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FINAL

2018 INTEGRATED RESOURCE PLAN

Silicon Valley Power

BLACK & VEATCH PROJECT NO. 194535

COOPERATIVELY PREPARED WITH AND FOR

Silicon Valley Power

12 NOVEMBER 2018

BLACK & VEATCH

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Acronym List

AAGR	Annual Average Growth Rate
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CARB	California Air Resources Board
California ISO	California Independent System Operator, also CAISO
CEC	California Energy Commission (also Energy Commission)
CEC Guidelines	The CEC document, *Publically Owned Utility Integrated Resource Plan Submission and Review Guidelines* (July 2017 and October 2018)
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COTP	California-Oregon Transmission Project
CPUC	California Public Utilities Commission
CPWC	Cumulative Present Worth Cost
CRAT	Capacity Resource Accounting Table
EBT	Energy Balance Table
Energy Commission	California Energy Commission (also CEC)
EPA	U.S. Environmental Protection Agency
ES	Energy Storage
FY	Fiscal Year (July 1- June 30 for SVP; October 1-September 30 for the US Government)
GEAT	GHG Emissions Accounting Table
GHG	Greenhouse Gas
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Plan Adopted by a POU
IRP Filing	POU Adopted IRP Accompanied By The Required Supporting Information
LCOE	Levelized Cost of Energy
LMP	Locational Marginal Price
LSE	Load Serving Entity
MMBTU	One Million British Thermal Units
M-S-R PPA	California Joint Powers Agency, M-S-R Public Power Agency, of which the City of Santa Clara is a member along with Modesto Irrigation District and the City of Redding

M-S-R-REA	M-S-R Energy Authority
Mt	Metric Ton
MW	Megawatt
MWh	Megawatt-hour
MSSA	Metered Subsystem Aggregation Agreement
MTCO2e	Metric Tons of CO_2 equivalent
NCPA	Northern California Power Agency, members include the City of Santa Clara, Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville and Ukiah, the Plumas-Sierra Rural Electric Cooperative, the Truckee-Donner Public Utility District, the Bay Area Rapid Transit District and the Port of Oakland
NERC	North American Electric Reliability Council
NPV	Net Present Value
NQC	Net Qualifying Capacity
PCC	Portfolio Content Categories
PEV	Plug-In Electric Vehicle
POU	Publicly Owned Utility
PUC	Public Utilities Code
RA	Resource Adequacy
RE	Renewable Energy
REC	Renewable Energy Credit
RFP	Request for Proposal
RPS	Renewables Portfolio Standard
RPT	RPS Procurement Table
SB 100	Senate Bill 100 (The 100 Percent Clean Energy Act of 2017)
SB 350	Senate Bill 350 (De León, Chapter 547, Statutes of 2015)
SVP	Silicon Valley Power
TAC	Transmission Access Charge
TANC	Transmission Agency of Northern California
WAPA	Western Area Power Administration (also Western)
Western	Western Area Power Administration, (also WAPA)

1.0 Executive Summary

This report (Report) presents the Integrated Resource Plan (IRP) for the City of Santa Clara d.b.a. Silicon Valley Power (SVP), a municipal electric utility with 55,198 customers as of 2017. SVP serves the City of Santa Clara (City or Santa Clara) with a service area of approximately 19 square miles. SVP is dedicated to their community, customers, and employees. SVP provides safe, reliable, affordable, and sustainable energy solutions while deploying and scheduling resources that optimize the dispatch of SVP's generation and complying with statutory and regulatory requirements.

The goal of the IRP is to lay out a detailed plan to help ensure that the utility is able to meet its customer's annual peak and energy needs over the planning horizon in a cost-effective manner, while also meeting system reliability needs and other policies. The IRP summarized in this document provides an assessment of the future electric energy needs of SVP customers over the next 20 years (from 2019 through 2038) and summarizes the preferred plan for meeting those needs in a safe, reliable, cost-effective and environmentally responsible manner.

This IRP was developed in response to the Clean Energy and Pollution Reduction Act of 2015 (California Senate Bill 350; herein SB 350), which established new clean energy, clean air, and greenhouse gas (GHG) reduction goals for 2030, and established a number of requirements for publicly owned utilities (POUs). The most far-reaching goals and requirements include:

- An increase in the procurement of energy from renewable electricity sources, from 33 percent by 2020 to 60 percent by 2030 (SB 100). While the CEC IRP guidelines are based on the 50 percent renewable procurement by SB 350, with the recent passing of SB 100, SVP's modeling assumed a target of 60 percent procurement by 2030
- Consideration of programs that will help the State double energy efficiency savings in electricity and natural gas end uses by 2030
- A reduction in GHG emissions consistent with the targets set forth by the California Air Resources Board (CARB) in its July, 2018 report[1]
- Publicly owned utilities (POUs)[2], such as SVP, must develop an IRP that positions the POU to achieve the above goals and other objectives such as those related to reliability and cost-effectiveness. The IRP is to be approved by the POU boards by January 1, 2019 and submitted to the California Energy Commission (CEC) by April 30, 2019.

The recommended plan meets the 2030 renewable energy target as well as the intermediate targets for renewable energy and GHG emissions reduction. Meeting the GHG targets assumes that only SVP-owned resources count towards the emissions target. SVP finds that the generic emissions rate of 0.428 Mt CO_2e/MWh for spot market purchases per the CEC guidelines to be too high. If this rate is applied, SVP's portfolio emissions will exceed the GHG target. Section 2.4.1.2 describes SVP's approach to the accounting of carbon emissions.

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[1] California Air Resources Board, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018; SB 350 required CARB to develop recommendations based on the goal of achieving a 40% reduction in GHG by 2030.

[2] SB 350 is reflected in Public Utilities Code (PUC) Section 9621, which applies to POU's with an average electrical demand exceeding 700 gigawatt-hours, based on a three-year average commending January 1, 2013.

The 2018 IRP was developed through extensive analysis and incorporated input from internal and external partners and stakeholders. The analyses and underlying assumptions that produced a 20-Year Resource Plan to meet customers' energy needs through 2038 is outlined in this report. While the IRP is only required to extend to 2030, the CEC encouraged POUs to consider time periods extending beyond 2030 in its *Commission Guidelines*.[3] Incorporated into the IRP are anticipated changes facing SVP, the utility industry, and California over the planning period.

Although significant changes within the electric utility industry are anticipated to occur over the 20-year planning horizon for the IRP, SVP must plan for sufficient supplies of electricity while also maintaining competitive prices and achieving safety, environmental, operational, and reliability goals. During the preparation of the IRP, SVP considered a wide variety of supply and demand-side alternatives that could meet these many objectives. The IRP process has also taken into consideration the need to establish a flexible plan that will allow SVP to respond to uncertainty regarding technological and future regulatory change. Goals established to guide development of the IRP are presented in Figure 1-1.

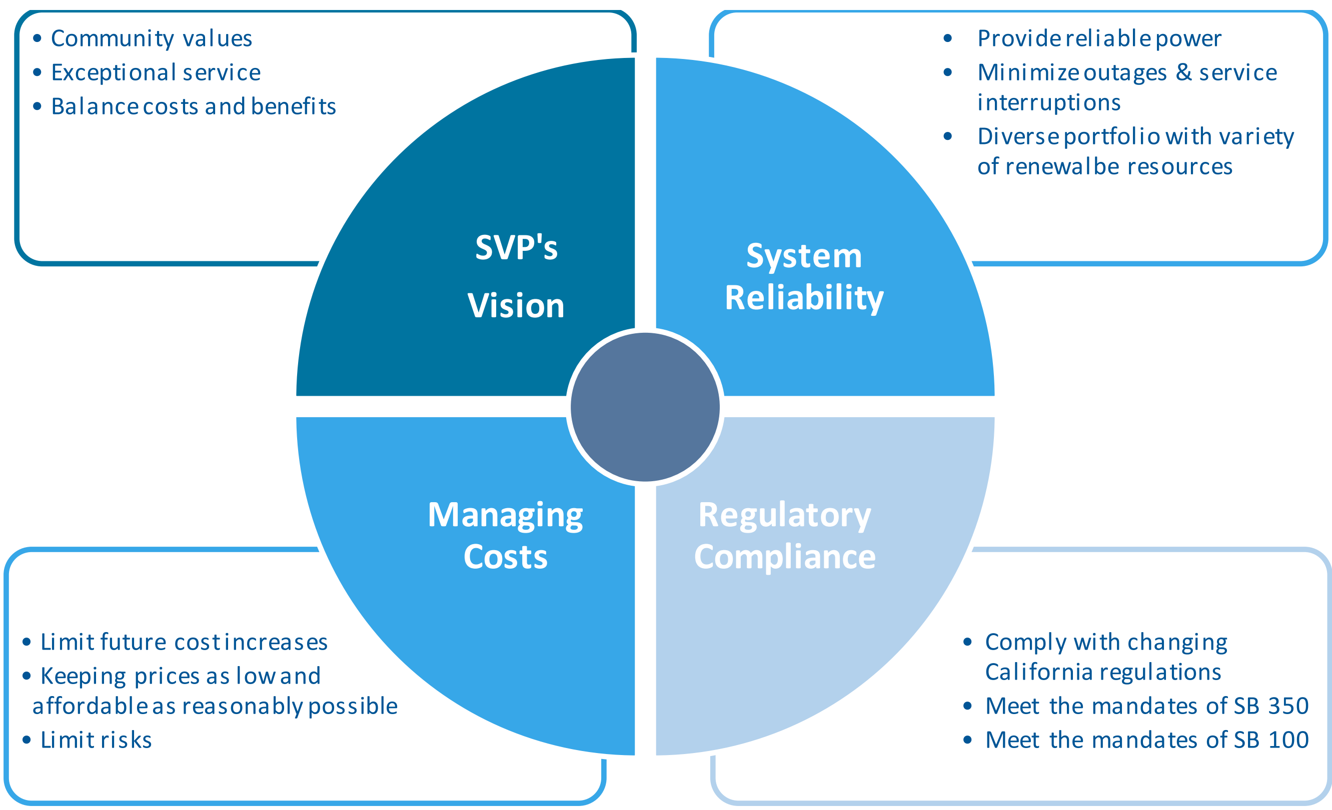

Figure 1-1 SVP's IRP Objectives

[3] Vidaver David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy, 2017, *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*, California Energy Commission. Publication Number: CEC-200-2017-004-CMD, p. 10.

A summary of the 20-Year Resource Plan is provided in Section 1.1. Supporting information, including studies, data, analyses and results plus associated exhibits for the IRP analysis is provided in the following sections of the Report:

- Section 2.0 Purpose and Background
- Section 3.0 Existing Resources and System Description
- Section 4.0 Energy and Demand Forecast
- Section 5.0 Customer Programs, Energy Efficiency and Demand Response Resources
- Section 6.0 The Need for Additional Resources and Resource Options
- Section 7.0 Modeling Assumptions, Tools, and Methodology
- Section 8.0 Evaluation and Results
- Section 9.0 Conclusions and Recommended Expansion Plan

Standardized tables requested by the CEC are in Appendix A. The organization and contents of this IRP reflect the requirements established in the CEC IRP Guidelines. The major requirements set forth in these guidelines and the primary section in which the required information is provided is shown in Table 1-1.

