Power Plant (“BVPP”) are also tracked in the Supply Adjustment Account and account for about 1 percent of the total.

Some components of supply costs as recorded into the Supply Adjustment Account do not exactly match the supply costs processed by BVES in the course of its operations. One reason for the difference between costs recorded into the Supply Adjustment Account and costs tracked by BVES is the time lag inherent in accrual accounting. Another reason is that the CAISO has the ability to issue settlement adjustments up to 36 months from the initial date on which the CAISO issues an invoice[[2]](#footnote-2). Finally, as discussed in more detail below, only expenses for RECs retired to satisfy annual RPS targets are recorded to the Supply Adjustment Account rather than the total contract expense for the RECs in a given year. In the end, costs recorded in the Supply Adjustment Account will match BVES’ day-to-day operational costs.

Table 2.1 below summarizes by component the supply costs processed by BVES in its day to day operations.

**Table 2.1**

**Supply Adjustment Account Components September 1, 2017 through October 31, 2022**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
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| --- | --- | --- | --- | --- | --- | --- | --- |
| **Cost Component** | **2017 Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** | **Total Costs** |
| SCE Transmission | $292,783 | $861,649 | $858,238 | $885,934 | $885,500 | $736,522 | **$4,520,626** |
| CAISO | $582,354 | $1,961,741 | $2,270,822 | $2,012,935 | $2,420,135 | $1,860,905 | **$11,108,892** |
| Scheduling | $30,000 | $91,829 | $88,341 | $99,900 | $84,000 | $70,000 | **$464,070** |
| Long-Term Purchased Energy | $2,051,133 | $4,993,200 | $5,375,915 | $6,206,719 | $5,644,180 | $4,436,558 | **$28,707,705** |
| Short-Term Purchased Energy | $0 | $935,047 | $664,243 | $0 | $0 | $0 | **$1,599,290** |
| Day Ahead Purchases | $409,038 | $1,125,156 | $1,029,169 | $410,252 | $838,074 | $552,779 | **$4,364,468** |
| CAISO Imbalance Purchase | $97,331 | $400,866 | $401,094 | $380,789 | $601,662 | $541,090 | **$2,422,832** |
| CAISO Imbalance Sales | ($84,349) | ($369,490) | ($415,874) | ($471,989) | ($766,756) | ($333,901) | **($2,442,359)** |
| Renewable Energy Credits (RECs) | $0 | $396,234 | $441,882 | $723,429 | $0 | $528,372 | **$2,089,917** |
| Natural Gas | $3,888 | $28,138 | $153,269 | $116,537 | $168,314 | $125,464 | **$595,610** |
| Natural Gas Transportation | $3,526 | $65,675 | $11,336 | $0 | $0 | $0 | **$80,537** |
| Long-Term RA Capacity | $287,000 | $832,500 | $854,700 | $94,800 | $0.00 | $0 | **$2,069,000** |
| Short-Term RA Capacity | N/A | N/A | N/A | N/A | $1,057,500 | $686,250 | **$1,743,750** |
| Heat Rate Option (Capacity) | N/A | N/A | N/A | N/A | N/A | N/A | **$0** |
| Physical Call Option (Capacity) | $48,800 | N/A | N/A | N/A | N/A | N/A | **$48,800** |
| **Total Costs** | **$3,721,504** | **$11,322,544** | **$11,733,135** | **$10,459,306** | **$10,932,609** | **$9,204,039** | **$57,373,138** |

The testimony in Chapter 2 provides the necessary information for the Commission to approve the costs recorded into the Supply Adjustment Account during the Review Period as shown in the table above. The testimony in Chapter 3 will provide the necessary information to approve the revenues recovered through the applicable Supply Adjustment Account Charges and tracked in the Supply Adjustment Account.

* 1. PURCHASED POWER AGREEMENTS

Table 2.2 below summarizes the long-term and monthly firm power costs, by year, during the Review Period (September 1, 2017 through October 31, 2022). The costs shown in the table represent the total of long and short-term (monthly) firm energy purchases shown in Table 2.1.

Table 2.2

Long-Term and Monthly Firm Power Supply Costs September 1, 2017 to October 31, 2022

|  |  |
| --- | --- |
| **Year** | **Power Supply Costs** |
| 2017\* | $3,721,504 |
| 2018 | $11,322,545 |
| 2019 | $11,733,135 |
| 2020 | $10,459,306 |
| 2021 | $10,932,609 |
| 2022\*\* | $9,204,039 |
| Total | $57,373,138 |
| \* September –December 2017. | |
| \*\* January – October 2022 | |

Table 2.3 below identifies the long-term and short-term (monthly) firm energy contracts in effect during the Review Period.

Table 2.3

Long-Term and Monthly Energy and Capacity Contracts During the Review Period

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Supplier/Counterparty** | **Product** | **Resource** | **Term of**  **Deliveries** | **Contract Length** | **MW Capacity** |
| EDF Trading North America, LLC | Annual Baseload | CAISO Firm Energy | 1/2015-11/30/2019 | 4 yrs, 11 mo | 12 |
| Shell Energy North America (US) L. P. | Seasonal Baseload | CAISO Firm Energy | 1/1 – 2/28  2015 – 2017  12/1 – 12/31  2015 – 2017  11/1 – 11/30  2015 – 2017 | 3 yrs | 5-7 |
| EDF Trading North America, LLC | Physical Call Option (Peaking) | CAISO Firm Energy | 0-3 MW  4/1 – 10/31  2015 – 2017  0 – 7 MW  1/1 – 3/31  11/1 – 12/31  2015 --– 2017 | 3 yrs | 3-7 |
| Shell Energy North America (US) L.P. | System Resource Adequacy Capacity | Gas Turbine, Combined Cycle | 8 – 31MW  3/1/2015 –  1/31/2020 | 4 yrs, 11 mo | 8 - 31\* |
| Powerex Short Term for January 2018 | Monthly Energy | CAISO Firm Energy | 1/1/2018 – 1/31/2018 | 1 Month | 7 |
| Anahau Short Term for February 2018 | Monthly Energy | CAISO Firm Energy | 2/1/2018 – 2/28/2018 | 1 Month | 7 |
| Exelon Generation Company, LLC | Seasonal Baseload | CAISO Firm Energy | 11/1/2018 – 2/28/2019 | 4 mo | 7 |
| Exelon Generation Company, LLC | Seasonal Baseload | CAISO Firm Energy | 11/1/2019 – 2/29/2020  11/1/2020 – 2/28/2021  11/1/2021 – 12/31/2022 | 3 yr, 2 mo | 3 - 7 |
| Morgan Stanley Capital Group, Inc. | Seasonal Baseload | CAISO Firm Energy | –  Shaped Volume | 4 yrs, 11 mo | 7 - 21 |
| California Choice Energy Authority | System Resource Adequacy Capacity | Geothermal | –  18 MW  1/2021  18 MW  2/2021  10 MW  3/2021  10 MW  4/2021  10 MW  5/2021  18 MW  11/2021  18 MW  12/2021 | 1 yr | 10 - 18 |
| California Choice Authority | System with Flexible Resource Adequacy Capacity | Natural Gas | 7 MW  1/2021 – 5/2021  11/2021 – 12/2021 | 1 yr | 7 - 8 |
| Exelon Generation Company, LLC | System Resource Adequacy Capacity | Gas Cogeneration | 6/2021 – 7/2021 | 2 mo | 19 - 21 |
| Exelon Generation Company, LLC | System Resource Adequacy Capacity | Gas Cogeneration | 8/2021 | 1 mo | 20 |
| Marin Clean Energy | System Resource Adequacy | Biomass | 10 – 17 MW  1/2022 – 4//2022  10 MW  6/2022  8MW  10/2022  18 MW  12/2022 | 7 mo | 8 – 18 |
| Marin Clean Energy | System with Flexible Resource Adequacy | Natural Gas | 5 – 17 MW  1/2022 – 6/2022  8 – 20 MW  10/2022 – 12/2022 | 9 mo | 5 - 21 |

\* MW Capacity in RA product refers to the combined amount of RA.

During the Review Period, BVES entered into long-term (defined as periods greater than 12 months in duration) contractual agreements with two suppliers. Both of these long-term contracts, which are listed in the table above, have been reviewed and approved by the Commission in prior proceedings. During the same period, BVES signed a number of monthly contracts with five suppliers. These short-term contracts have not been reviewed by the Commission. A discussion of each energy contract follows.

* + 1. Powerex Short-term Contract for Seasonal On-Peak Energy

BVES purchased on-peak energy from Powerex for the month of January 2018. The costs shown here are included in the costs as “Short-Term Purchased Energy” in Table 2.1.

Table 2.4

Powerex Seasonal On-Peak Energy

|  |  |
| --- | --- |
|  | Total |
| January 2018 | $133,985.60 |

* + 1. Anahau Short-term Contract for Seasonal On-Peak Energy

BVES purchased on-peak energy from Anahau for the month of February 2018. The costs shown here are included in the costs as “Short-Term Purchased Energy” in Table 2.1.

Table 2.5

Anahau Seasonal On-Peak Energy

|  |  |
| --- | --- |
|  | Total |
| February 2018 | $109,132.80 |

* + 1. Exelon Generation Company Short-term Contract for Seasonal Energy

In October 2018, BVES executed a short-term contract with Exelon Generation Company, LLC. For Seasonal Baseload Energy for November 1, 2018 through February 28. 2019. The costs shown here are included in the costs as “Short-Term Purchased Energy” in Table 2.1.

Table 2.6

Exelon Generation Company Seasonal Energy

|  |  |  |  |
| --- | --- | --- | --- |
|  | 2018 | 2019 | Total |
| Seasonal Baseload Cost | $691,928 | $664,243 | $1,356,171 |

* + 1. Exelon Generation Seasonal Baseload (November 1, 2019 – December 31, 2022) Contract

In September 2019, BVES executed a long-term, 3 year, 2 month contract with Exelon Generation Company for Seasonal Baseload Shaped Volume Energy. The costs shown here are included in the costs as “Long-Term Purchased Energy” in Table 2.1.

In Decision (“D”) D.19-08-030 the Commission approved the Exelon Generation Seasonal Baseload contract. The Commission required BVES to exercise prudent administration of the contract over its life. Set forth in Table 2.5 below are the costs related to the annual seasonal baseload product under the Constellation agreement from November 1, 2019 through December 31, 2022. The costs shown here are included in the costs as “Long-Term Purchased Energy” in Table 2.1.

Table 2.7

Exelon Generation Company Seasonal Baseload Costs

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | 2019\* | 2020 | 2021 | 2022\*\* | Total |
| Seasonal Baseload Cost | $294,471 | $585,947 | $583,070 | $288,599 | $1,752,087 |

\*Only November - December 2019

\*\*Only January – October 2022

* + 1. Morgan Stanley Contract

As a result of a 2018-2019 RFP process, BVES executed a contract with Morgan Stanley for a shaped volume of annual firm baseload energy for all hours for the time period of December 2019 through October 2024 for a Total of 606,165 MWh in an hourly shaped format. In Decision (“D”) D.19-08-030 the Commission approved the Morgan Stanley contract. The Commission required BVES to exercise prudent administration of the contract over its life.[[3]](#footnote-3)

Set forth in Table 2.4 below are the costs related to the annual baseload product under the Morgan Stanley agreement from December 1, 2019 through October 31, 2024. The costs shown here are included in the costs as “Long-Term Purchased Energy” in Table 2.1.

Table 2. 8

Morgan Stanley Annual Baseload Costs



|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | 2019\* | 2020 | 2021 | 2022 | Total |
| Annual Baseload Cost | $512,324 | $5,620,772 | $5,061,110 | $4,057,959 | $15,252,165 |

\*Only December 2019.

\*\*January 2022 through October 30, 2022







F. Avangrid RECs Contract

BVES determined it would seek a REC-only contract to meet its RPS requirements after the termination of the LACSD contract. As the result of a June 2012 solicitation, BVES entered into a ten-year contract with Iberdrola Renewables, LLC (now called Avangrid Renewables, LLC or “Avangrid”) for RECs. On July, 2013, the Commission approved the Avangrid contract through Resolution E-4604.

The costs of the Avangrid RECs contract for the Review Period are set forth below. The contract costs shown in Table 2.9 below reflect the total cost of RECs purchased under the contract with Avangrid, while values shown in Table 2.1 show the value of RECs that were retired for RPS compliance purposes.

**Table 2.9**

**Avangrid RECs Contract Costs and Volumes (MWh)**



|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| REC Cost | $381,825 | $369,666 | $394,164 | $464,949 | $560,100 | Contracted to pay $559,596 |

G. California Choice Energy Authority – Resource Adequacy

Monthly Firm Baseload Energy and Resource Adequacy

While pursuing long-term contracts to replace the expiring Shell Resource Adequacy (RA) contract, BVES conducted monthly competitive solicitations for RA to meet its RA requirements. These solicitations for procurements of system RA continued throughout 2019 – 2022.

Set forth in Table 2.10 below are the amounts of capacity costs related to the monthly competitive solicitations. Despite consistent solicitations for RA throughout the years of 2019 and 2020, BVES was unable to secure RA capacity for the remaining months in 2020. BVES continued to solicit offers for RA for the year of 2021 and secured three short-term contracts for RA. The short-term contract with California Choice Energy Authority secured RA capacity for the months of January through May 2021 and November through December 2021. The annual RA capacity product under the California Choice Energy Authority agreement from January 1, 2021 – May 31, 2021 and November 1, 2021 – December 31, 2021 are set forth in Table 2.10 below. The costs shown below in the table are also shown in Table 2.1 in the rows labeled “Short-Term (Monthly) RA Capacity.”



**Table 2.10**

**California Choice Energy Authority Resource Adequacy Contract**

|  |  |
| --- | --- |
|  | **2021** |
| Short-Term RA Capacity – California Choice Energy Authority | $422,500 |

H. Exelon Generation – Resource Adequacy

BVES continued to conduct monthly competitive solicitations for RA to meet its remaining 2021 RA requirements. Two short-term contracts for RA were executed with Exelon Generation. The short-term contracts with Exelon Generation secured RA capacity for the months of June through August 2021. The annual RA capacity product under the two Exelon Generation agreements from June 1, 2021 – August 31, 2021 are set forth in Table 2.11 below. **Table 2.11**

**Exelon Generation Resource Adequacy Contracts**



|  |  |
| --- | --- |
|  | **2021** |
| Short-Term RA Capacity – Constellation | $635,000 |

I. Marin Clean Energy – Resource Adequacy

BVES continued to conduct monthly competitive solicitations for RA to meet its remaining 2021 and 2022 RA requirements. Despite consistent solicitations for RA throughout the years, BVES was unable to secure RA capacity for the remaining months of September and October in 2021. However, BVES did execute a short-term contract for 2022 RA with Marin Clean Energy. The short-term contract with Marin Clean Energy secured RA capacity for the months of January through June 2022 and October through December 2022. The annual RA capacity product under the Marin Clean Energy agreement from January 1, 2022 – June 30, 2022 and October 1, 202 – December 31, 2022 are set forth in Table 2.12 below.

**Table 2.12**

**Marin Clean Energy Resource Adequacy Contracts**

|  |  |
| --- | --- |
|  | **2022** |
| Short-Term RA Capacity – Marin Clean Energy | $847,750 |

J. Energy Costs Were Appropriately Recorded Into the Supply Adjustment Account

The energy costs relating to the 2019 Morgan Stanley contract, the long-term Exelon Generation contract, and the monthly energy and capacity contracts and the Avangrid RECs contract were appropriately recorded into the Supply Adjustment Account.

The above testimony, coupled with the findings by the Commission in D.19-08-027, D.19-08-030, Advice Letter 370-EA, and Advice Letter 913-E, provide the basis for the Commission to conclude that all costs relating to the 2019 Morgan Stanley contract, long-term Exelon Generation contract, and the monthly energy and capacity contracts, and the Avangrid RECs contract, with respect to the time period of the Review Period, were appropriately recorded in the Supply Adjustment Account.[[4]](#footnote-6)

V. CONTRACT ADMINISTRATION

This testimony will demonstrate that BVES’ contract administration was prudent during the Review Period. BVES will demonstrate that during the Review Period it administered all contracts for which it has responsibility in a manner consistent with applicable standards.

