Bear Valley Electric Service Integrated Resource Plan 2016 – 2024

June 2016

Bear Valley
Electric Service
A Division of Golden State Water Company

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1. Executive Summary

The 2016-2024 Integrated Resource Plan (IRP) for Bear Valley Electric Service (BVES) is the primary document used in planning, evaluating and acquiring energy resources to meet the forecasted energy requirements of BVES' retail customers, consistent with goals set by the State Legislature. The goal of the IRP is to identify reliable, best-fit, least-cost energy resources to serve the needs of BVES' electric customers. The amount and type of resources in the IRP must also be consistent with California Public Utilities Commission (hereafter CPUC or Commission) regulations and California State laws governing, among other issues, resource adequacy, renewable energy and greenhouse gas emissions limits.

Note that for the IRP, BVES' analysis used retail sales adjusted for billing lag. In other words, the analysis began with billed sales and used sample load research data to allocate the retail sales by class to each of the calendar months. The result is retail sales data that can be matched to contract and production flows, the weather, and the economy. This adjusted retail sales data is then grossed up to account for line loss to derive energy requirements for the IRP.

BVES saw strong growth in total electric sales of 7.5% for 2015 as compared to 2014, driven mostly by non-permanent, single family residential and large commercial customers.[1] Firm sales (non-snowmaking load) increased 4.9% over the same period while snowmaking load increased 36%. Snowmaking load for 2015 was at the 80th percentile of all annual snowmaking loads over the last 20 years, compared to the annual range of 64%.[2] There have been years where snow making electric usage exceeded the levels achieved in 2015.

Firm sales are tied fundamentally to economic growth in BVES' service territory. Growth in residential and commercial classes will continue as the economy expands through the forecast horizon. These firm sales will receive a boost mid-year 2016 if electric vehicle charging stations are installed in the BVES service area.

Average snowmaking load growth began in 2015 due to the expansion of BVES' capacity to serve Bear Mountain of 1.3 MW; this growth will further increase significantly in the winter season 2018-2019 due to the planned 13 MW expansion of capacity serving Snow Summit ski resort.

However, even with moderate growth increasing in 2016 through 2018, total retail sales will be dampened significantly by the production of solar generated power by net energy metering (NEM) customers. The growth in sales from 2014 to 2015 was strong despite growth in solar production of approximately 1,227,000 kWh in 2015. Slight to moderate growth in total sales is anticipated by BVES, depending on the further growth

[1] Sales are billing-lag adjusted.
[2] Snowmaking load has vacillated above and below an average annual amount of 14,000,000 kWh for a range of 9,000,000 kWh.

in net metering production. By 2020, net metering production could be as low as 5,600,000 kWh per year or as high as 12,800,000 kWh. The higher the level of net metering production becomes (i.e., distributed generation renewables), the lower the growth in total retail sales for BVES. By 2020, BVES annual sales should range from 149,300,000 kWh to 156,500,000 kWh.

This strengthening trend in sales is driven by the recovery of the real estate market, the entertainment industry, and personal income growth in the Los Angeles Metropolitan Area. Los Angeles is the primary area supporting the investment and recreational activities in BVES' service area, since over 85% of non-permanent BVES customers reside in Los Angeles. Economic expansion in this Metropolitan Area stimulates growth in the recreational, retail, and real estate sectors for BVES' service-oriented economy. The forecast anticipates this growth to be dampened by 1.0 % per year in the residential sector and 0.6% per year in the commercial sector due to measurable impacts of energy efficiency on electric consumption. The magnitude of these impacts is determined by a statistical analysis of historic data. Efficiency impacts on electric sales are anticipated to continue; however, the economy will push sales beyond the efficiency impacts resulting in overall moderate growth in sales through 2024, assuming low penetration of Distributed Generation (solar) in BVES' service area.

The largest risk to retail sales growth and the biggest challenge to BVES managing the system load requirement is the growth in net energy metering (NEM) customers (customers using solar panels to generate electricity and offsetting their consumption with solar power production). As of December 31, 2015 BVES has 272 customers on the NEM rate (13 commercial and 259 residential). NEM production has increased from an estimated 714,000 kWh in 2013 to 1,028,000 kWh in 2014 (a 44 % annual increase) to 2,255,344 kWh in 2015 (a 119% annual increase). 2016 has seen continued strong growth in net metering. Electricity production from NEM customers in the first quarter for 2016 NEM production reflects a 170% increase over first quarter 2015. NEM and/or solar distributed generation (solar DG) production is projected to be 5,060,000 kWh in 2016, 12,800,000 kWh in 2020, and 15,356,000 kWh by 2024. The growth is driven by the savings opportunity that exists under the current Net Metering Tariff versus the current BVES standard retail rates, the current 30% Federal Investment Tax Credit (ITC) for residential and commercial solar projects, and the reduced cost of solar installation.

BVES' current production forecast reflects BVES NEM customers achieving 33% of the potential load by 2024, of all customers who could achieve full payback of the solar production investment within 5 years or less. Refer to Chapter 4 for more information about Net Energy Metering.

Sales to A-5 primary customers (interruptible sales) have received a boost in each ski season since 2015, and will continue to receive a boost from the 1.3 MW expansion of substation capacity at Bear Mountain by adjusting the regulators serving this ski resort. Estimated sales impact for this expansion is 580,320 kWh each year. A-5 primary customers (the ski resorts) should also contribute to a significant sales boost beginning in the winter season of 2018-2019 from a planned expansion of electric service to Mammoth Resort's Snow Summit ski resort through a substation project adding at least

13 MW of capacity to the existing 2.5 MW of capacity served by BVES. The expansion of BVES' service will displace current diesel-generated electricity. This should add 6.9 million kWh per year to sales.

Growth in the commercial base due to ski resort expansion and commercial growth incentivized by a contemplated BVES Economic Development Rate is estimated to add about 0.8 million kWh to firm sales. In addition, electric vehicle (EV) charging could add 174,267 kWh sales in 2016, growing to 431,438 kWh sales in 2024. This assumes 50 (full time equivalent) electric cars in 2016 increasing to 125 cars by 2024. Increased sales due to EV charging stations are based on the planned installation of charging stations sponsored by the South Coast Air Quality Management District (SCAQMD) in the BVES service area and continued interest in installing local charging stations by Tesla Motors. Combined, the above increases should add a total of 0.8 million kWh to annual sales by 2019 (6% of total retail sales). This growth along with the sales growth tied to the economy will allow for moderate growth in sales despite the displaced retail sales created by NEM/renewable DG solar production from residential and commercial customers.

To reduce BVES' exposure to price spikes and to secure lower wholesale power costs for over 36 to 59 months, BVES requested Commission approval in June 2013 of the Master Agreement with EDF and four products overall consisting of annual baseload (EDF), seasonal baseload (Shell), a physical daily call option (EDF) and resource adequacy ("RA", Shell).[3] The Commission approved the proposed contracts on December 4, 2014. On December 9, 2014, BVES executed the annual, seasonal and call option products which resulted in a January 1, 2015 start date for these products. BVES executed the RA transaction with Shell in January with a March 2015 start date. The contract volumes are detailed in Section 2.G, Table 2.13.

The annual baseload contract hedges 70% of annual energy requirements in 2015 through a fixed price contract. The seasonal baseload contract hedges 12% of the annual energy requirement in 2015 through a fixed price contract. The physical call option provides a hedge up to 18% of annual energy requirements by setting a price ceiling of $75/ MWh. Therefore, nearly 100% of 2015 energy requirements were hedged through contracts, and 82% of energy requirements were covered by fixed price contracts.

The CAISO Market Redesign and Technology Upgrade (MRTU) Tariff has been in operation since April 1, 2009. Overall, the CAISO markets have performed as designed. While some extreme prices have occurred due to actual system constraints, improvements in the market software and modeling of the grid have resulted in less frequent price spikes. The CAISO will likely continue to introduce new features and functionality over the next few years, some of which may affect BVES, such as the Resource Adequacy (RA) program and a possible CAISO capacity market.

[3] BVES had a Master Agreement with Shell already in place. It then negotiated another Master Agreement with EDF, and then secured four energy contracts, two each with Shell and EDF.

Due to changes over time in the CAISO tariff, BVES has had to take a modified approach to fulfilling its RA obligation. It is not yet known if the CPUC will adopt BVES' changes in its RA and capacity counting conventions. In the meantime, BVES will continue to procure RA resources including a 15% reserve margin, and will use its Bear Valley Power Plant (BVPP) as a "behind-the-meter," distributed generation resource that decreases BVES' RA obligation. Other options for reducing the RA obligations, and the associated cost, would be development of a BVES-owned 2.7 MW AC solar project, located on the capped Bear Valley Sanitary Landfill, and facilitating further renewable DG growth in the residential and commercial sectors. Both these sources of solar production would decrease BVES' overall load and therefore reduce the RA requirement for BVES. BVES is also assessing the benefits of stored power via flow battery technology as a means to manage its load profile and reduce peak load and therefore the RA requirement. A cost benefit analysis for flow battery applications for BVES load management began in March 2016, with the analytical results expected in the spring of 2016.

With a ten-year contract for Renewable Energy Credits (RECs) in place, BVES anticipates satisfying its obligations under the Commission's Renewables Portfolio Standard (RPS) program through at least the year 2021. This contract, approved by the Commission in July 2013, provides the flexibility needed to manage the current RPS requirements that ramp up from 20% of retail sales to 33% by 2020 and to 50% by 2030.[4]

BVES analyzed the market environment utilizing IHS-CERA's energy market, economic, and policy outlook for the California market region and the Los Angeles economy, a sales and energy requirement forecast model, weather data from 2006 to 2014, the residential customer saturation survey, and the hourly load shape data by customer class from 2006 to 2013.

BVES tested a variety of supply options against the energy market probable outcomes to determine a robust strategy plan for Energy Resource Supply that would minimize the energy costs for BVES and create the most benefit for the customer using average total cost of energy, average fixed cost, and emission reduction measures to judge the outcome of the strategies against the forecast environment. The net present value of these benefits across the various forecast scenarios was used to select the optimal strategy that BVES should pursue to provide probable least cost and most benefit to customers. From the analysis supporting this IRP, the following conclusions and possible options have been reached:

Conclusions

- The current transmission capacity contracted with SCE (39 MW), the generation capacity of the BVPP (8.4 MW), and the demand-side management (DSM) resources available from the interruptible customers (currently 12 MW)

[4] AB 350 was signed by Governor Brown in October 2015 and, among other changes, makes the 33% RPS a floor and not a ceiling and establishes a floor of 50% by 2030. See Chapter 3 for more information about the future of the RPS.

are sufficient to meet BVES' firm load requirements through 2024 under normal and colder than normal weather conditions defined as those experienced within the last ten years.

- Model enhancements and a survey of customers provided significant support to the planning process and forecasting accuracy.
- There is a significant uncertainty in the RA requirement given the uncertainty of the policy requirement for local and flexible RA for BVES, load-mitigating solar NEM/DG production, and the regulatory approval for the addition of a BVES-owned 2.7 MW solar facility directly connected to the BVES system.

Options Being Considered

- Maintain the current annual baseload fixed price coverage at 12 MW, as the daytime load requirement in the summer is likely to diminish with the landfill solar possibly on line by 2019 and net metering production volumes already significant and growing. Assess the need of annual baseload each year as solar production increases are realized.
- Increase the daytime and summer load by offering to customers an electric vehicle pilot program and eventually a special residential rate encouraging use of electricity for transportation needs. Already the SCAQMD has selected Big Bear Lake to install two universal charging stations in 2016.
- Also to increase the summer and daytime load, offer an economic development rate targeting summer or year-round users of electricity, in order to increase the load factor of the energy requirements. This program would encourage off-peak usage, improve BVES' system load factor, and enhance cost savings of fixed price contracts. This approach would reduce all-in cost of energy for customers and reduce average fixed cost per MWh for customers.
- Continue support of the energy efficiency program already in place targeting lighting efficiency for residential customers, which could reduce lighting usage by 25%, assuming full participation in the retrofit program. This could also reduce peak loads by up to 9.5 MW as the lighting load is aligned with the system peak (7 PM to 10 PM at Christmas holidays). This should also allow more snowmaking energy sales relative to the capacity of the BVES system as Mammoth Resorts becomes more confident in BVES' capability to serve additional load without interruption.
- Design a Demand Response program targeting electric water heating and spa cycling during peak hours for 15 minute intervals in order to curb up to 3 MW of peak usage. This will enhance energy sales relative to capacity of the BVES system and will enhance the benefits of Mammoth substation expansion, should that occur.
- Create a Commercial Time-of-Use Rate to reflect the cost differentials of power across 4 time periods in order to encourage shifting of load from the most expensive time periods to least expensive periods, reducing average cost of power for customers.
- Add 2.7 MW of utility-owned solar generation to BVES service area via the landfill project and continue to support NEM or solar DG in order to reduce average energy cost, reduce average fixed costs by increasing daytime capacity

and reducing interruptions, and reduce air emissions. This includes the possibility of additional utility owned solar on commercial customer property.

- Improve reliability of system and reduce price spikes via fuel diversity in supply and increasing BVES local capacity relative to its total supply portfolio.
- Monitor economic development trends in the BVES service area regularly in order to determine when it is appropriate to incorporate these developments into the sales and load forecast.
- Continue internal model improvements.
- Continue customer surveys; use the survey data to build a forecasting tool for individual customers and therefore enhance the distribution planning initiatives.

For the reader's benefit, because acronyms are frequently used throughout this IRP, a glossary of acronyms is included in Appendix F.

2. BVES Loads and Resources

2.A Description of BVES

Bear Valley Electric Service (BVES), a division of Golden State Water Company (GSWC), is an investor-owned utility (IOU). BVES provides electric service in a resort community to approximately 24,000 customers,[5] of which approximately 22,000 are residential customers with a mix of approximately 40% full-time and 60% part-time residents. Approximately 1,500 of the total number of customers are commercial, industrial and public-authority customers, including two ski resorts. This includes 272 net energy metering (NEM) customers.[6]

BVES' historical peak load is 45 MW;[7] winter monthly peaks occur when snowmaking machines at the ski resorts are operating and recreational visitors are present (generally between 5:00 pm and 11:00 pm on weekends). In the summer months, the load in BVES' service area ranges from an average minimum of about 11 MW (early summer mornings) to a maximum of approximately 24 MW (weekend holiday, mid-morning and late evenings).

BVES purchases wholesale power to meet the majority of its energy requirements. To aid in meeting peak demand for electric energy, BVES installed and now operates the Bear Valley Power Plant (BVPP), a natural gas-fired, 8.4 MW generation plant, with a tested heat rate of 11,500 Btu/kWh, in its service area. The BVPP became commercially operational on January 1, 2005.

BVES has two receipt points of power from Southern California Edison Company (SCE), the Goldhill transfer station and Radford Feeder. The majority of BVES' power is transmitted over SCE's 33 kV distribution line from the Cottonwood substation to the Goldhill transfer station. The remainder of BVES' energy is transmitted over SCE's 33 kV distribution facilities from the Zanja substation near Redlands, over the Radford Feeder to BVES' Village substation.[8]

BVES' distribution system is located and operates under the Balancing Authority of the California Independent System Operator (CAISO); however, BVES does not own any transmission facilities and is not a Participating Transmission Owner (PTO) under the CAISO Tariff. BVES facilities are indirectly interconnected with the CAISO-controlled grid via wholesale distribution access facilities owned, controlled and operated by SCE, that are then directly interconnected with SCE transmission facilities that are part of the CAISO-controlled grid. Lastly, the BVPP does not operate under a Participating Generation Agreement (PGA) and thereby is not considered a CAISO controlled unit under the CAISO Tariff.

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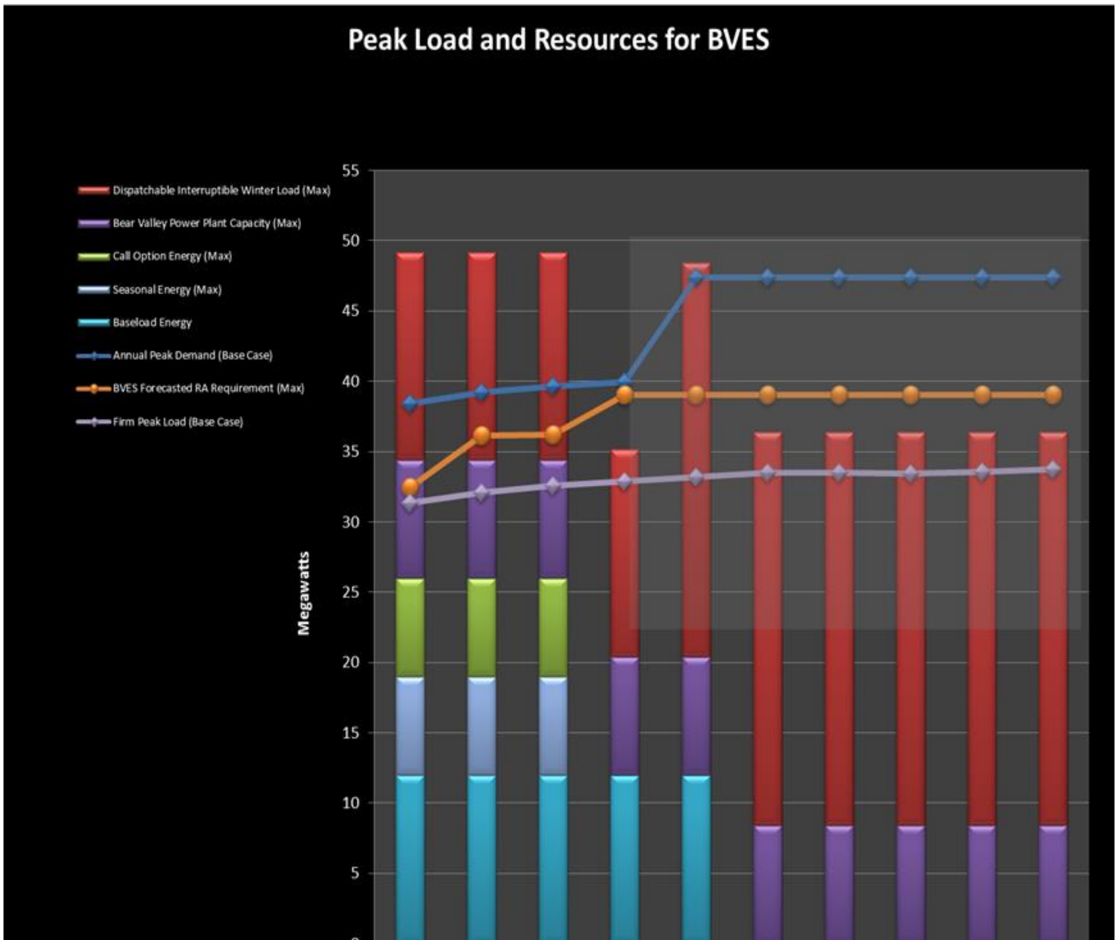
[5] Based on number of active billed accounts as of November 2014.
[6] Includes systems under construction.
[7] The historical peak of 45 MW occurred on 12/26/2015. Prior peaks include 44.9 MW which occurred on December 31, 2014; 38 MW on January 12, 2013 and 44.6 MW on December 30, 2012.
[8] BVES refers to voltages on these SCE lines as 34.5 kV.

It should be noted that because GSWC is a holder of Congestion Revenue Rights (CRRs), BVES falls under direct tariff regulation by the CAISO. BVES must indirectly adhere to the CAISO Tariff due to power scheduling and RA requirements. The requirements are imposed on BVES by its third party schedule coordinator (SC),[9] who must abide by the CAISO Tariff to schedule BVES' power and RA resources.

[9] Currently APX is under contract with BVES to act as its SC and provide schedule coordination services.

2. B Summary of Loads and Resources

Figure 2.1 summarizes the forecast of BVES' resources and requirements through the year 2024.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Dispatchable Interruptible Winter Load (Max)	14.8	14.8	14.8	14.8	28.0	28.0	28.0	28.0	28.0	28.0
Bear Valley Power Plant Capacity (Max)	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Call Option Energy (Max)	7	7	7	0	0	0	0	0	0	0
Seasonal Energy (Max)	7	7	7	0	0	0	0	0	0	0
Baseload Energy	12	12	12	12	12	0	0	0	0	0
Annual Peak Demand (Base Case)	38.4	39.2	39.7	39.9	47.4	47.4	47.4	47.4	47.4	47.4
BVES Forecasted RA Requirement (Max)	32.5	36.2	36.2	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Firm Peak Load (Base Case)	31.3	32.1	32.6	32.9	33.2	33.5	33.5	33.5	33.6	33.8

Figure 2.1 Loads and Resources for BVES

The peak load and resource forecast compares contracted energy and generation resources to the base case peak demand. From this analysis the resource deficit is determined. The base case forecast assumes normal weather and average snowmaking activity experienced over a 10-year time period. Moderate economic growth is assumed for the Los Angeles region, which drives tourism and real estate for the BVES service area economy. Displacing retail sales and therefore energy requirements for BVES is solar and Distributed Generation (DG) solar production

2.C Forecast of Load Requirements

2.C.1 Load Duration Analysis and Conclusions

After a careful review of the BVES system's peak load forecasts, it is concluded that even in extreme weather scenarios where capacity limits are approached, the duration of the peak load is very short-lived (see Figures 2.5 and 2.6 below). Options ,under consideration, include (1) reducing peak demand through continued support of lighting efficiency program for residential and commercial class, (2) interruptible tariff schedules, (3) water heater cycling, and spa cycling, which shift load usage by a few hours and even minutes to achieve the resource balance needed during peak hours.

Also under consideration at this time is the application of flow batteries, a family of battery chemistries including vanadium, redox, zinc bromine, and iron chromium in which a liquid electrolyte is cycled through an electron chemical cell. This battery system typically stores power up to 10 hours, and can store power for longer periods if necessary. The battery system would be used to condition the system load and reduce capacity requirements. Given the short duration of the top 5 MW of system firm load and the wide swings in the non-firm load shape, and the fact that this technology can store power for long durations, this technology could help BVES achieve the load conditioning required to significantly reduce capacity costs. A cost benefit analysis viewing system load balancing and battery investment requirement is underway and will be presented in a future IRP.

Following is a detailed overview of peak load forecasts.

2.C.2 Base Case Peak Load Forecast

Figures 2.2, 2.3, and 2.4 below illustrate BVES' forecasted load derived from forecasted energy requirements (kWh) and hourly load shape patterns observed from 2008 to 2013. BVES has a wide range of firm and non-firm hourly loads due to varying weather patterns, economic cycles and timing of hourly load relative to monthly sales. BVES sets a target hourly load forecast based on all the hourly load shapes observed across the years 2008 to 2013 and the forecasted monthly energy requirements across the weather and net metering scenarios. A conservative forecast using normal weather and a high net metering production scenario was chosen to evaluate energy contracts and asset evaluations. The previously mentioned BVES-owned solar project is assumed in the planning case and does create additional capacity for the daytime hours, creating savings and other benefits for all customers. Note that capacity constraints limit total peak load for a couple of hours (almost immeasurable), collapsing the differences in the system coincident peak load across the various shapes. Although total system peak is constrained from 2019 to 2024, over a couple of hours, the firm peak load is not constrained. Interruption on non-firm load alone would allow for all firm load to be served without interruption, and is therefore the most likely solution to be implemented in the future under unforeseen supply source interruption.

Other solutions under consideration but not included in the most likely case are as follows:

1. Utility-sponsored residential lighting efficiency program targeting all residential lighting bulbs above 9 watts. This has a load reduction potential of 9.5 MW.
2. Flow battery technology could remove the need for interruption of non-firm customers. The cost benefit analysis of this technology is underway and will be presented in a future IRP.
3. Proposed demand response programs for water heaters and spas could also reduce total system peak.
4. Enhance the current import capacity by 1-2 MW at a fraction of the cost of other supply alternatives would involve reconfiguring BVES' distribution system by adding circuits to the Radford line during winter months.

All of these options will be assessed based on the benefit to the customer. Capacity expansion is not required to serve firm peak load over the forecast horizon of 2015 to 2024. Also, the anticipated growth in non-firm load is largely determined by the planned 13 MW capacity expansion in late 2018 at Mammoth's Snow Summit ski resort.