Table 1-1 Summary of Key IRP Filing Requirements and Location in SVP's IRP

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN SVP'S IRP
A. Planning Horizon and Objective of Expansion Plan	"adopt an IRP that ensures the utility achieves the specific goals and targets by 2030, including...greenhouse gas emissions reductions of 40 percent below 1990 levels, and...at least 50 percent of eligible renewable resources...The minimum planning horizon...begins no later than January 1 of the year that the POU's governing board adopts the plan and ends no earlier than December 31, 2030...POUs are encouraged to undertake and present analysis....that addresses the post-2030 period"	Section 8
B. Scenarios and Sensitivity Analysis	"IRP Filings.... must meet the requirements of PUC Section 9621. POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options."	Section 8
C. Standardized Tables	"POUs must submit the following four Standardized Tables... • Capacity Resource Accounting Table (CRAT) • Energy Balance Table (EBT) • RPS Procurement Table (RPT) • GHG Emissions Accounting Table (GEAT)"	Appendix A
D. Supporting Information	"(1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP... and (2) additional information required by these guidelines. Supporting Information supplements the data submitted in the Standardized Tables."	Section 4, 5, 6; all Appendices

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN SVP'S IRP
E. Demand Forecast	"1. Reporting Requirements…annual forecasted peak demand (MW) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT… 2. Demand Forecast Method and Assumptions. 3. Demand Forecast – Other Regions. If the POU uses system modeling…the IRP Filing must include the demand forecast assumptions for regions outside the POU jurisdiction."	Section 4, Appendix A
F. Resource Procurement Plan	"…the mix of resources… in the IRP [as]…reported on the CRAT, EBT, and GEAT, and RPS procurement must also be reported on the RPT [along with] all inputs, assumptions, and methodologies …The IRP Filing must address: 1. Diversified Procurement Portfolio 2. RPS Planning Requirements 3. Energy Efficiency and Demand Response Resources 4. Energy Storage 5. Transportation Electrification"	Section 4, 5, 8, Appendix A
G. System and Local Reliability	"Filing POUs [must] adopt an IRP to… meets the goal of ensuring system and local reliability… and report: 1. Reliability Criteria…the planning reserve margin and how it was determined. 2. Local Reliability Area. The IRP Filing must identify any local transmission constrained areas in the POU service territory…" 3. Net Demand in Peak hours… how renewable resources, multi-hour energy storage, and distributed energy resources, including energy efficiency, were considered for meeting reliability needs during net peak hour	Section 4
H. Greenhouse Gas Emissions	"POUs must report in the GEAT estimated emissions intensities (in metric tons of carbon dioxide equivalent [CO_2e] per megawatt hour…for each supply resource reported in the EBT."	Section 8, Appendix A
I. Retail Rates	"…the IRP Filing must include, as Supporting Information, a report or study on rate impacts under the IRP scenario, if that report or study was considered by the local governing authority as part of its IRP planning."	Section 8
J. T&D Systems	"…adopt an IRP [that] achieves the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."	Section 3
K. Localized Air Pollutants and Disadvantaged Communities	"…adopt IRPs to…[achieve] the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities…[discuss] how current programs and policies in place…address local air pollution…[and] how programs assist and prioritize disadvantaged communities."	Section 8

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN SVP'S IRP
Summarized from Chapter 2 of Vidaver David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy. 2017 and 2018. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2017-004-CMD and CEC-200-2018-004-SD.		

1.1 SUMMARY OF THE 20-YEAR RESOURCE PLAN

The SVP IRP, described herein, was based on the load forecast developed by SVP and described in Section 4. The expansion plans were designed to meet the SVP's load requirements and other planning objectives stated herein.

Section 6 of this report explains that the Existing System Scenario combined with Renewable Energy Credits (RECs) and new renewable additions are expected to meet the SVP renewable generation and environmental mandates through 2030 as well as through 2038, which is the end of the planning period.

Two expansion plans were developed and evaluated to add additional renewable resources based on the cost and characteristics of selected solar and wind options described in Section 6. The base case assumes a balanced procurement scenario adding an equal amount of wind and solar, in terms of generation, to the portfolio. An alternate case, assuming 80 percent wind additions and 20 percent solar additions was also evaluated as described in Section 6. Based on these characteristics and additional assumptions and methods described in Section 7, the long-term cumulative present worth cost (CPWC) of two competing resource expansion plans are developed and presented in Section 8. Additionally, multiple sensitivity cases were also evaluated as described below. The CPWC considers the cost of generation which includes fuel costs, variable O&M and emissions cost for existing resources. The calculations also include the build cost of new resource additions and the cost or revenue from spot market purchases and sales.

The following five scenarios were evaluated as part of the IRP analysis.

- Base Case: Existing system with a renewable target of 60 percent by 2030. Note: SVP initially approached the analysis for the IRP based on the renewable target of 50 percent by 2030. However, with the recent signing of SB 100, SVP decided to model meeting the renewable target of 60 percent by 2030. This case, assumes expected load growth and a balanced procurement scenario adding an equal amount of wind and solar to the portfolio.
- High Wind Case: SVP's expected load growth with an 80 percent wind and 20 percent solar expansion plan
- High Load Sensitivity: Base Case with high load growth assumptions. Renewable additions to this case were at 50 percent solar and 50 percent wind ratio
- Low Load Sensitivity: Base Case with low load growth assumptions
- High GHG Price Sensitivity: Base Case with high carbon price forecast

Except for the High Wind Case, all expansion plans are based on 50 percent wind and 50 percent solar additions. Only solar and wind resources were evaluated as future resources due to SVP's need for additional renewable energy resources and SVP's customer desire for additional renewable energy at a reasonable cost. The list of projects considered for inclusion in the expansion plans is shown in Table 1-2. All cases include the addition of a new contract for a wind resource, Viento Loco in 2022 with an installed capacity of 200MW.

Table 1-2 Projects Considered by SVP in the IRP Expansion Plans (All Capacities are the Maximum Rated and Not Firm Capacities)

	PROJECT 1	PROJECT 2
Name	NorCal Solar	NorCal Wind
Location	NorCal	NorCal
Type	PV	Wind
Capacity (MW)	10	100
Scalable	No	Yes
AC Capacity Factor (%)	30%	40.0%
Annual Energy (MWh)	26,280	350,400
Energy Storage? (Yes/No/Maybe)	Not included	Not included
ES Capacity (MW, %)	Not included	Not included
ES Duration (Hrs)	Not included	Not included
Transmission Requirements	None	To COTP, WAPA
LMP Market Location (To Value)	NP15	NP15
Transmission Access Charge (TAC) Costs (2018-$/kW/mo)	0.000	2.258
Transmission Costs (2018-$/MWh)	0.000	0.000
Transmission Escalation Rate		5.00%

The results of the various cases are reported in Section 8 and are also summarized in Table 1-3. As presented in the table, all the cases and sensitivities were solved to meet the 60 percent renewable target by 2030 while also meeting intermediate renewable targets. Of the two expansion plans considered, the table shows that the High Wind Case has the lowest CPWC followed closely by the Base Case. The next subsection explains the reasoning for the selection of the Base Case as the preferred case. Since the completion of the modeling, SVP has made updates to the assumptions underlying the IRP. These updates are reflected in the Standardized Tables and are to take precedence over the numbers provided in this Report. The change includes a reduction in the generation from a few RPS-eligible facilities, which results in increased market purchases and additional withdrawals from banked RECs. In total, SVP continues to maintain a healthy REC balance for the duration of the planning period. Since this change is common to all cases and sensitivities modeled, the relative ranking of the results presented on in this report is not expected to change.

Table 1-3 CPWC and Renewable Summary by Case

CASE	DESCRIPTION	CPWC ($1,000s)	% HIGHER THAN LOWEST CPWC	2030 RENEWABLE % OF RETAIL SALES	INTERMEDIATE MILESTONE RENEWABLES MET?
Base Case	Expected Load Growth with 50/50 solar and wind additions	$1,682,712	6%	60%	Yes
High Wind Case	Expected Load Growth with 80/50 wind and solar additions	$1,583,361	0%	60%	Yes
High GHG Sensitivity	Base Case and high GHG price forecast	$1,833,029	16%	60%	Yes
High Load Sensitivity	High Load Growth with 50/50 solar and wind additions	$2,888,563	82%	60%	Yes
Low Load Sensitivity	Low Load Growth with 50/50 solar and wind additions	$1,342,780	-15%	60%	Yes

1.1.1 Preferred and Recommended Case, Base Case

The Base Case is SVP's preferred and recommended case. Under this case, a balanced procurement plan is adopted adding equal amounts of solar and wind resources to the portfolio. The procurement under this case is based on the recent signing of SB 100 which targets 60 percent renewables by 2030. This scenario considers the existing system, known new contracts, RECs and addition of renewable generation. By the end of the planning period, the scenario adds 670 MWs of new solar and 500 MWs of new wind. Due to the difference in capacity factor of these resources, the generation translates into a 50-50 split between wind and solar. While this case is not the cheapest option, it allows for a balanced procurement of resources for SVP and avoids reliance on one single technology. Additionally, this case provides SVP flexibility to modify the procurement as needed while progressing through the planning period. Table 1-4 provides a breakdown of the CPWC results for the Base Case by year and Table 1-5 provides an overview of the renewables adequacy combined with RECs to meet the renewable targets.

1.1.2 Recommendation

The Base Case is the recommended plan in this IRP for SVP. This plan offers the best combination of low cost, flexibility, reliability, and environmental responsibility as measured by the goals established for POUs by the state. The four detailed tables required by the CEC Guidelines are provided in Appendix A for this preferred expansion plan. Internal IRP approval by Santa Clara's City Council is expected in November 2018.

Table 1-4 CPWC Results for the Preferred and Recommended SVP Case, Base Case

Cumulative Present Worth for the Base Case, $2017 at a 4.5% discount rate							
Year	Generation Cost ($000)	New Resource Additions		Market Activity		Total System Cost ($000)	Cumulative Present Worth ($000)
		New Build Cost ($000)	Fixed O&M ($000)	Market Purchases ($000)	Market Sales ($000)		
2019	49,458	-	-	22,114	4,877	66,696	66,696
2020	51,690	-	-	35,711	3,167	84,235	150,931
2021	44,582	-	-	19,747	5,359	58,970	209,901
2022	40,552	-	-	15,129	7,549	48,132	258,033
2023	39,239	-	-	18,042	6,950	50,331	308,364
2024	44,709	-	-	32,231	1,743	75,197	383,561
2025	43,948	-	-	35,136	1,345	77,739	461,300
2026	43,854	-	-	36,995	1,151	79,699	540,999
2027	41,693	-	-	35,636	926	76,403	617,402
2028	40,084	-	-	36,021	709	75,396	692,798
2029	38,758	-	-	37,425	550	75,634	768,432
2030	35,546	20,553	4,106	20,581	1,266	79,520	847,952
2031	35,501	19,668	3,929	23,518	822	81,793	929,745
2032	33,727	36,845	7,403	17,330	1,096	94,210	1,023,955
2033	30,959	52,506	10,533	14,563	1,687	106,874	1,130,829
2034	31,761	50,975	10,204	17,142	1,372	108,710	1,239,539
2035	26,932	64,574	12,940	11,383	4,064	111,766	1,351,305
2036	27,152	61,793	12,416	12,122	4,050	109,434	1,460,739
2037	23,805	73,596	14,757	8,861	8,761	112,258	1,572,996
2038	24,115	70,427	14,122	9,533	8,481	109,716	1,682,712

Table 1-5 Renewable Energy and REC Adequacy in the Preferred and Recommended Scenario, Base Case