Under Standards of Conduct (“SOC”) 4, BVES is required to administer all contracts and generation resources and dispatch the energy in a least-cost manner.[[5]](#footnote-7) BVES’ goal is to administer its power contracts to maximize the benefits to its ratepayers provided by the terms of the contracts at the lowest achievable cost, which is consistent with SOC 4.

BVES monitors the compliance of each seller under its power contracts with BVES. This activity generally includes (i) verifying that the seller is complying with contract terms, including any credit support and collateral requirements; (ii) verifying that billing and payments are accurate and consistent with the terms of the contract; (iii) reviewing interruptions of service and force majeure events, if any; (iv) renegotiating contract provisions as necessary due to changed circumstances or conditions; and (v) resolving disputes.

A. Compliance with Contract Terms, and Billing and Payments.

Sellers were monitored to ensure that they are complying with contract terms. Billings and payments of each seller were reviewed and verified to ensure that they were accurate and consistent with the terms of the contract. Generally, personnel in BVES’ office in Big Bear carry out these functions, with assistance of staff located in GSWC’s main office in San Dimas.

* + 1. Review Interruptions or Changes of Service or Force Majeure Events.

(Do we have a current example for this?) Personnel in BVES’ office in Big Bear reviewed any interruptions or changes of service and force majeure events that may be claimed by sellers under their contract. For example, when Shell notified BVES in August 2015 that it needed to replace the CAISO resource identified in its contract for system RA, BVES personnel ensured the replacement process adhered to the terms of the contract, thus ensuring the change would not result in any change in service.

* + 1. Resolving Disputes and/or Renegotiation of Contracts

BVES personnel renegotiated contract provisions as necessary, due to changed circumstances or conditions, and resolved disputes under contracts when they arose.

For example, BVES worked with Morgan Stanley to resolve a discrepancy between the contract and the delivery of energy for two days in July 2020. Morgan Stanley failed to match 750 MWh of energy for July 5, 2020 and July 6, 2020 as per the contract and had to credit BVES back for the SP15 hourly price (LMP hourly price) for the discrepancy. BVES personnel ensured the correction adhered to the terms of the contract.

* + 1. Purchase of Short Term Energy

BVES minimized its exposure to the sometimes price-volatile, day-ahead bilateral market, CAISO Day-ahead market, and CAISO Imbalance market (together, the “Spot Market”) by relying upon long-term power contracts to meet most of its load requirements. During the Review Period, BVES’ long-term power contracts for annual and seasonal energy met approximately 71 to 96% of BVES’ annual load requirements.

BVES’ remaining load requirements were covered through purchases in the Spot Market. On a daily basis for the day-ahead CAISO market, BVES determines how much energy BVES is short or long and then procures energy from, or sells energy into, the Spot Market. Over the Review Period, BVES purchased short-term energy from the Spot Market and sold surplus energy into the Spot Market in a manner that was prudent and minimized costs to BVES’ ratepayers[[6]](#footnote-8).

1. **Scheduling Protocols**

CAISO protocols require each utility, through its Scheduling Coordinator, to submit day-ahead schedules that included resources sufficient to meet nearly all of its day-ahead forecasted loads. Typically, each day BVES forecasts its day-ahead load and identifies any hourly energy requirements or surpluses.

With the introduction of the MRTU market in 2009, there has been a substantial increase in the depth of the CAISO imbalance energy market and a corresponding reduction in price volatility. As a result, BVES has reduced the amount of day-ahead bilateral purchases and sales it engages in, and instead relies on the CAISO Day-ahead and imbalance markets for the vast majority of its hourly shortfalls or surpluses in supply.

1. **BVES’ Winter Loads Very Unpredictable**

During the non-winter months, BVES was able to match relatively closely its baseload requirements with its long-term resources. BVES’ loads are fairly consistent on a day-to-day basis during the non-winter months, resulting in minimal Spot Market energy purchases and sales.

Unlike BVES’ load in the non-winter months, BVES’ winter loads can vary dramatically on a day-to-basis. The dramatic swings in daily winter loads depends upon whether its largest customer, the Bear Mountain ski resort, uses its snow-making equipment (a 10 MW to 13 MW load)[[7]](#footnote-9). Bear Mountain provides daily forecasts of planned snowmaking loads to BVES; however, snowmaking requires a certain mix of low temperature and humidity which results in the resort’s daily forecasts being inaccurate at times.

1. **Monthly Spot Market and Imbalance Purchases and Sales and Costs**

Table 2.11 below presents BVES’ annual day-ahead energy purchases and imbalance energy purchases and sales as well as the average price per MWh. The purchase amounts shown below are also included in Table 2.1 in the rows titled “Day Ahead Purchases and Sales,” “CAISO Imbalance Purchases,” and “CAISO Imbalance Sales”.

Table 2.11  
Spot Market Purchases and Sales

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Total** |
|  | **Sep-Dec** |  |  |  |  | **Jan-Oct** |  |
| Day-Ahead Purchases ($) | $409,038 | $1,125,156 | $1,029,169 | $410,252 | $838,074 | $192,402 | $4,004,091 |
| Day-Ahead Purchases (MWh) | 8,341 | 21,797 | 22,731 | 10,258 | 17,498 | 4,078 | 84,703 |
| Average Day-Ahead Price/MWh | $49.04 | $51.62 | $45.28 | $39.99 | $47.90 | $47.18 | $47.27 |
| CAISO Imbalance Energy Purchases ($) | $97,351 | $400,866 | $401,094 | $380,789 | $601,662 | $688,633 | $2,570,375 |
| CAISO Imbalance Purchases (MWh) | 2,400 | 8,785 | 9,597 | 11,437 | 12,342 | 16,712 | 61,273 |
| Average Imbalance Purchase Price | $40.55 | $45.63 | $41.79 | $33.29 | $48.75 | $41.21 | $41.95 |
| CAISO Imbalance Energy Sales ($) | -$84,349 | -$369,490 | -$415,874 | -$471,989 | -$765,756 | -$520,396 | -$2,627,854 |
| CAISO Imbalance Sales (MWh) | -$2,253 | -8,823 | -10,653 | -16,254 | -16,742 | -14,214 | -68,939 |
| Average CAISO Imbalance Sale Price/MWh | -$37.44 | $41.88 | $39.04 | $29.04 | $45.74 | $36.61 | $38.12 |

With advent of the MRTU market in 2009, BVES began tracking the odd lot day-ahead bid offers from Shell and other sellers against the CAISO real-time imbalance energy prices. BVES found that pricing structures were nearly identical. BVES began selling its surplus energy directly into the CAISO imbalance energy market, with the added benefit of capturing CAISO price spikes and increased revenues. Accordingly, there were no day-ahead surplus sales outside of the CAISO market for the Review Period.

The price for imbalance energy purchases and sales in the CAISO imbalance market is determined by the CAISO. BVES has no alternative source for imbalance energy and no ability to affect the price set by the CAISO. By selling or purchasing short-term energy through the CAISO imbalance market, BVES’ imbalance sales and purchases are the least-cost to BVES’ customers. CAISO imbalance sales and energy purchases were relatively small, generally averaging less than 1 MW per hour except in the winter months of December through February. During that period, CAISO imbalance energy purchases and sales can reach approximately 15 MW per hour, reflective of the difficulty of balancing energy procurement with snow-making and vacation loads.

* + 1. Least-Cost Dispatch of Resources

Except for the BVPP, BVES’ resource portfolio is comprised of non-dispatchable power purchase agreements. The only dispatchable resource BVES has is its BVPP, comprised of seven 1.2 MW (total capacity 8.4 MW) internal combustion engines fueled by natural gas. BVPP is limited by air district rules to 1,000 hours of operation annually per engine.

The BVPP is currently treated as a distributed generation resource by the CAISO. When operating, the BVPP reduces BVES’ metered peak demand on the CAISO system, as measured by the SCE meters at the Goldhill receipt point. If energy prices in the CAISO markets are less than the cost of production from the BVPP and there is sufficient capacity on SCE transmission lines serving BVES, then BVES does not operate the BVPP. If the prices in the imbalance market are greater than the cost of production from the BVPP, then it might be operated.

BVES has an Energy Supply Specialist (“ESS”) who monitors real-time prices in CAISO imbalance market pricing through OASIS. The CAISO imbalance market provides a gauge of the CAISO market. This allows the ESS to dispatch the BVPP when economically beneficial to BVES’ customers.

A primary benefit of constructing the BVPP was to provide peaking capacity to BVES to make up for transmission limitations on the SCE transmission facilities serving BVES’ distribution system.[[8]](#footnote-10) In 2003, BVES was limited to 37 MW of import on the two SCE lines serving BVES. Whenever loads exceeded 37 MW, BVES had to request the ski resorts, its largest customers, to reduce snow-making loads. This was adversely affecting the entire local economy because when the resorts could not make snow, local tourism declined. By operating the BVPP when loads exceeded SCE’s transmission capacity, BVES did not have to interrupt the service to the ski resorts. The BVPP also provides a backup source of energy in the event one or both of the transmission lines serving BVES goes down, which can happen during periods of high fire danger or other acts of God (wind, earthquake etc). After the BVPP was built, SCE increased the amount of transmission available to BVES’ system to 39 MW.

The BVPP is almost always operated during the two-week period around Christmas and New Year’s Day, when temperatures are cold, snowmaking is operating and tourists and vacationers flock to BVES’ service territory. Other winter holidays like MLK day may also warrant use of the BVPP.

This testimony demonstrates that BVES prudently administered the power contracts during the Review Period, and prudently dispatched the BVPP during the Review Period, and that the associated costs in the Supply Adjustment Account over the Review Period are reasonable.

VI. NATURAL GAS PROCUREMENT, TRANSPORTATION AND STORAGE

In June 2019, BVES’ agreement with Southwest Gas Corporation (“SWG”) expired and BVES transferred from a GS-70 rate schedule to a Commercial GS-40 rate schedule. BVES operated the BVPP to meet winter peaking loads during the Review Period. Prior to the expiration of the GS-70 rate schedule agreement with SWG, BVES purchased natural gas and entered into a natural gas transportation service agreement with its local distribution company SWG to transport gas from Southern California Gas (“SoCalGas”) Company’s natural gas transmission system to the BVPP.

A. Procurement of Natural Gas

BVES purchased small amounts of natural gas as compared to other electric generating facility owners. As such, BVES is a price-taker in the natural gas market. BVES’ gas purchase process has evolved over time. BVES initiated its gas acquisition process by contacting a number of gas marketers to determine who might be interested in serving BVES’ modest gas purchase requirements. Over time, BVES executed enabling agreements with Pacific Summit, HESCO, Redwood Gas Marketing and British Petroleum (“BP”) to permit BVES to purchase gas from several different gas suppliers, though only the enabling agreement with BP remains. BVES has considered adding additional natural gas suppliers to its portfolio, but the small quantities of gas to purchase has historically discouraged sellers to engage in time-consuming competitive bidding.



Table 2.12 below shows BVES annual costs and amounts of natural gas from September 1, 2017 through October 31, 2022. These costs are also included in Table 2.1.

Table 2.13

BVES Natural Gas Costs

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **2017 Sep- Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| Annual Cost | $3,888 | $28,138 | $153,269 | $116,537 | $168,314 | $279,678 |

(for 2022, includes 2021 values as an estimate for future month’s data)

This testimony demonstrates that BVES prudently procured gas for its BVPP and the associated costs are reasonable.

B. Natural Gas Transportation

Prior to the expiration of the natural gas purchased by BVES was transported from the SoCalGas transmission system to the BVPP through a transportation agreement with SWG. BVES agreed to an annual minimum gas transport amount to avoid paying the initial capital cost associated with a necessary distribution pipeline. BVES agreed to transport a minimum amount of natural gas each year or pay SWG’s margin rate for the difference between 24,960 MMBTU and actual use. SWG’s margin rate is currently $1.28349/MMBTU so the minimum amount BVES could pay each year was $32,035 if it used no natural gas at all during the year. Typically, BVES did not use 24,960 MMBTU annually unless operation of the BVPP was economic. Because of the relatively high heat rate of the BVPP, its energy costs are generally more expensive than purchasing from the CAISO day-ahead market or imbalance market.

Table 2.13 below summarizes natural gas transportation costs from September 2017 through May 2019. The costs shown below are also included in Table 2.1,

Table 2.14  
BVES Natural Gas Transportation Costs

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **2017**  **Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| Natural Gas Transportation | $3,888 | $65,675 | $11,336 | $0 | $0 | $0 |

Those gas transportation costs that BVES had limited discretion to control were managed consistent with the objective of minimizing costs to BVES’ ratepayers. This testimony demonstrates that BVES acted prudently in procuring gas transportation services to produce energy at the BVPP and the associated costs were reasonable.

C. Gas Contracts Prudently Administered

BVES monitors the compliance of its counterparty under gas contracts executed by BVES. This activity generally includes (i) verifying that the counterparty is complying with contract terms, including any credit support and collateral requirements; (ii) verifying that billing and payments are accurate and consistent with the terms of the contract; (iii) reviewing interruptions of service and force majeure events, if any; (iv) renegotiating contract provisions as necessary due to changed circumstances or conditions; and (v) resolving disputes.

Where BVES had discretion to control costs, it did so in a manner consistent with the objective of minimizing costs to BVES’ ratepayers.

This demonstrates that BVES prudently administered its gas contracts during the Review Period and the associated costs are reasonable.

VII. Capacity Costs



BVES incurred capacity costs pursuant to separate power products it purchased during the Review Period. A. Physical Call Option Costs

In its January 2011 RFP for Firm Energy, one of the four products sought was an instrument to control peaking/intermediate energy. After evaluating bids, BVES determined a physical call option would provide value by allowing it to fix on-peak energy prices at a known price ($75). The costs of this peak energy physical call option are shown in Table 2.15 below. The costs shown below are also identified in Table 2.1.

**Table 2.15**

**Annual Physical Call Option Capacity Costs**

|  |  |
| --- | --- |
|  | **2017**  **–September - December** |
| Physical Call Option Premium Costs | $48,800 |

B. Resource Adequacy Capacity Costs

The CPUC has implemented a resource adequacy (“RA”) requirement to ensure sufficient resources for the CAISO to operate the grid in a safe and reliable manner in real time. For several years, the CPUC has developed and refined the RA requirement for the large investor-owned utilities and certain electric service providers, but has postponed[[9]](#footnote-11) development of specific RA requirements for BVES and certain other small and multi-jurisdictional utilities.

When the CAISO filed with the FERC for approval of pre-MRTU tariff changes to implement the CPUC’s RA program, BVES filed a protest at FERC. The CAISO agreed that the CPUC had not yet established an RA program for BVES. FERC ruled that the CAISO should treat all entities the same and should, therefore, impose an Interim Reliability Requirements Program (“IRRP”) for BVES under the CAISO tariff. In a subsequent order, FERC provided a means to identify such a program until the CPUC developed an RAR program for BVES and other small and multi-jurisdictional utilities.

In order to comply with the FERC ruling, BVES met with the CAISO prior to filing its RA proposal with the CPUC. BVES proposed to determine its monthly peak demand for RA requirement purposes based on the State’s coincident peak demand and treat the BVPP as a distributed generation resource rather than as a generator controlled by the CAISO. This proposal, in effect until the CPUC issues a decision, reduces BVES’ capacity obligations throughout the year, primarily through reduced coincident peak obligations.

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

To meet the requirements of the RA capacity proposal set forth above, BVES issued an RFP for resource capacity and other power products. GSWC, on behalf of BVES, reached agreement with Shell to provide the following amounts of resource capacity: 35 MW of RA capacity in November, December, January and February and 18 MW during the other months of the year.

Table 2.15 below summarizes the RA capacity purchases of BVES under the Shell agreement. The costs shown below are also identified in Table 2.1 in the row titled “Long-Term RA Capacity.”