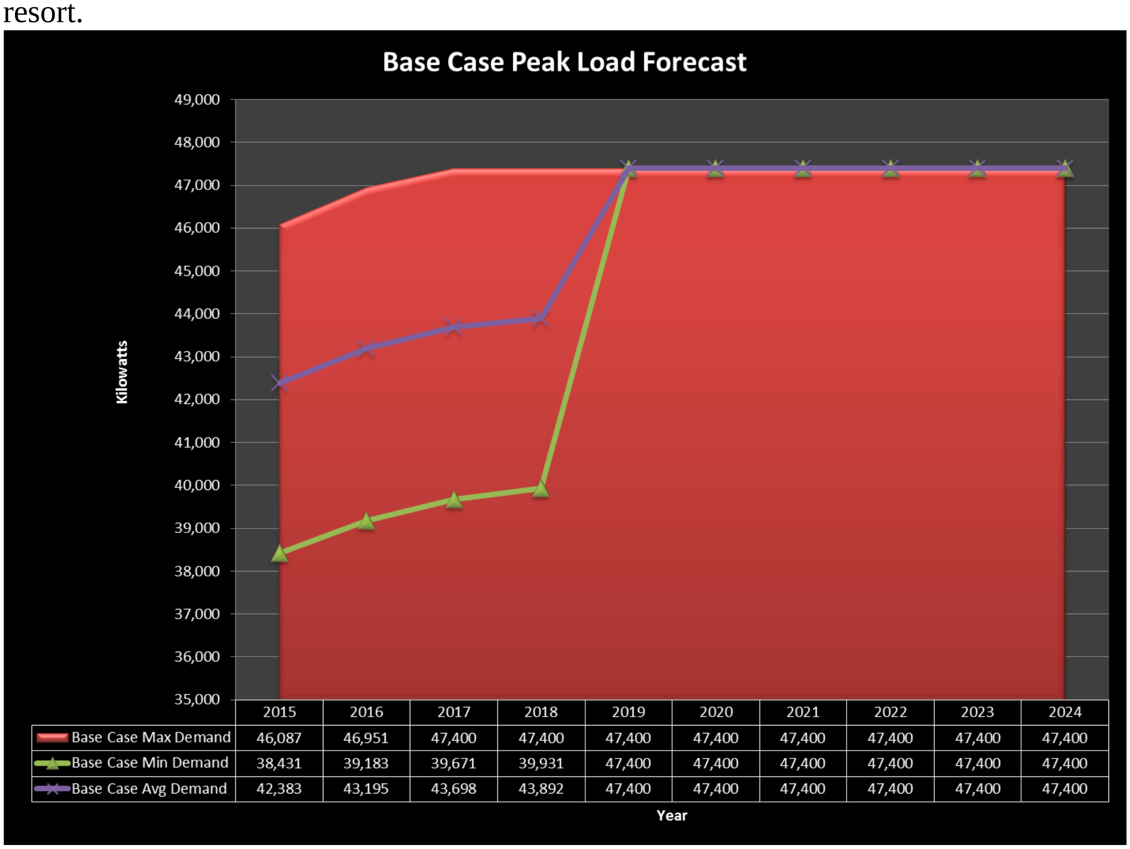
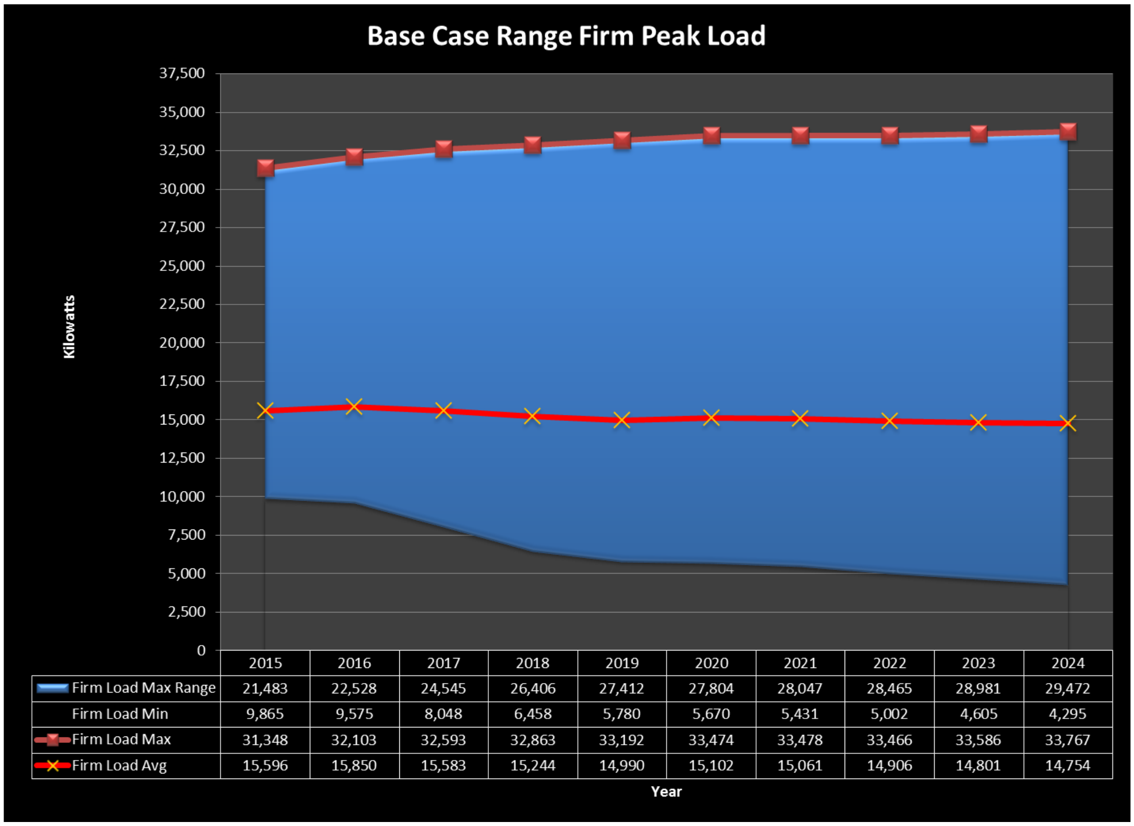


Figure 2.2: Range of Peak Load Forecast Across Load Shape Profiles

2.C.3 Firm and Non-firm Peak Load Forecast



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Firm Load Max Range	21,483	22,528	24,545	26,406	27,412	27,804	28,047	28,465	28,981	29,472
Firm Load Min	9,865	9,575	8,048	6,458	5,780	5,670	5,431	5,002	4,605	4,295
Firm Load Max	31,348	32,103	32,593	32,863	33,192	33,474	33,478	33,466	33,586	33,767
Firm Load Avg	15,596	15,850	15,583	15,244	14,990	15,102	15,061	14,906	14,801	14,754

Figure 2.3: Range of Firm Peak Load Forecast Across Load Shape Profiles

There is a more defined range for firm peak load coincident with the system peak because there is enough system capacity to meet the entire firm load across all load shape scenarios. The range in firm peak load is mostly created by the variance in hourly weather across the years 2008-2013, which defines the hourly load shapes for each rate class applied to the most likely scenario. Also contributing to the range in the peak load forecasts is the variance in the coincidence factors between the class shapes and the system load pattern across the years 2008-2013. A cold snap within the month would not necessarily be picked up in the monthly weather data used to define the monthly sales forecast. Similarly, a surge in activity within the month is not necessarily picked up by the monthly economic data used to define monthly sales. Energy consumption between the classes that are more in step with each other creates a higher peak load for the system, given the same monthly energy consumption. Using a variety of shapes (2008-2013) on the energy requirement forecasts does address these hourly load timing impacts on system peak load.

To forecast the firm load impact on system peak, BVES developed a base case economic scenario for sales using normal monthly weather data (Heating Degree Days base 65 degrees, and cooling Degree Days base 65) and applied the varying hourly load shape derived from 2008 to 2013 data to forecast retail sales by rate class, adjusted for line losses to derive hourly load forecast range for each rate class and hour from 2015 to 2024. The rate class hourly load forecasts are concatenated for all firm rate classes to derive the peak load for each hour. Figure 2.3 shows the range of firm load coincident with the system peak load for the most likely case, used for contract and asset planning. The range of the hourly firm peak load varies by year, from 21,483 kW in 2015 to 29,472 kW in 2024. The maximum level increases over time due to the economy and electric vehicles. The minimum summer load is also impacted by the economy and electric vehicles. However, increases in solar production by customers (NEM, and later renewable DG) and by BVES-owned solar will reduce the minimum summer load over time. Variation in the growth rates of each rate class' load shape creates a portion of the difference in the range of firm peak load coincident with the system peak load over time.

BVES' average firm peak load is expected to decline by 5.4% from 2018 to 2024 while the maximum firm peak load is expected to grow by 7.7% over the same period.

Specifically, the economy of BVES' service area is driven by growth in the entertainment and real estate markets in the greater Los Angeles area (thus positively affecting San Bernardino County), economic development which attracts new industry into the A-4 rate class, and potential demand from electric vehicles.[10] Winter sales combined with a potential large boost in non-firm sales (discussed further below) in winter months alters system peak load hours and increases the coincidence factors of the rate class hourly load forecasts. This therefore causes the firm peak load coincident with the system peak to increase faster than the growth in sales. Therefore, the system peak demand does reach the capacity limit under all load shape scenarios by 2019. BVES could reach the limit sooner depending on the coincidence factor across the rate classes of customers. Only the interruptible customers are interrupted as the system capacity is reached.

Figure 2.4 shows the range for non-firm peak load (BVES' A-5 Primary rate). There is significant variation in the load patterns of the A-5 Primary class, mostly because of snowmaking load uncertainty. Sales to A-5 Primary customers have varied as much as 40%. Although the loads each year vacillate around a mean load of 13,790 kW, the weather and the economy dictate what the actual load will be. While non-firm peak load can be as high as 28,092 kW, non-firm peak load coincident with the system peak is at most 26,357 kW. This is because of diversity between the load patterns of the A-5 Primary customers compared to the BVES system load pattern. Note that BVES anticipates interruption to average 1,344 kWh a year from 2019 to 2024, resulting from 2 to 3 hours interruption during the winter season. This is a minimal amount due to the diversity between the firm load and the system load, and the daytime load will be significantly supported by solar production. Also, efficiency improvements for residential and commercial lighting will further dampen the load requirement during the peak hours of 7 to 10 PM in the winter season. Additional efficiency adoption, supported by the existing lighting program, should create excess capacity during the nighttime for BVES (5 to 9 MW impact anticipated).

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[10] A possible pilot project for electric vehicles is discussed in further detail in Section 5.E.

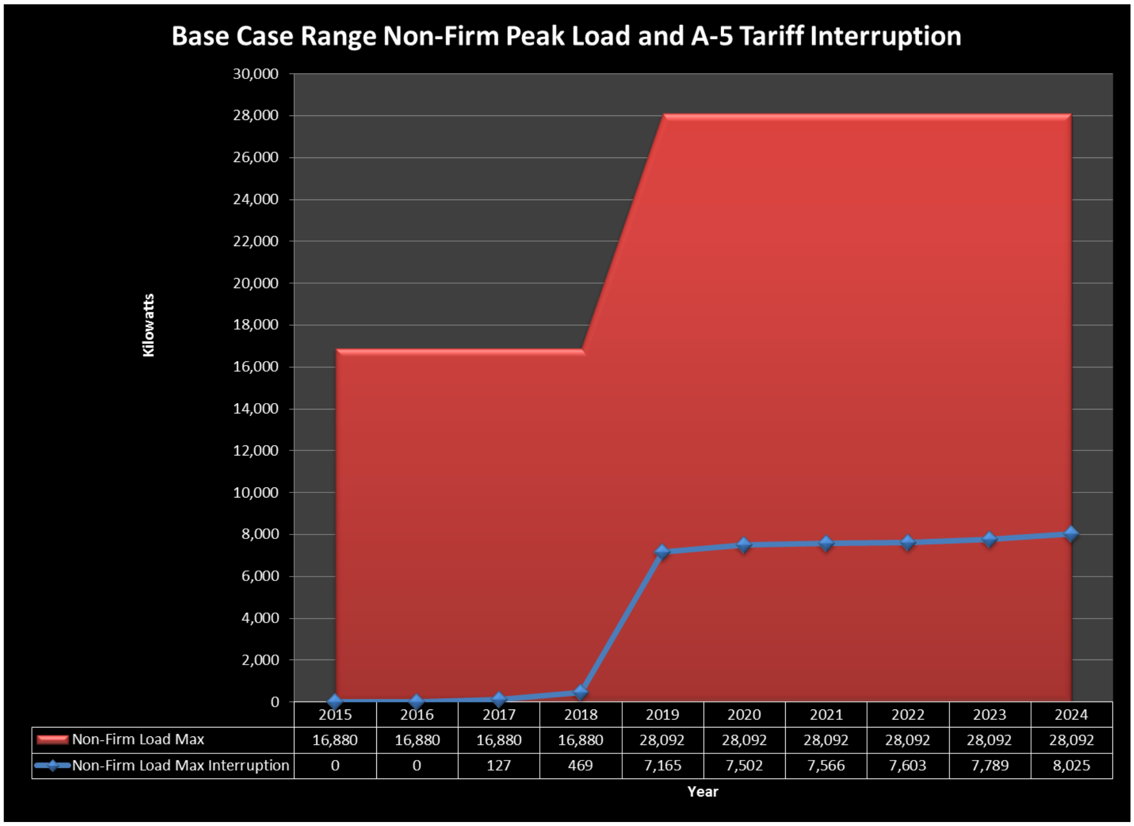

Figure 2.4: Range of Non-Firm Peak Load and A-5 Tariff Interruption

There is a wide range of interruption depending on the load shape pattern assumed for non-firm load, which is derived from the 2008 to 2013 observed load shape patterns for the A-5 rate class and the forecasted firm sales. The 1.3 MW growth in Bear Mountain's[11] load due to adjustments on the regulators monitoring substation flow and the planned 13 MW expansion in the substation serving the Snow Summit resort in the winter of 2018-2019 are forecasted to bring the system load close to capacity, though load interruption would be minimal. Options for adding daytime load relief in 2018 may include the continuation of customer-sited solar generation up to 5.8 MW by 2018 (growing to 6.4 MW by 2020) and the 2.7 MW of landfill solar capacity.

Only under consideration at this time are the following options. Energy storage (batteries) could be used to balance the system and give BVES the ability to serve the load without interruption. An additional 3 MW capacity relief through new demand response measures (e.g., cycled electric water heaters and spa heating pumps) could also mitigate load interruption during late evening peak hours. It should be noted that the battery storage and demand side management programs are only proposed and not utilized in the base case forecast. A detailed cost benefit analysis will be required before these options gain traction in the planning process. The benefits of these proposed items are highlighted later in this IRP. Under the most likely case, BVES can

[11] Mammoth Mountain Ski Area is the new owner of Bear Mountain Resorts (Snow Summit and Bear Mountain).

serve the firm and interruptible load with a minimal amount of interruption. Stress cases reveal a benefit of these proposed programs.

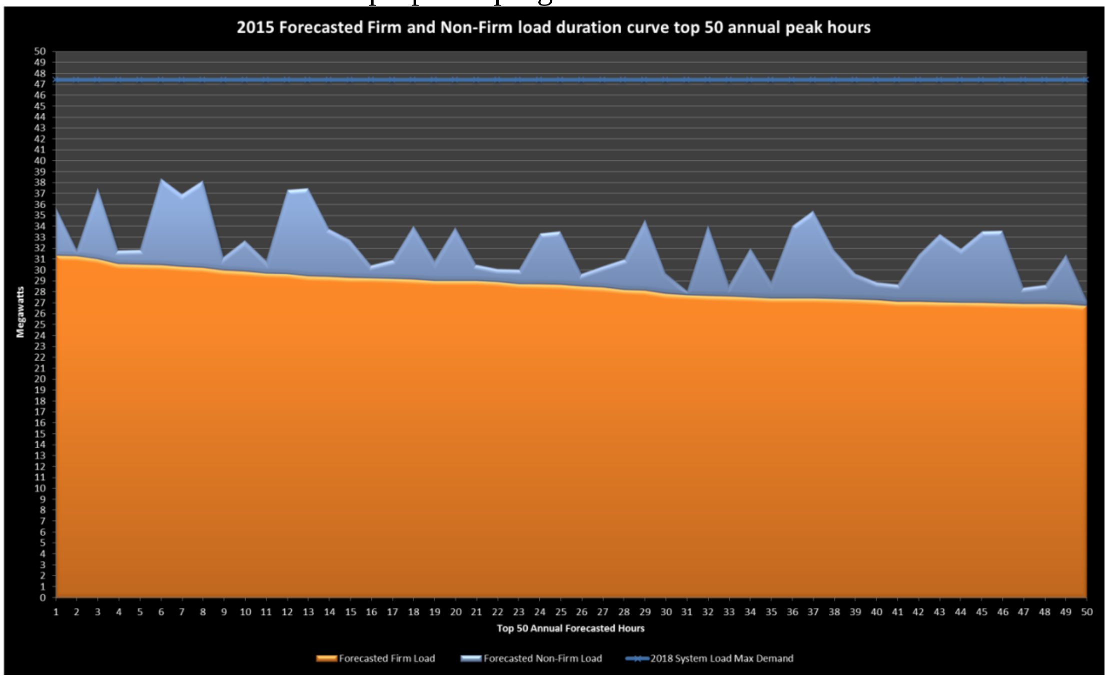

Figure 2.5: 2015 Forecasted Firm and Non-Firm Load Duration Curve

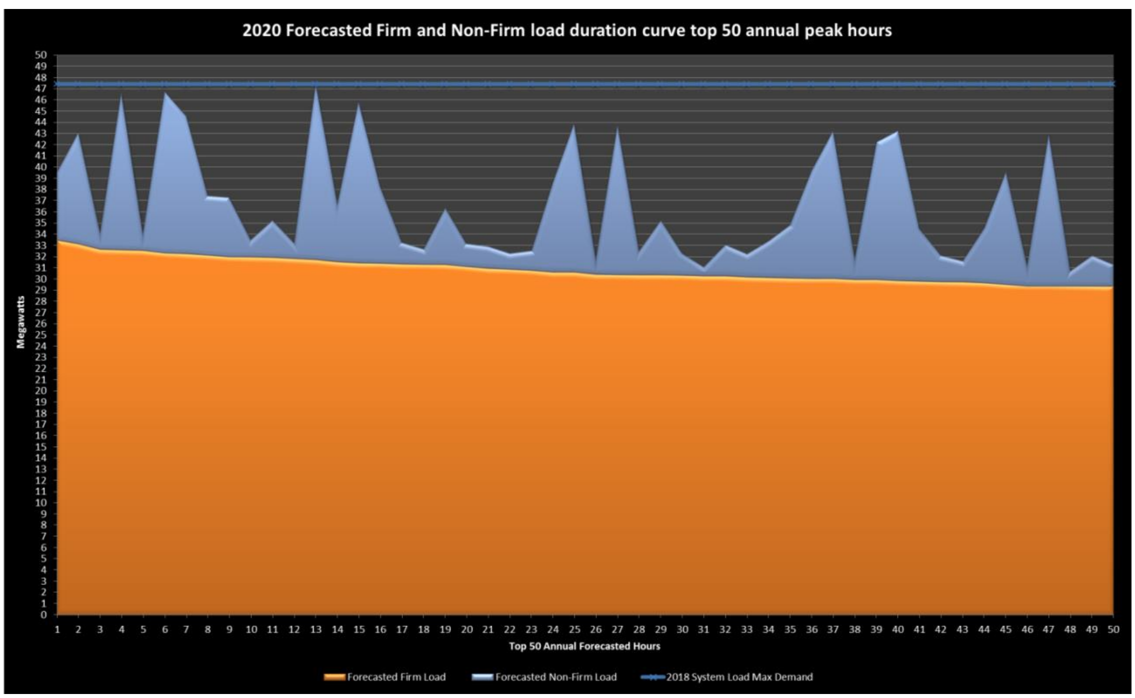

Figure 2.6: 2020 Forecasted Firm and Non-Firm Load Duration Curve

Weather alone can affect the firm peak load demand forecast by approximately 3.5 MW. The current resource plan is derived from a base case forecast assuming normal weather conditions and using sound economic modeling and assumptions. Variations in weather and short term economic cycles within the years 2006-2013, which cause deviations around the base case, are also considered. Economic conditions and economic development will be studied each year in order to update resource planning. Potential changes under consideration in the BVES service territory included in the base case forecast comprise the following:

- Expansion of the ski resorts' snowmaking capabilities and increases of their commercial load at the base of the resort through economic development initiatives.
- New business development in Big Bear Lake or Big Bear City through economic development initiatives such as university extension, summer amusement park, high altitude athletic training center, county fair, and village entertainment.
- Impact of continuing California drought conditions on the economy in BVES' service area, exacerbated by urban sprawl in Southern California.
- Continuation of solar/renewable DG after the NEM cap is reached through a tariff structure that is more equitable for all customers, reducing daytime energy requirements and freeing up capacity to facilitate daytime load growth.

2. D Forecast of Energy Sales

2.D.1 Retail Sales Trends

BVES' annual retail sales remain below the all-time sales achieved in 2006. Energy sales declined in 2007 and continued to decline significantly through 2010. While the national economic recession was partially the cause, the decline in real estate values had a major effect on the growth of the Big Bear economy and local activity. With the recovery in the economy and real estate more pronounced in 2012 and continuing through May 2015, BVES sales have increased from the 2010 levels. In 2014, BVES sales were 7.3% short of the peak sales in 2006 while 4.4% higher than the trough in 2010.

When sales are adjusted for weather, the resulting values are due to demographic and economic activity only. The peak in sales due to demographic and economic activity occurred in 2006, reaching 148,436 MWh. Sales then declined, hitting a low in 2010, of 129,583 MWh. As incomes in the Log Angeles-Long Beach-Santa Ana metropolitan statistical area (MSA) continue to increase, the real estate and tourism industries see growth in the BVES service area and, therefore, result in increased electricity sales.

Figure 2.7 illustrates the trend in BVES energy sales from 2005 through 2015.

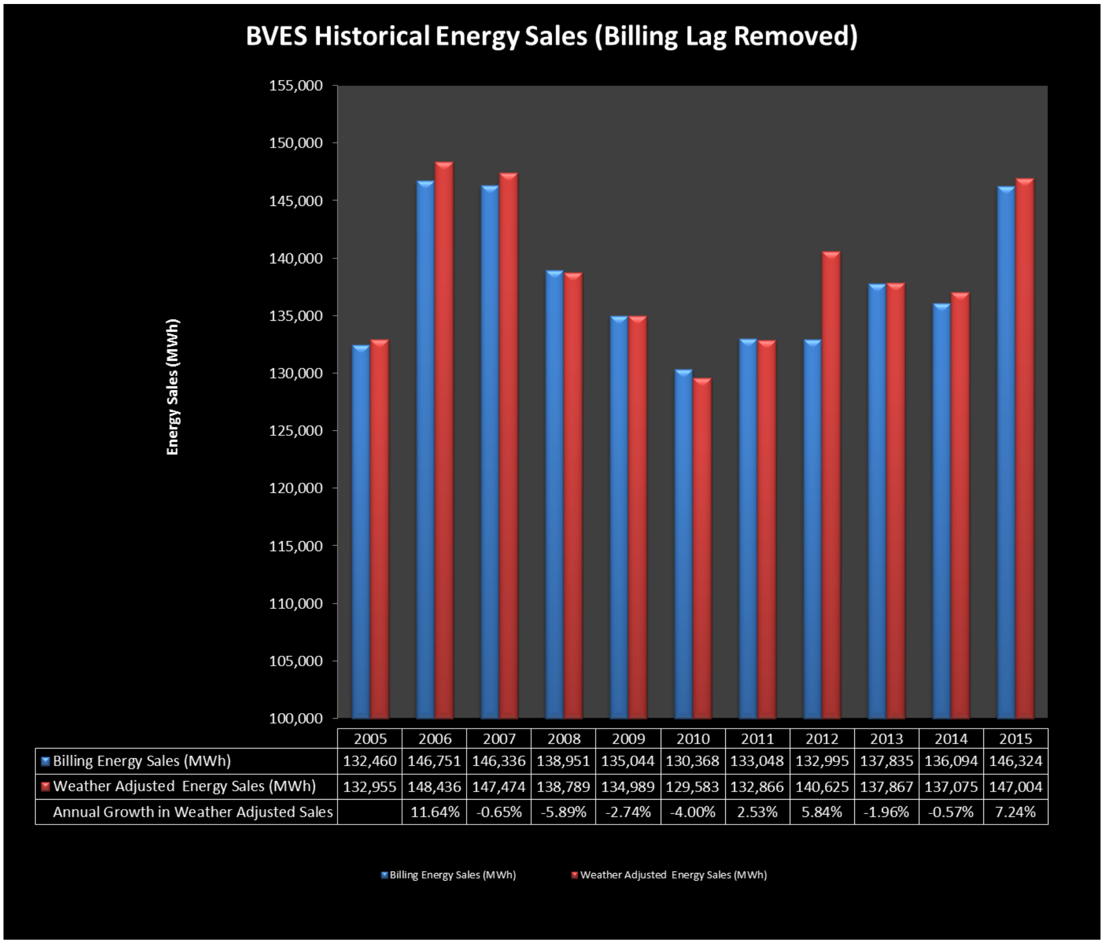

Figure 2.7: BVES Historical Energy Sales

Demand for electricity is a derived demand; that is, consumers do not buy electricity in and of itself. Instead, consumers buy goods and services that require electricity. BVES saw the impact of the real estate boom in California through 2007, after which the real estate sector began to crumble. BVES' service territory was particularly distressed because many homes are second homes and are expendable when real estate markets decline. This was reflected in the weather-adjusted residential sales from 2007 to 2010. Big Bear Lake was especially hard hit economically as an area dependent on discretionary income of the Los Angeles-Long Beach-Santa Ana MSA. A healthy recovery has continued since 2010 with a moderate decrease in 2013, a stall in 2014 and strong growth in 2015.

Since 2006, renewable DG by residential customers through the net energy metering tariff has increasingly displaced retail sales. This became even more evident after the introduction of the Bear Valley Solar Initiative and the extension of the 30% Investment Tax Credit offered by the federal government to encourage solar production. The table below illustrates displaced sales by year.

Year	Net Energy Metering Displaced Retail Sales (kWh)
2004	8,561
2005	32,618
2006	76,505
2007	95,659
2008	154,225
2009	190,077
2010	261,474
2011	402,300
2012	592,015
2013	714,369
2014	1,028,618
2015	2,255,334

The combination of customer generated solar power and the impacts of energy efficiency continued to dampen sales over the historic period.

2.D.2 Economic Structure of BVES' Service Area

The economic activities in the BVES service area depend mostly on recreation, food services and lodging, real estate and rentals. There is also a high amount of retirement activity in the service area. The percent of total employment in these industries and the retirement age population as a percent of total population are high relative to other major metropolitan areas in California.

There is a strong correlation between the BVES service area economy and that of the Los Angeles-Long Beach-Santa Ana MSA because 85% of the non-permanent residential customers reside in the Los Angeles metropolitan area. Resurgence in the Los Angeles-Long Beach-Santa Ana MSA economy will have a positive effect on the BVES area. As personal income increases in BVES' area, so should real estate investment, recreational activity, lodging, restaurants, and retail activity for the BVES area economy, which in turn stimulates other commercial and residential activity for the local economy. Personal income for the Los Angeles-Long Beach-Santa Ana MSA reflects the wages and salaries of the area along with proprietors' income, real estate returns, stock market returns, and additional income received by retirees and government aid recipients. As these income sources increase, so should interest in activities in the BVES area.[12]

The Los Angeles-Long Beach-Santa Ana MSA economy is in turn dependent on the national economy, which also affects SP15[13] power prices and Southern California

[12] The electric sales forecast for BVES' service area is tied to the forecast of variables of the LA-Long Beach-Santa Ana MSA, provided by IHS-CERA, a vendor of economic and financial data forecasts.
[13] Refer to glossary for explanation of SP15.

natural gas prices. All of these factors are added to the forecasting models for the electric sales and power cost forecasts and the annual IRP planning tool.

2.D.3 Macro Economic Outlook

The U.S. economy[14] grew moderately in 2015 and is projected to maintain that trajectory in 2016 and beyond due to a variety of factors:

- The abundance of natural gas and oil made available through the rapid advancement of resource extraction in the shale regions provides a boost to the whole economy via increase in disposable income ($1B / $.01 drop in gasoline price).
- The "mature" status of shale natural gas production has reduced gas prices to the $3.00-$3.50 per MMBtu range over the long term (2016 to 2024), allowing the petro-chemical and primary metals sector to grow.
- Jobs have increased significantly across many sectors of the U.S. economy, created both directly and indirectly by the increase in production activity of the natural gas and oil industry (3 million by 2020). Although the upstream extraction portion of the industry continues to be challenged in 2016 by extremely low oil and gas prices, the technology and the drilling strategy should allow for production to be strong in the low price environment. Positive surprises on the reserves measurements for gas should add to the production capabilities for both oil and gas.
- The information technology boom continues, benefiting the California economy, and spanning many regions of the U.S.
- An increase in automobile sales occurs as pent up demand is released.
- The housing industry experiences a strong recovery due to low mortgage rates, housing price equilibrium, economic recovery, and the baby boomer generation downsizing their homes.
- US households have worked through the debt bubble and consumption is driving the growth in the US due to increased optimism.

In addition, the US economy is growing without help from exports as China, Europe, Mexico and Canada face weaker economies. Although the economic slow-down in China has challenged the commodity industries (energy and metals), all major suppliers will make adjustments and revisit strategies in order to maintain growth in production and maintain market share. Movement away from price collusion and towards open competition should maintain health in the commodity industry. There is a new order in the oil industry as suppliers view market share as being more effective than reducing production to manipulate oil price. Supply cost reduction through innovation and new allies in supply projects could set lower oil industry prices resulting in strong growth and benefits to all consumers. The natural gas industry continues to make technology and drilling strategy enhancements and invest in the infrastructure to bring gas to markets. Already demand for gas has increased significantly as gas-intensive

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[14] From IHS-CERA's *US Markets: An Executive Summary of Regional Economies*, Winter 2015, IHS-CERA *Spring Energy Series for 2016*.

manufacturing expands in the US. As supply adjusts to these changes, the demand will increase as commodity intensive industries benefit from sustained lower prices.

The California economy has maintained strong growth throughout 2013 to 2015, ranking 11th out of 50 states. California continues to grow faster than the U.S. as a whole because of growth in technical services, biotech, entertainment and related services industries, apparel manufacturing, housing construction, transportation, transportation materials, population growth, venture capital availability, and renewable product manufacturing. The highly educated work force in combination with venture capital availability continues to boost economic growth in burgeoning industries for California. The drought in California has dampened growth to some degree, impacting the agriculture industry severely. Water availability will have to be managed as droughts occur, but urban sprawl will continue to challenge water supply even in less severe drought conditions. In addition, exports have suffered due to the significant slowdown of the Chinese economy.