Renewable Energy Achieved (GWh) and Renewable Energy Credits (1,000)																					
Silicon Valley Power																					
Technology	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Solar		62	62	158	157	157	157	156	155	155	155	154	521	521	864	1,203	1,228	1,569	1,574	1,910	1,910
Wind		453	454	1,022	1,422	1,422	1,423	1,416	1,416	1,416	1,417	1,417	1,767	1,725	1,803	2,021	2,021	2,371	2,377	2,721	2,721
Small Hydro		544	544	544	544	544	308	307	307	307	308	307	307	307	308	177	177	177	177	177	177
Landfill Gas		98	98	98	98	98	98	98	98	95	96	84	84	84	84	84	-	-	-	-	-
Geothermal		342	336	329	322	316	310	303	297	291	285	280	274	269	263	258	253	248	243	238	233
Total RECs Generated		**1,499**	**1,494**	**2,150**	**2,543**	**2,536**	**2,295**	**2,280**	**2,274**	**2,265**	**2,260**	**2,242**	**2,954**	**2,905**	**3,323**	**3,742**	**3,679**	**4,365**	**4,371**	**5,046**	**5,041**
RPS Target, %		31%	33%	36%	39%	42%	45%	48%	50%	53%	55%	58%	60%	63%	65%	68%	71%	73%	76%	79%	81%
RPS Target		1,190	1,394	1,584	1,758	1,937	2,128	2,304	2,429	2,556	2,705	2,856	3,010	3,175	3,344	3,515	3,689	3,867	4,047	4,231	4,419
REC Sales Obligation		(111)	(111)	(111)	(111)	(72)	(72)	(72)	(72)	(72)	-	-	-	-	-	-	-	-	-	-	-
RECs Available for compliance		**1,387**	**1,382**	**2,039**	**2,432**	**2,464**	**2,223**	**2,208**	**2,202**	**2,193**	**2,260**	**2,242**	**2,954**	**2,905**	**3,323**	**3,742**	**3,679**	**4,365**	**4,371**	**5,046**	**5,041**
Historical Banked RECs	2,856																				
Deposits		198	-	455	674	527	94	-	-	-	-	-	-	-	-	227	-	498	323	815	623
Withdrawals		-	12	-	-	-	-	96	227	363	445	615	56	270	21	-	11	-	-	-	-
REC Bank Balance		**3,054**	**3,042**	**3,497**	**4,170**	**4,697**	**4,791**	**4,695**	**4,468**	**4,105**	**3,660**	**3,045**	**2,989**	**2,719**	**2,698**	**2,925**	**2,915**	**3,413**	**3,736**	**4,551**	**5,174**
Renewable Generation and REC withdrawals		**1,499**	**1,506**	**2,150**	**2,543**	**2,536**	**2,295**	**2,376**	**2,501**	**2,629**	**2,705**	**2,856**	**3,010**	**3,175**	**3,344**	**3,742**	**3,689**	**4,365**	**4,371**	**5,046**	**5,041**
Renewable and RECs as a % of retail sales		**39%**	**36%**	**49%**	**56%**	**55%**	**49%**	**50%**	**51%**	**54%**	**55%**	**58%**	**60%**	**63%**	**65%**	**72%**	**71%**	**83%**	**82%**	**94%**	**93%**

2.0 Purpose and Background

An overview of the integrated resource planning process and the relevant regulatory policies that guide development of the IRP are summarized below. An outline of the methodology used to perform study evaluations is also provided with a detailed description in Section 7 of this Report. This section also describes the stakeholder process conducted by SVP to welcome and incorporate input from the stakeholders into the IRP process.

2.1 OVERVIEW OF THE INTEGRATED RESOURCE PLANNING PROCESS

Integrated resource planning identifies a long-term plan that provides adequate resources to meet future peak and energy needs, while also maintaining a targeted reserve margin to maintain system reliability, and to achieve a reasonable balance between fiscal responsibility and environmental stewardship. An effective resource plan should also provide the utility with flexibility to accommodate uncertainties and risk related to future conditions, including commodity pricing risk, technological change, and regulatory change.

IRPs require the use of sophisticated analytical tools that allow comparisons of the costs and benefits among alternative supply side and demand side resource options that, together, may constitute a long-term expansion plan. This is often performed using detailed computer models that simulate utility operation on an hour-by-hour basis and are used to develop the long-term costs of an expansion plan. Typical expansion plans consider supply side and demand side options for inclusion in the long term plan. Supply side options include conventional, renewable, and distributed energy resources. Demand side options include demand response programs, energy efficiency programs, and other “behind the meter” options, all of which can be implemented to reduce the overall utility load. SVP, through their procurement process, has continuously evaluated these options coupled with RECs pursuant to meeting CARB’s GHG targets and Renewable Portfolio Standards (RPS).

The key steps of IRP development undertaken by SVP are shown in Figure 2-1. These steps were performed over a one year and were structured to address all regulatory and legislative requirements. Internal IRP approval by the Santa Clara’s City Council is expected in November 2018.

Step 1
- **ESTABLISH GOALS AND OBJECTIVES**
- Identify the aim of the IRP to balance: economics/rates, reliable and flexibile of supply, regulatory compliance, environmental considerations, and stakeholder involvement.

Step 2
- **INVOLVE SVP CUSTOMERS AND STAKEHOLDERS IN IRP PROCESS EARLY**
- Seek individuals and groups who have an interest in SVP's future resource plan (Stakeholders) and invite their participation. Community Meeting #1.
- Engage Large industrial/commercial customers in smaller stakeholder groups and individually.

Step 3
- **DENTIFY PROCESSES, CONSTRAINTS, ASSUMPTIONS**
- Develop IRP process that meets required IRP schedule and contents
- Identify detailed regulatory and other requirements (GHG, RPS, reliability targets, etc)
- identify stakeholder involvement process and evaluate objectives/concerns
- Identify input assumptions needed for detailed modeling ; develop inputs

Step 4
- **IDENTIFY RESOURCE NEEDS**
- Determine the load forecast and need for incremental resources
- Consider requirements / constraints applicable to incremental resources (GHG, renewables, contribution to reliability and stability)

Step 5
- **IDENTIFY RESOURCE OPTIONS AND PORTFOLIOS**
- Identify resource options to be evaluated and develop cost / performance characteristics
- Consider combinations of resource options (portfolios) to be evaluated

Step 6
- **PERFORM ANALYSIS OF OPTIONS, IDENTIFY PREFERRED PLAN**
- Analyze resource portfolios (screening, detailed quantitative or qualitative evaluation)
- Perform sensitivity analyses to assess performance under range of potential market and industry conditions.

Step 7
- **Keep Stakeholders Involved Thourghout the IRP Process**
- As part of the Stakeholder process, SVP provided a Stakeholder Survey to all participants. Community Meeting #2.
- Large industrial/Commercial group meeting

Step 8
- **PREPARE IRP DOCUMENT, SECURE INTERNAL APPROVALS, SUBMIT**
- Develop the IRP document, get feedback from internal and external sources, secure approval from Board and submit in accordance with regulatory requirements

Figure 2-1 SVP's Integrated Resource Planning Process

2.2 METHODOLOGY

Silicon Valley Power is in a state of growth. Since 2011, SVP had seen a steady 2 to 3 percent increase in demand, until 2015-2017 when the average growth increased to 5 percent or more each year. SVP load growth is shown in Figure 2-2. As more large scale projects, including, data center new builds, and mixed-use commercial and residential developments are in the process of being developed and planned in the City of Santa Clara, SVP continually adapts, enhances, and plans load procurement strategies. SVP is a fully integrated utility, is fully resourced, and/or holds "long" generation positions at least through 2030. SVP plans for a diversified portfolio of resources that meets customer loads and meets state mandated requirements. Being fully resourced is a challenge in today's California legislative situation. Many years there are proposals to mandate a particular favored resource (hydrogen storage, battery storage, biomass, solar and wind before the ITC/PTC expires, etc.). Considerations ought to be made for utilities that plan and balance their resources to match their load.

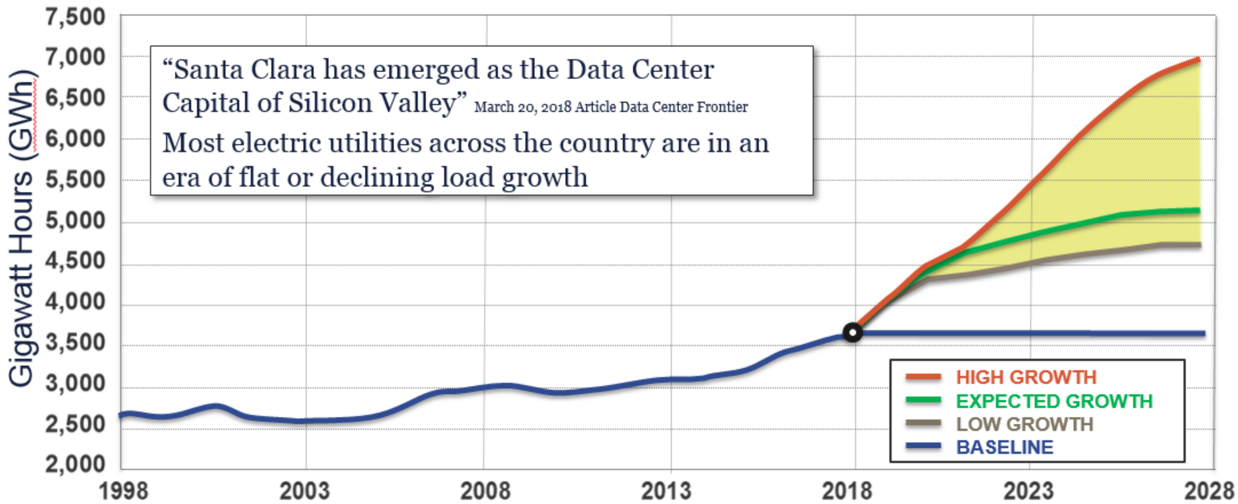

Figure 2-2 SVP Load Growth

When new resources are needed, SVP solicits power projects through a request for proposal (RFP) process and/or through direct offerings from project developers. Also, SVP will respond to RFP's from other generators if the generation and market price fits into the portfolio. Power projects are selected based on cost and, in addition, other market factors such as locational marginal prices (LMPs), portfolio fit, resource location, etc. The process to solicit for or develop resources begins 3 to 5 years before the resource is needed. Between 2016 and 2018 SVP signed 289.9 MW of new renewables that will come on-line in the 2021/2022-timeframe.

The analysis for this IRP utilized the PLEXOS modeling tool to model SVP's power system to rank the various scenarios in terms of present value cost as well as for tracking whether a portfolio achieves other objectives such as GHG and renewable energy goals.

PLEXOS is one of the leading simulation software that uses state-of-the-art mathematical optimization to provide extensive simulation capabilities across electric power, water, and gas systems. PLEXOS is used comprehensively by utilities, ISOs, consultants, and government agencies for Renewable Integration studies, Market design, Integrated Resource Planning, portfolio planning and risk management. PLEXOS has been used by SVP to model its electric portfolio and to produce 10-year budget forecasts.

For this IRP, PLEXOS was used to develop a 20-year IRP that simultaneously satisfies system reliability constraints and RPS targets and minimizes the Net Present Value (NPV) of the sum of investment cost and operation cost over a 20-year planning horizon.

Specifically, the Long-Term Plan module in PLEXOS, was used to develop the least cost expansion plan. The objective function of the Long-Term Plan is the minimization of NPV of the sum of capital cost, fixed cost, and variable operation cost of the system over the planning period from 2019 to 2038. Key inputs to the model include:

- System load forecast
- Existing resources, planned resource additions, and expected retirements
- Operating parameters of the existing resources and costs
- Future candidates, operating parameters, and associated capital cost, fixed and variable operating cost
- System reliability constraint
- Annual RPS target
- System discount rate

It was assumed that SVP has sufficient local and system resource to meet local and system Resource Adequacy constraints, either with its portfolio or through short-term capacity market purchases. For RPS target, the system assumes the RPS target of 60 percent by 2030 and 100 percent by 2045, in line with the requirements of SB100. Table 2-1 shows the annual RPS percentage targets implemented in the model:

Table 2-1 RPS targets modeled in PLEXOS

YEAR	RPS% TARGET		YEAR	RPS% TARGET
2019	31%		2033	68%
2020	33%		2034	71%
2021	36%		2035	73%
2022	39%		2036	76%
2023	42%		2037	79%
2024	45%		2038	81%
2025	48%		2039	84%
2026	50%		2040	87%
2027	53%		2041	89%
2028	55%		2042	92%
2029	58%		2043	95%
2030	60%		2044	97%
2031	63%		2045	100%
2032	65%			

Initial simulation shows that without additional renewable resources, SVP is short in 2032 to meet the annual RPS target. However, given the renewable target requirement in 2030, SVP pulled forward the addition of renewable resources to 2030 to be more proactive and flexible in renewable additions and to be less reliant on the use of RECs to meet the targets.

Given the cost and performance parameters of potential wind and solar projects, the PLEXOS Long-Term Plan module is used to determine the combination of new solar and wind resources that meets RPS targets and minimizes the NPV of investment and operating cost.

In the base case, a balanced procurement of wind and solar is assumed for the renewable resources added, meaning 50 percent of renewable energy added will be wind and the other 50 percent is from the solar. Several sensitivity cases are also simulated:

- High Wind Case with 80 percent wind and 20 percent solar
- High load Sensitivity
- Low load Sensitivity
- High GHG Price Sensitivity

2.3 STATE LAWS, POLICY, AND REGULATIONS

This section explains various California laws and regulatory requirements passed in recent years that apply to SVP and other POUs. Legislation and instructions outlined in SB 350, PUC 9621, and the CEC guidelines to POUs were utilized in this IRP preparation. Additionally, this section describes other laws, policies, and regulations that also impact long-range planning and influenced culminated in the SB 350 and PUC 9621 requirements. Figure 2-3 shows several important legislative actions that impact POUs such as SVP.