Table 2.15  
Annual RA Capacity Costs

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **2017**  **Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| Long-Term RA Capacity | $287,000 | $832,500 | $854,700 | $94,800 | $0 | $0 |
| Short-Term (Monthly) RA Capacity\* | N/A | N/A | N/A | $0 | $1,057,500 | $686,250 |
| \*As discussed previously, BVES had a long-term RA capacity with Shell that expired November 30, 2013; its replacement long term RA contract with Shell began in March 2015. | | | | | | |

With the pending expiration of the Shell (after January 2020) and EDF (after 2017) contracts, BVES began pursuing long and short-term resource adequacy products for its resource adequacy requirements in February 2020 and beyond. In April 2019, BVES began releasing periodic (primarily monthly) solicitations for resource adequacy capacity for 2020. In August 2020, BVES began releasing periodic solicitations for resource adequacy capacity for the remainder of 2020 and all of 2021. BVES was unable to secure resource adequacy capacity for 2020 but was able execute a short-term contract with Pacific Energy Advisors for January through May and November through December in 2021. Following continued solicitations, BVES executed two short-term contracts with Exelon Generation for June through July and August 2021 resource adequacy capacity and a short-term contract with Marin Clean Energy for resource adequacy capacity for January through June and October through December 2022. BVES continues to release solicitations to meet its resource adequacy requirements for 2021 through 2022.

C. Capacity Contracts Prudently Administered

BVES monitors the compliance of the short-term monthly suppliers of capacity described above under the capacity contracts. This activity generally includes (i) verifying that the suppliers are complying with contract terms, including any credit support and collateral requirements; (ii) verifying that billing and payments are accurate and consistent with the terms of the contract; (iii) reviewing interruptions of service and force majeure events, if any; (iv) renegotiating contract provisions as necessary due to changed circumstances or conditions; and (v) resolving disputes.

Where BVES had discretion to control costs under the capacity contracts, it did so in a manner consistent with the objective of minimizing costs to BVES’ ratepayers.

This testimony demonstrates that BVES prudently administered its capacity contracts during the Review Period and the associated costs are reasonable.

VIII. transmission costsA. SCE Provides Transmission Pursuant to FERC-Approved Tariffs

SCE provides transmission service to BVES under tariffs and rates approved by the Federal Energy Regulatory Commission (“FERC”). Table 2.16 below summarizes BVES’ annual transmission costs during the Review Period. The costs shown below are also identified in Table 2.1.

Table 2.16  
Annual SCE Transmission Costs

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **2017**  **Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| $292,783 | $861,649 | $858,238 | $885,934 | $885,500 | $736,522 |

Table 2.17 below provides a summary of FERC approved tariffs for SCE to provide transmission-related services to BVES during the Review Period.

Table 2.17  
FERC-Approved Transmission Agreements

| **Contract or Tariff Name** | **SCE FERC Rate Schedule Designation** | **FERC Docket of Acceptance or Approval & Date** | **Effective Date of Current Rate Schedule** |
| --- | --- | --- | --- |
| Agreement for Services | SCE Rate Schedule FERC No. 349 | ER04-922-001 Jan. 18, 2005) | Jan. 1, 2002 |
| Second Revised Service Agreement No. 4 under Wholesale Distribution Access Tariff | SCE FERC Electric Tariff, Second Revised Volume No. 5, Second Revised Service Agreement No. 4 | ER03-549-000 (Mar. 24, 2004), 106 FERC ¶ 61,308; ER04-922-000 (Aug. 6, 2004) | Apr. 24, 2003 (rates); Mar. 17, 2004 (non-rate terms) |
| Amended and Restated Transmission Service Agreement | SCE Rate Schedule FERC No. 465 | ER17-2227-000 (Sept. 13, 2017) (letter order) | May 1, 2019 |
| Letter Agreement | SCE Rate Schedule FERC No. 467 | ER05-380-000 (letter order of Feb. 17, 2005) | Dec. 16, 2004 |
| Second Amended and Restated 33kV Added Facilities Agreement | SCE First Revised Rate Schedule FERC No. 466 | ER21-02948-000 (Nov. 8, 2021), letter order) | Oct. 1, 2021 |
| Bear Valley Project Distribution Facilities Agreement | SCE Rate Schedule FERC No. 468 | ER 21-02948-000 (Nov. 8, 2021) | Oct. 1, 2021 |
| SCE Transmission Owner Tariff, Appendix II, Charges for Wholesale Transmission Services | SCE FERC Electric Tariff, Third Revised Volume No. 6 | ER 11-3697 Formula Rate TO10 update (filed Nov.1, 2016) | Jan. 1, 2017 (Didn’t find this one - maybe old?) |
| SCE Transmission Owner Tariff, Appendix VI, Reliability Services Rate Schedule | SCE FERC Electric Tariff, Third Revised Volume No. 6 | ER 19-219 (Nov. 13, 2018) (letter order) | Jan. 1, 2019 |

B. Transmission Tariffs Prudently Administered

BVES monitors the compliance of SCE under the FERC-approved tariffs for transmission service. This activity generally includes (i) verifying that SCE is complying with tariff terms; (ii) verifying that billing and payments are accurate and consistent with the terms of the tariff; (iii) reviewing interruptions of service and force majeure events, if any; (iv) participating in FERC proceedings regarding SCE transmission service and costs; and (v) resolving disputes.

BVES has intervened and participated in FERC proceedings regarding SCE’s transmission service and rates to BVES in an attempt to keep the rates at the lowest possible level. However, once FERC has approved the service terms and rates, BVES is required to pay SCE the FERC-approved rates and amounts and recover them in retail rates under the file-rate doctrine and established principles of Federal preemption. These FERC-approved tariffs were administered by BVES in a prudent manner.

Those transmission costs that BVES had limited discretion to control were managed consistent with the objective of minimizing costs to BVES’ ratepayers. This testimony demonstrates that BVES procured electric transmission services pursuant to FERC-approved tariffs, administered the FERC-approved tariffs prudently, and that the associated FERC-approved costs should be recovered in rates.

IX. Schedule Coordinator costs

A. CAISO Requires Schedule Coordinator

Every entity must either be or have a schedule coordinator (“SC”) to interface with the CASIO. The CAISO does not accept schedules from individual utilities, generators or marketers – only SCs. BVES is not an SC and cannot become an SC without spending at least $1,000,000 and hiring a full-time scheduling staff. For BVES, contracting with a SC is the most cost-efficient means to satisfy the CAISO’s requirement to interface only with an SC.

* + 1. Contracts for Schedule Coordinator Services

BVES cannot avoid the costs related to a Schedule Coordinator; it’s SC during the Review Period was and continues to be Automated Power Exchange (“APX”). APX is one of the largest, if not the largest, SC operating within the CAISO marketplace. BVES has been satisfied with the quality of service provided by APX. During its tenure as BVES’ SC, APX essentially has maintained its initial pricing structure, with only a small annual adjustment to its fees.

Table 2.18 below sets forth BVES payments for SC services during the Review Period. The costs shown below are also identified in Table 2.1 in the row titled “Scheduling.”

Table 2.18  
Scheduling Coordinator Charges

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **2017**  **Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| $30,000 | $91,829 | $88,341 | $99,900 | $84,000 | $70,000 |

This testimony demonstrates that BVES prudently incurred the SC services and the associated costs are reasonable.

* + 1. Schedule Coordinator Contracts Prudently Administered

BVES monitors the compliance of its Schedule Coordinator under its Schedule Coordinator contract. This activity generally includes (i) verifying that the Schedule Coordinator is complying with contract terms, including any credit support and collateral requirements; (ii) verifying that billing and payments are accurate and consistent with the terms of the contract; (iii) renegotiating contract provisions as necessary due to changed circumstances or conditions; and (iv) resolving disputes.

Where BVES had discretion to control costs under the Schedule Coordinator contracts, it did so in a manner consistent with the objective of minimizing costs to BVES’ ratepayers. This testimony demonstrates that BVES prudently administered the Schedule Coordinator contracts during the Review Period and the associated costs are reasonable.

X. CAISO ChargesA. Annual CAISO Charges

The CAISO manages the electric grid in which BVES is located. BVES must pay to the CAISO certain FERC-approved charges for grid management services (including ancillary services). BVES has no alternative to purchasing these services other than at FERC-approved rates. BVES does not self-provide any CAISO-required ancillary services.

Set forth in the Table 2.21 below are the amounts BVES paid for CAISO grid management and ancillary services during the Review Period. The costs shown below are also identified in Table 2.1.

Table 2.19  
Annual CAISO Charges

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **2017**  **Sep-Dec** | **2018** | **2019** | **2020** | **2021** | **2022**  **Jan-Oct** |
| $582,354 | $1,961,741 | $2,270,822 | $2,012,935 | $2,420,135 | $1,860,905 |

B. CAISO Tariffs Administered Prudently

BVES monitors the compliance of the CAISO under its FERC-approved tariffs for independent transmission service provider services. This activity generally includes (i) verifying that the CAISO is complying with its tariff terms; (ii) verifying that billing and payments are accurate and consistent with the terms of the CAISO tariff; (iii) monitoring and/or participating in FERC proceedings regarding CAISO services and costs; and (iv) resolving disputes.

BVES monitors FERC proceedings regarding CAISO services and rates in an attempt to keep the rates at the lowest possible level. However, once FERC has approved the service terms and rates, BVES is required to pay CAISO FERC-approved rates and amounts and recover them in retail rates under the file-rate doctrine and established principles of Federal preemption. These FERC-approved tariffs were administered by BVES in a prudent manner.

Those CAISO costs that BVES had discretion to control were managed consistent with the objective of minimizing costs to BVES’ ratepayers. This testimony demonstrates that BVES administered the FERC-approved tariffs prudently and that the associated FERC-approved costs should be recovered in rates.

XI. summary and conclusion of testimony on SUPPLY ADJUSTMENT ACCOUNT costs

A total of $60,836,928 of costs were processed by BVES in its day to day operations and ultimately recorded into the Supply Adjustment Account for the Review Period September 1, 2017 through October 31, 2022, as summarized below:

1. Contracted firm energy costs of $30,306,995.

2. Spot Market purchases of energy of $6,787,300.

3. Spot Market sales of energy of $(2,442,359).

4. SCE transmission costs of $4,520,626.

5. CAISO costs of $11,108,892.

6. Scheduling Coordinator costs of $464,070.

7. Natural gas costs of $595,610 and natural gas transportation costs of $80,537.

8. Renewable Energy Credit (Retired) costs of $2,089,917.

9. Resource adequacy costs of $3,812,750.

10. Physical call option costs of $48,800.

This testimony provides the basis for the Commission to approve $57,373,138 of power costs recorded into the Supply Adjustment Account over the Review Period. As previously discussed, most of these Supply Adjustment Account costs have already been recovered through revenues recorded into the Supply Adjustment Account as a result of Supply Adjustment Account Charges (i.e., transmission charges, energy charges and amortization charges, if any).

1. SUPPLY ADJUSTMENT BALANCING ACCOUNT REVENUES  
   SEPTEMBER 1, 2017 TO OCTOBER 31, 2022
   1. PURPOSE

The purpose of this testimony is to describe revenues recorded into the Supply Adjustment Balancing Account (“Supply Adjustment Account”)[[10]](#footnote-12) during the period September 1, 2017 through October 31, 2022 (“Review Period”). This testimony will provide the basis for the Commission to conclude that the revenues recorded into the Supply Adjustment Account are proper.

Power-related costs recorded into the Supply Adjustment Account are addressed in Chapter 2 of this Volume.

* 1. BACKGROUND

BVES has a Supply Adjustment Account which tracks, among other things, the revenues resulting from billed monthly sales for each rate tariff for residential and non-residential customers, and the revenues from the sale of surplus energy into the CAISO’s imbalance energy market. Amounts recorded into the Supply Adjustment Account were last reviewed by the Commission in Application 17-05-004 and approved in D.19-08-027.

* 1. SUMMARY
     1. Supply Adjustment Account Last Reviewed In Application 17-05-004 and Approved in D. 19-08-027.

In BVES’ last general rate case (“GRC”) application BVES addressed all Supply Adjustment Account-related revenues for the period of September 1, 2011 through October 31, 2016. Those revenues were approved in D.19-08-027. This testimony will address all Supply Adjustment Account-related revenues for the period September 1, 2017 through October 31, 2022 (the “Review Period”).

* + 1. Summary of Supply Adjustment Account Revenues

Revenues from customer billings of the Supply Charge, the Transmission Charge and the Supply Adjustment Charge and revenues from sales of surplus energy, as discussed below, are tracked and recorded into the Supply Adjustment Account.

Table 3.1 below summarizes by component the supply-related revenues recorded into the Supply Adjustment Account over the Review Period.

**Table 3.1**

**Supply Adjustment Account Revenues September 1, 2011 through October 31, 2016**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Revenue Components** | **2011 Sep-Dec** | **2012** | **2013** | **2014** | **2015** | **2016 Jan-Oct** | **Total Supply Revenues** |
| Transmission Charge | $386,077 | $1,108,469 | $1,132,971 | $1,190,152 | $3,036,462 | $2,406,496 | $9,260,626 |
| Supply Charge | $3,666,730 | $11,608,121 | $11,931,698 | $11,200,957 | $10,445,614 | $8,549,959 | $57,403,078 |
| Supply Adjustment Charge | $976,025 | $2,855,680 | $2,900,591 | $2,589,409 | $1,403,657 | $(359) | $10,725,002 |
| **Total Supply Revenues** | **$5,028,831** | **$15,572,270** | **$15,965,260** | **$14,980,5175** | **$14,885,733** | **$10,956,095** | **$77,388,706** |

* 1. SUPPLY ADJUSTMENT ACCOUNT REVENUES FROM CUSTOMER BILLS

Annual supply-related revenues from customer charges and billings recorded into the Supply Adjustment Account are shown in the table below. The Supply Adjustment Account Charges are comprised of three separate charges: the Supply Charge, the Transmission Charge, and the Supply Adjustment Charge. As provided in BVES’ Preliminary Statement, the Transmission charge is intended to recover costs related to transmission service, which for BVES is provided by Southern California Edison (“SCE”) and the California Independent System Operator (“CAISO”). The Supply Charge is intended to recover all purchased power costs and fuel-related costs. The Supply Charge and Transmission Charge are incorporated into the rates charged to customers.

At any time, the balance of revenues and costs in the Supply Adjustment may be positive (i.e., more revenues than costs) or negative (i.e., more costs than revenues). The Adjustment Charge (which can be either a charge to recover more revenue from customers to offset prior under-collections or a credit to return revenues or prior over-collections to customers) is intended to address positive and negative balances that accrue in the Supply Adjustment Account so that customers are only charged rates that are necessary to recover all purchased power costs, fuel-related costs and transmission costs.

* 1. SUMMARY AND CONCLUSION OF TESTIMONY ON SUPPLY ADJUSTMENT ACCOUNT REVENUES

A total of $77,388,706 of revenue was recorded into the Supply Adjustment Account for the Review Period September 1, 2011 through October 31, 2016, as summarized below:

* Transmission Charge revenues of $9,260,626.
* Supply Charge revenues of $57,403,078.
* Supply Adjustment Charge net revenues of $10,725,002.

This testimony provides the basis for the Commission to approve a total of $77,388,706 of supply-related revenues recorded into the Supply Adjustment Account over the Review Period.

1. SUPPLY ADJUSTMENT BALANCING ACCOUNT CUMULATIVE NET BALANCES  
   SEPTEMBER 1, 2017 TO OCTOBER 31, 2022
   1. PURPOSE

The purpose of this chapter is to provide the end-of-the year cumulative net balance recorded in the Supply Adjustment Account during the Review Period. Cumulative balances include adjustments for accrued interest, prior period adjustments issued by the CAISO and administrative costs. As demonstrated below, there is an over collection of over $5.4M at the end of the review period, October 31, 2016.

* 1. BACKGROUND

As a result of the 2001 Energy Crisis, BVES suffered a significant under-collection in its Supply Adjustment Account. In D.02-07-041, the Commission authorized BVES to recover $24 million of under-collected sales revenue over a ten-year period via a Supply Adjustment Charge of $0.02246/kWh. BVES was authorized to maintain the surcharge “until August 31, 2011, or until such time as the remaining balance in the PPAC Balancing Account is less than $100,000, whichever should occur first.” (D. 02-07-041, OP No. 5). In D. 14-11-002, the Commission approved the reduction of the Supply Adjustment charge to $.01729 per kWh.