2.D.4 Factors Affecting Wholesale Energy Prices

Drought creates a challenge for the power industry in California as the majority of gas fired generation requires water for cooling. Although water usage is restricted, the price of water is not yet high enough to fund water supply growth opportunities such as seawater desalination projects. Water restrictions can dictate power dispatch options and therefore increase prices as much as $8.00/MWh, according to IHS-CERA.[15] A more favorable solution for the power industry might involve dynamic water pricing that would then allow generators better dispatch options. The resulting impact would likely cause only a $2.00/MWh increase in prices. The power industry’s marginal revenue product for water is estimated by IHS-CERA to be $26,000 per acre-foot whereas the marginal revenue product for the agriculture industry is $2,000 per acre-foot. As a result, there is an opportunity for the trading of water rights between the agriculture and power industries. Either restriction of water usage or water pricing could create upward pressure on wholesale power prices.

The boom in the natural gas industry in the U.S. will not only allow the country to be the top producer of natural gas and accelerate growth, but will also allow California to receive discounted gas prices in the market. The supply boom in the Northeast, Rockies, Texas, Louisiana, Arkansas, Oklahoma, and Alberta, Canada will “push” gas toward the West as suppliers compete for markets. The planned northeastern pipeline expansions will allow more Marcellus shale gas to enter the market, benefiting the whole US economy. Because gas-fired generation is a major source of electricity for California, the lower gas prices will put downward pressure on southern California power prices.

Also providing a boost in near term power supplies will be the increase in supply availability from Powder River basin coal inventories, which will in turn have a

[15] IHS-CERA, *Water Scarcity: What are the Potential Implications for U.S. Power Plant Economics?* Alex Klaessig and Meg McIntosh, December 2014.

dampening effect on western market power prices. Renewables will continue to expand rapidly and provide a boost to power supplies, providing a hedge against reductions in hydro production due to drought. Gas fired generation will be an important energy asset to California as renewable energy is intermittent and only gas fired generation can ramp up quickly to follow load losses due to renewable power interruptions (i.e., cloudy days).

Although there will be downward pressure on power prices in Southern California, prices for SP15 are expected to increase moderately due to the following reasons:

- The California economy will expand at an average rate of 2.8 percent per year.
- 23 GW of power generation capacity will be retired in western power markets by 2020 due to once-through cooling regulations.
- Western power markets will add almost 22 GW of solar and 8 GW of wind capacity by 2020, challenging dispatch planning and fossil fuel generators.
- California will have to deploy flexible and fast ramping natural gas fired resources with higher heat rates than current marginal resources to compensate for the intermittency of renewable power generation.
- Natural gas prices will increase moderately, averaging $3.50/MMBtu over the 10-year forecast due to strong demand growth in the manufacturing sector, strong demand growth from the power industry due to environmental policies favoring gas fired generation, increases in liquid natural gas (LNG) exports and gas pipeline exports to Mexico.

The economic growth and fuel price assumptions used in this IRP forecast are shown in Figure 2.8.[16]

	US GDP	CA GDP	LA GDP	LA Leisure	LA Housing Starts	LA Pop Cohort 55-64	SP-15 Power Price (Peak Period)	SP-15 Power Price (off - Peak	SOCAL Gas Price
	APCT	APCT	APCT	APCT	APCT	APCT	$ / MWh	$ / MWh	$ / Mmbtu
2009	-2.75%	-4.38%	-5.22%	-8.44%	-48.61%	3.92%	$28.34	$20.42	$3.97
2010	2.16%	1.10%	0.22%	2.75%	17.83%	3.91%	$39.98	$29.48	$4.01
2011	1.40%	1.21%	0.18%	5.25%	58.96%	4.03%	$36.80	$22.72	$3.63
2012	2.03%	2.46%	1.48%	1.29%	22.55%	2.80%	$34.86	$24.19	$2.39
2013	1.88%	2.34%	1.57%	2.78%	32.22%	2.86%	$48.35	$37.81	$3.21
2014	2.22%	2.82%	2.26%	4.98%	12.22%	2.60%	$51.22	$40.83	$4.49
2015	2.17%	2.42%	2.67%	3.17%	33.94%	2.06%	$33.70	$28.61	$2.70
2016	2.98%	3.28%	2.73%	1.13%	-4.20%	1.28%	$31.24	$23.58	$2.15
2017	2.68%	3.10%	3.02%	1.26%	-7.73%	0.95%	$35.86	$27.09	$2.53
2018	2.51%	2.86%	2.65%	1.62%	-0.45%	0.72%	$39.13	$30.76	$2.78
2019	2.60%	2.91%	2.42%	2.10%	4.65%	0.54%	$41.98	$34.45	$2.86
2020	2.53%	2.77%	2.24%	1.55%	2.79%	0.42%	$45.49	$38.47	$2.89
2021	2.38%	2.63%	2.01%	0.79%	-1.14%	0.22%	$50.64	$43.95	$3.09
2022	2.31%	2.59%	2.13%	0.57%	-1.49%	0.18%	$52.84	$46.35	$3.19
2023	2.27%	2.56%	2.25%	1.00%	-1.11%	0.13%	$55.34	$48.97	$3.43
2024	2.20%	2.65%	2.35%	1.26%	-0.29%	0.11%	$57.60	$51.77	$3.83

Figure 2.8: Economic Growth and Fuel Price Assumptions

[16] Data taken from IHS-CERA, Spring 2015 West Power Market Outlook, 2015 to 2040.

2.D.5 Additional Forecast Factors

In addition to economic growth and lower gas prices, the following factors should affect retail sales and have been considered in the forecast.

- Expansion of the ski resorts' snowmaking capability, enabled by improvements to the existing substation which will add 1.3 MW to load capacity in 2015 and anticipated substation expansion of 13 MW in Winter 2018-2019. This could increase BVES sales significantly for the A-5 primary rate class.
- Mammoth's two ski resorts may increase their commercial load at the base operations of the resorts utilizing potential BVES economic development initiatives in 2018.
- New business development in Big Bear Lake or Big Bear City through possible BVES economic development initiatives (such as university extension, summer amusement park, high altitude athletic training center, county fair, and village entertainment) that could add 795,000 kWh sales per year starting December 2018.
- Impact of continuing California drought conditions on BVES service area economy, exacerbated by urban sprawl in Southern California, may continue to dampen sales.
- BVES' Net Metering program, which reimburses customers for their excess solar output at their applicable retail rate, should continue to grow due to the extension of the 30% Investment Tax Credit through 2020, and displace BVES electric sales. Beginning in 2015, Net Metering solar capacity and production increased due to the launch of the Bear Valley Solar Initiative, which funded a portion of installation costs. Although the Solar Initiative is no longer funded, it is projected that up to 9.5% of sales will be displaced by Net Metering activity by 2024.
- Electric Vehicle charging load initiated by EV charging installations funded by the SCAQMD in summer 2016, and a utility sponsored program starting the end of 2018, could add 174,267 kWh in sales initially and reach a level of 431,478,956 kWh per year in 2024. Six to eight charging stations could be installed at locations in the Big Bear Lake Village, ski resorts, and BVES office by summer of 2018.

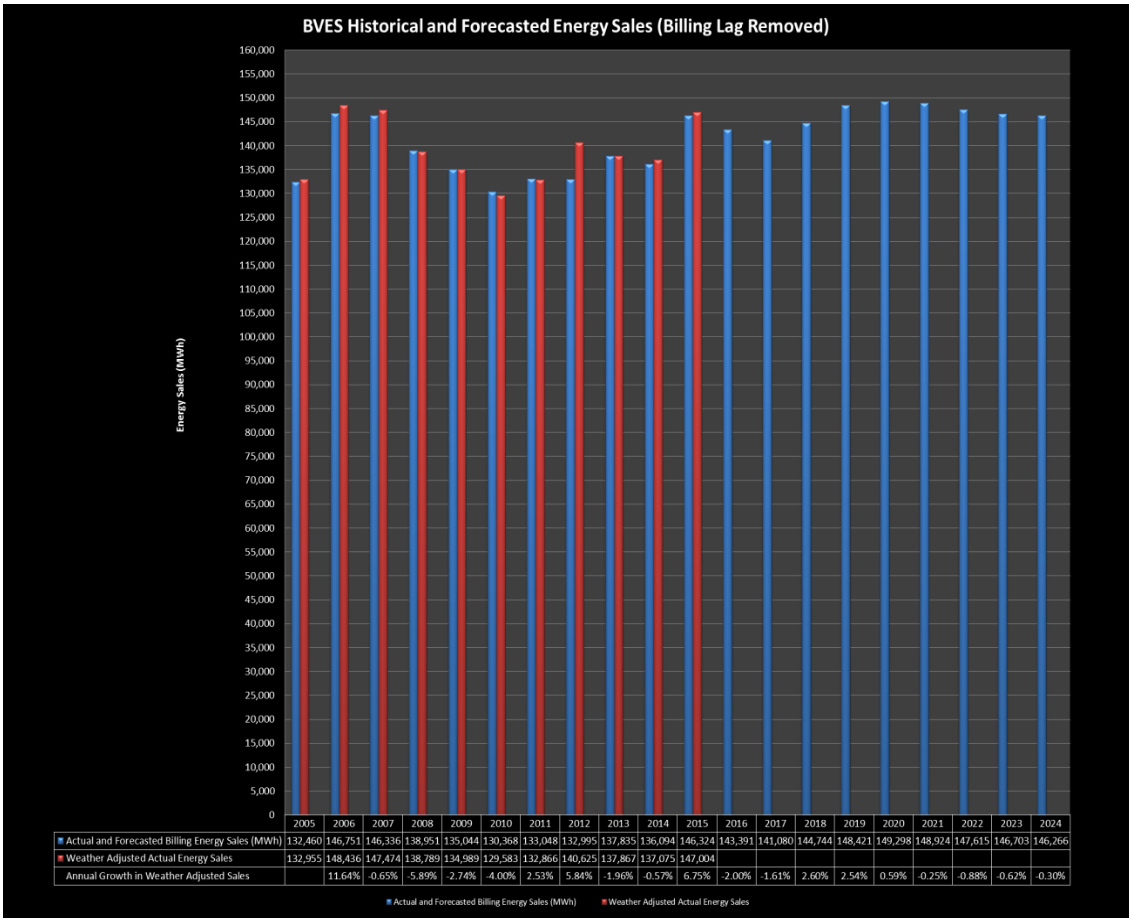
2.D.6 Energy Sales Forecast

Figure 2.9 illustrates the forecasted trend in BVES' energy sales. The system sales forecast is divided into firm and non-firm sales. BVES is committed to providing firm sales, while non-firm sales are interruptible. The system firm and non-firm sales are forecasted using:

- Normal weather assumptions with average levels of snowmaking (base case) with added activity as described in Section 2.D.5.
- Colder and warmer than normal winter weather with higher and lower than normal snowmaking usage assumptions (2008 to 2013 weather and hourly load shape patterns).

- Additional snowmaking load added for the 1.3 MW expansion at Bear Mountain in 2015 and anticipated 13 MW expansion at Snow Summit in November 2018.
- Electric Vehicle load added to firm sales,
- Condo development and/or economic development added to retail sales for the A-4 customer class.
- Energy sales reduced by efficiency impact over the forecast horizon.
- Distributed Generation using renewable technology (now under Net Metering Tariff) assessed separately and then subtracted from the retail sales generated from the analysis above. This should grow rapidly through 2020 and will then slow significantly after that time period as the Investment Tax Credit is reduced.

There is a divergence in the usage forecast across the firm and non-firm sales worth noting because BVES is committed to supplying the firm sales which are anticipated to grow over the forecast period. Non-firm sales are not expected to grow after anticipated expansions, but instead vacillate around the average use over time, some years above the average and some years below the average.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Actual and Forecasted Billing Energy Sales (MWh)	132,460	146,751	146,336	138,951	135,044	130,368	133,048	132,995	137,835	136,094	146,324	143,391	141,080	144,744	148,421	149,298	148,924	147,615	146,703	146,266
Weather Adjusted Actual Energy Sales	132,955	148,436	147,474	138,789	134,989	129,583	132,866	140,625	137,867	137,075	147,004									
Annual Growth in Weather Adjusted Sales		11.64%	-0.65%	-5.89%	-2.74%	-4.00%	2.53%	5.84%	-1.96%	-0.57%	6.75%	-2.00%	-1.61%	2.60%	2.54%	0.59%	-0.25%	-0.88%	-0.62%	-0.30%

Figure 2.9: BVES Historical and Forecasted Energy Sales

BVES' energy forecasting methodology in this IRP began by using historic customer billing data from January 1996 through 2014. Past usage and customer counts were then used to develop models specific to each rate class. Data were aligned with calendar months corresponding to monthly weather conditions captured by heating and cooling degree days.[17] A set of regression models was then used to forecast monthly demand and energy for the period 2015 through 2024.[18] As a check of the demand and energy forecasts, the capacity factor was also considered.[19] The load research sample data was utilized to derive hourly load shapes for each of the rate classes which results in an hourly load forecast based on those load shapes and the retail sales. The retail sales and the peak load are adjusted to reflect line losses in order to determine energy and load requirements for the IRP.[20]

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[17] Weather data was sourced from NOAA for the Big Bear Lake (station 40741) location.
[18] The forecast model for this IRP through 2024 uses real per capita income, real estate activity, retirement age cohort 55-65, entertainment activity, or transfer payments as economic drivers for some rate classes. The model also includes California's relative price of electricity as compared to the US.
[19] The capacity factor is the ratio of the electrical energy produced by a generating unit for a period of time compared to the electrical energy that could have been produced at continuous full power operation during the same period.
[20] The adjustment factor for line losses is 1.06442. For total losses, the adjustment factor is 1.137119.

2.E Summary Forecast of Demand and Energy

Figure 2.10 provides a summary of BVES' annual forecast for demand and energy requirements.

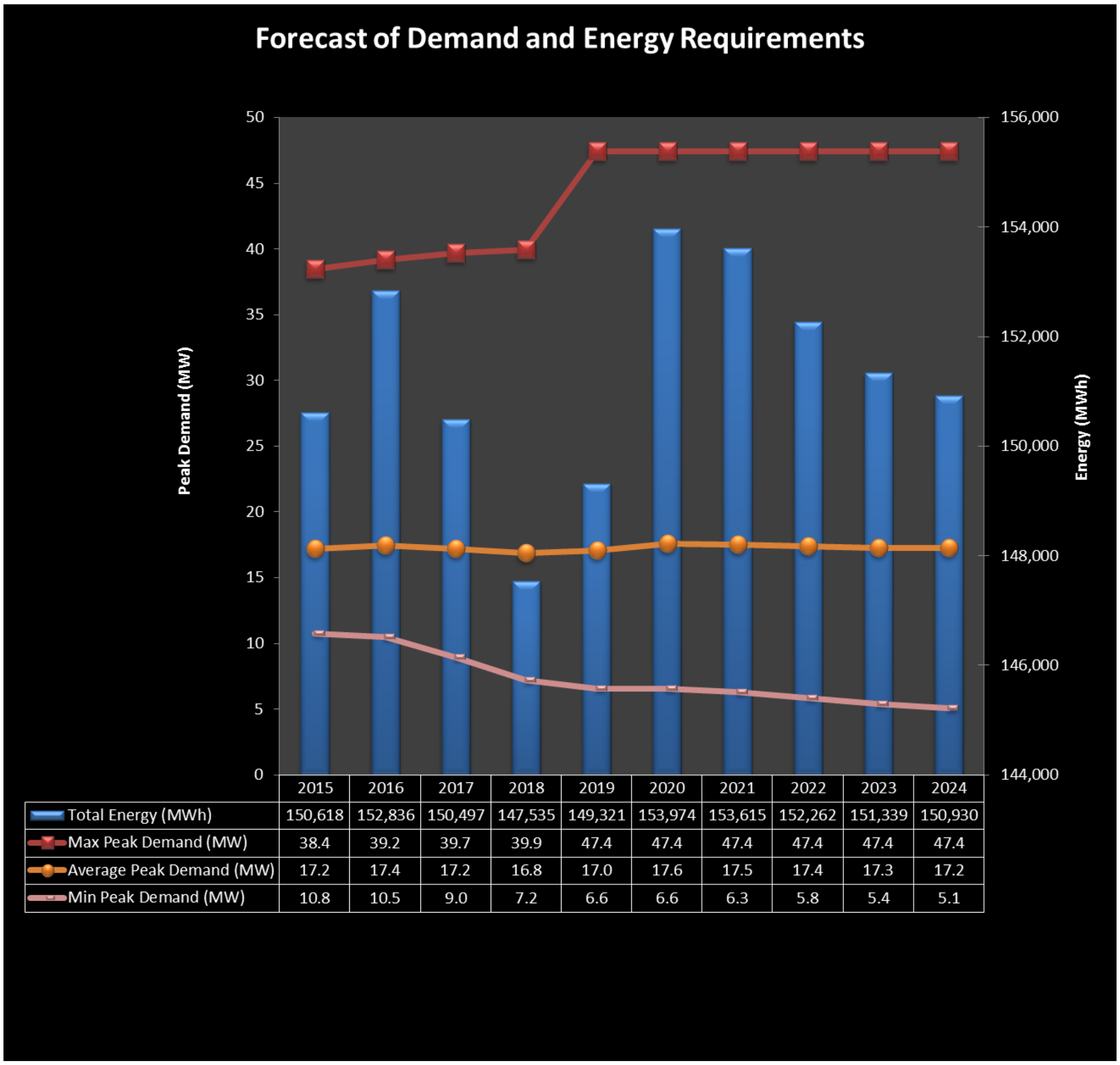
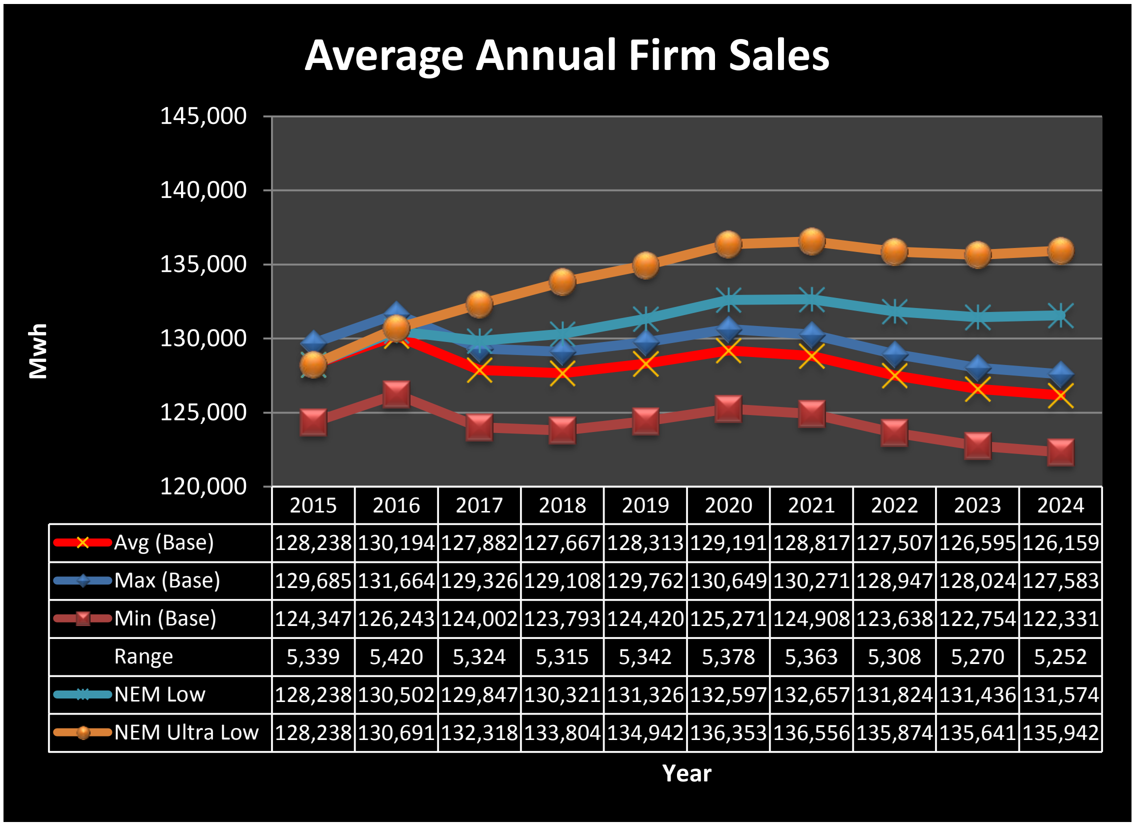


Figure 2.10: Forecast of Demand and Energy Requirements

Figure 2.10 reflects both sales and load for the average of the high, median, and low weather scenarios in the base case. The sales and load forecast is derived from the base case forecast of energy sales, which are adjusted for line losses to derive energy requirements, which are multiplied by the hourly load shape factors derived from the 2008-2013 load shapes to derive hourly load forecasts for each class. The concatenated class load shapes for each load shape case (2008-2023) are used to derive a forecast range for system load. Note that for the energy requirement, the load shapes will impact the non-firm portion of sales and therefore the overall energy requirements. This is because the load is affected by different load shapes and the system load requirement may hit a capacity level for a particular shape; therefore, non-firm sales would be diminished by the sales interruption. Because firm sales are not interrupted, they are not altered by the shapes assumption. Load requirements are impacted by the shapes assumption and, therefore, the shapes assumption does impact capacity requirements and cost.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Avg (Base)	128,238	130,194	127,882	127,667	128,313	129,191	128,817	127,507	126,595	126,159
Max (Base)	129,685	131,664	129,326	129,108	129,762	130,649	130,271	128,947	128,024	127,583
Min (Base)	124,347	126,243	124,002	123,793	124,420	125,271	124,908	123,638	122,754	122,331
Range	5,339	5,420	5,324	5,315	5,342	5,378	5,363	5,308	5,270	5,252
NEM Low	128,238	130,502	129,847	130,321	131,326	132,597	132,657	131,824	131,436	131,574
NEM Ultra Low	128,238	130,691	132,318	133,804	134,942	136,353	136,556	135,874	135,641	135,942

Figure 2.11 Firm Sales Forecast

Weather also has an impact on firm sales, though mostly in the winter season as electric-driven heating load is required in the winter because most homes and commercial establishments have heaters and use electricity for ventilation of central heating system or space heating. The larger commercial establishments and some homes have air conditioning for warmer months; therefore, weather drives commercial sales year round. The summer air conditioning demand is somewhat diminished by the cooler nighttime temperatures in the summer. Lighting load is impacted to some degree by weather as the colder temperatures result in more daytime hours spent indoors, creating more lighting demand in the winter. Because most homes are not air conditioned and have heating fueled by gas, there is a wider range between the average temperature case and the minimum case versus the maximum case and the average case. See Figure 2.11 above for the range in base case sales created by weather alone.

Because a significantly larger portion of sales occur in the winter season between the Christmas and New Year's holidays, there is a higher coincidence in the customer class loads during this period in a colder than normal season which results in a higher peak load forecast due to sales effect and coincidence factor increase. Also, in general, there is more of a coincidence between snowmaking and the other classes during a colder than normal winter season; this can push up peak demand for the BVES system. Therefore, there is more of a peak demand response due to weather than the energy sales response due to weather.

In a milder than normal winter and the resulting lower amount of electricity usage for snowmaking, there is more of a divergence of the peak load patterns between classes. The peak load for the low case is significantly lower than the high case and the difference in the peak load is more pronounced than the difference in the energy sales between the high and low scenarios. The low case weather conditions actually shift the timing of the system peak load into early January as opposed to late December for the base case or the high case.

BVES' wholesale energy requirements, as measured by the meters at the two SCE receipt points, include retail sales plus SCE distribution feeder losses and BVES system distribution losses. BVES system losses are approximately 14 percent.[21]

Under certain high loading scenarios, BVES may experience capacity deficiency. In order to mitigate interruption and obtain best-fit, least-cost supply while considering the loading order,[22] the following capital investment scenarios may be considered:

- Further invest in an energy efficiency public purpose program which targets residential lighting in order to reduce load during the critical peak period of 7 to 10 PM during the winter hours.
- Implement a load control/demand response program for spa and electric hot water heaters providing up to 3 MW of peak capacity via reduced demand during peak hours.
- Increase BVES-owned solar capacity (on top of the planned 2.7 MW of solar capacity located on the local capped landfill).
- Invest in an electricity storage system to balance the system load and accommodate more sales given the same level of capacity.
- Enhance the current import capacity by 1-2 MW at a fraction of the cost of other supply alternatives would involve reconfiguring BVES' distribution system by adding circuits to the Radford line during winter months.

Further explanations of the possible capital projects and the potential benefits of those projects are provided in Section 5.E, Possible Capital Projects, in this IRP.

2.F Current and Planned Resources

2.F.1 Background

[21] Based on a study for BVES using 2009 data. The BVES distribution system includes 4 kV and 34 kV systems, and the losses cited include both SCE distribution system losses and BVES system losses.
[22] See Section 5.C for a more detailed discussion on the loading order in California.

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

The 13 MW annual baseload contract, heat rate call option and resource adequacy contracts covered the period 2009 through November 2013. The seasonal baseload contract, supplying 5 MW in November and 7 MW in December, January and February, covered 2009 through December 31, 2011.

To replace the above contracts, BVES issued two separate competitive Requests for Proposals (RFP), one for annual and seasonal baseload and a physical call option and the other for system RA. After a thorough evaluation of the bids, BVES awarded the annual baseload and RA contracts to EDF Trading North America, LLC (EDF) while Shell was awarded the contracts for seasonal baseload and the physical call option.

2.F.2 Current Energy Contracts

In December 2014, BVES received the Commission approval of the power purchase agreements resulting from the RFPs. The contracts for the annual and seasonal baseload and physical call option began delivering power January 1, 2015 while the RA contract commenced in March 2015. EDF is the provider of the annual baseload and physical call option products, while Shell is the provider of the seasonal baseload and RA. The contracts' attributes are shown in Table 2.12.

Product *	Resource Type	Term Years	Capacity (MW)	Time Dimensions (hours/day, days/week)
Annual Baseload	CAISO Firm Energy	4 yrs, 11 mo	12 MW	24/7 All months
Seasonal Baseload	CAISO Firm Energy	3 yrs	5 MW Nov 7 MW Dec-Feb	24/7 All Months
Physical Call Option with $75/MWh Strike	CAISO Firm Energy	3 years	7 MW winter; 3 MW other	16/7 All Months
System Resource Adequacy Capacity	Gas Turbine; Combined Cycle Combustion Turbine	4 yrs, 11 mo	15 - 31 MW ** depending on month	24/7 All Months
* For all products, delivery point is SP15 EZ Gen Hub in CAISO, as defined in the EEI Master Power Purchase and Sale Agreement, as amended. ** MW capacity in RA product refers to the combined amount of RA that BVES will purchase.				

Table 2.12: Current Energy Contracts

Because the Commission approval of the Shell and EDF contracts did not occur before the November 2013 expiration of the previous Shell contract, BVES purchased its annual and seasonal baseload and RA requirements on a monthly basis by issuing Requests for Offers (RFO) to various energy supply firms.[23] The resulting monthly transactions were governed by the Western Systems Power Pool (WSPP) Agreement in effect at the time of the transactions.[24] The amount of firm energy and capacity (RA) BVES purchased on a monthly basis matched the volumes in the contracts that the CPUC approved in December 2014.