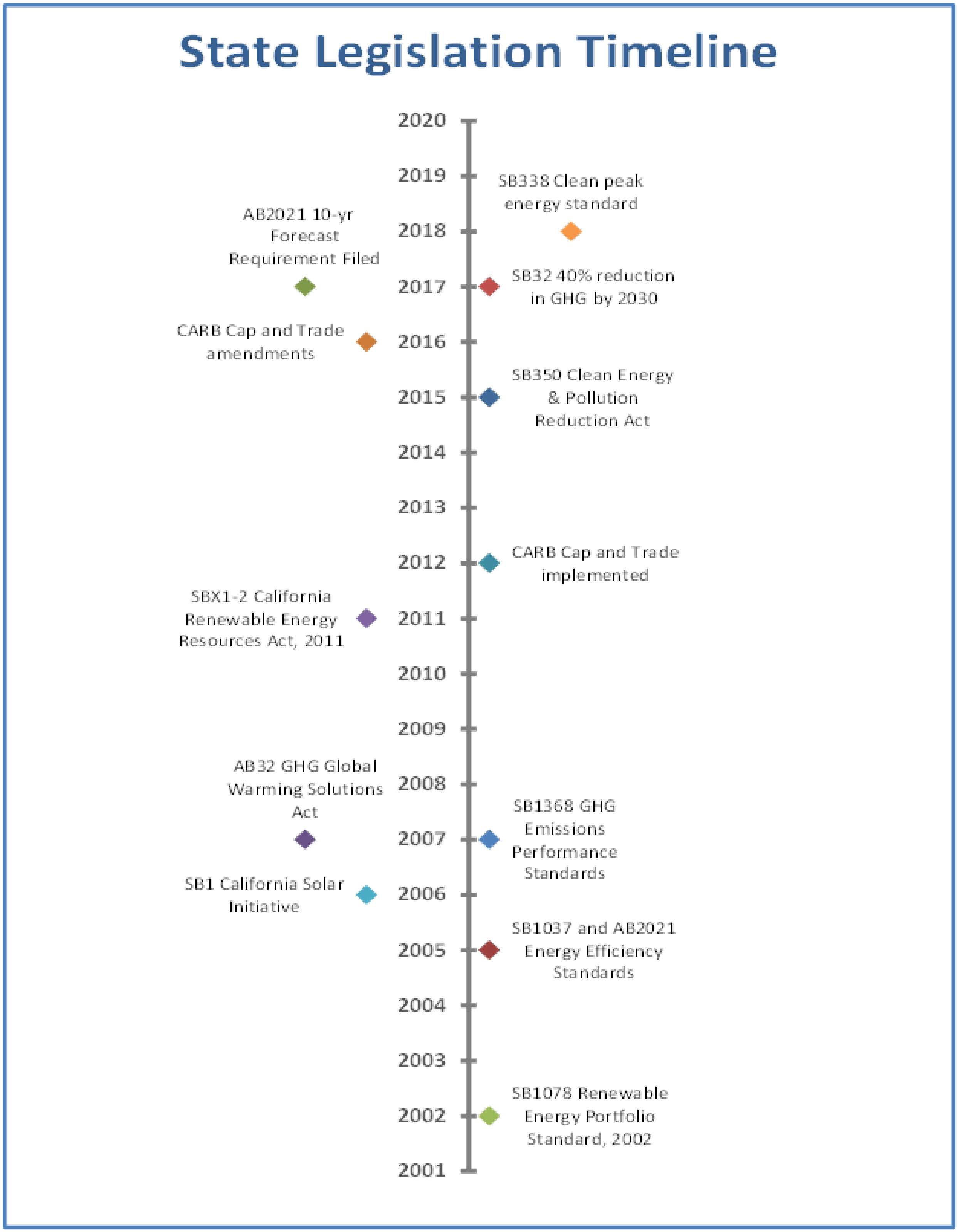

Figure 2-3 Timeline of Key State Legislative Actions Impacting IRP Planning

2.3.1 SB 350, PUC 9621 and SB 100

This Report is filed by SVP in accordance with the mandates of California Senate Bill (SB) 350 (de Leon, Chapter 547, Statutes of 2015) and associated changes to Public Utilities Code (PUC) Section 9621. SB 350, the "Clean Energy and Pollution Reduction Act of 2015," was signed into law by Governor Brown in October 2015 and required POUs with a three-year (2013-2016) average annual energy requirement of greater than 700 GWh to submit an IRP to the California Energy Commission.

SB 350 requires POUs to file an IRP consistent with PUC 9621, and the Energy Commission to review and determine IRP consistency. IRPs must be approved by POUs by January 1, 2019 and filed with the Energy Commission by April 30, 2019. The IRP is to be updated at least once every five years thereafter. SVP will follow the established City of Santa Clara process to bring the IRP forward for approval by the City Council, as is done with all compliance obligations that require governing board approval per law, regulation or California Code, Public Utilities Code. Budgeting, planning, forecasting, procurement, reporting, compliance is a part of SVP's normal business processes and practices. SVP will continually update, modify the business practices that feed into the IRP to reflect current market conditions, technologies, and changes in regulation and bring it to the Santa Clara City Council every five years.

PUC 9621 established several targets that affect future resource additions. These include:

- Achieving a statewide target that doubles energy efficiency savings in electricity and natural gas end uses by 2030 to the extent it is cost-effective, feasible, and does not adversely impact public health and safety
- The development of IRPs that achieve GHG emissions reduction targets established by the CARB, in coordination with the CPUC and the Energy Commission that result in GHG emission reductions of 40 percent from 1990 levels by 2030.

  NOTE: In July, 2018 the CARB staff, in coordination with the CEC and CPUC staff, issued targets that were developed around an economy-wide, 260 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) as the mass-based GHG target for the state in 2030.[4] The achievement of this target is spread across all GHG-contributing sectors, with the electric sector targeted to account for a 51 percent to 72 percent reduction from the 1990 GHG emission level of 108 $MMTCO_2e$. This goal is show in Table 2-2.
- Achieving a renewable resource level of at least 50 percent by 2030 for the amount of electricity generated and sold to retail customers. PUC 9621 also requires compliance with the interim renewable targets in the California Renewables Portfolio Standard Program; for periods beyond the 2018 date of this IRP, the interim targets are 33 percent by the end of 2020, 40 percent by the end of 2024, and 45 percent by the end of 2027.[5] Annual updates must be submitted by the POU.
- These objectives are to be met while also complying with the goals in PUC 454.52 related to serving customers at just and reasonable rates, minimizing ratepayer impacts, ensuring

[4] California Air Resources Board, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018.

[5] PUC Division 1, Part 1, Chapter 2.3, Article 16, 399.11-399.32, the interim requirements are listed in 399.15(b.2.B) and 339.30 (c, 2).

reliability, strengthening the transmission and distribution system, enhance demand-side management, and minimizing pollutants with early priority on disadvantaged communities.

Table 2-2 Estimated 2030 GHG Emissions by Sector (MMTCO2e)

SECTOR	1990	2030 SCOPING PLAN RANGES	% CHANGE FROM 1990
Electric Power	108	30-53	-72 to -51
Agriculture	26	24-25	-8 to -4
Residential and Commercial	44	38-40	-14 to -9
High GWP	3	8-11	267 to 367
Industrial	98	83-90	-15 to -8
Recycling and Waste	7	8-9	14 to 29
Transportation	152	103-111	-32 to -27
Natural Working Lands Net Sink	-7	TBD	TBD
Subtotal	431	294-339	-32 to -21
Cap-and-Trade Program	n/a	34-79	n/a
Total	431	260	-40
California Air Resources Board, Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets, July 2018, p. 23.			

The CARB document also set forth proposed GHG targets for the individual POUs. These targets are shown in Table 2-3 and include a targeted 2030 range of between 275,000 and 485,000 MTCO2e for SVP; this amounts to 0.915 percent of the 2030 electricity sector emissions. CARB has proposed to update these targets on a 5-year basis to coincide with the IRP filing requirements.

Table 2-3 POU Share of 2030 GHG Emissions Projected by CARB

POU	% OF 2030 ELECTRIC SECTOR EMISSIONS	LOW 2030 TARGET $MTCO_2E$*	HIGH 2030 TARGET $MTCO_2E$*
City of Burbank	0.430	129,000	228,000
City of San Francisco	0.041	12,000	22,000
City of Anaheim	1.015	305,000	538,000
City of Palo Alto	0.174	52,000	92,000
City of Pasadena	0.426	128,000	226,000
City of Riverside	0.918	275,000	487,000
City of Vernon	0.497	149,000	263,000

POU	% OF 2030 ELECTRIC SECTOR EMISSIONS	LOW 2030 TARGET $MTCO_2E$*	HIGH 2030 TARGET $MTCO_2E$*
City of Redding	0.191	57,000	101,000
City of Glendale	0.396	119,000	210,000
Imperial Irrigation District	1.745	524,000	925,000
L.A. Dept of Water & Power	8.851	2,655,000	4,691,000
Modesto Irrigation District	1.055	317,000	559,000
City of Roseville	0.452	136,000	240,000
Silicon Valley Power	0.915	275,000	485,000
SMUD	3.621	1,086,000	1,919,000
Turlock Irrigation District	0.629	189,000	333,000
*Low target based on 30 $MMTCO_2e$ for the sector; high target based on 53 $MMTCO_2e$ for the sector. Emission targets for each utility are rounded to the nearest 1,000 $MTCO_2e$.			
California Air Resources Board, *Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets*, July 2018, p. 30.			

In September 2018, SB 100, known as *The 100 Percent Clean Energy Act of 2017*, passed and further modifies the RPS requirements from 50 percent by 2030 to 60 percent by 2030, and create the policy of planning to meet all of the state's retail electricity supply with a mix of RPS-eligible and zero-carbon resources by December 31, 2045, thereby achieving a 100 percent clean energy supply.

SB 100 accelerates the RPS obligations for retail sellers, including SVP and other POUs as follows:

- From 40 percent to 44 percent by 2024
- From 45 percent to 52 percent by 2027; and
- From 50 percent to 60 percent by 2030.

SB 100 also states that achieving this policy shall not increase carbon emissions elsewhere in the western grid and shall not involve resource shuffling. The bill would also require the CPUC, CEC, the CARB, and other state agencies to incorporate this policy into their regulations and decisions.

SB 338 was signed into law in September 2017 and became effective in January, 2018. This law requires California utilities to rely on energy efficiency, demand management, energy storage, and other strategies to meet peak electricity needs. This included revisions to Public Utilities Code section 9621(c), requiring the local governing board to *"consider the role of existing renewable generation, grid operational efficiencies, energy storage, and distributed energy resources, including energy efficiency, in helping to ensure each utility meets energy needs and reliability needs in hours to encompass the hour of peak demand of electricity, excluding demand met by variable renewable generation directly connected to a California balancing authority, as defined in Section 399.12, while* *reducing the need for new electricity generation resources and new transmission resources in achieving the state's energy goals at the least cost to ratepayers."*

SVP notes that development of its IRP began well in advance of the effective date of these provisions. However, as part of the comprehensive process SVP has undertaken to develop this current IRP, the utility reviewed and considered resource options that included all of the technologically feasible and cost effective options available to SVP, including what options would be best utilized for energy needs and reliability requirements during hours of peak demand for the utility. This includes a review of the best available options considering both new and existing preferred resources, as would necessarily be assessed in order to ensure that SVP provides its customers with the cleanest and most cost effective generation resources, while also ensuring that SVP meets all of the statutory requirements of not only Section 9621, but other procurement and resources mandates, as well.

SVP currently meets peak demand through its diverse portfolio of resources, which has been determined to result in the least cost to the ratepayers and is projected to remain the least cost method to meet forecast demand until 2023. Additional capacity needs will be met with capacity purchases. As costs of energy storage continues to decline, SVP plans to re-evaluate energy storage potential annually. Section 5 of this report provides a detailed description on those planned efforts.