As discussed in Chapter 2, while pursuing long-term contracts to replace the Shell contracts set to expire at the end of November 2013, BVES entered into monthly contracts for firm energy and RA for the months of December 2013 through December 2014 (energy) and December 2013 through February 2015 (RA). The monthly contract prices were lower than the prior fixed price Shell contract, thereby reducing overall costs. BVES observed daily forward prices below a forecast of spot market prices and determined monthly coverage was optimal. The lower energy costs in this period coupled with supply rates based on previous, higher costs, led to an over-collection by the end of 2014. The over collection continued and in March 2015 BVES filed AL 300-E requesting a refund for customers of $826,362. AL 300-E was approved May 21, 2015. The Commission then approved AL 304-E to terminate the previously reduced Supply Adjustment Charge $0.01729 per kWh. Even after the reduction of the Supply Adjustment Charge pursuant to the D.14-11-002 and the refund pursuant to AL 300-E, the over collection continued. Subsequently the Commission approved AL 314-E seeking to refund to customers $4,729,499 over a 24 month period beginning May 1, 2016.

* 1. NET BALANCE OF SUPPLY ADJUSTMENT ACCOUNT

Calculation of the end-of-the-year net balance amount in the Supply Adjustment Account during the Review Period includes of the following:

* Supply costs as discussed in Chapter 2 of this Volume;
* Supply and transmission-related revenues from billings as discussed in Chapter 3.

Table 4.1 below provides a summary of the cumulative end-of-the year net balances.

**Table 4.1**

**Supply Adjustment Account Revenues, Costs and Cumulative Net Balance**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** |
| **Sep-Dec** |  |  |  |  | **Jan-Oct** |
| Transmission Charge Revenue | $386,077 | $1,108,469 | $1,132,971 | $1,190,152 | $3,036,462 | $2,406,496 |
| Supply Charge Revenue | $3,666,730 | $11,608,121 | $11,931,698 | $11,200,957 | $10,445,614 | $8,549,959 |
| Supply Adjustment Charge Revenue | $976,025 | $2,855,680 | $2,900,591 | $2,589,409 | $1,403,657 | -$359 |
| Supply Costs | -$4,918,853 | -$12,577,751 | -$13,849,572 | -$10,106,894 | -$10,852,373 | -$8,600,686 |
| **Cumulative Net Balance** | **-$8,446,734** | **-$5,558,243** | **-$3,645,181** | **$1,040,876** | **$4,041,963** | **$5,446,284** |

The cumulative balances recorded in the Supply Adjustment Account are maintained by the Accounting staff at Golden State Water Company’s office in San Dimas. They provide a view of whether balances recorded in the account are under-collected or over-collected. At the end of the Review Period, October 31, 2016, the cumulative balance in the Supply Adjustment Account shows an over-collection of $5,446,284. Advice Letter 314-E, discussed above, is currently refunding over $4.7M to customers over a 24 month period, beginning May 1, 2016. BVES will continually monitor the cumulative net balance in the Supply Adjustment Account and adjust annually as needed.

CHAPTER 5  
Forecast of Power Supply Costs – 2018 to 2021

Joseph Phalen

The purpose of this Chapter is to provide a description and basis for the forecast of supply costs to be used in setting rates for the forecast years in the BVES application. Actual costs incurred by BVES for power supply and delivery are recorded in the Supply Adjustment Account. The forecasts provided in this chapter are intended only to be used for the rate setting process.

Chapter 2 of this volume provides a review of BVES’ power supply-related costs, several of which continue into the forecast period

There are 11 tables referenced in this testimony that appear in Appendix A following Chapter 5. The tables in Appendix A are referred to as Table A-1, Table A-2, *etc*. BVES’ power supply costs are comprised of three major components. These are energy and capacity costs, including Resource Adequacy (RA) capacity, transmission costs and the California Independent System Operator (CAISO) ancillary services.

BVES has fixed most of its energy and capacity costs through a series of long-term energy and RA purchases. As a result of these long-term energy purchases, BVES’ total power supply costs are fairly stable, with approximately 78 percent of all energy and capacity costs fixed through November 2019[[11]](#footnote-13). BVES is currently planning to enter into a new series of long-term energy purchases that will seek both low power supply costs while maintaining a high degree of certainty of the level of costs during the contract period.

BVES has little or no control over transmission costs and CAISO costs.

* 1. Forecast of Hourly Requirements

The power supply forecast uses the sales and load forecast referenced in the Results of Operations, Volume 2. Work papers supporting the forecast include hourly requirements.

* 1. Existing Resources

In January and December 2011, BVES issued RFPs for firm power supply and resource adequacy to procure additional resources for delivery beginning December 2013. When designing its RFP for generation resources, BVES identified capacity attributes, renewable and non-renewable requirements that its future resource mix had to meet.

As a result of this competitive bidding process, in December 2014 and January 2015, BVES subsequently executed four separate confirmation agreements for four distinct products with EDF Trading North America, LLC (EDF) and Shell Energy North America (Shell) with delivery dates commencing on January 1, 2015 and March 1, 2015. The power purchase agreements (“PPAs”) cover baseload energy, seasonal baseload energy, and on-peak physical call option and RA capacity. The Commission approved the four confirmation agreements in D.14-12-003. The baseload purchase is for 12 MW for the period January 2015 through November 2019 supplied by EDF. By purchasing 12 MW of baseload energy, BVES was able to fix the price of almost 64% of its annual energy requirements.

The second product is seasonal baseload energy, supplied by Shell, of 5 MW in November and 7 MW in December, January and February, which are BVES’ high-load periods. Loads are typically greater than 20 MW during most hours of December, January and February. For the month of November loads typically only exceed 20 MW if it is cold enough for the ski resorts (BVES’ largest customers) to begin snowmaking activities. As a result, BVES could be long in energy in some hours during November and have to sell energy back into the California Independent System Operator’s (CAISO) imbalance (real-time) market. By purchasing 5 and 7 MW of seasonal baseload energy, BVES was able to fix the price of approximately 14% more of its load for a total of 78% when combined with the annual baseload product.

The third product is an energy physical call option supplied by EDF for energy during the on-peak hours. This product caps BVES’ energy cost exposure to $75/MWh for volumes covered by the option. During the months of April through October, BVES may purchase up to 3 MW of energy for the on-peak hours of 0600 to 2200, while in the months of November through March, BVES may purchase up to 7 MW of energy for the on-peak hours of 0600 to 2200. The importance of the physical call option is that BVES can choose to fix on-peak energy prices rather than accept the market price in an environment of sustained high prices that may occur for a variety of reasons. The physical call option products provide an additional 15.15% of price stability. Total existing price stabilizing hedges equate to 95.8% of total load.

The final product is RA capacity supplied by Shell to meet the CAISO’s resource adequacy requirements. By ensuring that purchases meet the CPUC/CAISO mandates for RA, BVES is able to participate fully in the CAISO market with little concern about potential penalties related to inadequate resources.

These four products meet a very large percentage of BVES’ retail energy and capacity requirements. Generally, BVES takes delivery of the baseload product(s) and then determines how to meet any requirements in excess of the baseload needs based on daily economics. If the peaking option is less expensive than market prices, BVES will choose to exercise the daily option. If market prices are less than the option price, BVES purchases from the market.

If these four products, plus the BVPP, do not meet BVES’ requirements, any remaining energy can be purchased in the day-ahead market. Although the BVPP supplied power is not hedged completely due to volatility in the gas market, the gas prices are more stable than the power prices; and therefore, there is some price stability in the BVPP as a resource. If the BVPP is included as a hedging instrument, all of the BVES load is hedged with either a fixed price contract, a physical call option, or the BVPP supplied power.

The four products supplied by EDF and Shell are further described in Table A-1.

* 1. Power Supply Cost Forecast 2018-2021

An annual summary of BVES’ power supply costs for 2018 through 2021 is shown in Table A-2. Table A-3 provides the monthly power supply forecast for 2018 through 2021. A description of the major components and assumptions used in preparing the forecast are discussed below.

* + 1. Natural Gas Costs

Underlying the forecasts of long-term spot energy prices and generation costs from the Bear Valley Power Plant is the forecast of natural gas prices. BVES purchased a forecast of long-term natural gas prices from a well-regarded, commercially-available forecasting firm. Table A-4 summarizes the forecast of natural gas prices in $/MMBTU.

* + 1. Annual Baseload Energy Costs

The single largest component of BVES’ power supply costs are long-term baseload energy contracts. BVES currently has a 12 MW annual baseload power purchase that extends through November 2019. The contract provides for 105,120 MWh annually of energy at a constant rate of 12 MW per hour at an annual cost of approximately $5 million per year

In 2019, BVES will likely replace the EDF baseload purchase with a new baseload power purchase. BVES requires 12 MW of baseload energy beginning in late 2019. For forecasting purposes BVES is expecting prices to remain the same for the period beginning December 2019 through 2021.

BVES’ *total* energy requirements (sales plus losses) for 2018 through 2021 have been forecasted to be approximately 165,000MWh annually so the existing annual baseload contract and the projected annual baseload contract will meet about 64 percent of BVES’ annual energy needs at a fixed and known cost.

* + 1. Seasonal Baseload Energy Purchase

BVES is a winter peaking utility. During the December through February period, BVES’ loads seldom drop below 20 MW, as increased demand for heating and snow-making help keep loads high.

To better meet an expected increase in demand for winter energy, BVES plans to adjust the seasonal baseload volumes it purchases by splitting the seasonal products into on-peak and off-peak components. BVES intends to purchase 8 MW on-peak and 12 MW off-peak seasonal baseload for December, January and February and 4 MW on-peak and 7 MW off-peak for November. In total, the seasonal baseload purchase is expected to provide 23,771 MWh annually. The forecasted annual costs of both the on-peak and off-peak seasonal energy are $520,000 and $360,000, respectively.

With the expiration of the seasonal baseload purchase at the end of 2017, BVES has begun the replacement process. Bids received from various vendors were in the $40/MWh range. At this time, BVES has not made a decision on the preferred vendor. The seasonal baseload purchase is a must-take resource.

The new seasonal baseload purchase is projected to result in an increase of almost $73,000 per year, or almost 9% over the cost of the seasonal contract that expires at the end of 2017. While the cost does increase slightly, the per unit cost declines because the volumes increase a little over 5,000 MWh per year, or almost 27% more volume than the seasonal contract that expires at the end of 2017.

Table A-6 presents the monthly purchases under the seasonal baseload purchase.

* + 1. Resource Adequacy Capacity

BVES’ system RA capacity should equal 115 percent of forecasted monthly peak demand. BVES does not own any RA resources but purchases monthly RA capacity (currently as part of its Shell purchases).

BVES’ RA purchases range from a low of 8 MW in April to a high of 31 MW in December.

As to projected prices to acquire RA capacity after the expiration of the current Shell RA contract, BVES predicts the average RA capacity costs over the 2018 -2021 timeframe to be approximately $860,000 per year.

It is possible that BVES’ firm energy purchases in 2019 and 2020 and thereafter, after the expiration of the current annual baseload contract with EDF and the RA contract with Shell, may include RA capacity as part of the purchase price (they currently do not). The Supply Adjustment Account will track actual expenses.

Table A-7 shows BVES’ monthly RA purchases under its current contract and the planned purchases and costs.

* + 1. Fixed Price Option

The EDF physical call option expires on December 31, 2017. BVES is anticipating replacing it with another fixed price call option beginning January 1, 2018. The purpose of the call option is to ensure that BVES does not pay more than $48/MWh for both on-peak and off-peak energy needs beyond its annual and seasonal baseload contracts purchases. BVES will seek both on-peak and off-peak winter volumes and summer on-peak volumes under the physical call option that will replace the expiring EDF call option.

The proposed strike price is $48/MWh and the monthly quantities for the period 2018 through 2020 are up to 3 MW in April through October and up to 10 MW in November through March. Additionally, the physical call option in the months of November through March will be split into both on and off-peak volumes while during the summer it is only on-peak.

The call option is intended to provide assurance that BVES’ wholesale energy costs in excess of the annual and seasonal baseload purchases will not exceed $48/MWh.

Daily premium price quotes that BVES has received for this $48 strike price call option vary from approximately $5.00 to $7.00 (winter on-peak), approximately $5.00 to $6.00 (winter off-peak) and approximately $4.50 to $5.50 (summer on-peak). The price would be fixed for the length of the option for each of the distinct products.

On an annual basis, the projected cost of the $48/MWh call option premium is approximately $230,000 per year. Note that while the proposed call option is a three-year contract from 2018 through 2020, BVES projects that it will pay approximately the same price for a like product in 2021.

Under the terms of the call option, BVES must exercise the call a day ahead of deliveries. If BVES calls on the option, it must purchase like amounts (MW) in each hour for the period for which the option is struck. For example, if in a given day in December BVES determines it needs an additional 8 MW of on-peak power delivered under the option, it will take delivery of 8MW each on-peak hour.

The purpose of the cap on energy prices is to protect BVES and its ratepayers from any shocks in the energy market that might cause prices to spike. With a $48/MWh cap through at least 2020, BVES would pay the average amounts per month of $7,200 in April through October and $36,000 in November through March.

It is difficult to determine the amount of energy savings because of the structure of the option. BVES must decide on a day-ahead basis how much energy it will take for the entire 16 hour on-peak or 8 hour off-peak period the next day. BVES may determine that it is less expensive to pay prices in excess of $48/MWh for a few hours rather than commit to an 8-hour or 16-hour purchase.

* + 1. Imbalance Purchases

While the majority of BVES’ energy requirements are met through annual and seasonal purchases, BVES still purchases in the daily spot and imbalance (real time) markets. BVES purchased a forecast of energy prices in the CAISO market and used this price forecast to simulate the monthly cost of imbalance energy.

The monthly imbalance energy is presented in Table A-8. Supporting work papers to this section summarize BVES’ projected hourly long and short energy by month for the forecast period 2018-2021.

* 1. Bear Valley Power Plant (BVPP)

The BVPP became commercially operational on January 1, 2005, and the original Permits to Operate (PTOs) were issued on May 16, 2007. Revised PTOs were then issued on March 26, 2009 in compliance with current air district rules that limit each engine to 1,000 hours of operation annually.[[12]](#footnote-14)

The BVPP is treated as a distributed generation resource by the CAISO under its Interim Reliability Requirements Program (IRRP).[[13]](#footnote-15) As such, the BVPP reduces BVES’ metered peak demand on the CAISO system, as measured by the SCE meters at Goldhill and Harnish substations. This structure is beneficial during summer on-peak periods when power costs have been higher than the marginal cost of operating the BVPP.

BVES can reduce and stabilize energy costs by contracting for as much energy as possible from high capacity factor resources and then planning to meet peak loads with the BVPP, typically when the local ski resorts are making snow. Operating in this fashion allows BVES to minimize capacity costs for a low capacity factor resource.

The BVPP has a certified heat rate of 11,900 BTU/kW-hour, higher than the CAISO system average and the heat rate options (except for the three summer months). The BVPP is normally not operated unless loads are greater than 34 MW (or 39 MW if both transmission supply lines are available) and BVES’ transmission lines are close to being fully utilized.

Table A-9 shows forecasted monthly generation, energy cost per MWh is shown in Table A-8 and (based upon the plant’s heat rate and forecasted cost of natural gas) and total cost of forecasted energy produced in the BVPP.

Even though the BVPP is infrequently used during the non-peak months to meet load, BVES does operate the plant for O&M purposes during those months. Any operation costs for testing are not included in the power supply forecast because of the short duration of operation (generally less than 1 or 2 hours per unit per month) and the unknown period when the engines are going to be run.

Currently, BVES can supply up to 39 MW of capacity from imports before having to rely on the BVPP to meet load. Excluding the additional snowmaking load that is possible, BVES should not be impacted by the limits of the transmission lines used to import energy.

* 1. Transmission and Distribution Charges

Besides energy costs, BVES’ largest cost component of total power supply costs is transmission costs. BVES pays Southern California Edison (SCE) for: (1) transmission service on three 33 kV lines that deliver power up the mountain; and (2) wholesale distribution tariff service (for service from Victor Substation near Victorville to Cottonwood Substation in Lucerne Valley and via the Zanja Substation near Redlands). BVES also pays the CAISO for energy imported into California. Together these transmission charges are approximately $2,800,000 annually.

Currently, BVES is charged monthly for four different uses of SCE’s non-CAISO grid, which are described in the following sections. Chapter 2 of this Volume provides a description of these charges and a review of the historical costs. Tables A-10 (SCE) and A-11 (CAISO) provide a summary of Monthly Transmission Costs through 2021.

* + 1. SCE’s Wholesale Distribution Charge

The Wholesale Distribution Access Tariff (WDAT) is assessed by SCE for equipment not included in CAISO’s grid charges. While the CAISO generally operates SCE’s transmission system at 220 kV and above, SCE retained control of its distribution system, including most 115 kV, 69 kV, and 34.5 kV distribution lines. The WDAT covers those facilities.