2.F.3 Bear Valley Power Plant (BVPP)

The BVPP became commercially operational on January 1, 2005. The current Permits to Operate (PTOs), issued on March 26, 2009 in compliance with current air district rules, limit each engine to 1,000 hours of operation annually.[25]

The BVPP is currently treated as a distributed generation, or “behind-the-meter” resource, by the CAISO and is not under a Participating Generator Agreement (PGA). When operating, the BVPP reduces BVES’ metered peak demand on the CAISO system, as measured by the SCE meters at the Goldhill receipt point.[26] Operation of the

[23] As noted, the seasonal baseload product expired December 2011.
[24] BVES is a member of the WSPP.
[25] 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 South Coast Air Quality Management District (which may take up to one year to process) and under current air district rules, would require additional CEMS equipment to continuously monitor CO.
[26] Operating the BVPP does not affect SCE’s metering at the Harnish receipt point.

BVPP can be very useful during on-peak periods when power costs may be higher than the marginal cost of operating the BVPP. Although there are maintenance costs such as running the BVPP for inspections and maintenance, these costs are not factored into the decision to run the plant based on economics. Only the marginal costs are considered in the economic evaluation of resource deployment.

BVES is able to reduce energy costs and increase price certainty by contracting for as much energy as possible from high capacity factor (baseload) resources and then meeting additional peaking and intermediate load through the CAISO Day Ahead (DA) market or the BVPP. If energy prices in the DA market are forecasted to be less than the cost of production from the BVPP, BVES does not operate the BVPP and instead purchases energy in the DA market. Otherwise, the BVPP could be utilized to satisfy demand. Operating in this fashion allows BVES to avoid paying capacity costs for a low capacity factor resource and also helps BVES reduce its contribution to system peaks.

2.G Procurement Plan

BVES analyzed the benefit of renewing existing contracts for annual and seasonal baseload and a physical call option(s) at the current contract volumes once the contracts expire. The total annual savings from renewing current contracts is potentially significant. Other options include maintaining the current annual baseload volume, extending the existing seasonal baseload and physical call option contracts but with different volumes and differentiating on and off peak load. This approach was selected as the optimal procurement strategy because it yields the highest savings and it maintains a minimal imbalance between demand and supply in daily transactions. Other options with higher contract volumes would yield higher savings; however, the imbalance in the market would exceed 1 MW, on average annually, for any given hour, creating speculative risk.

BVES also considered extending contracts beyond 59 months by tying contracts to specific assets with the goal of reducing contract prices as fuel producers try to hedge their production returns. Given the uncertainty in the gas market as shale plays mature, greater efficiency in production and drops in LNG prices, many buyers and producers wonder how low gas prices will go. As a result, this may be the best time to lock into contracts longer than 59 months at prices similar to the price bids for the contracts received from the existing suppliers of the energy products. The element of risk may incentivize suppliers to price product below the benchmark prices. Although BVES will pursue 59-month contracts to minimize the risk, there are benefits for "extended range" products that indicate savings would be multiples of the savings generated from the 59-month contracts. Only a few very large utilities have pursued these extended term contracts.

BVES developed a benchmark pricing methodology to facilitate approvals by the CPUC for BVES power contracts. This is a policy tool that provides pre-approved benchmark prices. If prices in the bids are below the benchmark prices, the product purchased by the utility would be reviewed by the Commission via an Advice Letter filing. This process is useful for both Commission review and utility executive office approval.

In the analysis for determining the benefits of contract volumes and renewals, BVES discounted the benchmark price based on experience on bidding in the latest procurement cycle. The discounted price was then applied to analysis as the contract price. Note that the benefit analysis assumed other capital projects and rate programs and demand side management occur concurrently with the renewed contracts, with the higher volumes for the annual baseload and existing volumes for the renewal of the other products. It was determined that the contract renewal and the capital projects and rate design initiatives complement each other; in other words, the initiatives and the procurement plan benefit as a whole do not diminish the individual initiatives values.

The contracts, existing and proposed, are listed in Table 2.13. Note that the evaluation end date is December 2024, even though contracts would extend beyond 2024.

<table>
<tr><th>Contract</th><th>Hours</th><th>Capacity</th><th>Duration</th></tr>
<tr><td>Annual Base Load Fixed Price (Existing)</td><td>7*24 Hours, All Months</td><td>12 MW</td><td>Jan 2015 – Nov 2019</td></tr>
<tr><td>Annual Base Load Fixed Price (<u>New</u>)</td><td>7*24 Hours, All Months</td><td>12 MW</td><td>Dec 2019 – Oct 2024</td></tr>
<tr><td>Annual Base Load Fixed Price (<u>New</u>)</td><td>7*24 Hours, All Months</td><td>12 MW</td><td>Nov 2024 – Sep 2029</td></tr>
<tr><td>Seasonal Base Load (Existing)</td><td>7*24 Hours, Nov</td><td>5 MW, 7MW</td><td>Jan 2015 – Dec 2017</td></tr>
<tr><td rowspan="2">Seasonal Base Load (<u>New</u>)</td><td>7*24 Hours, Nov</td><td>4 MW on-peak, 7 MW off-peak</td><td rowspan="2">Jan 2018 – Dec 2020
Jan 2021-Dec 2023
Jan 2024-TBD</td></tr>
<tr><td>7*24 Hours, Dec-Feb</td><td>8 MW on-peak, 12 MW off-peak</td></tr>
<tr><td rowspan="2">Call Option $75/MWh Cap (Existing)</td><td>6:00 AM to 10 PM</td><td>7 MW Nov-March</td><td rowspan="2">Jan 2015 – Dec 2017</td></tr>
<tr><td>7 Days/Week</td><td>5MW Apr-Oct</td></tr>
<tr><td rowspan="2">Call Option $68 or less/MWh Cap (<u>New</u>)</td><td>6AM to 10 pm, 7 Days/Week, Nov-Mar</td><td>10 MW on-peak, 10 MW off-peak</td><td rowspan="2">Jan 2018 – Dec 2020
Jan 2021-Dec 2023
Jan 2024-TBD</td></tr>
<tr><td>6AM to 10 pm, 7 Days/Week, Apr-Oct</td><td>3 MW on-peak, 3 MW MW off-peak</td></tr>
</table>

Table 2.13: Existing and Proposed Contracts for BVES

2.H Summary and Conclusions

An updated analysis of BVES' load for this IRP suggests that the current economic conditions and other factors will increase BVES' loads. The U.S. economy has grown moderately through 2015 and is projected to pick up speed in 2016 and beyond due to a variety of factors, including the ongoing low price environment for natural gas and oil, low prices for commodities in general, job increases, housing recovery, consumer debt reduction, and pent up consumer demand. In addition to macroeconomic growth, lower gas prices, regional economic expansion and continuing drought conditions also affect the forecast. Regional load growth is driven by expansion in the entertainment and real estate markets for Los Angeles, economic development which attracts new industry into the area, potential demand from electric vehicles, and planned expansion of Mammoth substation by 13 MW. These factors support strong sales growth for BVES.

However, customer distributed generation has reduced BVES' retail sales. Though this trend will continue, BVES will maintain moderate growth in total retail sales through the forecast horizon. The average firm peak load is expected to remain relatively flat from 2015 to 2024 and non-firm peak load is expected to grow by 62% over the same period, driven by the Mammoth capacity expansion of 13 MW expected by the winter of 2018 to 2019.

This IRP represents a conservative assessment of load growth. If Distributed Generation does not grow as robustly as anticipated, BVES firm load would grow anywhere between a slight growth rate to moderate growth rate. BVES will continue to monitor the continued adoption of customer Distributed Generation and moderate its forecasts accordingly.

Capacity constraints limit total peak load for the non-firm customer class; but even in extreme weather scenarios where capacity limits are approached, the duration of the peak load(s) is very short-lived. Options for managing peak loads effectively include Demand Side Management programs such as interruptible tariff schedules, time-of-use rates, and water heater and spa cycling. These measures can shift load usage by a few hours and even minutes to achieve the resource balance needed during peak hours. Additionally, BVES has planned a new utility-owned solar generation facility and is reviewing energy storage applications to meet peak load requirements or a combination thereof.

Still, BVES' annual retail sales remain below the all-time sales achieved in 2006. Energy sales declined in 2007 and continued to decline significantly through 2010. While the national economic recession was partially the cause, the decline in real estate values had a major effect on the growth of the Big Bear economy and local activity. With the recovery in the economy and real estate more pronounced in 2012 and continuing through 2015, BVES sales have increased from the 2010 levels. In 2015, BVES sales were 2.0% short of the peak sales in 2006 while 10.3% higher than the trough in 2010.

There is still a significant amount of commercial and residential developed property available for occupation to accommodate growth in residential and commercial activity driven from growth in demand from the Los Angeles economy. Economic development tariff rates contemplated for the upcoming General Rate Case stimulating economic growth in the summer, spring, and fall months should also stimulate growth in sales. Until underutilized rental property and commercial real estate is absorbed by the local economy, there will always be an attraction to investment in BVES' service area. The high cost of real estate in California has attracted real estate investment away from the coastal areas towards the Inland Empire. This will also boost investment into the BVES service area.

Although there will be downward pressure on wholesale power prices in Southern California, prices for SP15 are expected to increase moderately due to a variety of reasons, including economic growth in California, the 50% RPS requirement for energy resources by 2030, the carbon allowance pressures in the WECC region on electric prices, the eventual recovery of the world market stimulating growth in oil and gas prices, and challenges from managing the influx of intermittent resources. A review of the forward market prices relative to the spot market forecasts provided by IHS-CERA indicate that fixed price contracts may likely be bid at a price significantly discounted from the forward spot market view provided by IHS-CERA. All of the above indicators were considered in the testing of the benefits of fixed price contracts. The conclusion from the resource planning analysis indicates that BVES should continue to hedge a significant portion of energy requirements price through fixed price contracts. Renewable generation and battery technologies along with efficiency and load control will be blended into future resource plans with the contracts using a best-fit and least-cost criteria.

BVES' current energy contracts stem from power purchase agreements approved by the CPUC in December 2014. The contracts for the annual and seasonal baseload and physical call option began delivering power January 1, 2015 while the RA contract commenced in March 2015. EDF is the provider of the annual baseload and physical call option products, while Shell is the provider of the seasonal baseload and RA.

Planning for contract renewals, BVES will solicit requests for bids and maintain the same contract levels for annual base load contracts and will alter the seasonal contracts to vary for peak and off peak periods to accommodate the hourly load requirements of the forecast. The call options were adjusted slightly to match the new load forecast. BVES will remain conservative in the contract sizing due to the uncertain nature of the load growth of Distributed Generation by customers.

3. Renewable Resources

3.A Background of the Renewable Portfolio Standard (RPS)

Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2, California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires investor-owned utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33% of total procurement by 2020.

In January 2015, Governor Brown called on lawmakers to increase the RPS target to 50% by 2030 and in October 2015 he signed into law Senate Bill 350. SB 350 increases the RPS requirement to 50% by 2030 and also requires the CPUC to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030, doubling energy efficiency, and promoting transportation electrification.

3.B. BVES and the RPS

In late 2011, D.11-12-052 defined and implemented portfolio content categories ("PCCs"). Most retail sellers subject to the RPS must procure certain quantities from each of the PCCs. The PCCs, in brief summary, consist of:

1. Generation facilities that have their first point of interconnection to the Western Electricity Coordinating Council transmission grid within the metered boundaries of a California balancing authority area (PCC 1);[27]
2. Generation from a facility that is firmed and shaped with substitute electricity scheduled into a California balancing authority within the same calendar year as the generation from the facility eligible for the California renewables portfolio standard, and that the substitute electricity provides incremental electricity (PCC 2); and
3. Other products like unbundled RECs that do not apply to the first two categories (PCC 3).

Of importance, D.11-12-052 confirmed that BVES may satisfy its RPS obligations without regard to the PCC limitations to which other retail sellers must adhere. Since BVES is exempt from following the product content categories, it intends to comply with the majority of its RPS requirements with unbundled RECs (i.e. PCC 3), which is the least expensive option of the RPS-eligible products.

[27] Procurement claims from contract/ownership agreements executed before June 1, 2010, or January 13, 2011 for ESPs, are not subject to the PCC classifications established in D.11-12-052. For the purposes of RPS compliance, any eligible RPS RECs that are not subject to PCC 1, 2, or 3 will be placed in their own classification, referred to as PCC 0.

In June 2012, BVES issued an RFP for RECs that sought pre-2011 volumes in addition to its then-current and future compliance period needs. After identifying a successful bidder, BVES began negotiations for a long-term contract for unbundled RECs. In February 2013, GSWC on behalf of BVES filed Advice Letter 277-E with respect to its ten-year RPS agreement for the purchase of RECs from Iberdrola Renewables, LLC (now called “Avangrid Renewables, LLC, or “Avangrid”). CPUC Resolution E-4604, issued in July 2013, approved the ten year contract. The volumes in the ten-year REC contract were originally forecasted to fulfill all of BVES’ RPS obligations through 2023.[28] The updated retail sales forecast now projects full RPS compliance through 2021. See Table 3.1 for more details on contract volumes, RPS obligations, and forecasted length and shortfalls.

RPS Position Using 2016 IRP Sales Forecast -- 50% by 2030

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024
Retail Sales	143,391	141,080	144,744	148,421	149,298	148,924	147,615	146,703	146,266
RPS %	25.00%	27.00%	29.00%	31.00%	**33.00%**	**34.40%**	**35.80%**	**37.20%**	**40.00%**
BVES' RPS Obligation	35,848	38,092	41,976	46,010	49,268	51,230	52,846	54,573	58,507
Annual RECs (Base + Option RECs)	38,865	42,425	45,444	48,455	51,661	51,640	51,594	51,617	-
Length/(Shortfall)	3,017	4,333	3,468	2,445	2,393	410	(1,252)	(2,956)	(58,507)

Note:
The REC volumes in the contract with Avangrid were based on the 33% by 2020 RPS law. This table shows the annual RPS% increments proposed by the CPUC under the new 50% by 2030 law.

Table 3.1: BVES RPS Position Using 2016 IRP Sales Forecast

As previously discussed**,** BVES is planning to develop a 3 MW (DC) solar generation facility at the recently capped landfill owned by the County of San Bernardino and directly adjacent to BVES territory.[29] Assuming a 22.6% load factor for generation, the 3MW (DC) and 2.7 MW (AC) facility should produce approximately 5,300 MWh per year of RPS-eligible energy the first year with a 0.5% annual degradation rate over the next 20 years. Even with this solar generation project, BVES will likely still need to purchase additional RECs or other RPS-eligible products if forecasted sales come to fruition. BVES may issue an RFP for RPS-eligible products (likely unbundled RECs) sometime in the 2016-2018 timeframe. Procurement targets for the intervening years within a compliance period are not enforceable; rather, the targets determine the overall procurement requirement for that compliance period. As such, BVES must acquire and retire a sufficient amount of RECs prior to the end of Compliance Period III, which is December 31, 2020, to remain RPS compliant and is confident it will do so.

[28] Under the previous 33% by 2020 RPS, there were three compliance periods: 2011-2013, 2014-2016 and 2017-2020Newly required increments to reach 50% by 2030 are used for the analysis through the Avangrid contract end date of 2023.
[29] In August 2015, BVES issued an RFP seeking 2-4 MW of renewable energy generation in or near its service territory. Although BVES received only one bid, the proposed project was deemed highly viable, both economically and environmentally. BVES intends to purchase the solar facility outright once it is completed (subsequent to CPUC approval).

4. Net Energy Metering (NEM)

4.A Background of Net Energy Metering (NEM) Legislation

In 1995, California was one of the first states to formally adopt net energy metering (net metering or NEM) for wind and solar systems. Simply stated, net metering allows customers to use renewable resources (e.g., solar panels) to generate electricity and offset their consumption with their own power production. NEM is a tariff billing design that promotes the installation of onsite renewable generation by providing a bill credit for excess generation that is received by the electric grid when it is not serving onsite load. On a monthly basis, bill credits for excess generation are applied to a customer's bill at the full retail rate the customer would have paid for energy consumption. The full retail rate includes generation, distribution and transmission costs. At the end of a customer's 12-month billing period, any balance of surplus electricity is trued-up at a separate value called the net surplus compensation (NSC) rate, which is based on a 12-month rolling average of the wholesale market rate for electricity (approximately $.03-$.05 per kWh).

As noted above, a NEM customer is credited the full retail rate for excess energy put on BVES' distribution system. As a result of this state-mandated billing structure, BVES, like any utility that offers full-retail-rate NEM, does not collect the planned-for revenue needed to recoup its fixed and pass-through costs. While the NEM obligations of CPUC-regulated IOUs are capped at five percent of the utility's non-coincident peak demand across all customer segments, how the "missing" revenue is recovered has created some level of controversy in the industry. Some believe that non-NEM customers essentially subsidize NEM customers while others believe utilities are simply clinging to an outdated business model.

To address the issues surrounding the future of NEM and to continue support for distributed renewable resources, the CPUC in July 2014 adopted Rulemaking (R.)14-07-00. The NEM 2.0 proceeding currently applies only to the large IOUs because they are already at or near their respective NEM caps.[30]

In January 2016, the CPUC issued Decision (D.) 16-01-044 that adopted a NEM successor tariff. While the CPUC describes the decision as making adjustments to align the costs of NEM successor customers more closely with those of non-NEM customers, many parties, including the Big Three IOUs in California, strongly disagree. In March of 2016, the Big Three simultaneously requested that the CPUC vacate or modify their decision. The main issue for opponents of the January decision is the full retail rate credit provided to NEM customers unfairly penalizes customers without net metering. Non-NEM customers account for about 95% of all customers. BVES is not

[30] The California Solar Initiative, the rebate program upon which BVES' solar program was based and which was authorized only for the large IOUs, began in 2007. As a result, the large IOUs have or could meet the NEM cap sooner than BVES.

a party to the rulemaking but is monitoring it closely so that it can determine how to best navigate its NEM program as it gets closer to reaching its NEM cap of 3.3 MW. BVES is considering implementing a renewable DG tariff rate as its own "successor" tariff. The goal will be to achieve an equitable rate design for renewable DG customers customized to BVES rate design issues and meter technology capabilities.

BVES will continue to evaluate all costs and benefits of net metering and may seek to revise rates for future customers entering the program as BVES approaches the 5% limit on aggregated non-coincident class peak loads for net-metering production.

4.B Impact of Net Energy Metering (NEM) on BVES Sales

As of December 31, 2015, BVES has 272 customers on the NEM rate (13 commercial and 259 residential). Installed capacity through 2015 was 2.1 MW, with a staggering 1.4 MW installed in 2015 alone. The vast majority of BVES NEM customers are solar. The significant spike in the number of interconnected solar installations can be attributed to a dramatic decrease in the price of solar and the January 2015 launch of the Bear Valley Solar Initiative (BVSI).[31]

NEM annual energy production has increased from an estimated 714,000 kWh in 2013 to 1,028,000 kWh in 2014 (a 44 % annual increase) to 2,255,344 kWh in 2015 (a 119% annual increase). 2016 has seen continued strong growth in net metering. Electricity production from NEM customers in the first quarter of 2016 NEM production reflects a 170% increase over first quarter 2015.

The largest risk to BVES retail sales growth and the biggest challenge to managing the system load requirement is the growth in net energy metering (NEM) customers. NEM and/or solar distributed generation (solar DG) annual energy production is projected to be 5,060,000 kWh in 2016, 9,786,000 kWh in 2017, 11,747,000 kWh in 2018, 12,233,000 kWh in 2019, and 12,800,000 kWh in 2020, reaching 15,356,000 kWh by 2024. This corresponds with solar DG capacity of 3.1 MW in 2016, 5.8 MW in 2017, 6.0 MW in 2018, 6.3 MW in 2019, and 6.6 MW in 2020, reaching 7.9 MW by 2024. The growth is driven by the savings opportunity that exists under the current Net Metering Tariff versus the current BVES standard retail rates, the current 30% Federal Investment Tax Credit (ITC) for residential and commercial solar projects, and the reduced cost of solar installation. The current production forecast reflects BVES NEM customers achieving 33% of the potential load by 2024, of all customers who could achieve full payback of the solar production investment within 5 years or less.

A review of all the accounts of the residential and commercial customers who are not on the Net Metering program – what they pay currently versus what they would pay

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[31] The Bear Valley Solar Initiative (BVSI) is a CPUC-approved program that pays rebates to residential customers who install qualified solar systems. The BVSI applies only to residential customers, though any customer class may install solar or wind under BVES' NEM tariff. 2015 installed capacity includes residential, commercial, government and school installations.

under the net metering program – yields the estimated savings and the payback period for each individual customer were they to install a solar PV system in their home under the current NEM rates. The total kWh energy consumption of potential Net Metering customers with a payback less than 5 years was 46,139,277 kWh per year. It is very likely that up to 33% of the potential Net Metering Customers (Distributed Generation Renewables) could decide to install a solar system and subscribe to the Net Metering, or successor Distributed Generation Renewables program, and displace up to 15,356,000 kWh of BVES annual sales by 2024.

Already the Bear Valley Solar Initiative program (BVSI), where BVES pays rebates for installed residential solar capacity to the customer, is completed as the CPUC-approved incentive funds have been exhausted. As of April 2016, 2.3 MW of solar capacity has been installed for BVES customers as part of the NEM program.[32] The popularity of solar distributed generation will continue. However, the future rate structure of distributed renewable generation once the legislatively mandated threshold of NEM subscriptions reach 5% of the sum of non-coincident peak demand of all customer classes (3.3 MW based on 66 MW of combined non-coincident peak demand) will not likely include the full retail rate compensation under the current NEM rate for new distributed generation customers after the threshold for NEM subscriptions has been met. All existing NEM customers will remain on existing NEM tariff for 20 years after they subscribed on the NEM tariff. BVES could reach this 5% threshold by February 2017. A future solar or renewable DG tariff may better reflect the cost of service for solar generation customers and will ideally guarantee full recovery of these costs given the anticipated DG production profiles. This will avoid the non-NEM customers subsidizing the NEM customers, a more equitable option for future renewable DG.

Net Metering load has rapidly increased within the BVES service area, displacing retail sales. Analyzing the production capacity of NEM customers over time from a time series approach was not enough to fully capture the potential penetration of NEM production displacing retail sales. Times series analysis of the NEM customer capacity over time has underestimated the impact of NEM capacity enrollment. BVES also performed a payback period analysis of solar NEM program on all customers not participating in the Net Metering solar program in order to determine those customers most likely to strongly consider solar net metering (those with a payback of less than 5 years). Taken into account were the current underlying retail rates, the current NEM rate structure), the Federal ITC program, the cost of solar panel installation, and individual usage patterns of the customers. This set the potential for maximum enrollment into the NEM program. Also a time series analysis of the capacity enrollment of the NEM customers resulted in an alternative NEM enrollment forecast. The high NEM enrollment case has annual solar energy production amount equal to 1/3 of the potential NEM customer amount by 2024. A forecast of hourly load for NEM customers (displaced retail sales load) was applied to the electric consumption forecast to derive the retail sales forecast. Alternative forecasts of NEM production was used to derive the alternative forecasts for retail sales.

[32] BVES has seven wind NEM customers but the vast majority is solar.

Although BVES uses the conservative forecast with a high penetration of Net Metering/DG production in the BVES supply mix (15,355,000 KWh by 2024), other scenarios were considered for planning purposes. These include a low net metering penetration case which achieves an annual production level of 9,940,000 kWh by 2024, and an even lower NEM penetration case which achieves an annual production level of 5,600,000 kWh by 2024. Each of these lower net metering production cases will result in higher BVES retail sales. BVES will size its future energy contracts based on the more conservative sales forecast scenario with the highest NEM production levels.

5. Other Factors Affecting Resource Procurement

5.A CAISO Wholesale Market

The CAISO's Market Redesign and Technology Upgrade (MRTU) Tariff has been in operation since April 1, 2009. From BVES' perspective, it appears that the market has performed as intended. Given that MRTU enacted a complete overhaul of California's system of wholesale power delivery as a result of the California energy crisis in 2001, it has required occasional fine-tuning, as originally communicated to market participants by the CAISO.

To monitor the efficiency and effectiveness of ancillary services, congestion management and real-time (RT) spot markets, the CAISO maintains a Department of Market Monitoring (DMM). Another key charge of the DMM is to ensure that no participant can take unfair advantage of the rules or procedures or concentrate market power and inhibit competition. Once per year, the DMM publishes its "Annual Report on Market Issues and Performance" (Annual Report).[33] Section 5.A discusses the key points relevant to BVES contained in the 2014 Annual Report.

Generation Addition and Retirement

Almost 2,900 MW of new nameplate generation began commercial operation in the CAISO in 2014, contributing almost 1,900 MW of additional summer capacity.[34] Noteworthy is that almost all new generation capacity was renewable resources, and among those resources, the majority was solar. There were no retirements within the CAISO system in 2014.

The EPA rule on once-through-cooling went into effect in 2014 and California began compliance procedures on this policy immediately. The policy applies to 13,000 MW of Southern California generating capacity and 19,000 MW of California generating capacity. The rule requires power plants using once-through-cooling to reduce either water intake or impingement mortality and entrainment of marine life to levels comparable to facilities using closed-cycle wet cooling systems. IHS-CERA estimates that about 11,000 MW of generation capacity will be retired in compliance with the EPA rule. This does have a significant upward impact on the CAISO market prices over the forecast horizon.

Market Competitiveness

According to the DMM, overall wholesale energy prices in 2014 were approximately equal to competitive baseline price estimates modeled by DMM under perfectly

[33] For the full text of the Annual Report, see http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf
[34] CAISO Department of Market Monitoring, 2014 Annual Report on Market Issues & Performance, p.47.

competitive conditions.[35] These competitive baseline prices are calculated by re-simulating the market using actual DA market software with bids reflecting the marginal cost of gas-fired units. The total estimated cost of serving load in 2014 was $12.1 billion or just over $52/MWh.

Energy Market Prices

Regarding CAISO market pricing in 2014, electricity prices were higher than they were in 2013, primarily due to a 17% increase in natural gas prices in 2014. Another factor resulting in upward pressure on prices was a 70% decrease in hydro-electric production, year over year from 2013 to 2014. However, increased solar generation additions, moderate loads and decreased regional congestion had downward pressure on prices. Additionally, after normalizing for gas prices and greenhouse gas compliance costs, DMM estimates that wholesale power prices were stable, increasing just three percent in 2014 compared with 2013.

Day-Ahead vs. Real-time prices

In 2014, BVES purchased approximately 85% of its firm energy requirements through fixed priced contracts, with the remaining 15% in the DA market. Average real-time prices tended to be lower than DA prices, continuing a trend that began in 2013, partly attributable to a drop in real-time price spikes compared to prior years. The trend also reflects additional unscheduled generation in real-time, particularly from solar and wind generation.[36] Because BVES does not have generation assets that can bid into the CAISO market, it is considered a "load-only" entity and does not participate in the real-time market.[37] Overall, prices in 2014 were stable according to the DMM.

[35] CAISO Department of Market Monitoring, 2014 Annual Report on Market Issues & Performance, p. 4.
[36] CAISO Department of Market Monitoring, 2014 Annual Report on Market Issues & Performance, p. 1.
[37] BVES is exposed to real-time prices for imbalance energy but typically only in nominal amounts under normal circumstances.

5.B Resource Adequacy

The CPUC adopted a Resource Adequacy (RA) policy framework in 2004. In June 2013, the CPUC modified the RA program by adoption of a flexible capacity requirement. Each LSE will now show flexible resources for each month of the compliance year.[38] The RA program works in conjunction with regulatory requirements and processes adopted by the CPUC, CAISO and other regulatory authorities. Section 40 of the CAISO Tariff further defines the RA program and standardizes the obligations placed on generation units used to meet resource adequacy requirements and facilitates bilateral contracting between load-serving entities and generators. The CAISO and the CPUC continue to work with stakeholders to standardize RA requirements for demand response programs.