2.3.1.1 CEC IRP Guidelines

To facilitate IRP preparation and submittal, the CEC developed IRP guidelines for the state POUs. The guideline document, entitled *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*, was issued in July, 2017 (updated in August, 2018) and established a number of requirements to be included in the IRP Filing. These requirements include the following:

- POUs must submit the four Standardized Tables to the Energy Commission as part of the IRP Filing. These tables consist of the following:
    1. Capacity Resource Accounting Table (CRAT): Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.
    2. Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.
    3. GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.
    4. RPS Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.

    The four Standardized Tables for the adopted scenario are presented in Appendix A, and summary tables of this information are presented for recommended scenario in Section 8. The numbers presented in Section 8 are based on the modeling results. The Standardized Tables include some modifications to the numbers based on more recent information and takes precedence over Section 8.

- The minimum planning period begins January 1 of the year that the POU's board adopts the IRP (this is 2019 for SVP) and must go through 2030, although longer planning periods are encouraged.
- POUs are encouraged to evaluate alternative resource options through various scenarios and sensitivity analyses.
- The IRP Filing must include supporting information used to develop the Standardized Tables and other studies, data, analyses used or relied upon in developing the IRP.
- POUs are required to report the forecasted peak demand, forecasted retail sales, other loads, and net energy for load in the EBT. The IRP must explain the demand forecast method and assumptions utilized. The CEC encourages alternative demand forecast scenarios to be part of the IRP.
- The IRP must report the mix of resources in the required tables; this includes RPS procurement information in the RPT. The mix of resources refers to short-term and long-term electricity, electricity-related, and demand response products. RPS information provided must demonstrate the achievement of the RPS target by listing the RPS procurement targets, the projection of renewables as contained in a RPS procurement plan. The reporting of resource mix must also include the impacts of energy efficiency and demand response resources. Energy storage and transportation electrification should also be addressed in the IRP and included in the required tables, as appropriate.
- The IRP should address system reliability. This includes explaining how the planning reserve margin was established and a discussion of any local transmission constrained areas.
- GHG emission intensities must be reported in metric tons of carbon dioxide equivalent per MWh for each supply resource reported in the EBT.
- The IRP should be consistent with the goal of achieving just and reasonable rates and must include as Supporting Information, a report on rate impacts under the IRP plan if that report was considered in the IRP planning.
- The IRP should report on the contribution of the IRP to increasing the diversity, sustainability, and resilience of the transmission and distribution system.
- The IRP should be consistent with minimizing localized air pollutants and other GHG emissions with early priority on disadvantaged communities.

Table 2-4 lists the IRP Filing requirements as listed in the CEC guidelines document and indicates where in this IRP the corresponding information is provided. This table is also provided after the acronym table at the beginning of this IRP document.

Table 2-4 Summary of Key IRP Filing Requirements and Location in SVP's IRP

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN SVP'S IRP
A. Planning Horizon and Objective of Expansion Plan	"adopt an IRP that ensures the utility achieves the specific goals and targets by 2030, including...greenhouse gas emissions reductions of 40 percent below 1990 levels, and...at least 50 percent of eligible renewable resources...The minimum planning horizon...begins no later than January 1 of the year that the POU's governing board adopts the plan and ends no earlier than December 31, 2030...POUs are encouraged to undertake and present analysis....that addresses the post-2030 period"	Section 8
B. Scenarios and Sensitivity Analysis	"IRP Filings....must meet the requirements of PUC Section 9621. POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options."	Section 8
C. Standardized Tables	"POUs must submit the following four Standardized Tables... • Capacity Resource Accounting Table (CRAT) • Energy Balance Table (EBT) • RPS Procurement Table (RPT) • GHG Emissions Accounting Table (GEAT)"	Appendix A
D. Supporting Information	"(1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP... and (2) additional information required by these guidelines. Supporting Information supplements the data submitted in the Standardized Tables."	Section 4, 5, 7; all Appendices
E. Demand Forecast	"1. Reporting Requirements...annual forecasted peak demand (MW) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT... 2. Demand Forecast Method and Assumptions. 3. Demand Forecast – Other Regions. If the POU uses system modeling...the IRP Filing must include the demand forecast assumptions for regions outside the POU jurisdiction."	Section 4, Appendix A
F. Resource Procurement Plan	"...the mix of resources... in the IRP [as]...reported on the CRAT, EBT, and GEAT, and RPS procurement must also be reported on the RPT [along with] all inputs, assumptions, and methodologies ...The IRP Filing must address: 1. Diversified Procurement Portfolio 2. RPS Planning Requirements 3. Energy Efficiency and Demand Response Resources 4. Energy Storage 5. Transportation Electrification"	Section 8, Appendix A

ITEM	SELECTED TEXT FROM THE *CEC GUIDELINES*	LOCATION IN SVP'S IRP
G. System and Local Reliability	"Filing POUs [must] adopt an IRP to… meets the goal of ensuring system and local reliability…and report: 1. Reliability Criteria…the planning reserve margin and how it was determined. 2. Local Reliability Area. The IRP Filing must identify any local transmission constrained areas in the POU service territory…" 3. Net Demand in Peak hours… how renewable resources, multi-hour energy storage, and distributed energy resources, including energy efficiency, were considered for meeting reliability needs during net peak hour	Section 4
H. Greenhouse Gas Emissions	"POUs must report in the GEAT estimated emissions intensities (in metric tons of carbon dioxide equivalent [CO_2e] per megawatt hour…for each supply resource reported in the EBT."	Section 8, Appendix A
I. Retail Rates	"…the IRP Filing must include, as Supporting Information, a report or study on rate impacts under the IRP scenario, if that report or study was considered by the local governing authority as part of its IRP planning."	Section 8
J. T&D Systems	"…adopt and IRP [that] achieves the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities."	Section 3
K. Localized Air Pollutants and Disadvantaged Communities	"…adopt IRPs to…[achieve] the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities…[discuss] how current programs and policies in place…address local air pollution…[and] how programs assist and prioritize disadvantaged communities."	Section 8
Summarized from Chapter 2 of Vidaver David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy. 2017 and 2018. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2017-004-CMD and CEC-200-2018-004-SD.		

2.4 OTHER RELEVANT STATE LEGISLATION AND EXECUTIVE ORDERS

The following is a summary of key bills and orders, arranged chronologically within the categories of GHG emissions, energy efficiency, renewable energy, and solar power, in chronological order. SB 350 and PUC 9621 are, in many ways, the outgrowth of several preceding bills or executive orders affecting the electric utility industry.

2.4.1 Greenhouse Gas Emissions

2.4.1.1 Greenhouse Gas Emissions – Global Warming Solutions Act (AB 32)

On January 1, 2007, Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006 (the GWSA) took effect, prescribing a statewide cap on global warming pollution with a goal of returning to 1990 greenhouse gas emission levels by 2020. The law required utilities to report greenhouse gas emissions to the CARB, and allowed the CARB to adopt specific regulations for reducing greenhouse gas emissions.

On October 20, 2011, the CARB adopted a regulation implementing a cap-and-trade program, which became effective on January 1, 2012. The program, which was implemented in phases, covers emissions from electricity generators, electricity importers, large industrial sources, and transportation fuels. The cap on emissions was established in 2013, and was designed to decline every year consistent with reaching the 1990 emission levels by 2020. To achieve the goal, carbon allowances are distributed annually in amounts equal to the cap for that year. Some allowances are given freely, and others are auctioned off. Allowance owners may use allowances to emit carbon or sell the allowances on the secondary market.

CARB held an October 2, 2015 workshop to begin the development of 2016 cap-and-trade program amendments. CARB stated four objectives: (i) to extend the program beyond 2020; (ii) to improve programmatic efficiencies (covering auctions and data reporting); (iii) to better reflect the latest technical data on global warming potential and experiences with other emissions trading programs; and (iv) to maintain the environmental and market integrity of California's program.

The SVP resource plan must ultimately conform to the California greenhouse gas emission requirements stated in AB 32. The AB 32 scoping plan regulations require certain economic sectors of California to reduce GHG emissions to 1990 levels by 2020 through a Cap and Trade Emissions Reduction Program. As part of this Program, SVP must submit "allowances" for its emissions from its owned facilities, as well as a portion of the electricity SVP brings into California over its transmission assets. An allowance represents one metric ton of GHG emissions. The allowances are administered by the CARB.

In July of 2018, CARB released their staff report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets the proposed GHG Planning Target Ranges for publicly owned utilities, see Table 2-2.

In 2017, SVP divested its coal interest in the M-S-R San Juan generating station and ceased its natural gas power purchase agreement with Graphic Packaging. A total combined metric ton reduction of 434,983 MTCO2e resulted. This achievement puts SVP on its way to attaining the 2030 Sector Emissions targets cited above. SVP does have ownership in natural gas power plants and will continue to use those resources as needed as long as it makes financial sense. In the IRP modeling, SVP evaluated a high GHG cost scenario.

2.4.1.2 Carbon Emissions versus Carbon Intensity of Energy Delivered to Retail Customers

There are multiple ways to account for GHG emissions.

- Total Generation Portfolio GHG emissions through the mandatory greenhouse gas reporting (MRR) accounts for power plant ownership only. This report does not account for resources that are dispatched to the market that do not serve an entities retail load.
- Power Content Label/Power Source Disclosure is being updated through AB 1110 to include the carbon intensity of the power content label for resources delivered to the retail customers. This method does not account for the actual carbon content of unspecified energy in a given hour and does not account for unbundled RECs. The PCL is not designed to capture the actual GHG impact of a load serving entities demand portfolio in correlation with the procurement of resources and market dispatch. This method does not account for cause and causation GHG impacts to the electric grid nor does it account for the hourly GHG impact of resources

dispatched. The PCL is not an accurate measure of validating GHG compliance with the State's targets.

- SVP will use an alternative method to account for annual carbon emissions for energy delivered to the retail customers. This method aligns the mix of resources procured and dispatched into the energy markets and ultimately counted as delivered to our customers. SVP follows the State's loading order using renewable and GHG free resources to serve SVP's retail customers first. Excess resources or resources dispatched to support the California Independent System Operator Corporation (CAISO) market are not included in the GHG content delivered to retail customers. SVP will utilize the CAISO's hourly carbon numbers when SVP buys from the grid.

2.4.1.3 Greenhouse Gas Emissions – Emissions Performance Standard (SB 1368)

Senate Bill 1368 (SB 1368) became law on January 1, 2007. The bill provides for an emission performance standard (EPS), which restricts new investments in baseload fossil fuel electric generating resources that exceed the rate of greenhouse gas emissions for existing combined-cycle natural gas baseload generation. SB 1368 allows the CEC to establish a regulatory framework to enforce the EPS for POUs such as SVP. The CEC regulations prohibit any investment in baseload generation that does not meet the EPS of 1,100 pounds of carbon dioxide (CO_2) per MWh of electricity produced, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

2.4.1.4 Greenhouse Gas Emissions: SB 32 and AB197

SB 32, which was implemented on January 1, 2017, requires the California Air Resources Board (CARB) (the designated state agency charged with monitoring and regulating sources of emissions of greenhouse gases), to ensure that statewide greenhouse gas emissions are reduced by at least 40 percent below the 1990 level no later than December 31, 2030. Companion legislation, Assembly Bill 197 (AB 197), also implemented on January 1, 2017, increases legislative oversight of the CARB. In addition, AB 197 requires that the CARB, if adopting rules and regulations to achieve emissions reductions beyond the statewide greenhouse gas emissions limit, protect the state's most impacted and disadvantaged communities, follow specified requirements, consider the social costs of the emissions of greenhouse gases, and prioritize emission reduction rules and regulations that achieve specified results.

2.4.1.5 Energy Efficiency (SB 1037; AB 2021)

Senate Bill 1037 (SB 1037) was signed by then Governor Schwarzenegger on September 29, 2005. The bill requires that each POU, including SVP, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost-effective, reliable, and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs.

California Assembly Bill 2021 (AB 2021), signed by then Governor Schwarzenegger on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter, covering a ten-year future horizon. A subsequent bill has changed the time interval for establishing annual targets to every four years. Reporting requirements under AB 2021 include: (i) the identification of sources of funding for the investment in energy efficiency and demand reduction programs; (ii) the methodologies and input assumptions used to determine cost-effectiveness; and (iii) the results of an independent evaluation to measure and verify energy efficiency savings and demand reduction program impacts.