BVES requires wholesale distribution service from its CAISO energy take-out point at Victor Substation to Cottonwood Substation and via Zanja Substation. The current monthly fixed charge for this service is $55,014.48.

* + 1. SCE’s Non-CAISO Low-Voltage Transmission Charges

SCE provides 34.5 kV transmission service from its Cottonwood Substation to its Goldhill switching station, where BVES takes delivery. Goldhill is the primary delivery point for capacity and energy. Through an agreement with SCE, BVES has rights to 34 MW of transmission capacity via Goldhill.

BVES also has 5 MW of transmission capacity at the Radford Feeder. Generally, the Radford 34.5 kV line is de-energized during the summer fire season, at which time all of BVES’ energy requirements are delivered through Goldhill.

The current monthly fixed charge for use of SCE’s 34.5 kV lines is $16,245.58.

* + 1. SCE’s Reliability Services Charges

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

SCE’s RS Rate is different for wheeling customers, and the charges to BVES under its RS Rate have varied significantly over the past few years, ranging from a low of $0.02 per MWh to a high of $.16 per MWh. As of January 2017, the rate was increased from $0.04/MWh to $0.12/MWh.

At the 2016 rate of $0.04/MWh, BVES’ annual RS charges were approximately $6,000 and will be approximately $18,000 per year under the new rate for 2017; the exact cost depends upon the amount of energy BVES schedules each month. For forecasting purposes, BVES used the historically high value of $0.16/MWh for RS charges.

* + 1. SCE’s Added Facilities Charges

The FERC also approved rate schedules Nos. 466 and 468 for 33 kV added facilities and Bear Valley distribution facilities. The combined monthly charge is approximately $3,000.

* + 1. Total Monthly SCE Transmission Charges

The different monthly charges for transmission and wholesale distribution services from SCE total approximately $75,000 or $918,000 annually. Table A-10 presents 2018 Transmission charges by component.

**F.** **Scheduling and Dispatch Services**

BVES is not a schedule coordinator (SC) so it has contracted with the APX for SC services. Each day BVES schedules energy and enters the schedules with the APX for submission to the CAISO.

BVES pays approximately $7,500 per month or approximately $90,000 per year for the APX’s SC services.

G. California Independent System Operator Charges

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

The largest CAISO charge is for transmission access or use of California’s high voltage grid. CAISO charges vary as transmission filings are made by the various utilities that have turned over transmission to the CAISO.

BVES expects to pay approximately $1,860,000 annually for CAISO transmission charges, which may include charges for transmission, grid management, ancillary services and imbalance energy. The monthly payments to the CAISO are dependent upon several factors, including the total amount of energy used by BVES each month and how closely BVES is able to schedule energy deliveries to match load. Table A-11 presents CAISO charges by component.

BVES load is charged for its energy consumption, the Locational Marginal Price (LMP) at the Default Load Aggregation Point (DLAP) of SCE. In the day-ahead market, BVES will be charged hourly for its scheduled load at the DLAP SCE.[[14]](#footnote-16) Any real time deviations from the day ahead schedule will be settled every 10 minutes at the real time LMP of DLAP SCE. Historically, BVES has used the imbalance market to meet unanticipated ski resort snow making load during the winter. BVES can purchase its energy needs from the CAISO in its day ahead market. BVES also has the option of making bilateral energy purchases and scheduling them in the CAISO market through Inter-SC Trades in the day-ahead market.

H. Congestion Costs

Congestion Costs are one of the two components (transmission losses being the other) of the cost to deliver energy from one point to another within the CAISO. The cost of congestion is the difference in the Marginal Congestion Cost (MCC) component of the LMP between the price nodes specified for energy delivery and takeout. For BVES supply contracts, the source from the CAISO settlements perspective is the aggregated generation hub price for South of Path 15 (SP15-Gen Hub) area.[[15]](#footnote-17) The sink, or takeout point, is the Southern California Edison Default Load Aggregation Price (SCE\_DLAP). This price is the load-weighted aggregation of all load nodes within the SCE area. Congestion costs can be mitigated through the use of Congestion Revenue Rights (“CRRs”).

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

I. Grid Management Charges

CAISO grid management charges (“GMC”) are one of BVES’ greatest single monthly costs, exceeded only by monthly energy charges. Anticipating changes to the GMC is difficult due to the nature of the charge. As California utilities’ transmission revenue requirements change, the GMC will change.

* 1. Renewable Resources

BVES has the ability to meet all of its renewable resource requirements through the purchase of unbundled Renewable Energy Credits (RECs). Using RECs to meet BVES’ renewable requirements affords the company several advantages over other renewable alternatives.

BVES currently utilizes RECs to meet all of its RPS requirements and plans to purchase RECs in the future for to meet most of its RPS requirements because RECs are generally easier to procure than bundled RPS energy and RECs do not require other changes in the BVES resource procurement strategy. With the 50% renewables by 2030 requirement stemming from SB 350, BVES anticipates it will acquire a combination of unbundled RECs and bundled energy to meet the 2030 requirement, with the vast majority of its RPS supply consisting of RECs. However, for the 2018-2021 period, and based upon a cost of RECs of around $9/MWh and a requirement of approximately 49,000 RECs annually, BVES’ renewable costs are projected to be about $482,000 annually. This assumes that BVES will continue to be able to buy Category 3 RECs (as defined by SB2 (X1)).

* 1. Long-Term Risks to BVES’ Power Supply Costs

While BVES attempts to fix as much of its power supply costs as possible, there are still some variables that will impact total annual power supply costs in the long-term.

The first identified variable is CAISO charges. BVES must buy through the CAISO and cannot control any of the CAISO charges, including congestion charges. To the extent these charges change over time, BVES’ costs will increase or decrease in comparison to the forecast.

The second variable is natural gas costs. While BVES does not purchase any significant amounts of gas for the BVPP, if BVES has to purchase natural gas or if the MRTU LMP increases due to an increase in natural gas prices, BVES’ costs will rise.

The third variable is the imbalance in the scheduling of power in the day-ahead market. If BVES is short in its power supply due to under scheduling in the day-ahead market, BVES will have to rely on the real time market purchases, which are not protected from price spikes.

* 1. Summary of PROJECTED Power Supply Costs

BVES’ total power supply costs should remain relatively stable in 2018, 2019, 2020 and 2021 at approximately $11,300,000 to $12,300,000 annually, with the average *total* cost per MWh of approximately $72/MWh.[[16]](#footnote-18) Beginning in late 2019, when the current annual baseload contract ends, BVES’ power supply costs are projected to decline slightly on a cost/MWh basis and remain fairly constant under the assumption that BVES executes the proposed contracts at the current bid price. If future energy or natural gas costs significantly increase, the forecasted power supply costs will need to be revised. Table A-3 provides a summary of annual power supply costs by month.

Once BVES executes additional, long-term power supply contracts, it will have very limited exposure to increasing natural gas costs with only annual generation from the BVPP and market purchases of about 29,000 MWh.

APPENDIX a TO VOLUME 4

**Table A-1: BVES Existing EDF and Shell Contracts**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Supplier/Counterparty** | **Product** | **Resource** | **Term of**  **Deliveries** | **Contract Length** | **MW Capacity** |
| EDF Trading North America, LLC | Annual Baseload | CAISO Firm Energy | 1/2015-11/30/2019 | 4 yrs, 11 mo | 12 |
| Shell Energy North America (US) L. P. | Seasonal Baseload | CAISO Firm Energy | 7MW  1/1 – 2/28  2015 – 2017  7MW  12/1 – 12/31  2015 – 2017  5MW  11/1 – 11/30  2015 -- 2017 | 3 yrs | 5-7 |
| EDF Trading North America, LLC | Physical Call Option (Peaking) | CAISO Firm Energy | 0-3 MW  4/1 – 10/31  2015 – 2017  0 – 7 MW  1/1 – 3/31  11/1 – 12/31  2015 -- 2017 | 3 yrs | 3-7 |
| Shell Energy North America (US) L.P. | System Resource Adequacy Capacity | Gas Turbine, Combined Cycle | 8 – 31MW  3/1/2015 –  1/31/2020 | 4 yrs, 11 mo | 8 - 31\* |

**Table A-2: Summary of Power Supply Costs Base Case**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **2018** | **2019** | **2020** | **2021** |
| **ENERGY RESOURCES** | **FORECAST** | **FORECAST** | **FORECAST** | **FORECAST** |
| Monthly Energy Requirements | 163,298 | 164,495 | 165,294 | 166,474 |
| Losses | 18,605 | 18,133 | 17,431 | 17,050 |
| Losses | 13% | 12% | 12% | 11% |
| Delivered MWh (Sales to customers) | 144,693 | 146,362 | 147,864 | 149,424 |
|  |  |  |  |  |
| Annual Base Supply | 105,120 | 105,120 | 105,120 | 105,120 |
| Annual Seasonal Supply (Winter Only) | 23,771 | 23,771 | 23,771 | 23,771 |
| Total Contract Base Supply | 128,891 | 128,891 | 128,891 | 128,891 |
| Renewable Energy Credits | 45,444 | 48,455 | 51,661 | 51,640 |
| Call Option (on and off peak) | 743 | 1,523 | 5,924 | 7,178 |
| Day-Ahead Spot Purchases | 29,262 | 29,419 | 25,658 | 25,419 |
| Bear Valley Power Plant | 537 | 537 | 537 | 537 |
| Imbalance Energy Purchases | 7,553 | 7,553 | 7,553 | 7,553 |
| Imbalance Energy Sales | 3,636 | 3,434 | 3,297 | 3,077 |
| **TOTAL Resources not including RECs** | **163,349** | **164,489** | **165,266** | **166,501** |
|  |  |  |  |  |
| **COST OF SUPPLY** |  |  |  |  |
| Annual Base Supply | $4,993,200 | $4,993,200 | $4,993,200 | $4,993,200 |
| Annual Seasonal Supply (Winter Only) | $883,744 | $883,744 | $883,744 | $883,744 |
| Total Contract Base Supply | $5,876,944 | $5,876,944 | $5,876,944 | $5,876,944 |
|  |  |  |  |  |
| Renewable Energy Credits | $408,996 | $436,095 | $464,949 | $619,680 |
| Call Option (on and off peak) | $35,664 | $73,104 | $284,352 | $344,544 |
| Day-Ahead Spot Purchases | $1,011,644 | $1,048,913 | $1,003,396 | $1,074,218 |
| Bear Valley Power Plant | $21,282 | $21,402 | $22,872 | $23,028 |
| Imbalance Energy Purchases | $269,360 | $278,148 | $300,873 | $327,876 |
| Imbalance Energy Sales | $113,429 | $112,551 | $117,531 | $122,983 |
| **TOTAL cost including RECs** | **$7,510,461** | **$7,622,055** | **$7,835,855** | **$8,143,308** |
|  |  |  |  |  |
| **CAPACITY & OTHER COSTS** | | | |  |
| RA Capacity Charge | $832,500 | $854,700 | $876,900 | $876,900 |
| Minimum Nat Gas & Gas Transportation | $56,799 | $56,678 | $55,208 | $55,052 |
| CAISO & Related Charges | $1,767,610 | $1,884,942 | $2,010,487 | $2,144,820 |
| Transmission & Option Charges | $1,144,908 | $1,145,664 | $1,145,913 | $1,146,193 |
|  |  |  |  |  |
| **TOTAL SUPPLY COST** | **$11,312,278** | **$11,564,039** | **$11,924,364** | **$12,366,274** |