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

The purpose of the CPUC's Resource Adequacy program is to provide sufficient resources to the CAISO and appropriate incentives for new resources. In 2004, the CPUC adopted an RA policy framework (PU Code section 380) to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs). The CPUC has postponed a final decision on RAR requirements for BVES and other small and multi-jurisdictional utilities (SMJUs). The CPUC's decision D.10-06-018 on June 3, 2010 and R.11-10-023 again deferred this issue.[39]

Until such time as the CPUC provides a decision specifying RA requirements for BVES, BVES will continue to comply with the CAISO Tariff applicable to LSEs and submit its RA filings to the CAISO through its Schedule Coordinator. Substantively, BVES secures RA-eligible capacity under the CAISO Tariff that is similar to the CPUC RA program. BVES also complies with data requests from the California Energy Commission regarding load forecasts and historical loads consistent with the RA information requirements and processing applicable to the larger CPUC-jurisdictional entities.

In October 2014, the Commission opened R.14-10-010 to continue the CPUC's oversight of the program and consider refinements to the program. More recently, in late 2015, the Commission held a pre-hearing conference (PHC) to address the scope and schedule of the proceeding moving forward. It also indicated in the PHC announcement that the Commission was contemplating proposals on various topics, including RA obligations for small and multijurisdictional load serving entities. As such, BVES is closely monitoring the proceeding.

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[38] D.13-06-024, *Decision Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program*.

[39] D.10-06-018, page 3, states: "Track 3 of Phase 2 was established to address resource adequacy obligations for small and multi-jurisdictional load-serving entities that are not currently subject to the resource adequacy program. We find that it is appropriate to close this proceeding and resolve the Track 3 issues in a more appropriate proceeding." The new proceeding is R.11-10-023.

5.B.2 Background of BVES RA Proceedings

When the CAISO filed with FERC for approval of pre-MRTU tariff changes to implement the CPUC's RA program, BVES filed a protest at FERC to which the CAISO agreed that the CPUC had not yet established an RA program for BVES. FERC then ruled that the CAISO should treat all entities the same and should, therefore, impose an Interim Reliability Requirements Program (IRRP) for BVES under the CAISO tariff.[40] In a subsequent order, FERC provided a means to identify such a program until the CPUC developed an RA program for SMJUs.[41] The CPUC placed BVES issues in Phase II Track 3 of its 2009 RA proceeding, but that phase was ultimately deferred and the proceeding closed. The CPUC has delayed resolution in the current proceeding, R.11-10-023, and therefore BVES RA requirements will likely be postponed until further notice.

BVES complies with the FERC ruling and the CAISO Tariff by following these key provisions:

- BVES closely mirrors the State's monthly coincident peak demand calculation and provides the data to the CEC.[42]
- BVES treats the Bear Valley Power Plant (BVPP) as a distributed generation resource because the BVPP is not under a PGA and is behind the CAISO metering point. Such treatment effectively reduces BVES' monthly peak demand, thereby reducing BVES' capacity procurement obligation.

To comply with the current CAISO tariff, BVES follows a procurement obligation determination that is the functional equivalent to the program adopted by the CPUC for its jurisdictional LSEs. Beginning in early 2012, BVES began working with the CEC to count some of the BVPP capacity towards its RA obligation as a behind-the-meter resource. The CEC has calculated the BVES procurement obligation as presented by BVES, and the CAISO has accepted those values. Notwithstanding the absence of CPUC-specific RA program rules for BVES, BVES does not expect the CPUC to impose substantively different requirements should the CPUC ever adopt RA program elements particular to the company.

The current CAISO tariff applies default RA demonstration requirements on BVES through BVES' scheduling coordinator. BVES will continue to procure its obligation plus 15 percent reserve margin, as do other RA-obligated entities. The annual and monthly demand forecast submitted to CAISO for BVES will use the coincident-peak demand forecast calculated by the CEC. The CEC-calculated demand forecast, adjusted to account for the BVPP, is submitted to the CAISO for compliance purposes.

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[40] *California Independent System Operator Corp*, Order Accepting Tariff Revisions, as modified, FERC Docket ER06-723-000, 115 FERC ¶ 61,172 at P 48 (May 12, 2006).

[41] *California Independent System Operator Corp.*, Order on Rehearing, Clarification, and Compliance Filing, Docket No. ER06-723-001, *et al*., 118 FERC ¶ 61,045 at P 32 (Jan. 22, 2007).

[42] The CEC reviews this data and provides to BVES a procurement obligation value consistent with the treatment provided to other CPUC-jurisdictional LSEs.

To the extent that BVES is deficient in its capacity procurement, and the CAISO experiences an aggregate capacity shortfall for the same period, the CAISO would allocate backstop procurement to BVES in proportion to its shortfall. If there is no aggregate shortfall, CAISO would not undertake backstop procurement. In the unlikely event that the CAISO finds BVES' capacity procurement to be deficient, CAISO can inform the CPUC of BVES' deficiency which could be the subject of an enforcement action, although the basis for such enforcement action against BVES is not defined at this time.

Pending the adoption of a CPUC decision establishing RA requirements specific to BVES, and consistent with the current CAISO Tariff RA provisions, BVES is not subject to direct penalties for non-compliance with the RA procurement obligation. However, there are potential cost allocation mechanisms under the CAISO Tariff's CPM that apply to all LSEs.[43]

5.B.3 Calculation of RA for BVES

BVES has an RA procurement obligation that is established under the CAISO Tariff's default RA provision. The calculation of this obligation begins with BVES providing its previous year's historical annual load shape, year-ahead annual forecast, and BVPP output to the CEC who in turn issues to BVES its coincident peak demand level. Because BVES is a winter-peaking utility and has its summer peaks on holiday weekends, BVES' contribution to the CAISO system monthly coincident peak loads is insignificant because of the BVES system load timing diversity with CAISO.

For planning purposes, BVES assumes that its RA procurement obligations are as defined by the CAISO Tariff default provisions, which parallel the CPUC's program for jurisdictional LSEs; therefore, BVES plans for RA requirements equal to 115 percent of the CEC determined monthly coincident forecasted load. BVES has purchased RA capacity from Shell Energy North America as part of its long-term PPA to meet these RA obligations.

[43] Specifically, CAISO Tariff sections 40 and 43.

Table 5.1 illustrates BVES' forecasted RA requirements.

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Adjusted Coincident Factor Net BVPP (MW)	0.809	0.627	0.794	0.754	0.638	0.767	0.702	0.698	0.655	0.815	0.557	0.863
Adjusted Coincident Peak Demand (MW)	28.79	20.20	22.27	18.48	16.54	17.12	19.64	17.32	18.35	18.97	17.58	32.45
Adjusted 15% Reserve (MW)	4.32	3.03	3.34	2.77	2.48	2.57	2.95	2.60	2.75	2.85	2.64	4.87
Capacity Obligation w/15% reserve (MW)	33.11	23.23	25.61	21.25	19.02	19.69	22.59	19.92	21.10	21.82	20.22	37.32
Dispatchable DSM (MW)	8.98	8.98	8.98	8.98	0.19	0.19	0.19	0.19	0.19	0.19	8.98	8.98
Net Capacity Obligation (MW)	24.13	14.25	16.63	12.27	18.83	19.50	22.40	19.73	20.91	21.63	11.24	28.34
RA Contract (MW)	24.00	20.00	16.00	8.00	18.00	19.00	18.00	17.00	17.00	19.00	15.00	31.00

Table 5.1: BVES Forecasted Resource Adequacy Requirement

In December 2011, BVES issued a Request for Proposal (RFP) for RA for the period December 2013 through December 2017. BVES received bids from four suppliers. The RA contract was awarded to Shell and began in March 2015 for a term of 59 months.

5.B.4 Local RA Capacity

The CAISO will allocate responsibility for Local Capacity Area Resources to Scheduling Coordinators for Load Serving Entities and may procure Local Capacity if the CAISO determines there is a capacity deficiency within a Local Capacity Area. A deficiency in Local RA Capacity can occur because individual LSEs do not demonstrate sufficient procurement from local resources for twelve months in the Annual Resource Plans submissions or, notwithstanding sufficient compliance with LCR procurement obligation, because the CAISO determines a collective deficiency of local capacity in a LCA due to the effectiveness factors for the procured units. It should be noted that the CAISO does not consider the BVPP to be eligible as a Local Capacity Resource since it is not a participating generator in the CAISO system.

If required, the CAISO will make supplemental procurement for RA under the capacity procurement mechanism (CPM) provisions of its tariff described above. As detailed in the CAISO Tariff,[44] the CPM costs associated with the procurement of LCR will be allocated proportionately to all deficient LSEs within each Transmission Access Charge (TAC) Area, or in the case of a collective deficiency of local capacity, to all Scheduling Coordinators that serve load in the TAC Area. BVES' load is considered to be within the SCE TAC Area (LA Basin) by the CAISO.

[44] CAISO Tariff Section 43, Capacity Procurement Mechanism.

The CAISO has determined that BVES' 2015 portion of the load within this area is 12.05 MW. Although BVES is not within any specific LCA,[45] the CAISO may allocate CPM cost to BVES because of local capacity shortages. BVES attempted to obtain a Local Capacity Resource in its latest RFP for RA (December 2011), but none of the proposals received included Local RA capacity.

Table 5.2 illustrates BVES' Local Capacity requirements.

Load Serving Entity	CPUC or Non-CPUC	SCID	PGE TAC SHARE	SCE TAC SHARE	SDGE TAC SHARE	PG&E TAC Area Total (MW)	SCE TAC Area Total (MW)	San Diego TAC Area Total (MW)	Total Local Need by LSE (MW)
Bear Valley Electric Services	NON	APXG	0.00%	0.11%	0.00%	**0.00**	**12.05**	**0.00**	12.05

Table 5.2: BVES Local Resource Adequacy Requirement

The current Shell contract offer provides System RA only; thus, BVES remains exposed to possible allocation of local reliability costs by the CAISO. To this end, BVES is evaluating this situation and may issue an additional RFP for a local SCE-area RA obligation.

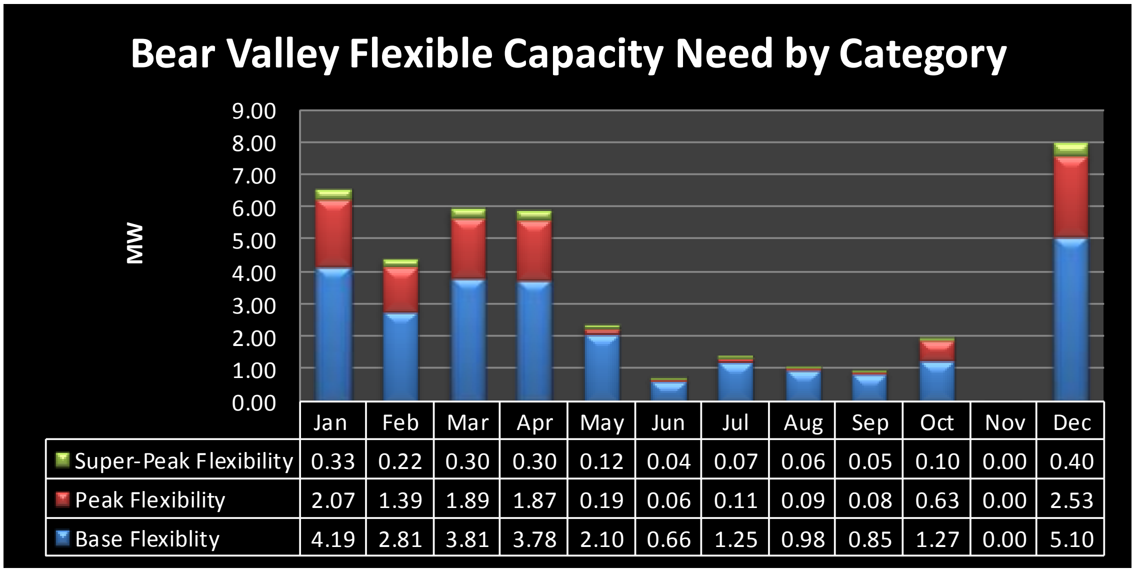
5.B.5 Flexible Resource Adequacy Capacity

Flexible capacity refers to resources that can ramp up and down, and start and stop quickly and multiple times per day. In June 2014, the CPUC issued a final decision to adopt firm flexible capacity obligations.[46] On August 1, 2014 the CAISO submitted tariff revisions with FERC to establish flexible capacity requirements.[47] FERC conditionally accepted the revisions with an effective date of November 1, 2014.

In addition to system and local capacity, BVES now has a CAISO tariff obligation to procure flexible RA resources. As noted above, the CPUC has yet to define BVES' RA requirement.

[45] BVES load does not reside within the "LA Basin" or any other Local Capacity Area as defined in the CAISO 2015 Local Capacity Technical Study.
[46] CPUC, *Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program*, Rulemaking 11-10-023 (June 27, 2013).
[47] *California Independent System Operator Corporation*, Order on Tariff Revisions, FERC Docket ER14-2574-000, 149 FERC ¶ 61,042 (October 16, 2014).

Figure 5.3 illustrates BVES' Flexible Capacity Requirements.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	0.33	0.22	0.30	0.30	0.12	0.04	0.07	0.06	0.05	0.10	0.00	0.40
Peak Flexibility	2.07	1.39	1.89	1.87	0.19	0.06	0.11	0.09	0.08	0.63	0.00	2.53
Base Flexiblity	4.19	2.81	3.81	3.78	2.10	0.66	1.25	0.98	0.85	1.27	0.00	5.10

Figure 5.3: BVES Flexible Resource Adequacy Requirement

BVES is evaluating this situation and may issue an additional RFP for flexible RA resources.

5.C Energy Efficiency and Demand Response

The California legislature and CPUC both require that utilities manage their need for generation resources by first making an effort to reduce the need for supply.[48] While CPUC decisions and recent legislation do not specifically reference BVES, BVES continues to promote the benefits of reduced consumption. Often the lowest cost supply is obtained by convincing customers to use less energy while still providing the same level of service to the customer. As a result, the CPUC's procurement policy includes a provision requiring that IOUs implement programs that will reduce the customer's need for energy (energy efficiency) and capacity (demand response). These customer oriented programs can take many forms and, together, are referred to by BVES as Demand Side Management (DSM).

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

> "In Decision (D).04-09-060, the Commission articulated its goal to pursue all cost-effective energy efficiency opportunities in support of the Energy Action Plan commitment that conservation and energy efficiency are first in the "loading order" of electricity and natural gas resources. In accordance with this overarching goal, D.04-09-060 established short- and long-term numerical

[48] AB 2021, Levine, Chapter 734, Statutes of 2006, and the CPUC's D.04-09-060.

> targets for electricity and natural gas savings. We stated that these targets must be aggressive and must stretch the capabilities and efforts of all those involved in program planning and implementation."

The loading order referred to in the CPUC decision immediately above is described as follows. Energy efficiency and demand response are top priorities for meeting California's energy needs. Next, the loading order calls for cost-effective renewable resources and distributed generation. Only after that should conventional energy resources be used to meet load.

The two basic forms of DSM are energy efficiency, which entails using less power to do the same job, and demand response, which modifies energy usage when needed for optimal grid operation. BVES' DSM programs are vital components in managing local system peaks and transmission constraints in the winter. The programs also contribute to reducing the CAISO peaks in the summer months.

BVES collects funds through its Public Purpose Program Charge to fund its DSM programs.[49] The Public Purpose Program Charge utilizes one-way balancing account treatment over the implementation cycles which allow carryover spending between years up to the total of the GRC cycle budget. This allows BVES to manage its programs over a longer timeframe.

5.C.1 Residential and Commercial Energy Efficiency

BVES' Residential Energy Efficiency Program offers lighting and high efficiency appliance rebates. Residential customers can exchange old incandescent light bulbs for new, energy efficient compact fluorescent light bulbs, or CFLs. After the inventory of CFLs is exhausted, BVES will continue the lighting exchange program but offer highly efficient LED bulbs instead of CFLs. Regarding appliances, BVES offers rebates for Energy Star labeled refrigerators, room air conditioners and high efficiency electric hot water heaters. Through its website, BVES offers energy saving tips, and an energy usage calculator that estimates an appliance's energy usage and costs.

For commercial customers, BVES offers rebates for lighting improvements including florescent lighting retrofits, specialty screw-in lamps, low wattage T8 lamps, exterior linear fluorescent fixtures, LED exit signs, occupancy sensors, time clocks and more. In addition, BVES encourages local businesses to seek innovative, energy efficient technologies. The 2015 Commercial Energy Efficiency Grant Program awards up to $10,000 in grant funding to help businesses improve their energy usage and lower their electric bill.

Regarding BVES' lighting load, it should be noted that this load is highly correlative with BVES' peak demand. Energy efficient lighting results in a significant peak

[49] The programs include Low Income Energy Efficiency (LIEE), Energy Savings Assistance (ESA) and California Alternate Rates (CARE).

demand benefit. BVES' unique peak demand time is between 4 PM and midnight from November 1st through February 28th.

5.C.2 Energy Savings Assistance (ESA) Program

The ESA program, funded through the Public Purpose Program Adjustment Mechanism, is available only for qualifying low income residential customers. The ESA Program provides funding for energy efficient refrigerators, hard-wired compact fluorescent fixtures, compact fluorescent bulbs, LEDs, smart strip surge protectors, low-flow showerheads and weatherization measures. BVES also provides educational materials to all customers promoting the use of energy efficient appliances, weatherization materials, thermostatic controls, and life style changes.

5.C.3 Demand Response

The one DR program currently offered by BVES targets its four largest customers through a time-of-use (TOU) interruptible tariff, first approved in its 2009 GRC.[50] This tariff provides a lower rate in exchange for the customer's agreement to interrupt or reduce load when called upon by BVES to do so, even to a zero load. This DR program currently provides approximately 12 MW of coincident winter demand reduction that can be called upon during BVES' highest peak demands. As discussed in Section 5.E, BVES is considering additional demand response programs that will target electric hot water heaters and spas and that may result in up to 3 MW of demand reduction.

5.D Possible Rate Proposals That May Affect Resource Procurement

In its forthcoming 2017 General Rate Case (GRC) Application, BVES may request approval for several new rates and initiatives, including a rate to support economic development, rates for electric vehicle (EV) charging stations, and additional TOU rates.

5.D.1 Economic Development Rate

A new rate that seeks to attract new businesses to its service territory is intended to help improve the BVES load factor, which is beneficial to all customers. Thus, a properly designed economic development rate reduces the overall average electrical rate.

The Economic Development Rate (EDR) may be similar to rates implemented by San Diego Gas & Electric, Southern California Edison and Pacific Gas & Electric to attract business and help increase kWh sales throughout their respective territories.

From Southern California Edison's Schedule Interim EDR-E:

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[50] Rate Schedule A-5 TOU.

> Unless provided herein, or in the Interim Economic Development Rate Agreement, all charges and provisions of the customer's Otherwise Applicable Tariff (OAT) shall apply, except that the customer's total bill shall be subject to discount as follows:
>
> 1. STANDARD: 12 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.
>
> 2. ENHANCED: 30 percent off the Customer's bill calculated based on the rate components comprising its OAT (excluding the generation service cost component unless that service is provided by SCE) for purchases of electricity (demand and energy) over the five-year term of this Agreement.

BVES may seek to implement a similar discount that could be available to three types of commercial customers:

- Expansion Customers – Customers that have plans to expand their load at their current site, and would be unable to expand their load given their current rate tariffs.
- Attraction Customers – Customers with plans to move their business to BVES' territory, and would be unable to move their load given our current rate tariffs and new business cost implementation.
- Retention Customers – Customers that are unable to retain businesses in Big Bear due to the high expenses to operate in BVES' territory.

5.D.2 Electric Vehicles and Related Rate

An effort to provide BVES customers with personal vehicle choices is to install electric vehicle charging stations at various locations in its service territory. With the decreased cost of electric and plug-in hybrid vehicles, there has been an increase in sales of these types of vehicles. Such a program could accommodate BVES' own customers and visitors to the Big Bear valley that own EVs and plug-in hybrids. Charging stations may be designed to encourage off peak usage, which will improve the BVES load factor and thus reduce costs to all customers. Even at peak periods, the added sales should benefit all customers, as contracts are more fully utilized and fixed charges are effectively reduced by added sales.

The CPUC allows utilities to own electric-vehicle charging infrastructures, noting that utilities will help procure, deliver, and supply electricity for plug-in electric vehicles.[51] BVES is actively monitoring and may participate in the proceeding.

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[51] D. 14-12-079

While there are multiple types of charging stations available, BVES is considering three types for installation in its service territory:[52]

- Eight-hour charging stations - Usually meant to be installed at residential homes.
- Level two charging stations - Can be public charging stations and would require an average of 1 hour of charge time for 25+ miles.
- Level three (fast-charging) stations - Can be public and would require an average of 30 minutes of charge time for 80+ miles.

With the installation of EV charging stations, customers could have 3 options available for electrical usage payment:

- Tie their usage to their existing BVES account and pay when they receive their utility bill at the end of the month.
- Pay at the charging station kiosk with a credit card.
- Charge at their residence and have the usage tied to their account automatically.

After sufficient studies have been conducted, BVES may apply for a separate rate tariff for EV charging stations as well as installation of sub-meters for all BVES EV customers. As a result, non-BVES customers charging at an EV station may be charged under a BVES pre-determined rate structure plus a convenience fee. The EV rate structure may be designed as a pass-through rate and not burden the customer installing the charging station on their commercial property. However, existing BVES customers may have a choice of paying through the previously mentioned method or have their EV-incurred charges added to their next monthly bill. Any related additional charges/convenience fees may be divided by the customer and BVES to cover the costs of parking leases for the charging stations and to fund the EV Pilot program.

The SCAQMD is finalizing plans to install two EV charging stations using a grant program funded by NRG settlement with California, for Los Angeles, Orange, and San Bernardino counties. These stations would be located in the Village retail district, the main hub for entertainment for Big Bear Lake. Tesla Motors has already made plans to install a charging station in Lake Arrowhead, within 20 miles of BVES service area. Both of these initiatives will help jump start the EV charging station trend in Big Bear Lake. With the proposed development of new charging stations in 2019 funded by the proposed BVES capital budget, the trend should continue and Electric Vehicle driven sales growth should increase for BVES.

[52] Source: http://www.chargepoint.com/stations/

5.D.3 Time-of-Use Rate

For small to medium commercial customers, BVES is also considering a voluntary TOU (Time-of-Use) rate.[53] With the current hourly breakdown set in place by BVES' hourly load research data, the voluntary rate schedule may mimic a similar type of time structure and therefore may require participants to shift their load from On-Peak hours (5:00 pm to 10:00 pm) to either Mid-Peak or Off-Peak hours to see any beneficial savings in their electricity bill. With enough participation, electrical demand will be shaved off the system at its most needed level.

Below is a typical TOU rate structure from Southern California Edison as well as a hypothetical tier structure based on BVES' TOU hours.

Typical TOU rates (SCE rates)[54]

Summer	Winter
On-Peak (Noon to 6pm) (Weekdays, excluding holidays)	
$0.19215 / kWh	
Mid-Peak (8am to Noon and 6pm to 11pm)	Mid-Peak (8am to 9pm)
$0.15897 / kWh	**$0.13834 / kWh**
Off-Peak (All other hours)	Off-Peak (All other hours)
$0.13690/ kWh	**$0.12987 / kWh**

[53] Rate Schedules A-1 to A-3.
[54] Rates are based on Southern California Edison's Schedule TOU-GS-1 (effective 01.01.16)

BVES TOU Rates (Hypothetical)
Rates Ranked from 1 (most expensive) to 6 (least expensive)
to Reflect BVES Average Hourly System Energy Cost Differentials

Summer	Winter
On-Peak (10am to 6pm) (Weekdays, excluding holidays)	On-Peak (5pm to 10pm) (Weekdays, excluding holidays)
3	**1**
Mid-Peak (7am to 4pm)	Mid-Peak (6am to 5pm and 10pm to Midnight)
5	**2**
Off-Peak (All other hours)	Off-Peak (All other hours)
6	**4**

The above hypothetical TOU rate structure would only be offered as a voluntary program to commercial customers willing to adjust their load usage during on-peak hours of the day.

5.E Capital Projects and Other Major Initiatives

BVES is acting upon or considering the following capital investment projects and other major initiatives, furthering its goals to mitigate service interruption, obtain least-cost supply, support load growth while reducing energy costs for all customers, comply with the 50% RPS by 2030, significantly reduce carbon emissions, and promote efficiency for the customer.

- Install 3 MW DC (2.7 AC) of solar capacity at the recently capped local landfill
- Continue energy efficiency programs to replace inefficient lighting, targeting the residential customers.
- Offer load control/demand response incentives for cycling of spa and electric hot water heaters. This is estimated to provide up to 3 MW of peak capacity via reduced demand during peak hours.
- Expand service at Mammoth Resorts' Snow Summit ski resort for snowmaking. The expansion should result in an additional 13 MW capacity serving Snow Summit.
- Offer economic development incentives for select industries moving into the area for a 5-year time period which may add summer load and year-long load.
- Launch a pilot project to test the adoption of electric vehicles by BVES customers and/or visitors with 4 charging stations.
- Analyze the cost benefit of implementing up to 5 MW of utility owned solar projects on customer property using a lease payment option to compensate the owner of the land utilized by the solar project.
- Analyze the costs and benefits of acquiring up to 5 MW of stored energy capacity to balance system load, reducing energy costs for all customers.

Figure 5.4 itemizes the potential benefits of some of the above-listed capital projects. This analysis was performed over the last two years and will be expanded to include all of these initiatives in a future IRP.

A description of each of the proposed initiatives and anticipated benefits follows.

2018-2024 Average Benefit Per Year	Energy Cost Savings Shared 1	Emission Reductions Value 2	Reduced Average Fixed Cost Savings 3	Direct Customer Savings 4	Customer Benefits 5
Economic Development Rate	$430,748	$0	$181,883	$199,387	$812,019
Electric Vehicle	$197		$0	$21,171	$21,368
Mammoth Substation Expansion 13 MW	$416,390	$192,342	$2,371,275	$642,296	$3,622,302
Efficiency Program Continued	-$6,448	$1,923	$188	$40,670	$36,332
Net Metering 6	$69,982	$22,756	-$199,490	$917,818	$811,065
2.7 MW Solar	$710,475	$72,738	$0	$0	$96,970
Total Benefit	**$1,621,342**	**$289,759**	**$2,353,856**	**$1,821,342**	**$5,400,056**
1) Reduced all-in energy costs serving all customers due to asset purchase or program implementation.					
2) Reduced carbon emissions valued at California and Canada GHG carbon allowance trading program.					
3) Fixed costs divided by energy sales decreases due to higher sales, reducing future rates.					
4) For net metering, efficiency, and Mammoth substation expansion, there are savings to select group.					
5) Sum of categories 1 to 4.					
6) Net Metering reduces kWh usage and therefore increases the fixed cost per kWh in future rate designs.					

Figure 5.4 Benefits of Potential Projects

Energy Efficiency (Lighting)

Energy efficiency programs not only reduce sales relative to end-use service, saving the customers implementing the efficiency change directly, but also produce savings to other customers not participating in the program. An efficiency program shaves the load during heavy usage hours, reducing capacity charges, and also creates energy savings by levelizing the load which allows for better fitting of contracts and reduced imbalances in scheduling. BVES analyzed a proposed targeted efficiency program for lighting bulb change-out in the residential sector to determine the impact of the program on the system load shape and to all customers in average energy costs. Also studied was the carbon pollution reduction, which is valued using the carbon allowance prices in California.