2.4.2 Renewable Energy

2.4.2.1 Portfolio Standard (SB 1078)

The adoption of Senate Bill 1078 in 2002 required utilities to meet or exceed a standard of 20 percent of its annual energy needs to be provided by state qualified renewable resources by 2017. The California Renewable Energy Resources Act, enacted in 2011 as SBX1-2 ("SBX1-2"), required utilities to develop and implement a renewable energy resource plan that provides a specified average of the Electric System's retail sales from eligible renewable energy resources. Additionally, the target was increased to 33 percent by 2020 as described in the section below. Legislation enacted in 2015, Senate Bill 350 ("SB 350"), requires that electricity generated each year from eligible renewable energy resources be at least 50 percent by December 31, 2030. SVP has a history of focusing on renewable procurement. SVP's 2017 power mix consisted of 38 percent eligible renewable resources. When large hydroelectric resources are included, SVP's power mix was 72 percent Greenhouse Gas (GHG) free. SVP expects to exceed the 50 percent mandate in 2030 and beyond based its existing system, RECs, and projected load.

2.4.2.2 Renewables Portfolio Standard (SBX1-2)

Senate Bill X1-2 (SBX1-2), the "California Renewable Energy Resources Act," was signed into law by Governor Brown on April 12, 2011. SBX1-2 codifies the RPS target for retail electricity sellers to serve 33 percent of their loads with eligible renewable energy resources by 2020. As enacted, SBX1-2 makes the requirements of the RPS program applicable to POUs.

SBX1-2 requires each POU to adopt and implement a renewable energy resource procurement plan involving the procurement of at least the following amounts of electricity products from eligible renewable energy resources, which may include renewable energy certificates ("RECs"), as a proportion of total kilowatt hours sold to the utility's retail end-use customers:

(i) over the 2011-2013 compliance period, an average of 20 percent of retail sales from January 1, 2011 to December 31, 2013, inclusive;

(ii) over the 2014-2016 compliance period, a total equal to 20 percent of 2014 retail sales, 20 percent of 2015 retail sales, and 25 percent of 2016 retail sales; and

(iii) over the 2017-2020 compliance period, a total equal to 27 percent of 2017 retail sales, 29 percent of 2018 retail sales, 31 percent of 2019 retail sales, and 33 percent of 2020 retail sales. (More recently, SB 350 increased the statewide RPS to 50 percent by 2030.)

In addition to meeting the renewable energy percent procurement target, the RPS established certain Portfolio Content Categories (PCC) that further divided the eligible renewable energy resources to be procured and established certain limits. The PCCs essentially classify renewable resources into one of four categories based on location of the interconnection and other factors as follows:

PCC1: products must be bundled and the POU may not resell the energy; the resource's first point of interconnection must be to a distribution system serving end-users *within* a California balancing authority area; renewable energy products having a first point of interconnection outside of a California balancing authority area must be scheduled hourly into the area without substituting electricity from another source.

PCC2: products must be bundled and interconnected to a network within WECC; the electricity must be scheduled into a California balancing authority area; the products must have a first point of interconnection *outside* of a California balancing authority area, and the electricity must not be in the portfolio of the POU prior to the date of contract or ownership agreement; the electricity must be scheduled into the California balancing authority area within the same calendar year that the electricity is generated, and the energy may not be sold back by the POU.

PCC3: unbundled renewable energy credits and products that do not meet the requirements of PCC1 or PCC2.

PCCO: renewable energy under contract prior to June 1, 2010 provided that the resource meets the RPS eligibility requirements in effect when the procurement agreement was executed; subsequent amendments do not increase the capacity or production or substitute a different resource (any such change would be classified into PP1, 2, or 3 and follow the portfolio balance requirements); and the duration of the contract may be extended if the original contract was for 15 years or more.

For the 2017-2020 period, a minimum of 75 percent of the renewable energy must be classified as a PCC1 resource and a maximum of 10 percent can be a PCC3 resource.

2.4.2.3 Solar Power (SB 1)

On August 21, 2006, Governor Schwarzenegger signed into law California Senate Bill 1 (also known as the "California Solar Initiative"). This legislation requires POUs, including SVP, to establish a program supporting the SB 1 goal to install 3,000 MW of photovoltaic energy in California. POUs are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer-funded incentives. The legislation gives a POU the choice of selecting an incentive based on the installed capacity or based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives would be required to decrease at a minimum average rate of 7 percent per year. POUs also have to meet certain reporting requirements regarding the installed capacity, the number of installed systems, the number of applicants, the amount of awarded incentives, and the contribution toward the program's goals.

2.5 FEDERAL ENERGY LEGISLATION

Currently, the state requirements described above dictate the renewable and emission standards for POUs in California. It is possible that in the future, more restrictive requirements could be mandated at the federal level resulting from new laws or regulations implemented by the U.S. Environmental Protection Agency (EPA).

In 2009, the EPA issued an "endangerment finding" that, it argued, allowed it to regulate emissions of greenhouse gases under existing law. This finding, and other findings and proposed rules, were challenged in court. Ultimately, it was found that the EPA had the authority to regulate greenhouse gas emissions from sources that were already covered under other emissions programs.

Meanwhile, the EPA developed a set of rules and regulations called the Clean Power Plan ("CPP"), which outlined specific emissions reductions targets for every state and required states to develop their own plans to achieve the targets. The CPP was also challenged in courts, with the result that a "stay," delayed implementation while the CPP worked its way through the courts. Before a decision was reached on the legality of the CPP, the EPA, under the administration of President Trump, announced it would repeal the CPP and replace it with other regulations. The repeal is still at the proposal phase as of the publication of this Report.

Greenhouse gas regulation at the federal level remains uncertain and, therefore, it is difficult to predict the extent to which future federal policy on the subject could impact SVP operations. This IRP was prepared assuming that California GHG emission reduction requirements would be the more stringent applicable requirements.

2.6 SVP'S PUBLIC STAKEHOLDER PROCESS

This IRP benefited from the public input process. The stakeholder process involved seeking groups who have an interest in future resource plans (Stakeholders) and inviting their participation so that relevant issues were identified and addressed. Through the process, participants were engaged and involved early in the IRP development. The result was that the concerns and perspectives of Stakeholders were considered, with the resulting resource plan achieving what is considered to be an appropriate balance of utility and Stakeholder objectives.

The Stakeholder process began with Silicon Valley Power's Strategic Plan launch in the spring of 2018. Stakeholders included large customers, local businesses, the community at large and employees. In the summer and fall of 2018, SVP held additional IRP specific meetings with interested Stakeholders. Additionally, SVP sought stakeholders' input by using the City of Santa Clara' s OpenGov - Open City Hall Platform to conduct a public survey. The survey was open from June to September 2018. SVP received 216 responses, 90 registered. Results are in Appendix B.

The IRP was subsequently discussed at the large customer meeting in the Fall of 2018 along with additional follow up with residential customers to coincide with the timing of the IRP presentation to the City Council in November 2018.

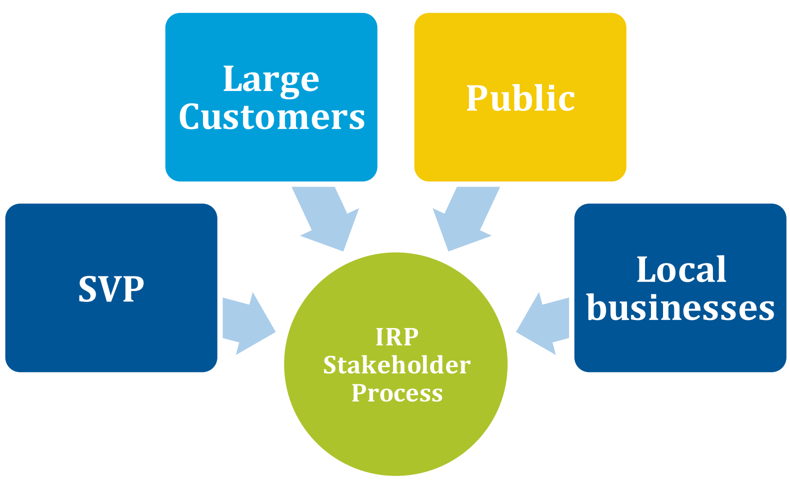

Figure 2-4 Stakeholder Engagement Participants

3.0 Existing Resources and System Description

The City of Santa Clara (the "City" or "Santa Clara") is located at the northwest border of the City of San Jose in Santa Clara County. SVP, a department within Santa Clara, has provided all electric service within the City's boundaries since 1896. SVP is responsible for operating the electric system consisting of generation, transmission, and distribution facilities. SVP is an enterprise fund, with budgeting separated from that for the City's general fund. SVP has an obligation to pay the general fund each year a sum equivalent up to 5 percent of the utility's revenues net of expenses, as a contribution in lieu of taxes.

As of 2017, the City's population was estimated at 129,000. As of December 2017, SVP served over 55,000 customers with over 3,500 GWh in sales and a peak demand of 587 MW. Eighty-four percent of the total number of customers are residential, however, over 90 percent of the utility retail sales are to commercial and industrial customers; shown in Figure 3-1 below. Approximately 74 percent of electric load is attributable to its largest "Key" Customers. Over 46 percent of the commercial and industrial sales comes from data centers.

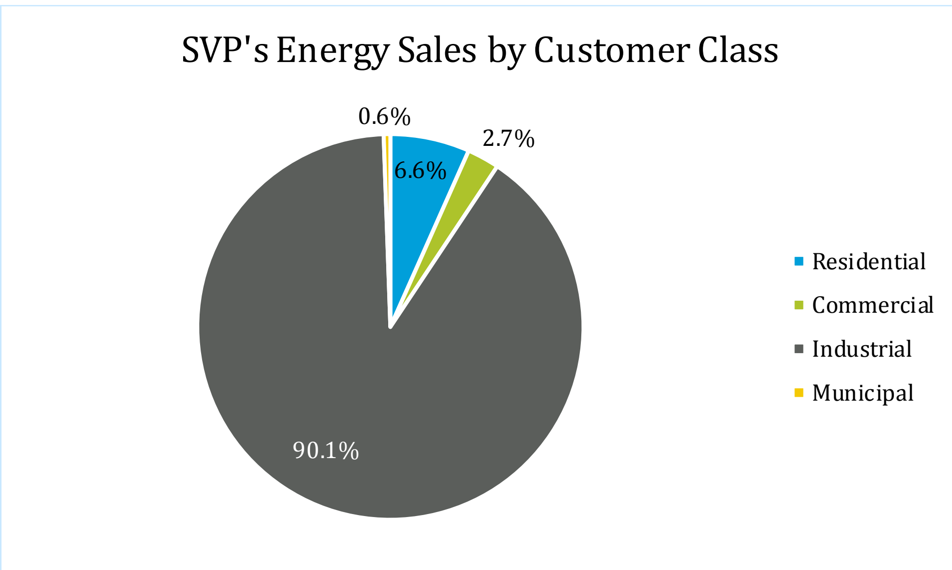

Figure 3-1 **SVP's Customer Mix by sales as of 2017**

This section provides a description of all the resources currently procured to meet customer load. SVP's portfolio includes City-owned resources, jointly-owned resources, and resources procured through Power Purchase Agreements. The City is a member of two joint powers agencies - Northern California Power Agency (NCPA) and M-S-R Public Power Agency (M-S-R PPA). Each of these agencies have shared interests in several facilities as described later in this section.

This IRP accounts for the City's Metered Subsystem Aggregation Agreement (MSSA) between the Northern California Power Agency (NCPA) and CAISO where SVP uses NCPA as its schedule coordinator and is not obligated to offer its generation into the CAISO market. SVP pays a Transmission Access Charge to CAISO for energy delivered into its service area.

SVP's energy resource planning strategies, methods and processes are consistent with applicable WECC and NERC standards, SVP's Strategic Plan, the MSSA and other relevant contracts into which the City has entered, Good Utility Practice, and sound economic and business principles. SVP will continue to maintain an integrated and balanced portfolio of resources that is sufficient to meet its obligations.