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **ATTACHMENT A-3** | | | | | | | | | | | | | | |
| **Monthly Forecast of Power Supply Costs 2018 - 2021** | | | | | | | | | | | | | | |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | | | | | | | | | | | | | | |
| HV Transmission Charges $/MWh | $11.13 |  |  |  |  |  |  |  |  |  |  |  |  |  |
| LV Transmission Charges $/MWh | $0.44 |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  |  | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| Monthly Peak (MW) |  | 39 | 32 | 30 | 23 | 25 | 23 | 27 | 25 | 25 | 23 | 34 | 43 |  |
| Monthly Energy (MWh) |  | 17,191 | 14,126 | 14,270 | 11,819 | 11,570 | 11,594 | 12,604 | 12,660 | 11,588 | 11,976 | 14,765 | 19,134 | **163,298** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Capacity Requirements** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Monthly Peak Less Partial BVPP Capacity |  | 23.28 | 19.08 | 17.74 | 13.92 | 13.68 | 13.64 | 16.75 | 15.75 | 14.56 | 13.99 | 16.15 | 25.84 |  |
| Reserve Requirements |  | 3.49 | 2.86 | 2.66 | 2.09 | 2.05 | 2.05 | 2.51 | 2.36 | 2.18 | 2.10 | 2.42 | 3.88 |  |
| Total Capacity Requirements |  | 26.77 | 21.94 | 20.40 | 16.01 | 15.73 | 15.68 | 19.26 | 18.11 | 16.74 | 16.09 | 18.57 | 29.72 |  |
| Resource Adequacy Capacity |  | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| Dispatchable DSM |  | 8.98 | 8.98 | 8.98 | 8.98 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 8.98 | 8.98 |  |
| Adjusted Coincident Factor |  | 0.685 | 0.705 | 0.709 | 0.767 | 0.688 | 0.744 | 0.770 | 0.799 | 0.706 | 0.786 | 0.562 | 0.676 |  |
| Net RA Capacity Position |  | 6 | 7 | 5 | 1 | 2 | 4 | -1 | -1 | 0 | 3 | 5 | 10 |  |
| RA Capacity Cost ($/kw-month) |  | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 |  |
| **Total Capacity Cost** |  | $90,000 | $75,000 | $60,000 | $30,000 | $67,500 | $71,250 | $67,500 | $63,750 | $63,750 | $71,250 | $56,250 | $116,250 | **$832,500** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Energy Purchases** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | **105,120** |
| Seasonal Baseload Energy On-peak |  | 3,968 | 3,584 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,924 | 3,968 | **13,444** |
| Seasonal Baseload Energy Off-peak |  | 2,976 | 2,688 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,687 | 2,976 | **10,327** |
| Energy Option On-Peak |  | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 372 | **372** |
| Energy Option Off-Peak |  | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 372 | **372** |
| Bear Valley Power Plant |  | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | **537** |
| Day-Ahead Purchases |  | 1375 | 603 | 4840 | 2908 | 2301 | 2391 | 3000 | 3275 | 2109 | 2705 | 1766 | 1988 | **29,262** |
| Imbalance Real-Time Energy |  | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | **7,553** |
| **Total Energy Purchases** |  | 17,192 | 14,126 | 14,270 | 11,818 | 11,570 | 11,594 | 12,604 | 12,659 | 11,588 | 11,976 | 14,469 | 19,483 | **163,349** |
|  |  | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -296 | 349 |  |
| Renewable Energy Credits |  | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | 3,787 | **45,444** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Real-Time Imbalance Energy Sales (MWh)** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Real-Time Imbalance Energy |  | 1009 | 1340 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 481 | 806 | **3,636** |
| Real-Time Imbalance Energy ($MWh) |  | $31.59 | $30.65 | $26.21 | $22.84 | $23.02 | $23.11 | $29.26 | $32.79 | $29.97 | $29.84 | $30.40 | $32.08 |  |
| Real-Time Imbalance Energy Sales Total |  | $31,882 | $41,078 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $14,623 | $25,846 | **$113,429** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** (no transportation added) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy On-Peak ($MWh) |  | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| Seasonal Baseload Energy On-peak ($MWh) |  | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 |  |
| Seasonal Baseload Energy Off-peak ($MWh) |  | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 |  |
| On-peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Off-Peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Bear Valley Power Plant ($/MWh) |  | $44.71 | $42.46 | $37.13 | $34.98 | $34.58 | $35.25 | $37.49 | $38.10 | $38.08 | $37.52 | $37.67 | $42.62 |  |
| Day-Ahead Purchases ($/MWh) |  | $36.72 | $35.69 | $30.80 | $28.74 | $29.17 | $29.51 | $37.34 | $42.29 | $37.91 | $37.85 | $35.62 | $37.00 |  |
| Imbalance Energy ($/MWh) |  | $36.72 | $35.69 | $30.80 | $28.74 | $29.17 | $29.51 | $37.34 | $42.29 | $37.91 | $37.85 | $35.62 | $37.00 |  |
| Renewable Energy Credits ($/MWh) |  | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost of Purchased Power/Generation** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | **$4,993,200** |
| Seasonal Baseload Energy On-peak |  | $154,157 | $139,238 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $74,747 | $154,157 | **$522,299** |
| Seasonal Baseload Energy Off-peak |  | $104,160 | $94,080 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $59,045 | $104,160 | **$361,445** |
| Energy Option On-peak |  | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $17,832 | **$17,832** |
| Energy Option Off-peak |  | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $17,832 | **$17,832** |
| Bear Valley Power Plant |  | $2,395 | $1,313 | $1,771 | $937 | $676 | $829 | $1,617 | $786 | $1,909 | $1,412 | $1,346 | $6,290 | **$21,282** |
| Day-Ahead Purchases |  | $50,506 | $21,509 | $149,059 | $83,585 | $67,114 | $70,552 | $112,028 | $138,512 | $79,948 | $102,399 | $62,884 | $73,547 | **$1,011,644** |
| Imbalance Energy |  | $33,056 | $17,725 | $14,338 | $7,004 | $9,372 | $15,920 | $23,649 | $18,415 | $29,892 | $11,543 | $31,551 | $56,895 | **$269,360** |
| Renewable Energy Credits |  | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | $34,083 | **$408,996** |
| **Total Purchased Power/Generation Cost** |  | $802,438 | $690,988 | $622,761 | $536,009 | $535,325 | $531,785 | $595,457 | $615,876 | $556,233 | $573,517 | $674,626 | $888,876 | **$7,623,890** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Transmission/Option Premium** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| W-DAT |  | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | **$660,168** |
| 33 kV Transmission Charges |  | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | **$194,952** |
| Amended Restated Transmission Agreement |  | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **$0** |
| Reliability |  | $2,548 | $2,064 | $2,047 | $1,701 | $1,670 | $1,646 | $1,800 | $1,799 | $1,644 | $1,741 | $2,263 | $3,285 | **$24,208** |
| Added Facilities |  | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | **$37,800** |
| Call Option Premium On-peak |  | $24,636 | $22,252 | $24,636 | $7,065 | $7,301 | $7,065 | $7,301 | $7,301 | $7,065 | $7,301 | $23,841 | $24,636 | **$170,400** |
| Call Option Premium Off-peak |  | $11,780 | $10,640 | $11,780 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $11,400 | $11,780 | **$57,380** |
| Total Cost |  | $113,374 | $109,365 | $112,873 | $83,177 | $83,381 | $83,122 | $83,511 | $83,510 | $83,119 | $83,452 | $111,914 | $114,111 | **$1,144,908** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Total Cost of Transmission and Energy |  | $915,812 | $800,354 | $735,634 | $619,185 | $618,705 | $614,906 | $678,968 | $699,386 | $639,352 | $656,969 | $786,540 | $1,002,987 | **$8,768,798** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **OTHER COSTS** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| CAISO Charges |  | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | $139,681 | **$1,676,169** |
| Schedule Coordinator Fee/Dispatch |  | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | **$91,441** |
| Minimum Nat Gas & Gas Transportation |  | $4,111 | $5,194 | $4,735 | $5,570 | $5,831 | $5,677 | $4,889 | $5,721 | $4,597 | $5,095 | $5,161 | $217 | **$56,799** |
| Total |  | $151,412 | $152,495 | $152,036 | $152,871 | $153,132 | $152,978 | $152,190 | $153,021 | $151,898 | $152,396 | $152,462 | $147,517 | **$1,824,409** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **TOTAL POWER SUPPLY COSTS** |  | **$1,125,342** | **$986,770** | **$947,670** | **$802,056** | **$839,337** | **$839,135** | **$898,658** | **$916,157** | **$855,000** | **$880,615** | **$980,629** | **$1,240,909** | **$11,312,278** |
| **Total Cost/MWh** |  | **$65.46** | **$69.85** | **$66.41** | **$67.86** | **$72.54** | **$72.37** | **$71.30** | **$72.37** | **$73.78** | **$73.53** | **$66.41** | **$64.85** | **$69.27** |
| Energy Cost |  | $802,438 | $690,988 | $622,761 | $536,009 | $535,325 | $531,785 | $595,457 | $615,876 | $556,233 | $573,517 | $674,626 | $888,876 | $7,623,890 |
| Energy Cost/MWh |  | $46.68 | $48.92 | $43.64 | $45.35 | $46.27 | $45.87 | $47.24 | $48.65 | $48.00 | $47.89 | $45.69 | $46.46 | $46.69 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2019** | | | | | | | | | | | | | | |
| HV Transmission Charges $/MWh | $11.13 |  |  |  |  |  |  |  |  |  |  |  |  |  |
| LV Transmission Charges $/MWh | $0.44 |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  |  | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| Monthly Peak (MW) |  | 39 | 32 | 30 | 23 | 25 | 23 | 27 | 25 | 26 | 23 | 34 | 43 |  |
| Monthly Energy (MWh) |  | 17,327 | 14,239 | 14,430 | 11,919 | 11,673 | 11,707 | 12,677 | 12,776 | 11,626 | 12,061 | 14,870 | 19,191 | **164,495** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Capacity Requirements** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Monthly Peak Less Partial BVPP Capacity |  | 23.46 | 19.21 | 17.98 | 14.11 | 13.84 | 13.80 | 16.93 | 15.92 | 14.71 | 14.13 | 16.23 | 26.04 |  |
| Reserve Requirements |  | 3.52 | 2.88 | 2.70 | 2.12 | 2.08 | 2.07 | 2.54 | 2.39 | 2.21 | 2.12 | 2.43 | 3.91 |  |
| Total Capacity Requirements |  | 26.97 | 22.09 | 20.67 | 16.22 | 15.92 | 15.87 | 19.47 | 18.31 | 16.92 | 16.25 | 18.66 | 29.95 |  |
| Resource Adequacy Capacity |  | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| Dispatchable DSM |  | 8.98 | 8.98 | 8.98 | 8.98 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 8.98 | 8.98 |  |
| Adjusted Coincident Factor |  | 0.685 | 0.705 | 0.709 | 0.767 | 0.688 | 0.744 | 0.770 | 0.799 | 0.706 | 0.786 | 0.562 | 0.676 |  |
| Net RA Capacity Position |  | 6 | 7 | 4 | 1 | 2 | 3 | -1 | -1 | 0 | 3 | 5 | 10 |  |
| RA Capacity Cost ($/kw-month) |  | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 |  |
| **Total Capacity Cost** |  | $92,400 | $77,000 | $61,600 | $30,800 | $69,300 | $73,150 | $69,300 | $65,450 | $65,450 | $73,150 | $57,750 | $119,350 | **$854,700** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Energy Purchases** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | **105,120** |
| Seasonal Baseload Energy On-peak |  | 3,968 | 3,584 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,924 | 3,968 | **13,444** |
| Seasonal Baseload Energy Off-peak |  | 2,976 | 2,688 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,687 | 2,976 | **10,327** |
| Energy Option On-peak |  | 56 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 334 | 372 | **762** |
| Energy Option Off-peak |  | 56 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 334 | 372 | **762** |
| Bear Valley Power Plant |  | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | **537** |
| Day-Ahead Purchases |  | 1,529 | 664 | 5,001 | 3,008 | 2,403 | 2,507 | 3,072 | 3,391 | 2,148 | 2,490 | 1,480 | 1,725 | **29,419** |
| Imbalance Real-Time Energy |  | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | **7,553** |
| **Total Energy Purchases** |  | 17,557 | 14,239 | 14,430 | 11,919 | 11,672 | 11,710 | 12,677 | 12,775 | 11,626 | 11,761 | 14,875 | 19,247 | **164,489** |
|  |  | 230 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | -300 | 6 | 56 |  |
| Renewable Energy Credits |  | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | 4,038 | **48,455** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Real-Time Imbalance Energy Sales (MWh)** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Real-Time Imbalance Energy |  | 910 | 1,290 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 456 | 779 | **3,434** |
| Real-Time Imbalance Energy ($MWh) |  | $32.78 | $32.46 | $28.86 | $24.84 | $23.98 | $23.67 | $30.19 | $33.68 | $29.68 | $29.73 | $31.81 | $33.86 |  |
| Real-Time Imbalance Energy Sales Total |  | $29,826 | $41,862 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $14,500 | $26,363 | **$112,551** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** (no transportation added) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy On-Peak ($MWh) |  | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| Seasonal Baseload Energy On-peak ($MWh) |  | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 |  |
| Seasonal Baseload Energy Off-peak ($MWh) |  | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 |  |
| On-peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Off-Peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Bear Valley Power Plant ($/MWh) |  | $43.97 | $43.81 | $40.52 | $35.96 | $33.64 | $34.21 | $38.00 | $38.05 | $35.79 | $35.72 | $38.34 | $43.37 |  |
| Day-Ahead Purchases ($/MWh) |  | $38.01 | $37.57 | $33.50 | $30.84 | $29.99 | $29.87 | $37.99 | $42.90 | $37.84 | $37.57 | $36.90 | $38.81 |  |
| Imbalance Energy ($/MWh) |  | $38.01 | $37.57 | $33.50 | $30.84 | $29.99 | $29.87 | $37.99 | $42.90 | $37.84 | $37.57 | $36.90 | $38.81 |  |
| Renewable Energy Credits ($/MWh) |  | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost of Purchased Power/Generation** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | **$4,993,200** |
| Seasonal Baseload Energy On-peak |  | $154,157 | $139,238 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $74,747 | $154,157 | **$522,299** |
| Seasonal Baseload Energy Off-peak |  | $104,160 | $94,080 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $59,045 | $104,160 | **$361,445** |
| Energy Option On-peak |  | $2,688 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $16,008 | $17,856 | **$36,552** |
| Energy Option Off-peak |  | $2,688 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $16,008 | $17,856 | **$36,552** |
| Bear Valley Power Plant |  | $2,356 | $1,354 | $1,933 | $963 | $657 | $805 | $1,639 | $785 | $1,794 | $1,344 | $1,369 | $6,401 | **$21,402** |
| Day-Ahead Purchases |  | $58,127 | $24,962 | $167,498 | $92,783 | $72,072 | $74,892 | $116,732 | $145,481 | $81,261 | $93,573 | $54,598 | $66,935 | **$1,048,913** |
| Imbalance Energy |  | $34,221 | $18,658 | $15,595 | $7,516 | $9,635 | $16,116 | $24,061 | $18,681 | $29,839 | $11,459 | $32,687 | $59,680 | **$278,148** |
| Renewable Energy Credits |  | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | $36,341 | **$436,095** |
| **Total Purchased Power/Generation Cost** |  | $818,818 | $697,674 | $644,877 | $548,003 | $542,785 | $538,554 | $602,853 | $625,368 | $559,635 | $566,798 | $701,774 | $887,466 | **$7,734,606** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Transmission/Option Premium** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| W-DAT |  | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | **$660,168** |
| 33 kV Transmission Charges |  | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | **$194,952** |
| Amended Restated Transmission Agreement |  | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **$0** |
| Reliability |  | $2,924 | $2,188 | $2,121 | $1,722 | $1,689 | $1,664 | $1,819 | $1,817 | $1,658 | $1,759 | $2,290 | $3,313 | **$24,964** |
| Added Facilities |  | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | **$37,800** |
| Call Option Premium On-peak |  | $24,636 | $22,252 | $24,636 | $7,065 | $7,301 | $7,065 | $7,301 | $7,301 | $7,065 | $7,301 | $23,841 | $24,636 | **$170,400** |
| Call Option Premium Off-peak |  | $11,780 | $10,640 | $11,780 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $11,400 | $11,780 | **$57,380** |
| Total Cost |  | $113,749 | $109,490 | $112,947 | $83,197 | $83,400 | $83,139 | $83,530 | $83,527 | $83,134 | $83,470 | $111,941 | $114,139 | **$1,145,664** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Total Cost of Transmission and Energy |  | $932,567 | $807,163 | $757,824 | $631,200 | $626,185 | $621,694 | $686,383 | $708,896 | $642,769 | $650,268 | $813,715 | $1,001,605 | **$8,880,270** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **OTHER COSTS** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| CAISO Charges |  | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | $149,458 | **$1,793,501** |
| Schedule Coordinator Fee/Dispatch |  | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | **$91,441** |
| Minimum Nat Gas & Gas Transportation |  | $4,151 | $5,152 | $4,574 | $5,544 | $5,849 | $5,702 | $4,868 | $5,722 | $4,713 | $5,162 | $5,137 | $105 | **$56,678** |
| Total |  | $161,229 | $162,231 | $161,652 | $162,622 | $162,928 | $162,780 | $161,946 | $162,800 | $161,791 | $162,241 | $162,216 | $157,184 | **$1,941,620** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **TOTAL POWER SUPPLY COSTS** |  | **$1,156,370** | **$1,004,532** | **$981,076** | **$824,622** | **$858,413** | **$857,624** | **$917,629** | **$937,146** | **$870,010** | **$885,659** | **$1,019,181** | **$1,251,775** | **$11,564,039** |
| **Total Cost/MWh** |  | **$66.74** | **$70.55** | **$67.99** | **$69.19** | **$73.54** | **$73.26** | **$72.39** | **$73.35** | **$74.83** | **$73.43** | **$68.54** | **$65.23** | **$70.30** |
| Energy Cost |  | $818,818 | $697,674 | $644,877 | $548,003 | $542,785 | $538,554 | $602,853 | $625,368 | $559,635 | $566,798 | $701,774 | $887,466 | $7,734,606 |
| Energy Cost/MWh |  | $47.26 | $49.00 | $44.69 | $45.98 | $46.50 | $46.00 | $47.56 | $48.95 | $48.14 | $46.99 | $47.20 | $46.24 | $47.02 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2020** | | | | | | | | | | | | | | |