The lighting efficiency program was considered based on the results of the energy appliance saturation survey for the residential sector. The survey for BVES' residential sector is available on the BVES website for customers to take on a voluntary basis with a random drawing bi-weekly for rewards. Based on 200 results of the survey, viewing the lighting fixtures installed in homes, it was determined that a lighting retrofit program issuing 9 watt LED bulbs in place of 40+ watt bulbs for residential customers would involve replacing 47% of the sector group. This would involve changing out 140,402 bulbs in the service sector. Because there is already an administration function in the existing efficiency program and this program would add only the cost of the 9 watt bulbs, BVES estimates that at $5.40 per 9 watt bulb, the incremental efficiency program expense would be $765,189. This expense could be spread over ten years and blended into the existing efficiency program and funded by a new public purpose program. The expenses could be deducted from the gross energy cost savings to all customers in order to derive a net energy cost savings of the program. Also calculated would be the direct benefit to participating customers, the emission reduction value, and the reduced average fixed cost created by the additional capacity of 1.6 MW at peak time periods.

The lighting efficiency program could net $36,322 per year total annual benefit for all customers. An additional benefit could be the avoided cost of adding 1.6 MW to the BVES system to service the load for all customers. By reducing the capacity requirement by 1.6 MW and assuming the gas fired generation cost of capacity of $750,000 per MW, the efficiency program could allow BVES to use the efficiency gain in place of an added 1.6 MW capacity in reserve, saving BVES $1,200,000 in asset purchase with an estimated annual savings of $103,000. With a combined benefit of $139,322 per year, an added residential lighting efficiency program replacing 40+ watt bulbs with 9 watt LED bulbs appears to be an attractive program.

In addition, the 1.6 MW of shaved load through efficiency could be viewed as a 1.6 MW hedge on price spikes. If prices are extremely high and load on the system is above the amount hedged by physical assets or contracts, the reduction in load of 1.6 MW would allow BVES to reduce system average costs by avoiding the 1.6 MW per hour purchase.

Energy Efficiency (Water Heater and Spa Cycling)

The demand response program for water heaters and spas could add up to 3 MW of capacity for winter time which provides added system reliability. With the possible 13 MW Mammoth substation expansion and the existing 12 MW of interruptible load currently available during winter time, it may be beneficial to have the added 3 MW of scheduled interruption (demand response) available to BVES in order to facilitate the snowmaking load without interruption for Mammoth. The water heater and spa load cycling would be on a 15-minute interval for residential and commercial customers volunteering to be on the program, with incentives at a rate to be determined.

The added 3 MW extension of interruptible load plus the 12 MW of existing interruptible load would benefit BVES in extreme load spike conditions where all available resources are needed to meet firm load. One indicator of value of the additional 3 MW of reserve capacity through the load control program would be the incremental cost of gas fired generation capacity at $750,000 / MW multiplied by the 3 MW of load interruption capability. This would equate to a $2,250,000 purchase, with a potential for annual savings of $193,500 per year. Another view of value would be the avoided cost of an expensive power purchase up to 3 MW in the day-ahead or real-time market during a spike in the CAISO. In other words, the demand reduction program through load control could add 3 MW to price hedging for BVES.

Mammoth Substation Expansion (13 MW)

BVES and Mammoth Resorts, the new owners of the Bear Mountain and Snow Summit ski resorts, are planning a 13 MW expansion of service at Snow Summit to the same level of service as Bear Mountain for snowmaking. The expansion will be in addition to the current 2.5 MW of substation capacity serving Snow Summit. The additional electric supply would displace the diesel snowmaking equipment currently used by Snow Summit. The diesel engines would remain as a backup if BVES has to interrupt supply to the ski resort, which is not anticipated in the base case and is only likely given a major supply interruption to BVES such as an SCE transmission interruption of a failure in the BVPP engines. This interruption option would be acceptable because Mammoth Resorts currently is an A-5 primary customer with 100% of load interruptible.

The substation expansion of electric service is forecasted to yield energy savings for Snow Summit. Benefits include reduced expenditure on energy and the emission allowance payments avoided by using BVES instead of diesel. All BVES' customers would benefit from the cleaner environment and the reduced average cost of electricity resulting from an increase in sales using the same level of existing capacity for the system. Mammoth would pay for the substation expansion via a proposed added facilities charge.

Possible Economic Development Initiatives

Viewing Appendix G, one can see that capacity over 19 MW out of the total of 47.4 MW available is utilized less than 25% of the time. This under-utilized capacity adds to the average cost of power, as the fixed charges have to be recovered across a relatively small amount of kWh.

By attracting summer load and year-long load into the area, BVES could reduce the average cost of power. BVES could target the following industries in the BVES area by offering significant savings for a limited time period for these select industries moving into the area.

- New entertainment options
- Summer amusement park
- High altitude athletic training center
- Extension of college system
- Condo base for Mammoth resorts
- County fair festival events in summer

The added sales due to new industries could leave the revenue results neutral; therefore, added sales could pay the cost of a discount. Refer to Section 5.D.1 for information about a potential Economic Development Rate.

BVES added these potential customers' load to the existing load to test the impact of new loads attracted through economic development rates. These loads totaled 800,000 kWh per year. These potential new customers combined use of 56,000 kWh in the winter and 88,000 kWh in the summer would help to increase the load factor of the system. The result of attracting new industry in the BVES service area could be reduced average energy costs of $437,748 per year in energy cost savings for all customers and $181,883 in average fixed cost reduction due to increased kWh sales. The new customers could receive discounts of $197,387 per year. Total benefit to all customers could be $812,019 per year.

Electric Vehicle Charging Stations

With the growing adoption of electric vehicles in California, especially in the Los Angeles Metropolitan area, there have been requests by BVES customers for an electric vehicle rate for residential customers. This could require a sub-meter at the residence to avoid significantly higher electricity costs, due to electric vehicle charging pushing a customer to a higher tier structure. Although there could be significant effort required to install sub-meters and to plan for added load in pockets within the neighborhood distribution system, the added sales could increase the capacity utilization and could levelize the load shape to some degree as the usage of charging stations within the BVES service area increases.

The substitution of electric power for gasoline would certainly reduce carbon emissions for BVES and California. The added sales served by the same amount of capacity at BVES could decrease the average fixed cost for all customers and could have an effect of decreasing rates for all customers in the future. There could be a direct savings to customers using electric energy versus gasoline.

Because of these savings and the fact that many Los Angeles residents travel to the Big Bear Lake region, BVES is considering a pilot project to test the adoption of electric vehicles by BVES customers and/or visitors. Research is ongoing for BVES-owned EV charging stations. However, in the near future, the SCAQMD is partnering with the City of Big Bear Lake to install four charging stations located in and near the Village. BVES can gather important information from the SCAQMD/City project as it further refines its EV charging plan project analysis.

Utility Owned Solar on the Customer Property

BVES is currently analyzing the benefits of increasing utility solar production using customer property. Because of the scarcity of available property suitable for solar and the high cost, this may provide a more cost effective alternative to a traditional utility scale solar farm. BVES would first consider large projects of 5 MW or greater in order to reduce cost of solar panel installation. BVES would design leasing compensation to the customer for the land use. BVES is analyzing the benefits and rate design issues at this time. Results will be addressed in a future IRP.

Flow Battery Technology Application to BVES System Load

BVES is analyzing the technology application and benefits of flow batteries as a tool for shaping the system load. The benefits would be to increase BVES' overall load factor and therefore reduce capacity and average costs per MWh for BVES customers. More electric sales could be made with the existing capacity, which reduces the average fixed cost of electricity to customers. Also BVES would be able to fit more solar production into the resource mix, reducing energy costs and emissions, fulfilling RPS requirements, and reducing RA requirements. The risk of price spikes and load interruption would also be reduced using flow battery technology. BVES would also be able to better size fixed price contracts and minimize imbalances between resources and demand, thereby reducing energy costs. This technology will allow BVES to accommodate the substantial increase of renewable DG production by customers. BVES is working with a battery provider to size the system and to determine all costs and benefits. The results will be detailed in a future IRP.

Benefits Assessment of Potential Capital Projects

Each potential capital project and/or growth initiative was evaluated as follows:

- Reduction in total average system cost created by added volume and timing of sales relative to the existing load shape curve of the BVES system. A more leveled load shape more fully utilizes the baseload contracts, therefore reducing the average cost of power.
- Emission reduction measured in metric tons of carbon emission multiplied by the carbon allowance market price in the California and Canada GHG program forecasted by IHS-CERA.
- Reduction in fixed charges by taking total demand revenue divided by kWh sales. In turn, added sales reduce the rate requirement per kWh required to recover fixed charges. Added sales with the same transmission and distribution system and generation assets should reduce rate requirements in future rate cases.
- Direct customer benefit applies to customers in the program or substitutes electricity for more costly alternative fuel.
- The analysis for all the initiatives calculates the benefits and nets out the cost of the initiatives to determine net benefit on an average annual basis for 2018 to 2024.
- Each initiative promotes a cleaner environment.

5.F Greenhouse Gas Emissions

Assembly Bill 32 (AB 32), also known as the Global Warming Solutions Act, was signed into law in 2006. AB 32 established legislation to reduce the State's greenhouse gas emissions (GHG) to 1990 levels (427 million metric tons of carbon dioxide equivalent[55] greenhouse gases) by 2020 and set a path for further reductions by 2050.

More recently, in April 2015 Governor Jerry Brown's Executive Order B-30-15 established a reduction of economy-wide CO_2 emissions to 1990 levels by 2020. The CO_2 cap and trade program began on January 1, 2013 and the program linked with Quebec on January 1, 2014. This is the market link of policies with CAISO prices as the policy targets and the technology successes of electric generation cleaning technologies, along with the growth in demand for electricity in general, influence the market prices for Carbon Allowances, which directly impacts the CAISO power prices. Also note that as Canada makes CO_2 policies more stringent, this too will impact Carbon Allowance prices for California.

The California Air Resources Board (CARB), in consultation with other agencies (e.g., CPUC and CEC), was charged with developing a comprehensive program to ensure the AB 32 GHG emissions reductions goals are achieved. This resulted in CARB's development and 2008 adoption of the Climate Change Scoping Plan (Plan).

The 2008 Plan identified specific measures within each of the State's major economic sectors, which are a mix of market-based mechanisms, regulations, voluntary actions, and economic incentives aimed at achieving the AB 32 year 2020 GHG reduction goals. Several of the 2008 Plan energy sector measures have been developed into regulations.

Throughout CARB's development of the regulations, the applicability and compliance requirements have increasingly focused on higher emitting sources. Due primarily to low emissions from the Bear Valley Power Plant (BVPP), a peaking plant, BVES currently has very limited compliance obligations under the regulations developed as part of the 2008 Plan.

Every five years CARB is required to complete Plan updates to review the major economic sector measures and determine whether the State is on track to meet the GHG reductions goals. The Plan update builds upon the initial Scoping Plan with new strategies and recommendations; it also identifies opportunities to leverage existing and new funds to further reduce GHG emissions through strategic planning and targeted low carbon investments. The plan also notes the state's progress toward meeting the near-term 2020 GHG emission reduction roles defined in the initial Scoping Plan.

[55] "Carbon dioxide equivalent" or "CO_2 equivalent" or CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas (per § 95102 of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions).

The update, which was formally approved by CARB in May 2014,[56] focuses on nine areas that have overlapping and complementary interests that were selected to address issues that underlie multiple sectors of the state economy. The areas of focus envisioned by CARB to help achieve the 2050 GHG reduction goals include energy, transportation, agriculture, water, waste management, natural and working lands, short-lived climate pollutants, green buildings and the cap-and-trade program.

Should BVES acquire, construct or operate any additional electric generating resources (i.e. additional engine in the BVPP), it may increase its compliance obligations. It is BVES' understanding that if a generation resource emits less than 25,000 metric tons of carbon dioxide per year it does not have to participate in the Cap-and-Trade program.

Aside from any new BVES-owned generation assets being considered, any increase in GHG-related costs will be passed onto BVES via its wholesale energy purchases. Therefore, the costs of GHG and AB 32 requirements will be compared via the competitive bidding process that BVES undergoes when acquiring resources and entering into future power purchase agreements.

5.G Summary and Conclusions

In 2014, overall wholesale energy prices were approximately equal to competitive baseline price estimates modeled by CAISO under perfectly competitive conditions. Electricity prices were higher than they were in 2013, primarily due to a 17% increase in natural gas prices in 2014, but after normalizing for gas prices and greenhouse gas compliance costs, CAISO estimates that wholesale power prices were stable, increasing just three percent in 2014 compared with 2013.

In 2014, BVES purchased approximately 85% of its firm energy requirements through fixed priced contracts, with the remaining 15% in the day-ahead market. Average real-time prices tended to be lower than day-ahead prices, continuing a trend that began in 2013, partly attributable to a drop in real-time price spikes compared to prior years.

Unless regulatory authorities make significant revisions to the RA policy, BVES will continue to meet its RA obligation under the CAISO Tariff based on its contribution to monthly CAISO coincident peak load and will offset its peak with the use of the Bear Valley Power Plant as a distributed-generation, behind-the-meter resource. Local RA and Flexible capacity requirements will remain an area of focus for BVES. Under the CAISO Tariff, BVES may be allocated its share of Local and Flexible RA costs if the CAISO must procure additional resources to resolve an issue on the CAISO grid.

BVES continues to promote the benefits of reduced consumption, in line with state goals and regulatory policies. BVES' DSM programs are vital components in managing

[56] See the full update at
http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf
(Note: CARB's link says "2013" but the update was issued May 2014.)

local system peaks and transmission constraints in the winter. The programs also contribute to reducing the CAISO peaks in the summer months.

BVES currently offers residential energy efficiency programs, mainly through lighting programs, rebates for efficient appliances, and a low-income program that funds energy efficient items for homes. The one demand response program currently offered by BVES targets its four largest customers through a time-of-use (TOU) interruptible tariff. BVES is considering additional demand response programs that will target electric hot water heaters and spas and that may result in up to 3 MW of demand reduction.

BVES may request approval for several new rates and initiatives, including a rate to support economic development, rates for owners of electric vehicles (EVs), and additional TOU rates. BVES may also pursue various capital projects, furthering its goals to mitigate service interruption, obtain least-cost supply, and support load growth while reducing energy costs for all customers. The projects include new BVES-owned renewable generation (solar), the Snow Summit substation expansion, and EV charging stations.

6. Power Supply Costs

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

The greatest change in the wholesale markets has been the sharp decline in natural gas prices due to a maturing of the production methods for natural gas (hydraulic fracturing, or "fracking"). Meanwhile, the demand for gas has increased due to coal driven power plant retirements, growth in the US economy as a whole and especially in the petro-chemical and primary metals industry, increases in exported LNG, and increases in exported pipeline gas to Mexico. Hydro production plunged below 50% of normal production in Northern California, also boosting the demand for natural gas. Renewables in California provided relief to reduced hydro production. Intermittency of renewables production will continue to challenge the CAISO markets as gas fired generation with fast ramp-up capabilities are required to follow the renewable production declines. Careful planning will pay off significantly in mitigating the supply cost exposure due to market price volatility during these uncertain times.

6.A Forecast of Power Supply Costs

Baseline simulations of power supply costs for the period 2015 – 2024 were performed under various assumptions, including:

- BVES entered into a new baseload purchase for 12 MW of energy beginning January 1, 2015
- BVES entered into a new seasonal energy purchase beginning January 1, 2015
- BVES meets a majority of its renewable obligations with RECs
- Any daily imbalances are either purchased or sold through the CAISO market
- BVES is required to enter into a new RA contract by early 2020 as the proposed RA contract expires, facing significantly higher costs for capacity by 2020 since California reserve margins may drop below 15% unless additional resources are brought on line, stimulating higher capacity prices and therefore, higher RA prices, in the power market
- The physical cap and seasonal baseload products expire December 2017, and the annual contract expires in November 2019, leaving BVES exposed to price spikes and potentially rising power prices
- BVES addresses this price exposure by renewing annual base load contracts of 12 MW and renewing seasonal contracts but differentiating peak and off peak periods at varying volumes to optimize coverage and minimize imbalances in the market.

- BVES pursues a solar project of 2.7 MW (AC) of capacity
- BVES uses economic development rate, electric vehicle pilot program, time of use rate, energy efficiency lighting program, and demand response program to optimize load patterns to achieve higher load factor

These costs are included in the power supply forecast, which assumes BVES meets its energy requirements net of solar production with “brown” energy and then “greens it up” with purchases of RECs to meet RPS goals.

In effect, the baseline simulation identifies BVES’ power supply costs if BVES acquires additional resources for the period late 2015 through late 2019.

Since the inception of the CAISO market, BVES has been able to meet its monthly short positions with Day-Ahead purchases. The price BVES pays for short positions is the Locational Marginal Price (LMP) at the default SCE load aggregation point and is calculated and published by approximately 1:00 PM the day before power flows.

It is not anticipated that BVES will exercise the physical call-option often under the base case scenario. However, under a scenario that assumes extreme weather, high economic growth or interruption of supply (electric transmission or gas pipeline outage, or generation outage), which has led to frequent congestion occurrences and price spikes, the call option would likely be utilized. Therefore, the price protection provided though the physical call option would be more valuable in protecting against any unanticipated price spikes in the market. BVES used the Black Scholes model, along with the current market data on prices and implied volatility, to assess the market value of call options with varying strike prices and premiums in order to determine a fair price for the call option. However, it is the protection from any unforeseen occurrence(s) that provides value of the call option beyond what the analytics alone can provide.

The power supply simulation shows that, at least from late 2019 to 2024, there will be a need for price protection; annual and seasonal baseload contracts will provide this protection. As BVES’ new firm contracts are anticipated to expire late 2019 at the same time as reserve margins in the California market may drop below 15% and natural gas prices and renewable power supply continue to grow over the forecast horizon, electricity and capacity prices are anticipated to increase, potentially creating price spikes in the energy and RA capacity market. The result is significant increases in energy and non-energy price components, which will affect supply costs for BVES.

BVES will pursue energy and capacity products to mitigate this potentially significant price increase from late 2019 to 2024. It should be noted that the cost analysis shown in this section is for the base case only. This case is one of many analyses performed to test strategies against uncertainties in the weather, economy, and economic development in the BVES service area. The costs illustrated represent the mid-range of supply costs BVES can expect for this planning cycle.

The results of the power supply simulation are summarized in Table 6.1.

Year	Nominal	Net Energy	Average Energy Cost per MWh	Other Delivery Charges per MWh	TOTAL All-In Cost per MWh	Total Power Supply Cost
2015	Annual	150,616	$44.96	$27.28	$72.24	$10,881,114.31
2016	Annual	152,834	$45.36	$28.57	$73.92	$11,298,119.84
2017	Annual	150,495	$46.91	$31.64	$78.55	$11,822,028.83
2018	Annual	150,387	$47.11	$32.76	$79.87	$12,010,765.42
2019	Annual	155,000	$47.65	$30.98	$78.63	$12,187,774.79
2020	Annual	159,625	$46.92	$30.28	$77.20	$12,323,162.55
2021	Annual	159,238	$49.64	$31.48	$81.12	$12,917,490.80
2022	Annual	157,857	$50.13	$31.75	$81.88	$12,925,740.57
2023	Annual	156,905	$50.42	$31.95	$82.37	$12,923,667.21
2024	Annual	156,468	$52.29	$32.05	$84.34	$13,196,159.67

Table 6.1: Base Case Forecast of Power Supply Costs (Nominal)

Figure 6.2 illustrates the growth in total power supply costs over the forecast period.

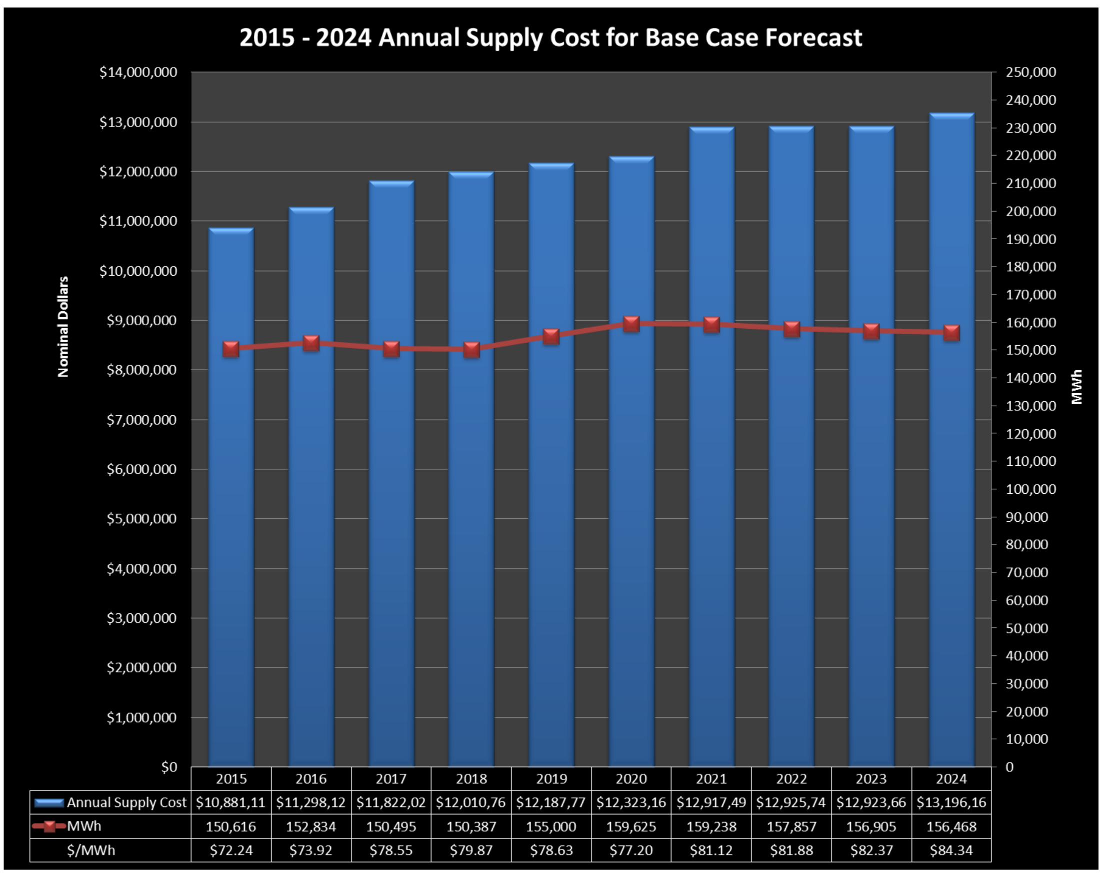


Figure 6.2: Forecasted Total Power Supply Costs (Nominal)

The initial analysis identified some of the important planning issues facing BVES in the coming years:

- BVES may continue to procure approximately 75 percent or more of its annual energy requirements and provide long-term cost stability.

- BVES will hedge the remaining portion of its energy requirement through a physical call option with price cap, a possible 2.7 MW solar project, and the 8.4 MW existing gas fired generation fleet with higher heat rate (12,500 btu / kWh) or a combination thereof.
- BVES may also use demand response of water heating and spa cycling programs to shave 3 MW of peak load for price hedging and load control.
- BVES will strive to improve on next-day forecasts in order to optimize the use of the day-ahead and real-time markets.
- BVES will strive to improve on long term forecasts to improve on shaping and sizing long-term fixed price contracts and in structuring call options.
- Renewal plans for future contracts (2019 and beyond) may begin in 2016, in an effort to minimize the price increases and potential spikes anticipated in the future. Sellers of long term fixed power contracts are likely to provide better pricing given the downside risk in gas prices and the surge in productivity in the renewables market.
- BVES has left headroom between the anticipated energy requirements and the hedged requirements in anticipation that efficiency gains, flow batteries or other storage technology, and Distributed Generation load are likely to recondition the system load and bring the BVES load requirement at or below the hedged volumes.
- BVES will pursue the valuation of the use of energy storage/batteries and solar production in BVES' service territory to hedge against price spikes and to capitalize on arbitrage opportunities, gaining funds in order to reduce the overall cost of supply for customers.

6.B SCE Transmission and Distribution Charges

After energy costs, BVES' largest cost component of total power supply costs is transmission costs. BVES pays SCE for transmission service on three SCE 33 kV lines that deliver power up the mountain to BVES, and for SCE wholesale distribution access tariff (WDAT) service (for service from SCE's Victor Substation near Victorville to SCE's Cottonwood Substation in Lucerne Valley and from SCE's Vista Substation to SCE's Zanja Substation near Redlands). BVES also pays the CAISO for transmission of energy imported into and through California. Together these transmission charges are approximately $2,900,000 annually.[57]

Currently, BVES is charged on a monthly basis for four different uses of SCE's non-CAISO grid. The four different categories of monthly charges for transmission and wholesale distribution services from SCE total approximately $1,337,743 annually.

6.C California Independent System Operator Charges

[57] Including Schedule Coordinator fees.

The CAISO charges BVES, through its Scheduling Coordinator (SC) Automated Power Exchange (APX), for ancillary services, grid management charges, imbalance energy, and CAISO uplifts.[58] 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 and typically represent a very small portion of BVES' energy requirements.

6.D Congestion Costs

Congestion Costs are one of the two components (transmission losses being the other) of the cost to deliver energy from one point to another within the CAISO. The cost of congestion is the difference in the Marginal Congestion Cost (MCC) component of the Locational Marginal Price[59] (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 (TH_SP15_Gen-APND) area.[60] The sink, or takeout, point is the Southern California Edison Default Load Aggregation Price (DLAP_SCE). This price is the load weighted aggregation of all load nodes within the SCE TAC area. The Congestion Cost is calculated using the Day Ahead Market Prices as follows:

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

Congestion costs can be mitigated through the use of Congestion Revenue Rights (CRRs). BVES' power contracts are for delivery to the SP15 area, so BVES must bear the cost for any congestion between SP15 and the DLAP.

In 2014, congestion on transmission constraints within the ISO system decreased compared to prior years and had a lower impact on average overall prices across the system.[61]
Congestion increased average day-ahead prices in the SCE area above the system average by approximately 0.5 percent. Real-time congestion did not have a significant

[58] CAISO uplift charges are collected from all customers to ensure market participants, including suppliers, are made whole. They reflect costs incurred to run the market for which there is no direct assignment to specific LSEs. They are collected from all customers to ensure the CAISO market is ultimately revenue neutral.
[59] The CAISO's market design creates marginal nodal or locational prices in its Day Ahead market process. The Locational Marginal Price or LMP is the algebraic sum of the 1) Marginal Energy Cost (MCE), 2) Marginal Cost of Congestion (MCC), and 3) Marginal Loss Cost (MLC).
[60] 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 SP15 areas. Generation scheduled to the aggregate generation hub is paid/charged the weighted hub price as calculated in the Day Ahead market.
[61] April 2014 CAISO Annual Report on Market Issues and Performance.

impact on overall average prices because multiple constraints had offsetting effects, with some increasing congestion and others decreasing congestion.[62]

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

6.E Risk Management

As a prudent utility, BVES generally assumes a low-risk posture. Rather than rely completely on the volatile spot market for supply, it seeks greater certainty in total power supply costs rather than risk substantial upward price movements in the energy market. For the past few years, BVES has been able to fix the cost of a large percentage of its total power supply costs through long-term PPAs. This has allowed BVES to reduce its exposure to market price uncertainty, but BVES still faces other sources of risk.