When procuring resources to serve customer load, risk management processes and procedures are followed using the City's official Risk Management Policy. SVP also procures fuel for its natural gas-fired generating facilities with supply contracts that are laddered with staggered start times and durations to limit its exposure to fuel price fluctuations. Risk management practices apply to decisions concerning the mix of resources and their loading order, including the decision to use supply or demand-side resources, whether to operate inside Santa Clara versus remote resources, what type of generation to procure and other questions. In general, SVP's approach has been to maintain a diverse portfolio of generating resources and market energy resources so that it can reduce risk and minimize exposure to loss of generating capacity. Due to SVP's dependence on transmission services provided by the CAISO and others to bring power from remote locations, SVP is exposed to costs increases and to power delivery interruptions during emergencies or facility failures. SVP continually seeks strategies to reduce the impacts of transmission cost increases and maintains contingency plans for such occurrences.

A summary of SVP's 2017 power supply resources and the percentage of total energy supplied by each are presented in Table 3-1. This does not include SVP's excess renewable resources sold to third parties. Due to SVP's long position in renewables, SVP will either sell excess renewable generation to other entities or bank RECs in excess of the RPS requirements to be utilized in future years. This allows SVP to evaluate additional eligible renewable resources projects that will optimize the value for the customers. Table 3-2 summarizes resources that are currently in SVP's portfolio for future delivery. Figure 3-2 shows the location of SVP's existing resources and Figure 3-3 shows the mix of energy production in 2017.

Table 3-1 SVP's Power Supply Resources

SOURCE	RESOURCE TYPE	RPS ELIGIBLE	PCC TYPE	2017 CAPACITY AVAILABLE (MW)	2017 ACTUAL ENERGY (GWH)*
City Owned/Contracted Power					
Ameresco FWD	Landfill Gas	Yes	PCC1	4.2	32.6
Ameresco Landfill	Landfill Gas	Yes	PCC0	0.8	2.1
Ameresco VASCO	Landfill Gas	Yes	PCC1	4.3	33.1
Stony Creek Hydro System	Small Hydro	Yes	PCC0	11.6	32.9
Cogeneration	Gas	No		7.0	46.6
DVR	Gas	No		147.8	405.6
Friant 1	Small Hydro	Yes	PCC1	25.0	130.8
Friant 2	Small Hydro	Yes	PCC1	7.3	31.5
G2 Landfill	Landfill Gas	Yes	PCC0	1.6	11.0
Gianera Generating Station	Gas	No		49.5	5.5
Graphic Packaging	Contract	No		27.7	121.5
Grizzly Hydro	Small Hydro	Yes	PCC0	17.7	91.2
Jenny Strand	Solar	Yes	PCC1	0.1	0.2
Manzana Wind	Wind	Yes	PCC1	50.0	134.0
Recurrent Solar	Solar	Yes	PCC1	20.0	57.7
SCL Exchange	Contract	No			0
Tioga Solar	Solar	Yes	PCC1	0.45	0.539
Tri Dam Southern/Sandbar	Small Hydro	Yes	PCC1	16.2	121.4
Tri-Dam Beardsley	Small Hydro	Yes	PCC1	11.5	83.8
Tri-Dam Donnells	Hydro	No		72.0	432.7
Tri-Dam Tulloch	Small Hydro	Yes	PCC1	25.7	139.5
WAPA small hydro	Small Hydro	Yes	PCC0	10.0	9.0
WAPA	Hydro	No		126.0	439.3
Total City-Owned Resources				**636.5**	**2,357.0**
Northern California Power Agency					
NCPA Collierville	Hydro	No		85.6	378.7
NCPA LEC	Gas	No		72.0	1876.7
NCPA CT	Natural Gas	No		31.0	7.2
NCPA New Spicer	Small Hydro	Yes	PCC0	6.0	13.4
Geo Plant 1-4 4	Geothermal	Yes	PCC0	55.7	62.1
Geo Unit 3Onsite Load	Geothermal	Yes	PCC0	0.0	6.3
Solar Geo Unit 1	Solar	Yes	PCC0	1.4	0.4
Solar Geo Unit 2	Solar	Yes	PCC0	1.3	0.9
Solar Hydro	Solar	Yes	PCC0	0	0.016
Total NCPA Resources				**253.0**	**461.8**
MCR Resources					
Big Horn 1	Wind	Yes	PCC0	105.0	246.5
Big Horn 2	Wind	Yes	PCC0	17.0	42.0
San Juan	Coal	No		51.0	331.3
Total MSR Resources				**173.0**	**619.8**
Total Renewable Resources				**392.9**	**1,282.9**
Total Zero Carbon Resources, not counted as renewable				**283.6**	**1,250.7**
Total (Generated and Purchased)				**1,062.0**	**3,439.0**

* Generation as delivered to retail sale customers

Source: Silicon Valley Power

Table 3-2 SVP's Power Supply Resources for future delivery

SOURCE	RESOURCE TYPE	RPS ELIGIBLE	PCC TYPE	INSTALLED CAPACITY (MW)	DELVERY YEAR
City Owned Power					
Central 40 Solar	Solar	Yes	PCC1	40.0	2021
Rooney Ranch	Wind	Yes	PCC1	19	2021
Sand Hill A	Wind	Yes	PCC1	13.0	2021
Sand Hill B	Wind	Yes	PCC1	17.5	2021
Viento Loco	Wind	Yes	PCC1	200.0	2022
Total Renewable Resources				**289.5**	

Source: Silicon Valley Power

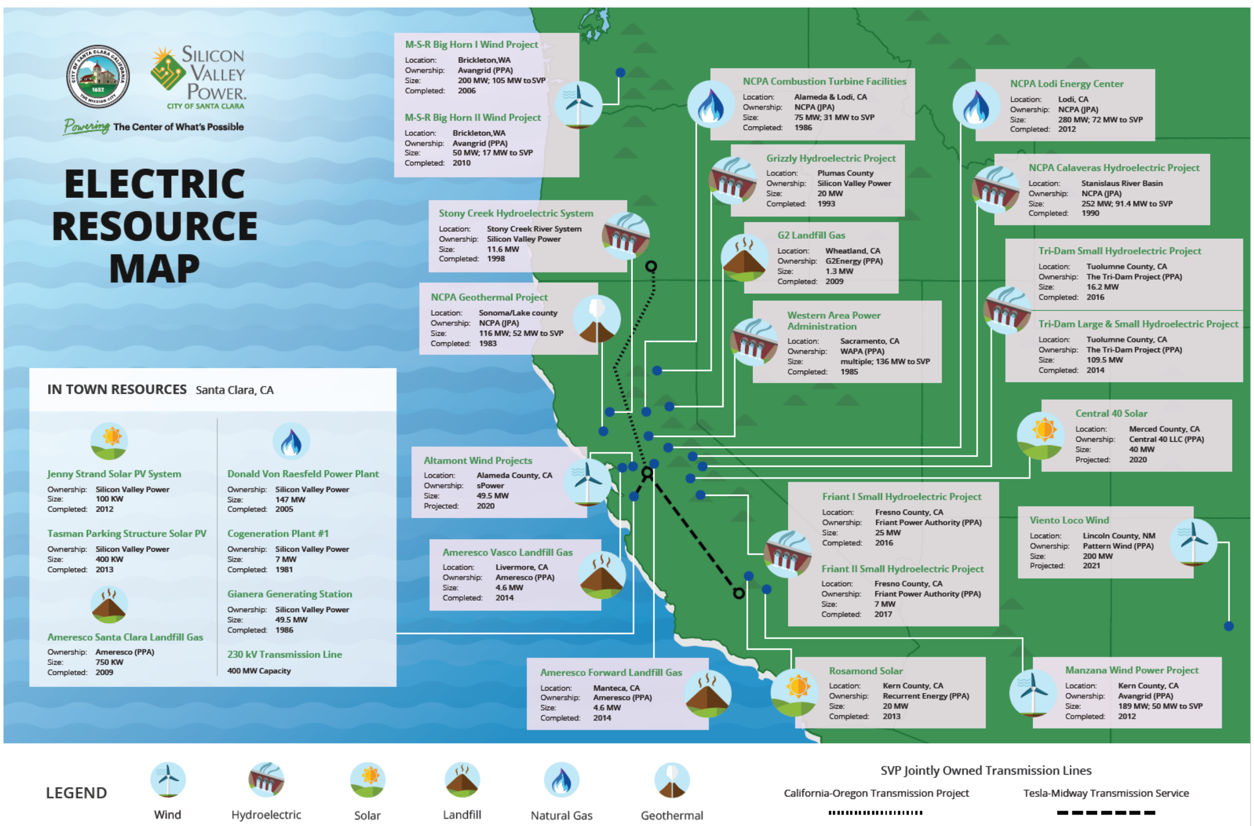

Figure 3-2 SVP's Power Resource Locations (Self-Owned and PPA)

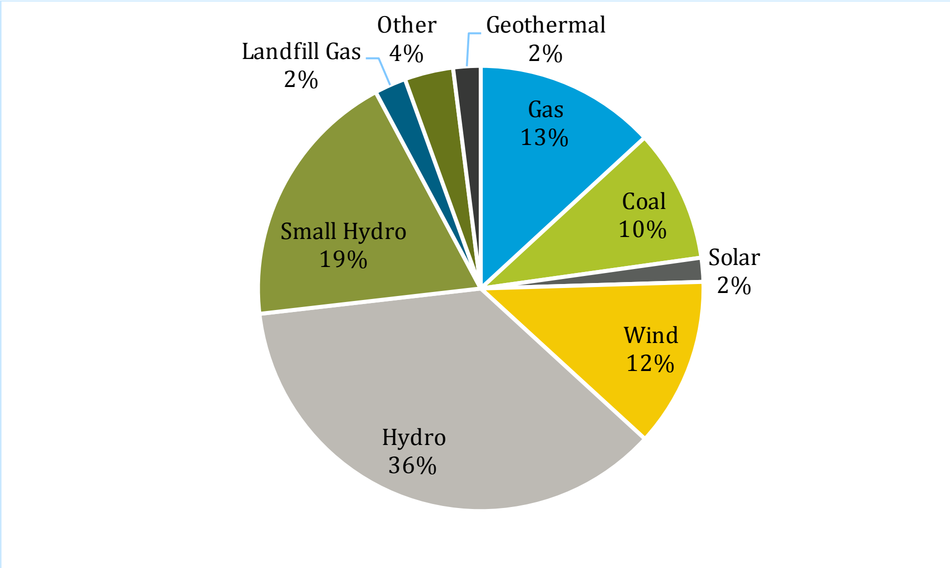

Figure 3-3 SVP's Mix of Energy Generation 2017 as delivered to retail sale

3.1 SANTA CLARA OWNED/CONTRACTED RESOURCES

3.1.1.1 Ameresco Landfill Gas Facilities

On February 12, 2008, SVP entered into a 20-year purchase power agreement with Ameresco for landfill gas generated electricity from the closed municipal landfill located in the city limits of SVP, which includes three microturbines, and is estimated to generate approximately 4,700 MWh per year during the first ten years of the contract and approximately 3,100 MWh per year during the final ten years of the contract. For the Fiscal Year ended June 30, 2017, SVP received approximately 1,820 MWh of energy from the Ameresco SVP landfill project. On May 25, 2010, SVP entered into a second 20-year power purchase agreement with Ameresco for landfill gas generated electricity for 4.6 MW (and potentially up to 9.2 MW) from the Forward landfill in Manteca, California. This project became operational in February 2014. On August 17, 2010, SVP entered into a third 20-year power purchase agreement with Ameresco for landfill gas generated electricity for up to 5 MW from the Vasco Road landfill near Livermore, CA. The Vasco Road landfill project became operational in February 2014.

3.1.1.2 Stony Creek Hydroelectric System

SVP owns and operates three hydroelectric plants consisting of (i) a 4.9 MW hydroelectric generating plant located at the United States Bureau of Reclamation Stony Gorge Dam near Willows, California, which was completed in 1985, (ii) a 6.2 MW hydroelectric generating plant located at the United States Army Corps of Engineers' Black Butte Dam near Orland, California, which was completed in late 1988, and (iii) a 0.53 MW hydroelectric generating plant located at the Orland Unit Water Users' Association High Line Canal/South Side Canal drop near the Black Butte dam, which was completed in late 1988.