| HV Transmission Charges $/MWh | $11.13 |  |  |  |  |  |  |  |  |  |  |  |  |  |
| LV Transmission Charges $/MWh | $0.44 |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  |  | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| Monthly Peak (MW) |  | 39 | 32 | 30 | 23 | 25 | 24 | 27 | 25 | 26 | 23 | 34 | 44 |  |
| Monthly Energy (MWh) |  | 17,557 | 14,344 | 14,453 | 11,968 | 11,772 | 11,660 | 12,784 | 12,850 | 11,670 | 12,228 | 14,849 | 19,160 | **165,294** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Capacity Requirements** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Monthly Peak Less Partial BVPP Capacity |  | 23.63 | 19.33 | 18.13 | 14.22 | 13.98 | 13.94 | 17.09 | 16.08 | 14.85 | 14.29 | 16.34 | 26.29 |  |
| Reserve Requirements |  | 3.54 | 2.90 | 2.72 | 2.13 | 2.10 | 2.09 | 2.56 | 2.41 | 2.23 | 2.14 | 2.45 | 3.94 |  |
| Total Capacity Requirements |  | 27.17 | 22.23 | 20.85 | 16.36 | 16.08 | 16.03 | 19.66 | 18.49 | 17.08 | 16.44 | 18.79 | 30.23 |  |
| Resource Adequacy Capacity |  | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| Dispatchable DSM |  | 8.98 | 8.98 | 8.98 | 8.98 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 8.98 | 8.98 |  |
| Adjusted Coincident Factor |  | 0.685 | 0.705 | 0.709 | 0.767 | 0.688 | 0.744 | 0.770 | 0.799 | 0.706 | 0.786 | 0.562 | 0.676 |  |
| Net RA Capacity Position |  | 6 | 7 | 4 | 1 | 2 | 3 | -1 | -1 | 0 | 3 | 5 | 10 |  |
| RA Capacity Cost ($/kw-month) |  | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 |  |
| **Total Capacity Cost** |  | $94,800 | $79,000 | $63,200 | $31,600 | $71,100 | $75,050 | $71,100 | $67,150 | $67,150 | $75,050 | $59,250 | $122,450 | **$876,900** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Energy Purchases** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | **105,120** |
| Seasonal Baseload Energy On-peak |  | 3,968 | 3,584 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,924 | 3,968 | **13,444** |
| Seasonal Baseload Energy Off-peak |  | 2,976 | 2,688 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,687 | 2,976 | **10,327** |
| Energy Option On-peak |  | 1,053 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 724 | 1,186 | **2,962** |
| Energy Option Off-peak |  | 1,053 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 724 | 1,186 | **2,962** |
| Bear Valley Power Plant |  | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | **537** |
| Day-Ahead Purchases |  | 2,076 | 1,252 | 2,525 | 2,328 | 1,844 | 2,020 | 2,356 | 2,622 | 2,030 | 2,800 | 1,805 | 2,000 | **25,658** |
| Imbalance Real-Time Energy |  | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | **7,553** |
| **Total Energy Purchases** |  | 20,115 | 14,872 | 11,954 | 11,238 | 11,113 | 11,223 | 11,960 | 12,006 | 11,509 | 12,071 | 16,022 | 21,183 | **165,266** |
|  |  | 2,559 | 528 | -2,499 | -730 | -659 | -437 | -824 | -844 | -161 | -157 | 1,173 | 2,023 |  |
| Renewable Energy Credits |  | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | 4,305 | **51,661** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Real-Time Imbalance Energy Sales (MWh)** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Real-Time Imbalance Energy |  | 892 | 1,243 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 416 | 745 | **3,297** |
| Real-Time Imbalance Energy ($MWh) |  | $35.87 | $34.92 | $32.13 | $28.22 | $26.55 | $26.01 | $31.99 | $35.82 | $32.50 | $32.91 | $35.44 | $36.74 |  |
| Real-Time Imbalance Energy Sales Total |  | $31,994 | $43,415 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $14,743 | $27,378 | **$117,531** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** (no transportation added) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy On-Peak ($MWh) |  | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| Seasonal Baseload Energy On-peak ($MWh) |  | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 |  |
| Seasonal Baseload Energy Off-peak ($MWh) |  | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 |  |
| On-peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Off-Peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Bear Valley Power Plant ($/MWh) |  | $45.83 | $46.73 | $44.99 | $43.63 | $40.01 | $38.23 | $38.66 | $39.22 | $38.64 | $38.96 | $40.65 | $45.00 |  |
| Day-Ahead Purchases ($/MWh) |  | $41.23 | $40.01 | $36.77 | $34.38 | $32.81 | $32.40 | $39.82 | $45.27 | $41.04 | $41.34 | $40.81 | $41.82 |  |
| Imbalance Energy ($/MWh) |  | $41.23 | $40.01 | $36.77 | $34.38 | $32.81 | $32.40 | $39.82 | $45.27 | $41.04 | $41.34 | $40.81 | $41.82 |  |
| Renewable Energy Credits ($/MWh) |  | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 | $9.00 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost of Purchased Power/Generation** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | **$4,993,200** |
| Seasonal Baseload Energy On-peak |  | $154,157 | $139,238 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $74,747 | $154,157 | **$522,299** |
| Seasonal Baseload Energy Off-peak |  | $104,160 | $94,080 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $59,045 | $104,160 | **$361,445** |
| Energy Option On-peak |  | $50,520 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $34,752 | $56,904 | **$142,176** |
| Energy Option Off-peak |  | $50,520 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $34,752 | $56,904 | **$142,176** |
| Bear Valley Power Plant |  | $2,456 | $1,445 | $2,147 | $1,168 | $782 | $899 | $1,668 | $809 | $1,937 | $1,466 | $1,452 | $6,643 | **$22,872** |
| Day-Ahead Purchases |  | $85,598 | $50,080 | $92,851 | $80,046 | $60,508 | $65,428 | $93,816 | $118,674 | $83,303 | $115,777 | $73,669 | $83,645 | **$1,003,396** |
| Imbalance Energy |  | $37,113 | $19,872 | $17,120 | $8,379 | $10,541 | $17,477 | $25,220 | $19,712 | $32,362 | $12,609 | $36,151 | $64,317 | **$300,873** |
| Renewable Energy Credits |  | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | $38,746 | **$464,949** |
| **Total Purchased Power/Generation Cost** |  | $947,349 | $726,501 | $574,373 | $538,739 | $534,657 | $532,951 | $583,530 | $602,021 | $566,748 | $592,677 | $764,284 | $989,555 | **$7,953,386** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Transmission/Option Premium** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| W-DAT |  | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | **$660,168** |
| 33 kV Transmission Charges |  | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | **$194,952** |
| Reliability |  | $2,955 | $2,209 | $2,141 | $1,739 | $1,707 | $1,679 | $1,836 | $1,834 | $1,677 | $1,781 | $2,312 | $3,344 | **$25,214** |
| Added Facilities |  | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | **$37,800** |
| Call Option Premium On-peak |  | $24,636 | $22,252 | $24,636 | $7,065 | $7,301 | $7,065 | $7,301 | $7,301 | $7,065 | $7,301 | $23,841 | $24,636 | **$170,400** |
| Call Option Premium Off-peak |  | $11,780 | $10,640 | $11,780 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $11,400 | $11,780 | **$57,380** |
| Total Cost |  | $113,781 | $109,510 | $112,967 | $83,214 | $83,417 | $83,155 | $83,547 | $83,544 | $83,153 | $83,492 | $111,963 | $114,170 | **$1,145,913** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Total Cost of Transmission and Energy |  | $1,061,130 | $836,011 | $687,340 | $621,953 | $618,074 | $616,106 | $667,077 | $685,566 | $649,900 | $676,169 | $876,248 | $1,103,725 | **$9,099,299** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **OTHER COSTS** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| CAISO Charges |  | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | $159,921 | **$1,919,046** |
| Schedule Coordinator Fee/Dispatch |  | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | **$91,441** |
| Minimum Nat Gas & Gas Transportation |  | $4,051 | $5,062 | $4,360 | $5,338 | $5,725 | $5,607 | $4,839 | $5,697 | $4,569 | $5,041 | $5,055 | -$136 | **$55,208** |
| Total |  | $171,592 | $172,603 | $171,901 | $172,879 | $173,265 | $173,148 | $172,380 | $173,238 | $172,110 | $172,581 | $172,595 | $167,405 | **$2,065,695** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **TOTAL POWER SUPPLY COSTS** |  | **$1,295,528** | **$1,044,199** | **$922,440** | **$826,432** | **$862,439** | **$864,304** | **$910,556** | **$925,954** | **$889,160** | **$923,801** | **$1,093,349** | **$1,366,202** | **$11,924,364** |
| **Total Cost/MWh** |  | **$73.79** | **$72.80** | **$63.82** | **$69.05** | **$73.26** | **$74.13** | **$71.23** | **$72.06** | **$76.19** | **$75.55** | **$73.63** | **$71.31** | **$72.14** |
| Energy Cost |  | $947,349 | $726,501 | $574,373 | $538,739 | $534,657 | $532,951 | $583,530 | $602,021 | $566,748 | $592,677 | $764,284 | $989,555 | $7,953,386 |
| Energy Cost/MWh |  | $53.96 | $50.65 | $39.74 | $45.02 | $45.42 | $45.71 | $45.65 | $46.85 | $48.56 | $48.47 | $51.47 | $51.65 | $48.12 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2021** | | | | | | | | | | | | | | |
| HV Transmission Charges $/MWh | $11.13 |  |  |  |  |  |  |  |  |  |  |  |  |  |
| LV Transmission Charges $/MWh | $0.44 |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  |  | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| Monthly Peak (MW) |  | 40 | 32 | 31 | 24 | 25 | 24 | 27 | 25 | 26 | 23 | 34 | 44 |  |
| Monthly Energy (MWh) |  | 17,917 | 14,436 | 14,537 | 12,087 | 11,872 | 11,770 | 12,899 | 12,968 | 11,796 | 12,350 | 14,668 | 19,175 | **166,474** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Capacity Requirements** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Monthly Peak Less Partial BVPP Capacity |  | 23.78 | 19.44 | 18.31 | 14.36 | 14.14 | 14.10 | 17.28 | 16.30 | 15.05 | 14.45 | 16.44 | 26.52 |  |
| Reserve Requirements |  | 3.57 | 2.92 | 2.75 | 2.15 | 2.12 | 2.12 | 2.59 | 2.45 | 2.26 | 2.17 | 2.47 | 3.98 |  |
| Total Capacity Requirements |  | 27.34 | 22.36 | 21.05 | 16.51 | 16.26 | 16.22 | 19.87 | 18.75 | 17.31 | 16.62 | 18.90 | 30.50 |  |
| Resource Adequacy Capacity |  | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| Dispatchable DSM |  | 8.98 | 8.98 | 8.98 | 8.98 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 8.98 | 8.98 |  |
| Adjusted Coincident Factor |  | 0.685 | 0.705 | 0.709 | 0.767 | 0.688 | 0.744 | 0.770 | 0.799 | 0.706 | 0.786 | 0.562 | 0.676 |  |
| Net RA Capacity Position |  | 6 | 7 | 4 | 0 | 2 | 3 | -2 | -2 | 0 | 3 | 5 | 9 |  |
| RA Capacity Cost ($/kw-month) |  | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 |  |
| **Total Capacity Cost** |  | $94,800 | $79,000 | $63,200 | $31,600 | $71,100 | $75,050 | $71,100 | $67,150 | $67,150 | $75,050 | $59,250 | $122,450 | **$876,900** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Energy Purchases** (MWh) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | **105,120** |
| Seasonal Baseload Energy On-peak |  | 3,968 | 3,584 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,924 | 3,968 | **13,444** |
| Seasonal Baseload Energy Off-peak |  | 2,976 | 2,688 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,687 | 2,976 | **10,327** |
| Energy Option On-peak |  | 1,183 | 522 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 678 | 1,207 | **3,589** |
| Energy Option Off-peak |  | 1,183 | 522 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 678 | 1,207 | **3,589** |
| Bear Valley Power Plant |  | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | **537** |
| Day-Ahead Purchases |  | 2,810 | 1,305 | 2,609 | 2,447 | 1,944 | 2,130 | 1,971 | 2,040 | 1,656 | 1,922 | 2,100 | 2,485 | **25,419** |
| Imbalance Real-Time Energy |  | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | **7,553** |
| **Total Energy Purchases** |  | 21,236 | 16,006 | 12,038 | 11,358 | 11,213 | 11,333 | 11,575 | 11,424 | 11,135 | 11,192 | 16,248 | 21,742 | **166,501** |
|  |  | 3,318 | 1,571 | -2,499 | -730 | -659 | -437 | -1,324 | -1,544 | -661 | -1,157 | 1,581 | 2,568 |  |
| Renewable Energy Credits |  | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | 4,303 | **51,640** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Real-Time Imbalance Energy Sales (MWh)** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Real-Time Imbalance Energy |  | 765 | 1,205 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 392 | 714 | **3,077** |
| Real-Time Imbalance Energy ($MWh) |  | $40.41 | $39.67 | $35.03 | $30.45 | $28.96 | $28.54 | $34.98 | $38.98 | $34.88 | $36.81 | $39.01 | $40.54 |  |
| Real-Time Imbalance Energy Sales Total |  | $30,934 | $47,807 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $15,287 | $28,955 | **$122,983** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** (no transportation added) |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy On-Peak ($MWh) |  | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| Seasonal Baseload Energy On-peak ($MWh) |  | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 | $38.85 |  |
| Seasonal Baseload Energy Off-peak ($MWh) |  | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 | $35.00 |  |
| On-peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Off-Peak Energy Option ($MWh) |  | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 | $48.00 |  |
| Bear Valley Power Plant ($/MWh) |  | $48.14 | $47.56 | $44.92 | $43.51 | $40.73 | $38.82 | $39.20 | $39.72 | $37.98 | $38.34 | $41.05 | $44.96 |  |
| Day-Ahead Purchases ($/MWh) |  | $46.01 | $45.12 | $39.72 | $35.88 | $35.32 | $34.77 | $42.76 | $48.84 | $43.57 | $46.00 | $44.46 | $45.90 |  |
| Imbalance Energy ($/MWh) |  | $46.01 | $45.12 | $39.72 | $35.88 | $35.32 | $34.77 | $42.76 | $48.84 | $43.57 | $46.00 | $44.46 | $45.90 |  |
| Renewable Energy Credits ($/MWh) |  | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 | $12.00 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost of Purchased Power/Generation** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Annual Baseload Energy |  | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | **$4,993,200** |
| Seasonal Baseload Energy On-peak |  | $154,157 | $139,238 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $74,747 | $154,157 | **$522,299** |
| Seasonal Baseload Energy Off-peak |  | $104,160 | $94,080 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $59,045 | $104,160 | **$361,445** |
| Energy Option On-peak |  | $56,760 | $25,032 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $32,544 | $57,936 | **$172,272** |
| Energy Option Off-peak |  | $56,760 | $25,032 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $32,544 | $57,936 | **$172,272** |
| Bear Valley Power Plant |  | $2,579 | $1,471 | $2,143 | $1,165 | $796 | $913 | $1,691 | $820 | $1,904 | $1,443 | $1,466 | $6,636 | **$23,028** |
| Day-Ahead Purchases |  | $129,303 | $58,870 | $103,628 | $87,815 | $68,663 | $74,053 | $84,267 | $99,621 | $72,161 | $88,416 | $93,353 | $114,067 | **$1,074,218** |
| Imbalance Energy |  | $41,419 | $22,412 | $18,495 | $8,743 | $11,349 | $18,758 | $27,081 | $21,266 | $34,356 | $14,030 | $39,385 | $70,583 | **$327,876** |
| Renewable Energy Credits |  | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | $51,640 | **$619,680** |
| **Total Purchased Power/Generation Cost** |  | $1,020,858 | $800,814 | $599,416 | $559,763 | $556,528 | $555,765 | $588,759 | $597,427 | $570,462 | $579,609 | $795,695 | $1,041,195 | **$8,266,291** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Transmission/Option Premium** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| W-DAT |  | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | $55,014 | **$660,168** |
| 33 kV Transmission Charges |  | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | $16,246 | **$194,952** |
| Reliability |  | $2,983 | $2,230 | $2,165 | $1,758 | $1,725 | $1,698 | $1,862 | $1,856 | $1,695 | $1,805 | $2,339 | $3,377 | **$25,493** |
| Added Facilities |  | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | $3,150 | **$37,800** |
| Call Option Premium On-peak |  | $24,636 | $22,252 | $24,636 | $7,065 | $7,301 | $7,065 | $7,301 | $7,301 | $7,065 | $7,301 | $23,841 | $24,636 | **$170,400** |
| Call Option Premium Off-peak |  | $11,780 | $10,640 | $11,780 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $11,400 | $11,780 | **$57,380** |
| Total Cost |  | $113,809 | $109,532 | $112,991 | $83,233 | $83,435 | $83,173 | $83,573 | $83,567 | $83,170 | $83,516 | $111,990 | $114,203 | **$1,146,193** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Total Cost of Transmission and Energy |  | $1,134,667 | $910,346 | $712,407 | $642,996 | $639,964 | $638,938 | $672,332 | $680,993 | $653,632 | $663,125 | $907,686 | $1,155,399 | **$9,412,484** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **OTHER COSTS** |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| CAISO Charges |  | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | $171,115 | **$2,053,379** |
| Schedule Coordinator Fee/Dispatch |  | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | $7,620 | **$91,441** |
| Minimum Nat Gas & Gas Transportation |  | $3,927 | $5,036 | $4,364 | $5,341 | $5,711 | $5,593 | $4,816 | $5,687 | $4,603 | $5,064 | $5,040 | -$130 | **$55,052** |
| Total |  | $182,662 | $183,771 | $183,099 | $184,076 | $184,446 | $184,328 | $183,551 | $184,422 | $183,338 | $183,799 | $183,775 | $178,605 | **$2,199,872** |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **TOTAL POWER SUPPLY COSTS** |  | **$1,381,196** | **$1,125,310** | **$958,706** | **$858,673** | **$895,509** | **$898,316** | **$926,983** | **$932,566** | **$904,120** | **$921,974** | **$1,135,424** | **$1,427,499** | **$12,366,274** |
| **Total Cost/MWh** |  | **$77.09** | **$77.95** | **$65.95** | **$71.04** | **$75.43** | **$76.32** | **$71.87** | **$71.91** | **$76.64** | **$74.65** | **$77.41** | **$74.45** | **$74.28** |
| Energy Cost |  | $1,020,858 | $800,814 | $599,416 | $559,763 | $556,528 | $555,765 | $588,759 | $597,427 | $570,462 | $579,609 | $795,695 | $1,041,195 | $8,266,291 |
| Energy Cost/MWh |  | $56.98 | $55.48 | $41.23 | $46.31 | $46.88 | $47.22 | $45.65 | $46.07 | $48.36 | $46.93 | $54.25 | $54.30 | $49.66 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |

Table A-4: Forecasted Monthly Natural Gas Costs

|  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| **2018** | 3.76 | 3.57 | 3.12 | 2.94 | 2.91 | 2.96 | 3.15 | 3.20 | 3.20 | 3.15 | 3.17 | 3.58 |
| **2019** | 3.70 | 3.68 | 3.41 | 3.02 | 2.83 | 2.87 | 3.19 | 3.20 | 3.01 | 3.00 | 3.22 | 3.64 |
| **2020** | 3.85 | 3.93 | 3.78 | 3.67 | 3.36 | 3.21 | 3.25 | 3.30 | 3.25 | 3.27 | 3.42 | 3.78 |
| **2021** | 4.05 | 4.00 | 3.77 | 3.66 | 3.42 | 3.26 | 3.29 | 3.34 | 3.19 | 3.22 | 3.45 | 3.78 |

Table A-5: Monthly Baseload Purchases (MWh)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| **2018** | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | 105,120 |
| **2019** | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | 105,120 |
| **2020** | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | 105,120 |
| **2021** | 8,928 | 8,064 | 8,916 | 8,640 | 8,928 | 8,640 | 8,928 | 8,928 | 8,640 | 8,928 | 8,652 | 8,928 | 105,120 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/ MWh** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| **2019** | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| **2020** | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
| **2021** | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 | $47.50 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | $4,993,200 |
| **2019** | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | $4,993,200 |
| **2020** | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | $4,993,200 |
| **2021** | $424,080 | $383,040 | $423,510 | $410,400 | $424,080 | $410,400 | $424,080 | $424,080 | $410,400 | $424,080 | $410,970 | $424,080 | $4,993,200 |

Table A-6: Seasonal Baseload Energy Purchases and Costs (MWh)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| **2018** | 6,944 | 6,272 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,611 | 6,944 | 23,771 |
| **2019** | 6,944 | 6,272 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,611 | 6,944 | 23,771 |
| **2020** | 6,944 | 6,272 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,611 | 6,944 | 23,771 |
| **2021** | 6,944 | 6,272 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,611 | 6,944 | 23,771 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 |  |
| **2019** | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 |  |
| **2020** | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 |  |
| **2021** | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 | $36.93 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $258,317 | $233,318 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $133,792 | $258,317 | $883,744 |
| **2019** | $258,317 | $233,318 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $133,792 | $258,317 | $883,744 |
| **2020** | $258,317 | $233,318 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $133,792 | $258,317 | $883,744 |
| **2021** | $258,317 | $233,318 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $133,792 | $258,317 | $883,744 |

Table A-7: Resource Adequacy Capacity Purchases and Costs

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| **2018** | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| **2019** | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| **2020** | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
| **2021** | 24 | 20 | 16 | 8 | 18 | 19 | 18 | 17 | 17 | 19 | 15 | 31 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/kW-month** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 | $3.75 |  |
| **2019** | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 | $3.85 |  |
| **2020** | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 |  |
| **2021** | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 | $3.95 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $90,000 | $75,000 | $60,000 | $30,000 | $67,500 | $71,250 | $67,500 | $63,750 | $63,750 | $71,250 | $56,250 | $116,250 | $832,500 |
| **2019** | $92,400 | $77,000 | $61,600 | $30,800 | $69,300 | $73,150 | $69,300 | $65,450 | $65,450 | $73,150 | $57,750 | $119,350 | $854,700 |
| **2020** | $94,800 | $79,000 | $63,200 | $31,600 | $71,100 | $75,050 | $71,100 | $67,150 | $67,150 | $75,050 | $59,250 | $122,450 | $876,900 |
| **2021** | $94,800 | $79,000 | $63,200 | $31,600 | $71,100 | $75,050 | $71,100 | $67,150 | $67,150 | $75,050 | $59,250 | $122,450 | $876,900 |

Table A-8: Monthly Imbalance Purchases and Costs

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| **2018** | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | 7,553 |
| **2019** | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | 7,553 |
| **2020** | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | 7,553 |
| **2021** | 900 | 497 | 466 | 244 | 321 | 540 | 633 | 435 | 789 | 305 | 886 | 1,538 | 7,553 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $36.72 | $35.69 | $30.80 | $28.74 | $29.17 | $29.51 | $37.34 | $42.29 | $37.91 | $37.85 | $35.62 | $37.00 |  |
| **2019** | $38.01 | $37.57 | $33.50 | $30.84 | $29.99 | $29.87 | $37.99 | $42.90 | $37.84 | $37.57 | $36.90 | $38.81 |  |
| **2020** | $41.23 | $40.01 | $36.77 | $34.38 | $32.81 | $32.40 | $39.82 | $45.27 | $41.04 | $41.34 | $40.81 | $41.82 |  |
| **2021** | $46.01 | $45.12 | $39.72 | $35.88 | $35.32 | $34.77 | $42.76 | $48.84 | $43.57 | $46.00 | $44.46 | $45.90 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $33,056 | $17,725 | $14,338 | $7,004 | $9,372 | $15,920 | $23,649 | $18,415 | $29,892 | $11,543 | $31,551 | $56,895 | $269,360 |
| **2019** | $34,221 | $18,658 | $15,595 | $7,516 | $9,635 | $16,116 | $24,061 | $18,681 | $29,839 | $11,459 | $32,687 | $59,680 | $278,148 |
| **2020** | $37,113 | $19,872 | $17,120 | $8,379 | $10,541 | $17,477 | $25,220 | $19,712 | $32,362 | $12,609 | $36,151 | $64,317 | $300,873 |
| **2021** | $41,419 | $22,412 | $18,495 | $8,743 | $11,349 | $18,758 | $27,081 | $21,266 | $34,356 | $14,030 | $39,385 | $70,583 | $327,876 |

Table A-9: Bear Valley Power Plant Generation and Costs

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| **2018** | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | 537 |
| **2019** | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | 537 |
| **2020** | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | 537 |
| **2021** | 54 | 31 | 48 | 27 | 20 | 24 | 43 | 21 | 50 | 38 | 36 | 148 | 537 |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Cost/MWh** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $44.71 | $42.46 | $37.13 | $34.98 | $34.58 | $35.25 | $37.49 | $38.10 | $38.08 | $37.52 | $37.67 | $42.62 |  |
| **2019** | $43.97 | $43.81 | $40.52 | $35.96 | $33.64 | $34.21 | $38.00 | $38.05 | $35.79 | $35.72 | $38.34 | $43.37 |  |
| **2020** | $45.83 | $46.73 | $44.99 | $43.63 | $40.01 | $38.23 | $38.66 | $39.22 | $38.64 | $38.96 | $40.65 | $45.00 |  |
| **2021** | $48.14 | $47.56 | $44.92 | $43.51 | $40.73 | $38.82 | $39.20 | $39.72 | $37.98 | $38.34 | $41.05 | $44.96 |  |
|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **Total Cost** |  |  |  |  |  |  |  |  |  |  |  |  |  |
| **2018** | $2,395 | $1,313 | $1,771 | $937 | $676 | $829 | $1,617 | $786 | $1,909 | $1,412 | $1,346 | $6,290 | $21,282 |
| **2019** | $2,356 | $1,354 | $1,933 | $963 | $657 | $805 | $1,639 | $785 | $1,794 | $1,344 | $1,369 | $6,401 | $21,402 |
| **2020** | $2,456 | $1,445 | $2,147 | $1,168 | $782 | $899 | $1,668 | $809 | $1,937 | $1,466 | $1,452 | $6,643 | $22,872 |
| **2021** | $2,579 | $1,471 | $2,143 | $1,165 | $796 | $913 | $1,691 | $820 | $1,904 | $1,443 | $1,466 | $6,636 | $23,028 |

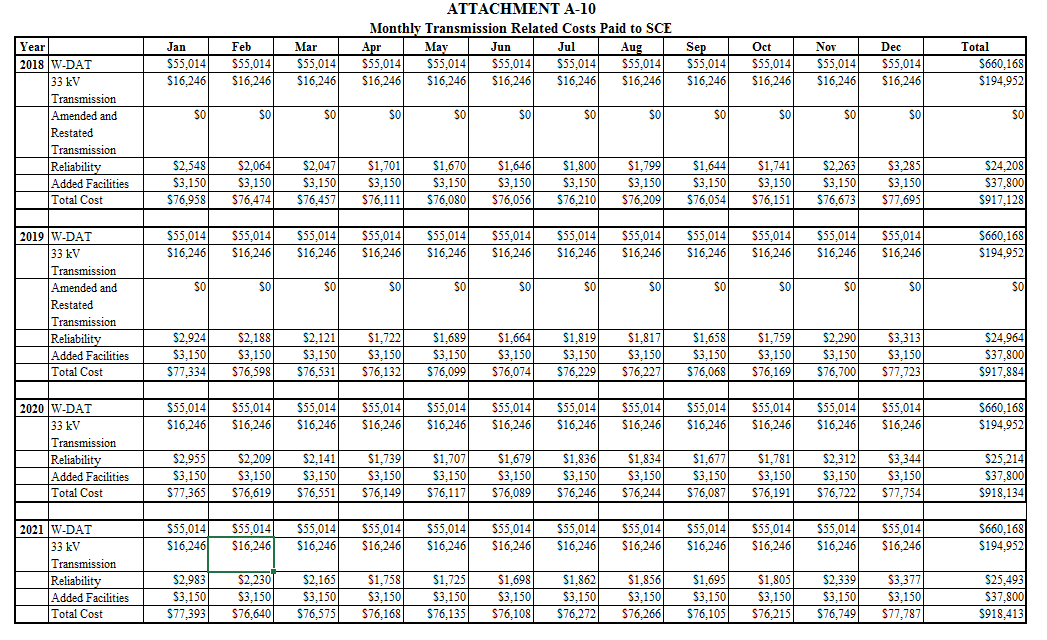
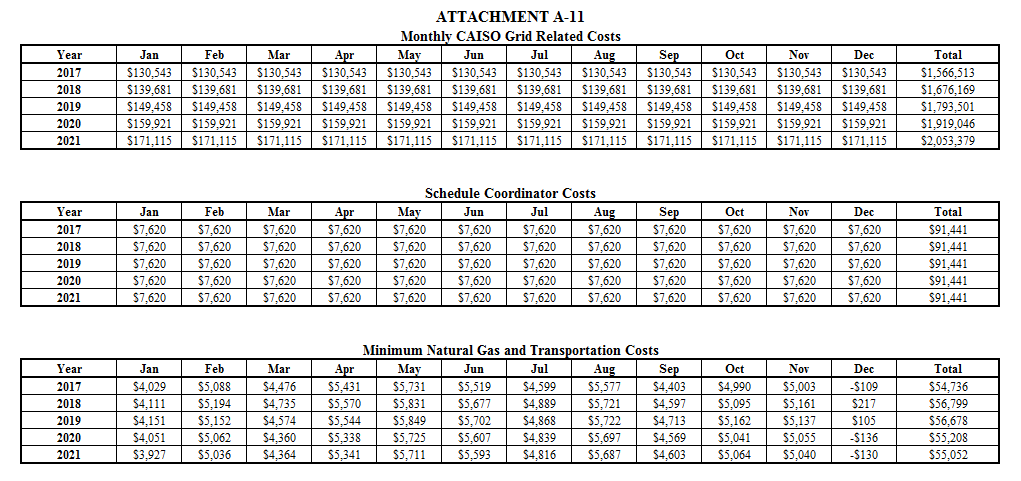


Table A-11: Monthly Transmission Costs Paid to CAISO



1. The Supply Adjustment Account was previously known as the Purchased Power Adjustment Clause or “PPAC” balancing account. [↑](#footnote-ref-1)
2. See more about the CAISO’s policies and practices on settlement adjustments in the CAISO’s Business Practice Manual for Settlements and Billing, Version 17 at <https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing> [↑](#footnote-ref-2)
3. [↑](#footnote-ref-3)
4. D.19-08-030 Although not legally required due to conclusions previously reached by the Commission in D.09-05-025, D.14-12-003, and D.11-06-030, Resolution E-4604, Resolution E-4507, Advice Letter 296-E and Advice Letter 297-E , the testimony provides the Commission the basis to conclude that the costs related to the 2009 Shell Contracts, the LACSD Contract, the 2015 Shell contracts, EDF contracts, and the Iberdrola RECs contract that were recorded in the Supply Adjustment Account with respect to the Review Period were “reasonable.” However, that is not required. Where power contracts have been previously approved by the Commission, the power costs recorded into the Supply Adjustment Account are not subject to a reasonableness review. The proper standard of review is whether the amounts recorded into the Supply Adjustment Account are “appropriate.” See, Scoping Memo at p. 4, PG&E ERRA proceeding – A. 09-12-002. [↑](#footnote-ref-6)
5. D.02-10-062, Conclusion of Law 11. [↑](#footnote-ref-7)
6. Spot market purchases include day-ahead energy purchased in the CAISO Day-ahead market. [↑](#footnote-ref-8)
7. Big Bear Mountain resorts, the owner of both Bear Mountain and Snow Summit, was purchased by Mammoth Mountain resorts in 2015. [↑](#footnote-ref-9)
8. The BVPP can also be used whenever there are outages on the transmission lines serving Big Bear to maintain essential services. The BVPP plus capacity from the smaller of the two SCE lines serving Big Bear are generally sufficient to serve most of BVES’ service territory during the non-snowmaking months. [↑](#footnote-ref-10)
9. A recent postponement was in D.10-06-018. [↑](#footnote-ref-11)
10. The Supply Adjustment Account was previously known as the Purchased Power Adjustment Clause or “PPAC” balancing account. [↑](#footnote-ref-12)
11. The current RA capacity contract with Shell expires January 31, 2020 [↑](#footnote-ref-13)
12. The 1,000 hours per engine annual limitation does not include hours BVPP operates due to loss of a transmission line. The limit can be increased by application to the air district (which may take up to one year to process) and includes provisions for added CEMS equipment to continuously monitor CO. [↑](#footnote-ref-14)
13. BVES is a CPUC Load Serving Entity. A CPUC proceeding to establish Resource Adequacy requirements for BVES is pending. At this time, the CPUC has not established Resource Adequacy requirements for BVES, including a Reserve Margin, Qualifying Capacity criteria, annual and monthly Demand Forecast requirements, and annual and monthly Resource Adequacy Plan requirements. This submission utilizes the coincident peak Demand determinations provided by the California Energy Commission (CEC) for BVES, which have been calculated from Demand Forecast information submitted to the CEC by BVES. Because BVES is a winter-peaking utility and has its summer peaks on holiday weekends, BVES has proposed to the CPUC that its capacity obligations be set based upon weekday loads that would be coincident with the CAISO monthly peak periods, which occur during weekdays, rather than weekend loads when the CAISO loads are generally reduced. BVES has requested that the CEC use this method for calculating its coincident peak demand determinations pending its approval by the CPUC. In addition, BVES has requested that the CEC reduce the coincident peak demand forecast for BVES by up to 8.4 MW to reflect the commitment by BVES of one or more of the units at the Bear Valley Power Plant (BVPP), a generation resource consisting of seven 1.2-MW gas-fired units located on the BVES side of the CAISO meter and owned and operated by BVES. BVES has proposed that the CPUC classify the BVPP as a distributed generation resource that reduces its forecasted peak demand. The CAISO has supported this proposal in comments filed with the CPUC. [↑](#footnote-ref-15)
14. The SCE DLAP LMP is the weighted average of the LMPs for all of the load nodes within the SCE service territory. [↑](#footnote-ref-16)
15. The CAISO derives the aggregated generation hub price by calculating a weighted average for all generators within the SP15 area. Weights are pre-determined by the CAISO on an annual basis based on previous year output. Generator hub prices are calculated for NP15, ZP26 and SP16 areas. Generation scheduled to the aggregate generation hubs is paid/charged the weighted hub price as calculated in the Day Ahead market. [↑](#footnote-ref-17)
16. The $72/MWh is measured at SCE’s delivery point. After adding in 13% losses, the cost to the customer is about $81/MWh. [↑](#footnote-ref-18)