BVES takes into account the Value at Risk (VAR) when determining how much of its future energy supplies to purchase through long-term PPAs. The VAR is a measure of how much total costs change when underlying variables, such as natural gas prices, change. Steps taken to mitigate VAR include the following:

- use of assets such as gas fired generation which indexes power prices to natural gas prices (which has a lower volatility rate than power prices in the Southern California market)
- use of solar project(s) to fix prices to the cost of capital of the solar facility
- use of physical call options with fixed strike prices to cap power prices
- use of lighting efficiency program for the residential sector in order to shave the nighttime peaks (BVES system peak period is 7 to 10 PM) and facilitate asset and contract coverage noted above
- flow battery applications to condition the system load and facilitate asset and contract coverage are under review at this time. (A future IRP will have cost benefit analysis of this technology application to BVES' system)
- use of demand response to reduce demand during periods of extreme price spikes when other hedging is fully exhausted

Additional risks BVES faces are forecast risk, market-price risk, regulatory risk, supply risk, counterparty risk, or a combination thereof. The growing portion of energy

[62] CAISO Department of Market Monitoring, 2014 Annual Report on Market Issues & Performance, p.14.

consumption from customer-owned distributed generation via the Net Metering program and its potential successor program is a significant concern. Customer solar production should increase from 1.6 % of sales in 2015 to 8% of retail sales by 2020, as this is well within the range of residential and commercial customer solar program potential (customers with less than a 5-year payback period). BVES has taken a conservative approach to forecasting retail sales in order to account for strong growth in customer owned Distributed Generation and has sized contracts and asset plans accordingly. The forecast could change significantly if the customer solar production does not grow as stated in the forecast. BVES continues to closely monitor customer Distributed Generation growth and will reassess resource requirements in future IRPs.

Forecast risk[63] is the risk associated with over- or under-forecasting BVES' retail requirements and having either too much or too little energy under long-term PPAs, requiring that BVES either buy at higher than expected costs in the spot market or sell surplus energy from existing contracts at a loss. BVES mitigates this risk by improving on forecasting models, using multiple models (regression, statistically adjusted end-use, conditional demand analysis models for individual customers) for long-term and mid-term forecasting periods, and neural network models for next day forecasting.

Market-price risk is the risk associated with entering into long-term PPAs with wholesale prices subsequently falling, such that BVES could have purchased the energy less expensively in the short-term or *spot* market. Conversely, if BVES chooses not to enter into a long-term PPA at current prices and then prices rise, BVES' price of power could rise dramatically as compared to not locking in prices at current rates. To mitigate market-price risk, BVES' planning assumptions utilize the forecasting of IHS-CERA, experts in global and regional economic trends, all facets of energy markets, policy assessments, and detail industries. IHS-CERA fully integrates all of the forecast products into one harmonious assessment of the power, fuels markets, and economy. The firm is well connected with energy, policy, manufacturing, and service sector leaders. Scenario analysis is also incorporated in the IHS-CERA support of BVES' IRP planning process. BVES incorporates this external analysis into the internal analysis used to plan for its future resource needs.

Regulatory risk is the risk of changes in regulations or new regulations that increase BVES' cost of doing business. For example, if BVES takes actions to meet current regulations and regulations are subsequently changed, BVES may incur increased and unforeseen costs to (1) undo earlier actions, and (2) meet the new regulations. To mitigate regulatory risk, BVES utilizes a number of resources to assess current and future policy affecting California energy markets. BVES utilizes various legal and market consultants as well to fully assess options that BVES should take in planning for the future.

Supply risk is the risk that contracted or pre-scheduled energy is not delivered for any reason, resulting in BVES incurring additional costs to replace the energy. Supply risk

[63] BVES is refining its Load Research Project to improve forecasts; specifically, future plans are to include addition of more refined customer data via, among other methods, a pole top collection system.

is especially applicable where BVES intends to pre-schedule via dispatching the BVPP to avoid higher costs but the BVPP does not operate during the planned time period. Another example is SCE and/or CAISO grid reliability under the scenario in which SCE's Goldhill transfer station is unable to deliver energy to BVES and the BVPP must be run to replace that supply via SCE from the grid. In viewing the capacity mix and the resource supply mix charts (see Figures 6.3, 6.4, and 6.5), it is clear that BVES has secured itself from supply risk and power price risk. Note that the supply diversity of varying fuels, and sources, also mitigates the supply availability and supply price risk.

Counterparty risk is the risk that a counterparty defaults on its obligations and BVES incurs additional costs to replace energy contracted from the counterparty. To mitigate this risk, BVES utilizes parent company guarantees. BVES also attempts to deal only with companies that have good credit ratings and periodically reviews their ratings.

BVES cannot avoid all risk; risk that cannot be avoided must be managed to the extent feasible and in the most cost-effective manner. Although BVES cannot control the actions of the market or other entities, BVES seeks to design its resource acquisition strategy to minimize the financial impact of forecast and market risk. For example, BVES intends to fix the price of roughly 80 percent of its energy requirements for the next few years, which minimizes the impact of sudden price spikes in the spot markets. BVES has fixed the price of a significant amount of its energy requirements through the acquisition of competitively-priced long-term PPAs. BVES' new generation assets should not only secure supply but offer price hedges tied to another fuel. Diversity of resources was a key element in the development of the capacity mix available to BVES. This reduces risk for all components discussed in this section. A new technology which BVES is analyzing is the flow battery integration into the system and distribution planning process. The multiple cost reducing benefits and the constant improvement in performance and cost reduction make batteries an excellent capacity and a potentially vital instrument for BVES resource planning.

BVES will continue to monitor, assess and reduce, where possible, its regulatory risk at both the federal and state levels. Different or new energy and environmental goals, at both the federal and state levels, could add new complexity and costs to BVES' operations. Any proposed changes, both at the federal and state level, will be taken into consideration by BVES in its integrated resource planning process.

Two major goals in risk management of BVES resources are as follows. 1) Meet the capacity of the firm customers first and interruptible customers second, and 2) hedge the energy requirement expenditures in the future via fixed price contracts, load conditioning through efficiency lighting programs and load control, addition of utility owned solar capacity, and the conditioning of system load to fit assets and contracts through flow batteries or other energy storage technology.

See Figure 6.3 below for an illustration of meeting capacity needs described herein. The load forecast takes into account the energy requirement to service BVES firm and non-firm load net of solar DG solar production from its customers. This is the load for which BVES must dedicate capacity resources. We use 2020 as an example because it is in the middle of the planning horizon and also by this period the Mammoth substation expansion, the growth due to economic development, the electric vehicle charging station load, and the economic growth driving sales should be well underway. BVES can import up to 39 MW of load from the CAISO during the peak season of winter months in the evening hours. BVES has a power plant (BVPP) capable of producing 8.4 MW at any time, during any season. BVES is planning to request funding for a public purpose program aimed at residential customer lighting efficiency. This should add 2.4 MW of load capability via reduction of peak load from the peak load forecast for 2020. The fact that the maximum capacity during the system peak period exceeded the peak load requirement for 2020 indicates that BVES' resource plan meets the capacity requirement. While other years' capacity needs are also met, the 2020 scenario illustrates the planning capacity when all demand growth initiatives are anticipated to be in place.

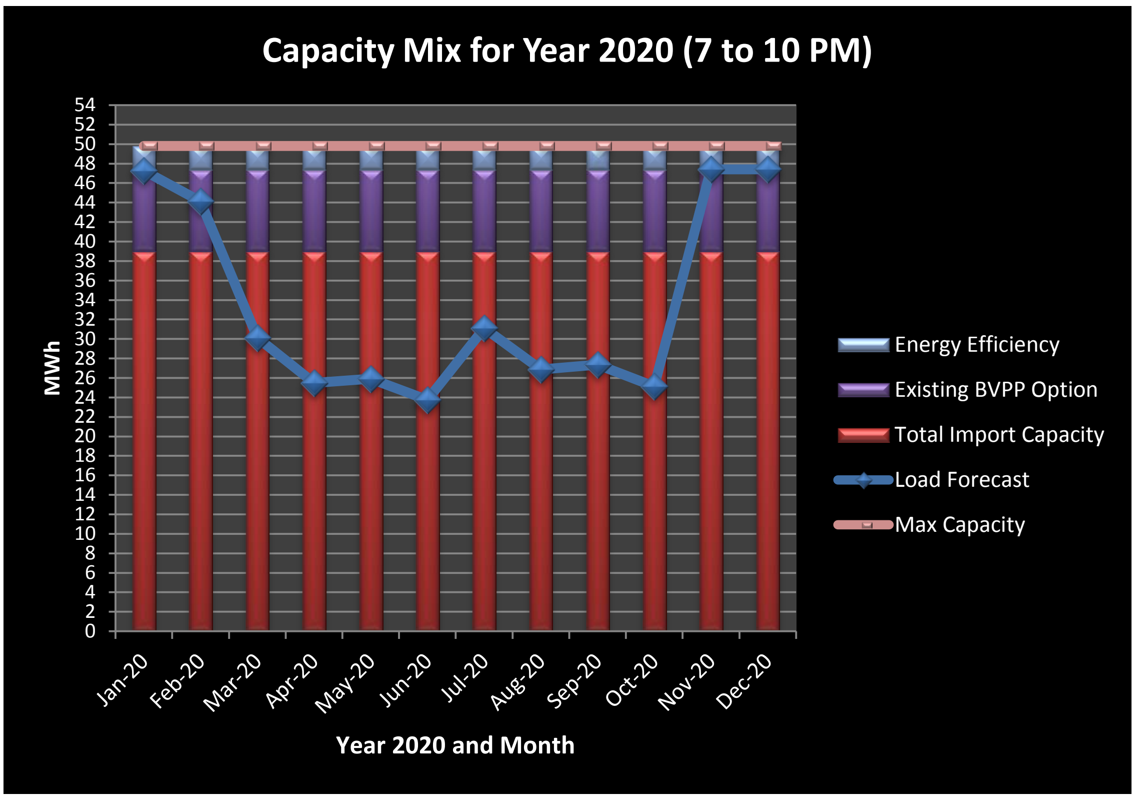


Figure 6.3: Resource Capacity Mix for Mid-Horizon Year 2020

The capacity stack illustrated in Figure 6.4 further illustrates capacity resources for daytime and night-time during the peak season. Added to the resource stack are the interruptible sales during the peak period which can be called upon to reduce the system demand in order for BVES to meet firm load. BVES does not anticipate the need to call on the interruptible customers more than a couple of hours to reduce load in 2020, or any other year in the planning horizon. This is a resource available to BVES should any of the resources mentioned below be curtailed due to unforeseen circumstances.

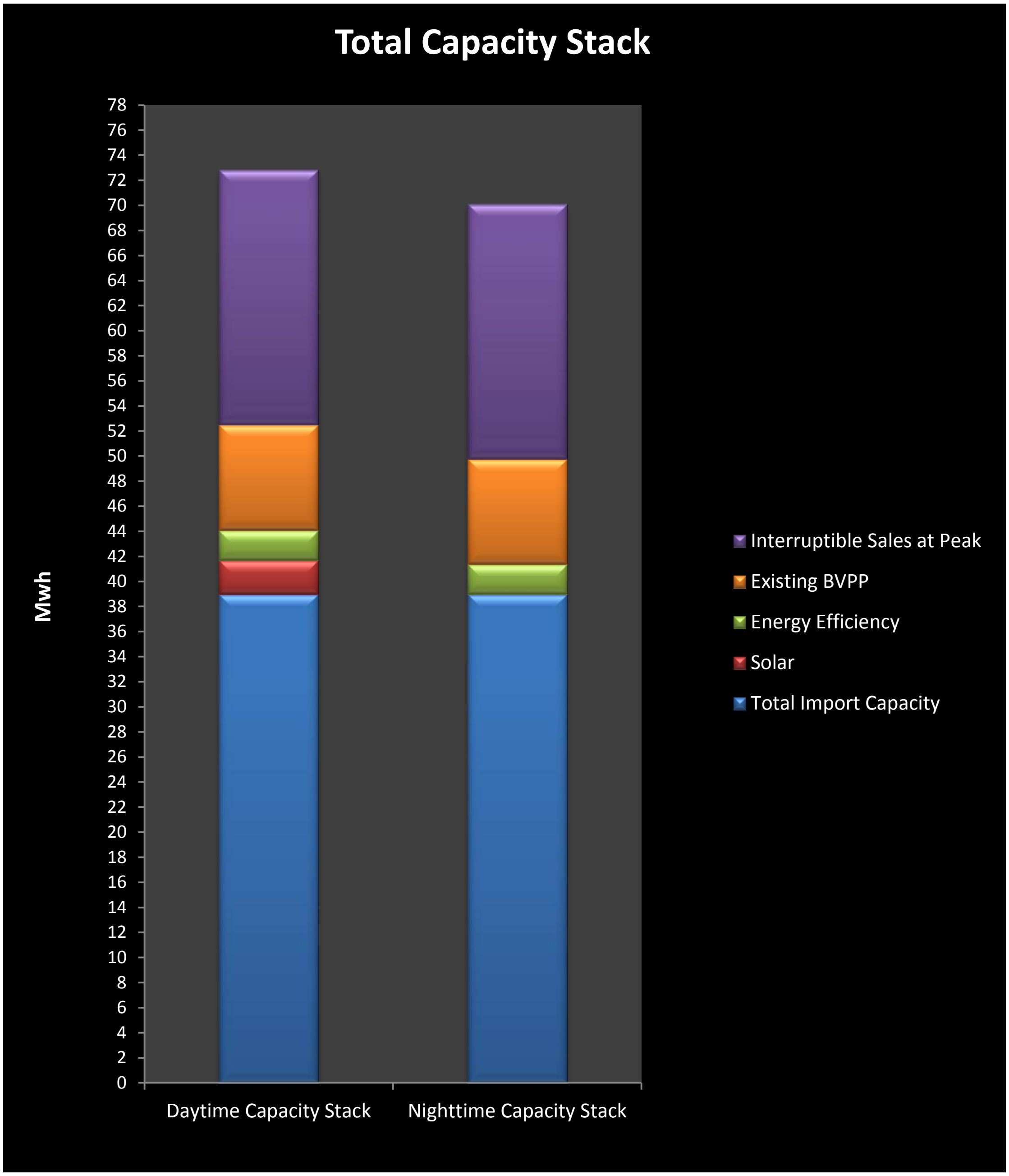


Figure 6.4: Resource Capacity Mix for Mid-Horizon Year 2020

In addition to planning for capacity needs, BVES must also plan for pricing uncertainty in the power market. Although price levels and volatility are quite low at this time, two years and beyond may be a very different pricing environment in the CAISO market. BVES has planned for higher prices and volatility in the wholesale market by planning to renew fixed price contracts and call options for a major portion of the load, as illustrated in Figure 6.5. The continuation of the existing lighting efficiency program should reduce a portion of the peak load and also further protect the BVES energy requirement costs from price spikes in the market. The BVPP is a gas fired generation plant and therefore does protect BVES from electricity price spikes as long as gas prices are not spiking at the same time. The proposed BVES solar plant of 2.7 MW will provide daytime protection of price spikes in both seasons. The price protection leaves very little exposure in winter time for price spikes. This exposure can be remedied through implementation of an energy storage system, which is under initial review at this time. The dashed line in Figure 6.5 indicates the anticipated use of the resources designed for price protection during the system peak hour. During peak periods, BVES anticipates using the open markets for required energy volumes above the fixed price volumes since the prices would likely be less than the required price threshold for BVES acquiring more assets or contracts. Given that this is for short durations of time; and, to avoid imbalances between supply through contracts and assets and demand, open market purchases should be less costly to BVES. BVES would use asset or contract physical call option to cover the unforeseen occurrences of price spikes, although the price spikes are not anticipated in the base case forecast. BVES is sheltered to some degree from price spikes due to the diversity in load pattern between BVES and the CAISO market. The resources are available, which mitigate price spikes, for the circumstances where the market prices do exceed BVES expectations.

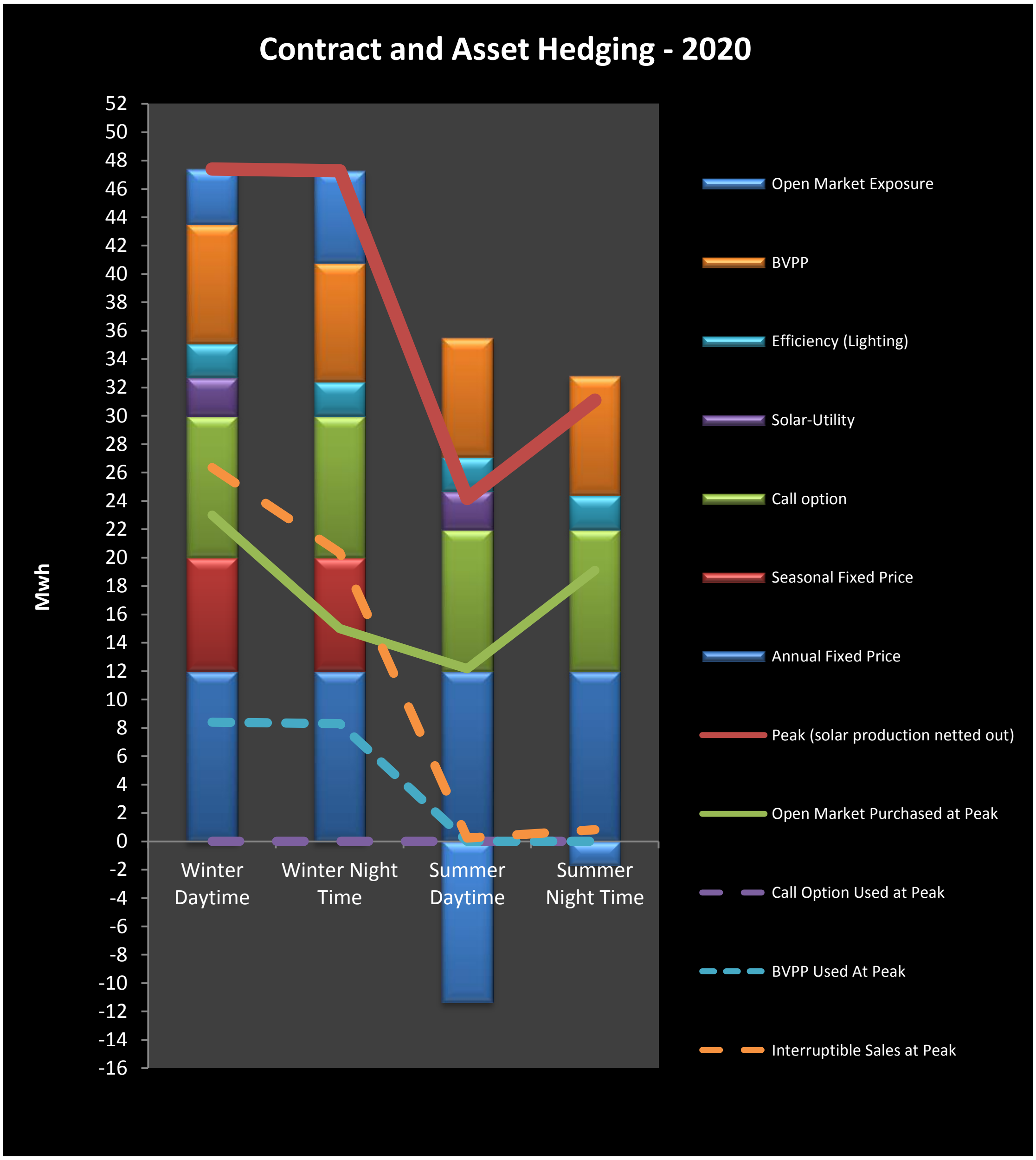


Figure 6.5: Total Capacity Stack and Utilization by 2020

Figure 6.6 provides an illustration of the utilization of price and capacity risk mitigating resources available to BVES on a monthly basis for 2020.

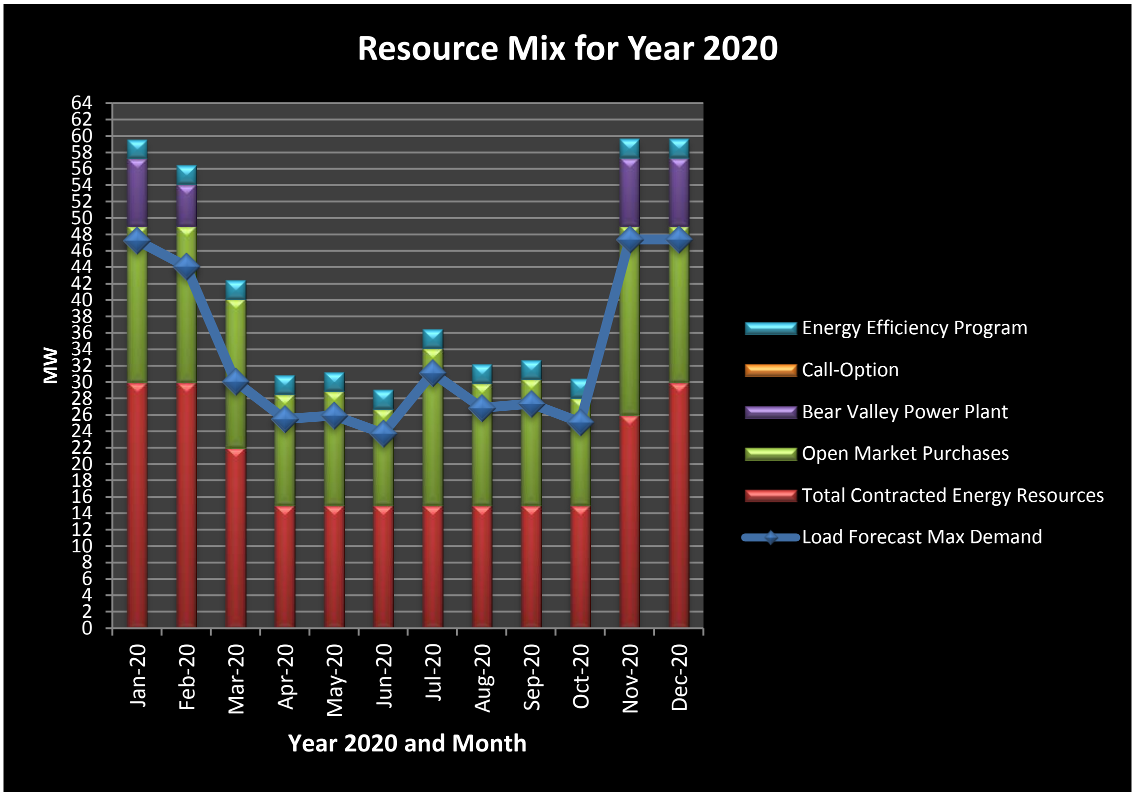


Figure 6.6: Resource Utilization Mix for Mid-Horizon Year 2020

6. F Summary and Conclusions

There are a number of components of BVES' total power supply costs, of which capacity and energy are the largest. Other costs include transmission on SCE-owned and operated facilities and CAISO charges.

The baseline simulation of power supply costs for the period 2015-2024 identified some of the important planning issues facing BVES in the nearer term (2015-2018), resulting in several mitigating actions that can be pursued. Such actions include continuing to procure 75 percent or more of BVES' annual energy requirements through fixed price contracts to provide long-term cost stability. BVES could hedge the remaining portion of its energy requirement through a physical call option with price cap, a 2.7 MW solar project, and the 8.4 MW existing gas fired BVPP or some combination of these options. BVES may also utilize demand response options like a water heating and spa cycling program to shave 3 MW of peak load for price hedging and load control. In addition, BVES may be able to shave up to 2.4 MW of load through the continuation of the existing efficiency program targeting lighting.

Regarding the outer years of late 2019 to 2024, BVES will pursue energy and capacity products to mitigate any significant price increases. BVES will also pursue flow battery technology as an instrument in shaping the system load and therefore reducing energy requirement expenses. BVES has left room between energy requirement and hedged volumes in the winter in order to utilize the strategies mentioned above which reshape the load profiles in order to remove the need for some of the market hedged volumes mentioned.

As a prudent utility, BVES generally assumes a low-risk posture. Rather than rely completely on the volatile spot market for supply, BVES seeks greater certainty in total power supply costs rather than risk substantial upward price movements in the energy market. For the past few years, BVES has been able to fix the cost of a large percentage of its total power supply costs through long-term PPAs. This has allowed BVES to reduce its exposure to market price uncertainty, but BVES still faces other sources of risk. Additional risks that BVES manages are forecast risk, market-price risk, regulatory risk, supply risk, counterparty risk and other types of business risk. BVES cannot avoid all risk; risk that cannot be avoided must be managed to the extent feasible and in the most cost effective manner. Although BVES cannot control the actions of the market or other entities, BVES seeks to design its resource acquisition strategy to minimize the financial impact of forecast and market risk.

Economic development will be closely monitored over the coming years in order to produce an accurate forecast and assure an adequate resource plan. Current approved expansions by customers are embedded in the current base case. Future expansion plans that are not yet announced are embedded in the base case forecast. Major game changers are not in the forecast of this IRP.

Enhancements to the forecasting process via forecast modeling, a customer survey, and a gathering of economic assumptions and economic development activities will allow BVES to enhance the risk management process and reduce the risk of price spikes. This process will also allow for improved resource planning and avoid capacity shortages and over-procurement of contract resources. Load forecasting model enhancements should further reduce forecast errors and allow for improved planning of resource requirements. Current economic development projects are covered in the base case; however, future projects which change the economic structure of the regional economy will be monitored for likelihood of occurrence and may be reflected in the forecast analysis.

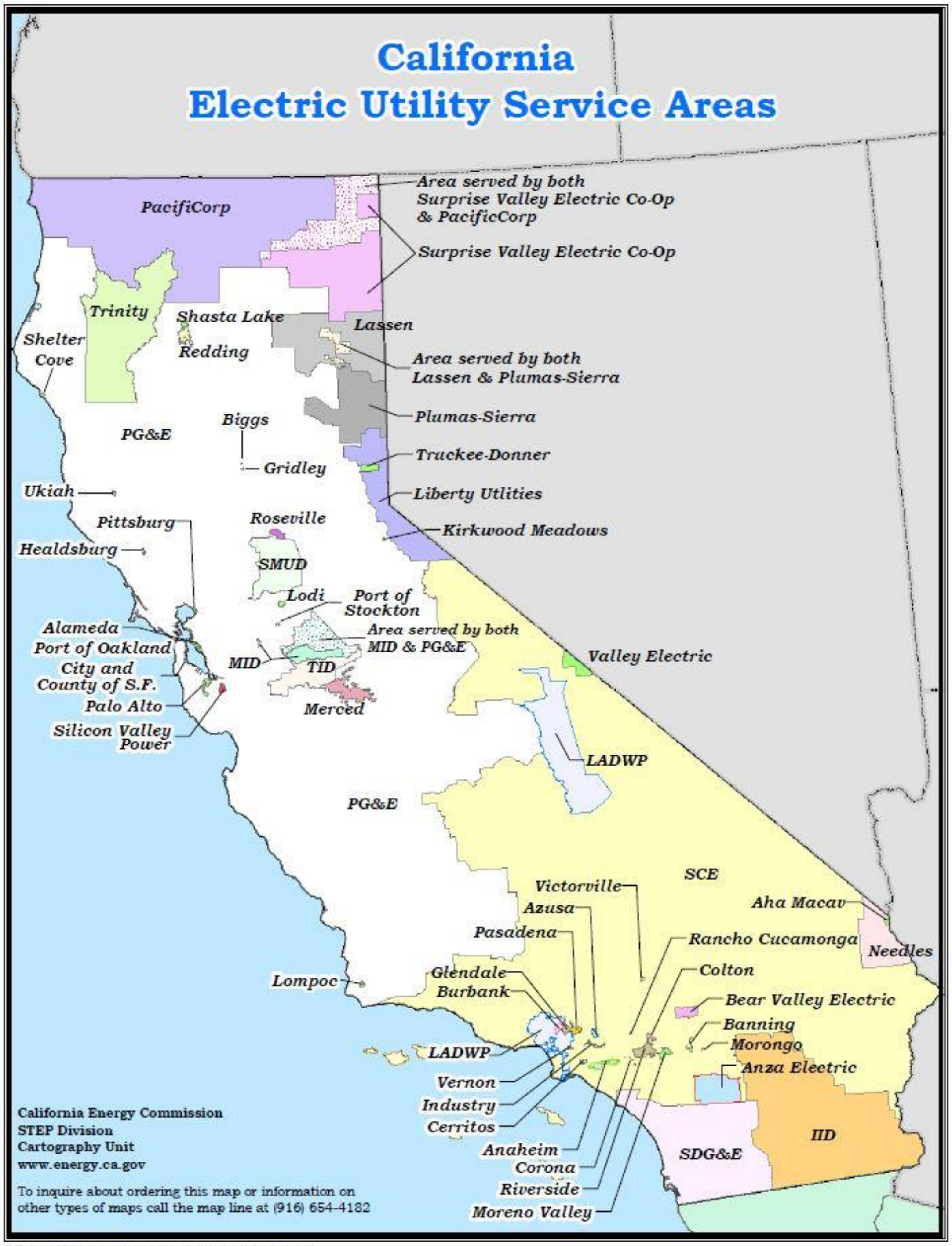
BVES will closely monitor the continued growth of customer-owned solar distributed generation. BVES must plan for this impact on the energy requirements in the future.

Utility solar projects will be reviewed as a cost mitigating instrument for energy costs for BVES. These projects may be located on customer property. If proven to be beneficial to BVES customers, BVES will pursue program and tariff designs to support implementation of these projects.

A forecast of sub-regions in the service area may be incorporated into the planning process in the future via new econometric models. This could enhance operations planning initiatives involving the sizing of equipment requirements, improve planning for Demand Response programs, and improve the efficiency of the power grid serving BVES, thereby reducing loss factors and load requirements relative to retail sales.

APPENDICES

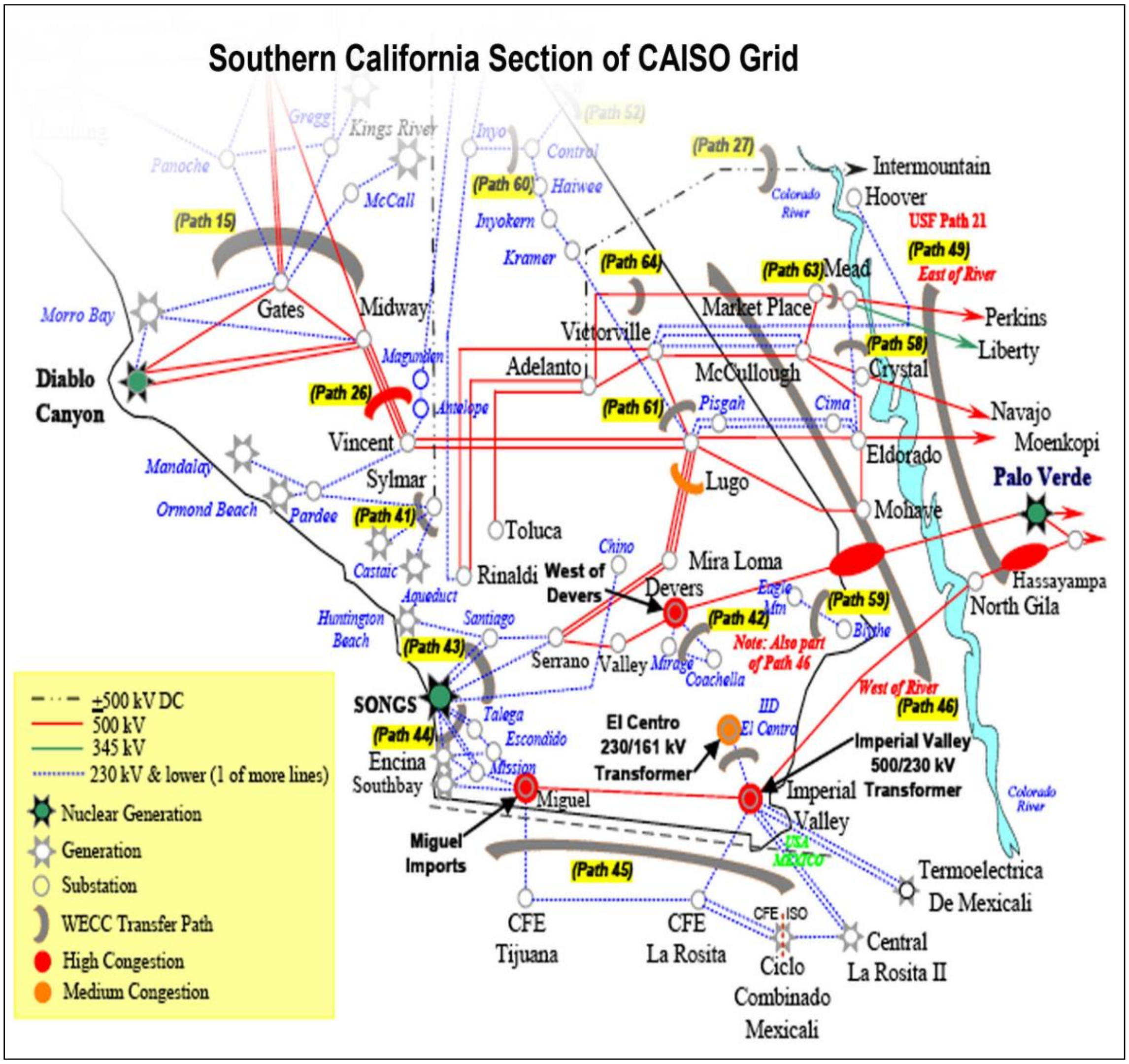
Appendix A: Map of California Electric Utility Service Areas



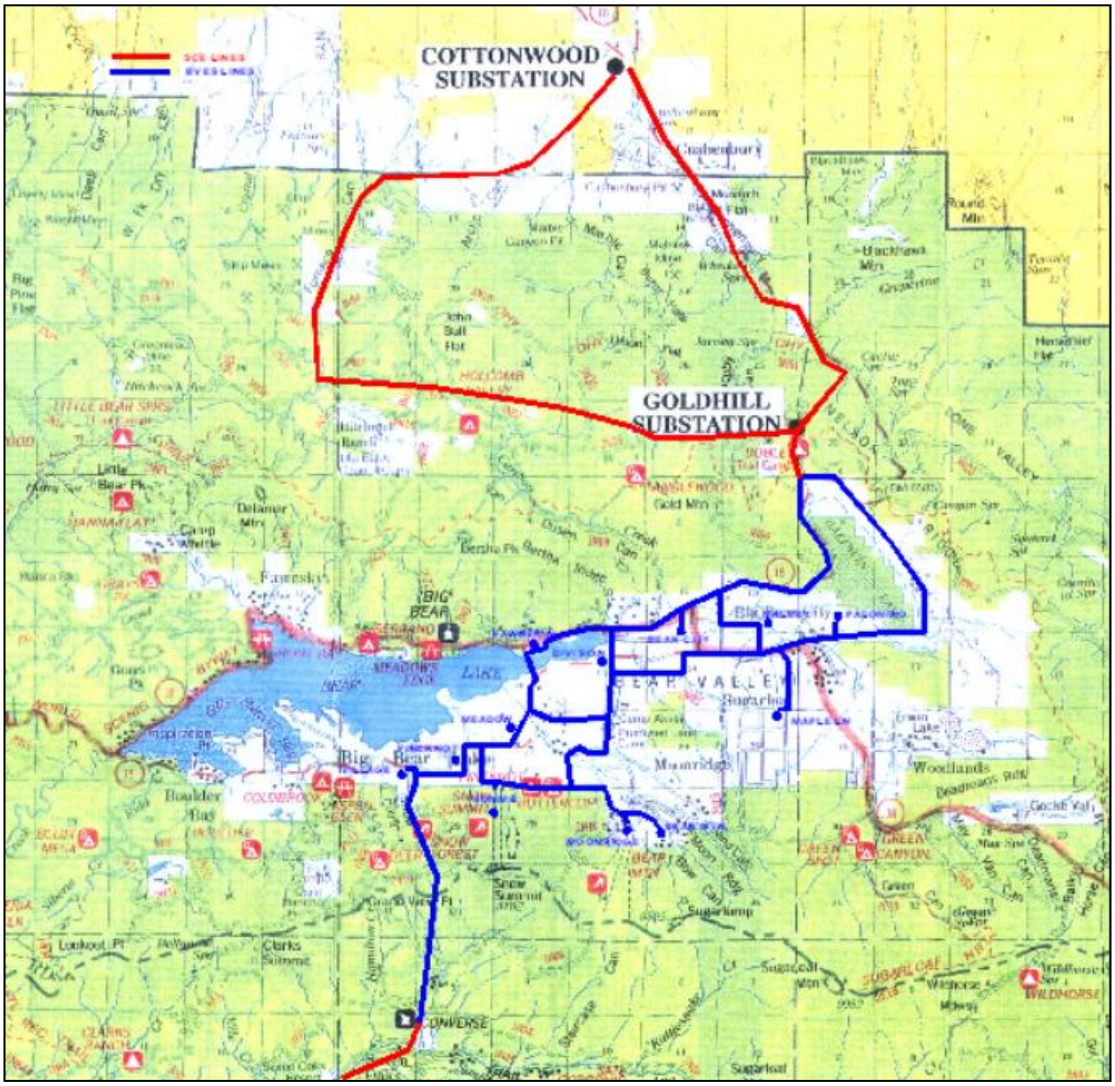
Source: California Energy Commission
http://www.energy.ca.gov/maps/serviceareas/electric_service_areas.html

Appendix B: Map of California Balancing Authorities

Appendix C: Map of Southern California Transmission System

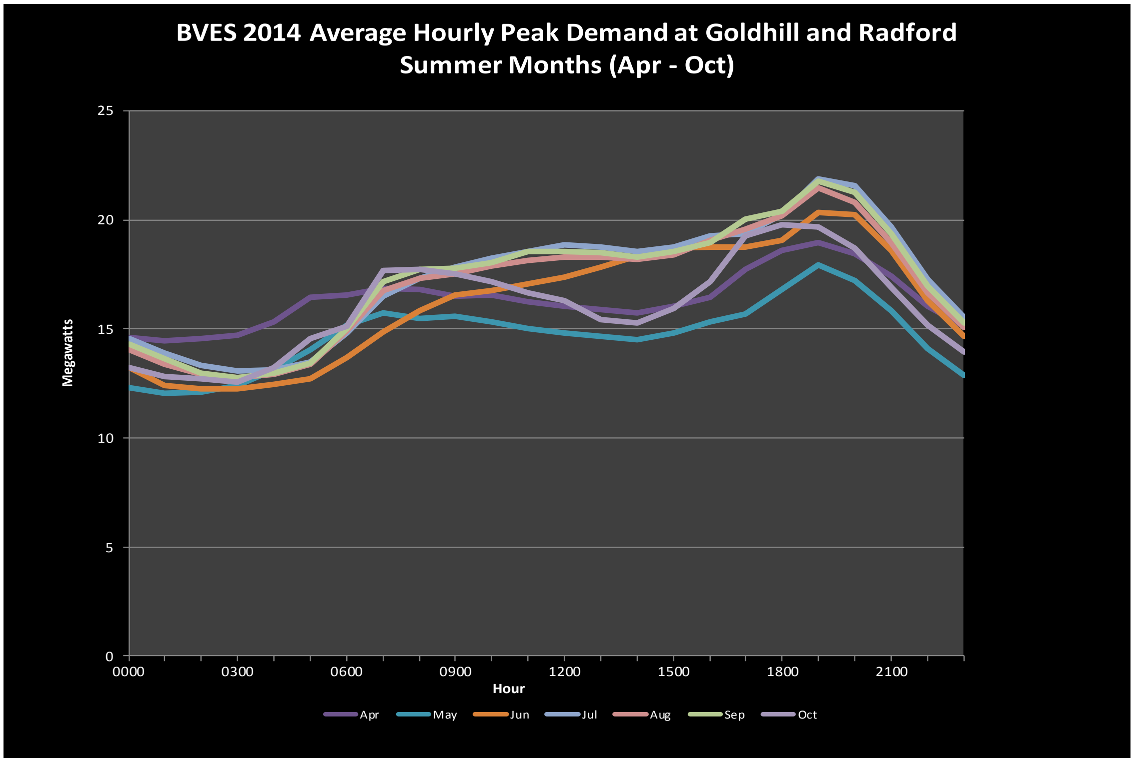


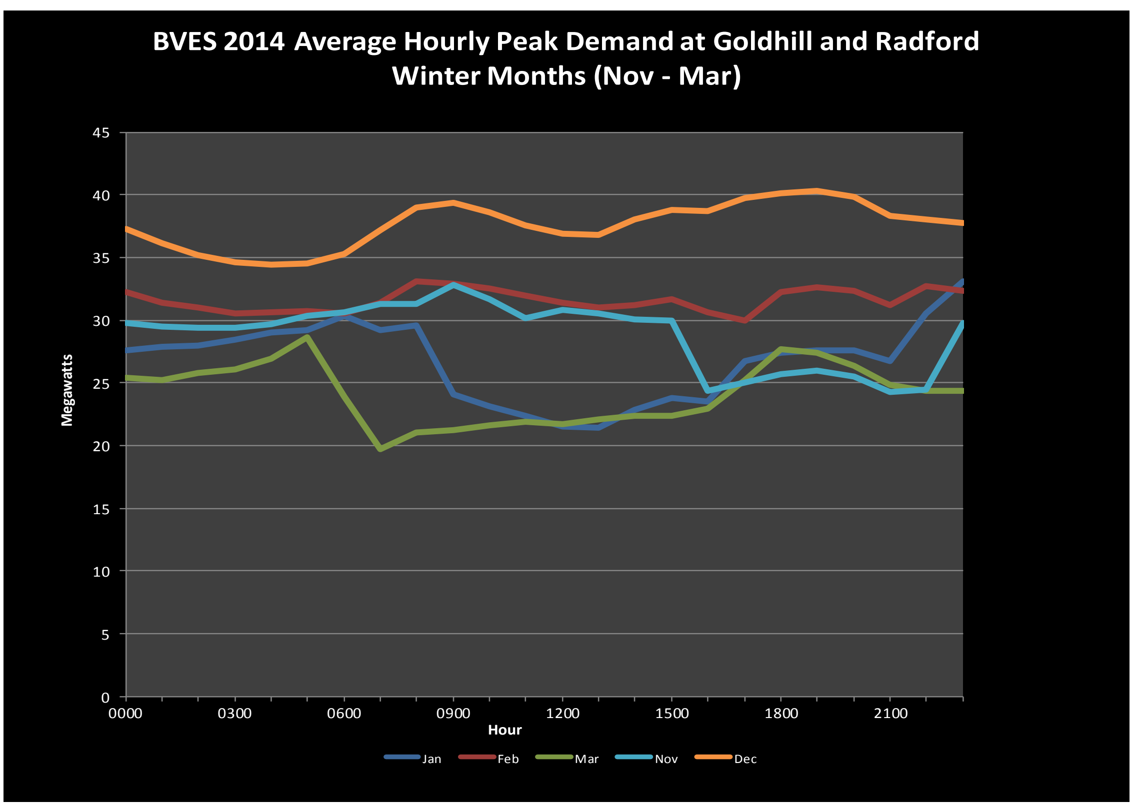
Appendix D: Map of BVES Power and Interconnection with SCE Power Lines



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

Appendix E: Monthly Average Load Curves
(Including Bear Valley Power Plant Reduction of CAISO Load)





Appendix F: Glossary of Acronyms

APX	APX, Inc.	The company that serves as the CAISO-certified Scheduling Coordinator (SC) for BVES.
BA	Balancing Authority	An entity that maintains load-resource balance within an area defined by a metered boundary. A balancing authority is the entity responsible for operating a control area. It matches generation with loads and maintains frequency within limits.
BVPP	Bear Valley Power Plant	The 8.4 MW natural gas-fired, peaking power plant owned and operated by Bear Valley Electric Service.
CAISO	California Independent System Operator Corporation	A not-for-profit public-benefit corporation charged with operating the majority of California's high-voltage wholesale power grid. The CAISO is the independent link between power plants and the utilities that serve the State's consumers, providing equal access to the grid for all qualified users and planning for transmission infrastructure.
CARB	California Air Resources Board	The "clean air agency" in the government of California, established in 1967 as a department within the cabinet-level California Environmental Protection Agency.
CO_2e	Carbon Dioxide Equivalency	A quantity that describes, for a given mixture and amount of greenhouse gas, the amount of CO2 that would have the same global warming potential (GWP), when measured over a specified timescale (generally, 100 years).
CRR	Congestion Revenue Rights	A financial mechanism designed to reduce the effect of congestion costs allocated to LSEs. A CRR is a uni-directional right to receive congestion charges from an entity causing transmission congestion.
DR	Demand Response	A set of programs offered by an LSE that provides its customers with financial incentives to reduce load in response to an event signal from the LSE.
DSM	Demand Side Management	Programs initiated by the LSE with its customers that include both EE and DR.
EE	Energy Efficiency	A set of programs offered by the LSE that provides its customers with financial incentives to install efficient electric equipment.
ESA	Energy Savings Assistance	An energy efficiency program offered by BVES under its 2013 GRC to replace the Low Income Energy Efficiency program, available only for qualifying low income residential customers.
GHG	Greenhouse Gas	A gas, such as water vapor, carbon dioxide, methane, chlorofluorocarbons (CFCs) and hydro-chloro-fluorocarbons (HCFCs), that absorbs and re-emits infrared radiation, warming the earth's surface and contributing to climate change.
GRC	General Rate Case	A process used by a utility to request recovery of its forecast revenue requirement including all operating and investment related costs. It establishes or changes the rate design and price levels to customers. It is a public process in which customers may participate.

Appendix F: Glossary of Acronyms (continued)		
ICPM	Interim Capacity Procurement Mechanism	A tariff which became effective on March 31, 2009 at the start of the new ISO market, enabling the ISO to acquire generation capacity to maintain grid reliability if (1) load serving entities fail to meet resource adequacy requirements; (2) procured resource adequacy resources are insufficient or (3) unexpected conditions create the need for additional capacity.
IHS-CERA	IHS Cambridge Energy Research Associates	A research company which provides independent analysis on energy markets, geopolitics, industry trends and strategy.
IOU	Investor Owned Utility	A privately-owned electric utility whose stock is publicly traded that is rate regulated and authorized to achieve an allowed rate of return for its shareholders.
IRP	Integrated Resource Plan	A document for planning, evaluating and acquiring generation resources to meet forecasted energy requirements. The goal of the IRP is to identify a mix of firm generation resources that provides reliable, least-cost energy to serve the needs of electric customers.
IRRP	Interim Reliability Requirements Program	A program which implements Resource Adequacy established by State authorities, including the CPUC and other local regulatory authorities, intended to remain effective until implementation of Market Redesign and Technology Upgrade.
LAP	Load Aggregation Point	A set of physical or theoretical Pricing Nodes as specified in the CAISO Tariff that are used for the submission of Bids and Settlement of Demand.
LCR	Local Capacity Resource	Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load or Proxy Demand Resource that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.
LMP	Locational Marginal Pricing	A market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid. Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity - the one that balances supply and demand - to market.
LSE	Load Serving Entity	An entity that provides electric power service to end-use customers. LSEs include but are not limited to IOUs, Energy Service Providers, Community Aggregation Groups and publicly-owned utilities.
MCC	Marginal Congestion Cost	The component of LMP at a node that accounts for the costs of congestion, as measured between that node and a reference bus.
MRTU	Market Redesign and Technology Upgrade	CAISO market redesign process implemented on April 1, 2009, intended to improve the reliability of energy supply and transmission grid management.
MSA	Metropolitan Statistical Area	A geographical region with a relatively high population density at its core and close economic ties throughout the area, such as Los Angeles-Long Beach-Santa Ana.
NEM	Net Energy Metering	A program and associated tariff which allows customers to use renewable resources (e.g., solar panels) to generate electricity and offset their consumption with their own power production.

Appendix F: Glossary of Acronyms (continued)		
PPA	Power Purchase Agreement	Power contract between an LSE and an electricity generator.
RA	Resource Adequacy	CPUC mandated level of capacity and reserves that each LSE must have to meet their customers' demand that is coincident with CAISO's peak load.
RFP	Request For Proposals	A document that an organization posts to elicit competitive bids from potential suppliers of a product or service.
RPS	Renewables Portfolio Standard	CPUC/Legislature requirement that all LSEs must obtain a specific percentage of the energy they sell to their retail customers through renewable generation sources.
SC	Scheduling Coordinator	An entity certified and authorized by the CAISO to schedule load and generation resources in the CAISO market.
SENA	Shell Energy North America	An energy provider with which BVES has contracted for multiple energy products to be delivered over the period 2009 through 2013.
SMJU	Small and Multi-Jurisdictional Utilities	CPUC-regulated utilities other than Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric, which serve retail customers in California.
SP15	South of Path 15	For purposes of energy pricing and definition of delivery location, the State is divided into three zones and scheduling points: SP15 in the south, NP15 in the north, and ZP26 in the center.
VAR	Value at Risk	A technique used to estimate the probability of portfolio losses based on the statistical analysis of historical price trends and volatilities.
WDAT	Wholesale Distribution Access Tariff	A fee levied by a transmission owner to an LSE with no transmission ownership for use of their transmission equipment.

Appendix G: Composition of BVES Hourly Load

				Base Case							
				Hours BVES System Load Above							
	10 MW	12 MW	19 MW	25 MW	30 MW	34 MW	39 MW	40 MW	45 MW	46 MW	50 MW
2011 Actual	8,760	7,976	2,195	1,004	375	77	4	0	0	0	0
2012 Actual	8,760	7,970	1,624	627	331	114	34	12	9	0	0
2013 Actual	8,760	8,233	1,894	794	418	83	0	0	0	0	0
2014 Actual	8,760	8,178	1,466	565	281	119	38	4	3	0	0
2015 Actual	8,755	8,147	1,853	907	539	240	59	3	0	0	0
2016	8,760	8,683	2,169	814	270	40	1	0	0	0	0
2017	8,745	8,323	2,221	811	293	45	2	0	0	0	0
2018	8,510	7,776	2,211	772	305	59	3	0	0	0	0
2019	8,185	7,329	2,244	849	522	362	189	8	4	0	0
2020	8,235	7,434	2,407	955	693	549	282	12	5	0	0
2021	8,168	7,361	2,418	958	694	547	277	12	5	0	0
2022	8,040	7,239	2,366	949	690	543	275	11	5	0	0
2023	7,907	7,159	2,346	944	687	540	273	11	5	0	0
2024	7,814	7,087	2,371	946	686	538	276	12	6	0	0

The chart above reflects the number of hours that the BVES system load is above certain MW thresholds. In the base case, BVES assumes normal weather and utilizes the 2013 load shape with the base case energy sales forecast to derive the hourly load forecast by class. From the hourly load forecast by class, the coincident system load MW forecast is derived.

Appendix H: WECC Environmental Allowance Prices

Allowances Prices (Real 2014 $)

Program	Acid Rain Program	CAIR	CSAPR Group 1[1]	CSAPR Group 2[1]	NOX SIP Call (May–Sept.)	CAIR annual	CAIR seasonal (May–Sept.)	CSAPR annual[1]	CSAPR seasonal[1]	RGGI[2]	California and Quebec GHG Trading Program[3]	Midwest CO2 trading program[4]
Pollutant	SO2	SO2	SO2	SO2	NOX	NOX	NOX	NOX	NOX	CO2	CO2e	CO2
Units	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/short ton	$/metric ton	$/metric ton
2005												
2006												
2007												
2008	270				871	2,973	742					
2009	78					1,395	308			3		
2010	17	33				455	48			2		
2011	3	4				158	19			2		
2012	2	2				34	11			2		
2013	1	1				39	19			3	12	
2014	1	1				35	22			5	12	
2015	1		74	196				442	638	6	12	
2016	1		72	193				434	626	7	13	
2017	1		95	142				378	568	9	14	
2018	1		81	122				325	488	9	17	
2019	1		68	103				274	410	10	24	
2020	0		56	84				224	336	11	33	
2021	0		105	158				422	264	11	39	14
2022	0		93	139				371	194	11	41	14
2023	0		80	121				321	169	11	41	15
2024	0		68	103				274	166	11	41	15
2025	0		57	85				228	163	11	41	16
2026	0		46	69				183	160	11	41	16
2027	0		35	53				141	157	11	41	16
2028										11	41	17
2029										11	41	17
2030										11	41	18
2031										11	41	19
2032										11	41	19
2033										11	41	20
2034										11	41	21
2035										11	41	21
2036										11	41	22
2037										11	41	22
2038										11	41	23
2039										11	41	23
2040										11	41	24

These allowance prices are inputs into the generation cost of power across the WECC region. The dispatch of generation plants is influenced by these allowance costs, and the derived dispatch of generation plants across the forecast years determines the SP-15 peak and off-peak period prices. These power prices are inputs into the power cost analysis in the BVES IRP.

Appendix I: RPS Position Using 2015 Sales Forecast

RPS Position Using 2015 IRP Sales Forecast -- Static 33% RPS 2020+

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Retail Sales	169,016	183,679	195,972	199,427	200,743	202,373	202,651	201,947	201,762	202,187
RPS %	23.30%	25.00%	27.00%	29.00%	31.00%	**33.00%**	**33.00%**	**33.00%**	**33.00%**	**33.00%**
BVES' RPS Obligation	39,381	45,920	52,912	57,834	62,230	66,783	66,875	66,643	66,581	66,722
Annual RECs (Base+Option)	35,837	38,865	42,425	45,444	48,455	51,661	51,640	51,594	51,617	-
Length/Shortfall	(3,544)	(7,055)	(10,487)	(12,390)	(13,775)	(15,122)	(15,235)	(15,049)	(14,964)	(66,722)
Length/(Shortfall) w/ Bank	14,088	7,034	(3,454)	(12,390)	(13,775)	(15,122)	(15,235)	(15,049)	(14,964)	(66,722)
2015 Bank	17,632									

All Volumes MWh

RPS Position Using 2015 IRP Sales Forecast -- Dynamic RPS 2020+

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Retail Sales	169,016	183,679	195,972	199,427	200,743	202,373	202,651	201,947	201,762	202,187
RPS %	23.30%	25.00%	27.00%	29.00%	31.00%	**33.00%**	**34.40%**	**35.80%**	**37.20%**	**40.00%**
BVES' RPS Obligation	39,381	45,920	52,912	57,834	62,230	66,783	69,712	72,297	75,055	80,875
Annual RECs (Base+Option)	35,837	38,865	42,425	45,444	48,455	51,661	51,640	51,594	51,617	-
Length/Shortfall	(3,544)	(7,055)	(10,487)	(12,390)	(13,775)	(15,122)	(18,072)	(20,703)	(23,438)	(80,875)
Length/(Shortfall) w/ Bank	14,088	7,034	(3,454)	(12,390)	(13,775)	(15,122)	(18,072)	(20,703)	(23,438)	(80,875)
2015 Bank	17,632									

All Volumes MWh

Notes:

1) The length or shortfall is determined by adding BVES' new forecasted RPS obligation to prior year excess RECs that are still "active" and available for use to meet RPS requirement then subtracting the total number of RECs BVES may purchase under its contract with Iberdrola.

2) In either the "static" or "dynamic" RPS scenarios, a shortfall occurs by 2017; once that shortfall occurs there are no excess RECs to consider.

3) A supply plan is not yet in place for 2024 and beyond.