3.1.1.3 Cogeneration

SVP owns and operates a cogeneration plant which began operation in 1981. The cogeneration plant provides steam for sale to a paperboard plant in SVP and delivers power to SVP's electric distribution system. SVP upgraded this plant to obtain a new name-plate rating of 7.0 MW, effective

July 1995. Fuel for the cogeneration plant (natural gas) is generally acquired under term contracts at prices fixed for the contract term.

3.1.1.4 Donald R. Von Raesfeld Power Plant

SVP constructed and placed into commercial operation on March 22, 2005, a 122 MW nominal/147 MW peak, natural gas-fired, combined cycle power plant known as the "Don Von Raesfeld Power Plant" (initially designated by the Santa Clara City Council as the Pico Power Plant). The Don Von Raesfeld Power (DVR) Plant is located in an industrial area of Santa Clara, on the site of SVP's Kifer Receiving Station. The DVR Power Plant includes its own switchyard, and connects to an existing 115 kV transmission line that currently crosses the plant site. Natural gas for the Don Von Raesfeld Power Plant is delivered through an approximately two mile gas pipeline from the local transmission main of PG&E. SVP has long-term agreements with EDF Trading North America and M-S-R EA in place for a significant portion of the plant's fuel requirements, and actively manages the quantity and price risks associated with fuel supply quantities not under long-term agreement. Fully base loaded, the DVR Power Plant could generate approximately 1,000 GWh of energy per year. However, SVP substitutes market purchases when it is economical to do so. For example, when there is ample solar during the mid-day summer and prices are advantageous, SVP will ramp down the DVR Power Plant to take advantage of the pricing and the lighter carbon resources available in the CAISO market.

3.1.1.5 Friant Small Hydroelectric Projects 1 & 2

Friant Power Authority, Facility 1: SVP will purchase up to 68,000 MWh per year of electricity over the term of the agreement, from January 1, 2016 to August 31, 2032. Facility 1 consists of three existing run-of-river hydroelectric generating plants: the River Outlet (2 MW), the Friant-Kern (15 MW), and the Madera (8 MW).

Friant Power Authority, Facility 2: SVP will purchase the Net Electrical Output from Facility 2, a new run-of-the river hydroelectric generating plant, Quinten Luallen Power Plant (7 MW), from July 10, 2012 to December 31, 2032.

3.1.1.6 G2 Landfill Gas

SVP entered into a power purchase agreement for, and began taking delivery of energy in January 2009 from, a 1.6 MW landfill gas facility, G2, near Wheatland, California.

3.1.1.7 Gianera Generating Station.

The City owns and operates a nominal 49.9 MW dual fuel (natural gas and fuel-oil) combustion turbine generating plant consisting of two 25 MW units, which were completed in 1986 and 1987, respectively. This generator helps meet the City's peak load if needed, Resource Adequacy requirements and lately has been dispatched by the CAISO to support California's peak loading hours.

3.1.1.8 Graphics Packaging

Graphics Packaging is a manufacturer of recycled paper products that also operated a 27.7 MW cogeneration facility within the City of SVP. This manufacturing facility and the cogeneration plant was permanently closed in December of 2017, and the power purchase agreement was terminated.

3.1.1.9 PG&E Grizzly Project

Pursuant to a 1990 settlement agreement with Pacific Gas and Electric Company (PG&E), SVP agreed to finance and own 100 percent of a 20 MW hydroelectric facility (Grizzly Project) located on Grizzly Creek above the North Fork of the Feather River in Plumas County, California. The Grizzly Project operates in combination with the hydroelectric facilities of PG&E's Bucks Creek project. Pursuant to the settlement agreement, SVP became a joint licensee in PG&E's Bucks Creek project. The construction of the Grizzly Project was financed (and refinanced) through the issuance by SVP of electric system revenue bonds. Pursuant to the settlement agreement, PG&E constructed and operates the Grizzly Project, which was placed into operation in November 1993.

Until the date SVP's ownership of the Grizzly Project is terminated (as described below), SVP will own and receive all energy generated by the Grizzly Project, less transmission losses, as described in the settlement agreement (which reflects a contract capacity amount of 17.66 MW).

The Grizzly Project facilities include a tunnel intake structure, surge tank, steel penstock, powerhouse, turbine, transmission line (nominally rated at 115 kV) for interconnection with PG&E's transmission system and certain additional switchyard equipment and related facilities. Annual energy generation of the Grizzly Project is estimated at 43.4 GWh in an average water year and 26.1 GWh in dry years. For the Fiscal Year that ended June 30, 2017, the Grizzly Project generated 88.33 GWh of energy.

Pursuant to the settlement agreement, SVP's interest in the Grizzly Project may revert to PG&E under certain limited circumstances. In the event of such reversion, Santa Clara will be reimbursed by PG&E for the fair market value of the project or be reimbursed for costs advanced by Santa Clara as provided in the settlement agreement. The earliest possible reverter date under the settlement agreement is November 18, 2027.

3.1.1.10 Manzana Wind Facility

On February 14, 2012, Santa Clara entered into a 20-year power purchase agreement for 50 MW of the output from Avangrid's Manzana Wind Power Project in Kern County, California, which began power deliveries in December 2012.

3.1.1.11 Recurrent

On July 14, 2011, SVP entered into a 25-year power purchase agreement for the entire output from the RE Rosamond One LLC project, a 20 MW solar photovoltaic-powered project in Kern County, California, which became operational in December 2013.

3.1.1.12 Jenny Strand Solar Park

Santa Clara originally entered into an agreement with MiaSole, a California corporation, on December 6, 2011 for the purpose of having MiaSole donate one thousand (1,000) solar modules to Santa Clara at no cost to Santa Clara to further City's ability to provide renewable power. On February 1, 2015, the original party "MiaSole" transferred ownership to MiaSole Hi-Tech Corp. MiaSole Hi-Tech Corp transferred 1,121 solar modules to Santa Clara.

3.1.1.13 Tioga Solar

On February 2, 2012, Santa Clara entered into a 20-year Power Purchase Agreement with Tioga Solar Santa Clara, LLC. The project is located on the City of Santa Clara's multi-level parking structure on Tasman Drive in the City of Santa Clara. Nameplate capacity is 389.76 kW.

3.1.1.14 Tri-Dam Large and Small Hydroelectric Project

In October 2013, Santa Clara entered into a power purchase agreement with the Tri-Dam Project and the Tri-Dam Power Authority to purchase the output from four hydroelectric power plants located on the Middle Fork of the Stanislaus River in Tuolumne County: 72 MW Donnells Powerhouse, 25.7 MW Tulloch Powerhouse, 11.0 MW Beardsley Powerhouse, and 16.2 MW Southern Powerhouse. Power deliveries from Donnells, Tulloch, and Beardsley commenced on January 1, 2014. Power deliveries from Southern/Sandbar commenced on January 1, 2017. The agreement is scheduled to terminate on December 31, 2023.

3.1.1.15 Seattle City Light (SCL) – NCPA Exchange Agreement

NCPA, on behalf of Healdsburg, Palo Alto, Ukiah, Lodi and Roseville, has negotiated a seasonal exchange agreement with Seattle City Light (SCL) for 60 MW of summer capacity and energy and a return of 46 MW of capacity and energy in the winter. Deliveries under the agreement began June 1, 1995. Effective May 31, 2008, Healdsburg, Palo Alto and Roseville assigned their participation percentages to Santa Clara. As a result, Santa Clara receives 32.6 MW from SCL during the months of June through October each year, and is obligated to provide 25 MW to SCL from December through mid-April each year. The SCL-NCPA exchange agreement terminated May 31, 2018.

3.1.1.16 Western Area Power Administration

On December 14, 2000, Santa Clara signed a 20-year agreement with Western Area Power Administration (WAPA) for the continued purchase of low-cost hydroelectricity from the Central Valley Project (CVP), replacing a prior agreement which expired December 31, 2004. The CVP, for which WAPA serves as marketing agency, is a series of federal hydroelectric facilities in Northern California operated by the United States Bureau of Reclamation. Service under the successor agreement began on January 1, 2005 and continues through December 31, 2025, with Santa Clara receiving a 9.06592 percent "slice of the system" allocation from WAPA. Effective April 1, 2015, WAPA reallocated shares and Santa Clara's base resource allocation increased to 9.60341 percent, which shall remain in effect until either superseded by another Exhibit A revision or termination of the agreement. The power marketed by WAPA to Santa Clara is provided on a take-or-pay basis where WAPA's annual costs are allocated to preference customers based on their CVP participation percentage. WAPA then allocates the annual take-or-pay charges to the preference customers based on a monthly percentage that is designed to reflect the anticipated seasonal energy deliveries. Santa Clara is obligated to its preference customer share of the costs associated with operating the CVP facilities. Under the successor agreement, Santa Clara's energy allocation dropped from pre-2005 levels of approximately 1,257 GWh to about 359 GWh per year delivered to Santa Clara based upon the hydrology of the CVP. For the Fiscal Year ended June 30, 2017, Santa Clara received 395.24 GWh of energy from WAPA. Santa Clara's Don Von Raesfeld power project, which commenced operation on March 22, 2005, was designed, in part, to offset the expected decrease in energy to be received from WAPA under the successor agreement beginning in 2005.

3.1.1.17 Future Power Supply Resources

Santa Clara has entered into a 20-year power purchase and sale agreement with Samsung contracted as Central 40, LLC to develop, own and operate a 40 MW capacity solar PV project located in Stanislaus County. The project is scheduled to begin commercial operations as of December 31, 2020. Additionally, Santa Clara commenced a re-power project with S-Power in 2016 at its existing Altamont Wind Project site. S-Power will own and operate 19 MW capacity of wind generation. Two additional power purchase agreements were entered with S-Power under the Rooney Ranch, LLC, including Sand Hill A (13 MW) and Sand Hill B (17.5 MW). In total, the re-power project will be upgraded to meet a 49.5 MW capacity and is scheduled to be commercially operating by December 31, 2020 under a 25-year agreement. Santa Clara has approved of a wind project to add an additional 200 MW of New Mexico wind generation through a 20-year power purchase agreement, contracted as Viento Loco, LLC. The project will be commercially online in the year 2022. This project will add to and further diversify the power portfolio of Santa Clara's resources mix.

Due to Santa Clara's projected retail demand growth driven primarily from the industrial sector and secondarily from the commercial sector, and to replace existing renewable energy contracts that will expire in the future, Santa Clara is actively exploring new renewable energy projects for procurement. Santa Clara is scoping renewable energy projects in the near term to also make use of the investment tax credit and production tax credit eligibility. Both federal incentives have begun to phase down and financing is no longer eligible for renewable energy projects starting construction in 2020 and later. Santa Clara is beginning to explore options for the procurement of energy storage and is undergoing economic analysis to understand how to cost-effectively invest in energy storage.

3.2 NCPA RESOURCES

The City, together with the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville and Ukiah, the Plumas-Sierra Rural Electric Cooperative, the Truckee-Donner Public Utility District, the Bay Area Rapid Transit District (BART) and the Port of Oakland, is a member of the California joint powers agency known as Northern California Power Agency (NCPA). The resources jointly-shared with Santa Clara is as follows:

3.2.1.1 NCPA Hydroelectric Project

NCPA's Hydroelectric Project Number One (the Hydroelectric Project) consists of (a) three diversion dams, (b) the 246.86 MW Collierville Powerhouse, (c) the Spicer Meadow Dam with a 6.0 MW powerhouse, and (d) associated tunnels located essentially on the North Fork Stanislaus River in Alpine, Tuolumne and Calaveras Counties, California, together with required transmission and related facilities.

The Hydroelectric Project, except for certain transmission facilities, is owned by the Calaveras County Water District (CCWD) and is licensed by the Federal Energy Regulatory Commission (FERC) pursuant to a 50-year License Project No. 2409 (issued in 1982) to CCWD. Pursuant to a Power Purchase Contract, NCPA (i) is entitled to the electric output of the Hydroelectric Project until February 2032, (ii) managed the construction of the Hydroelectric Project, and (iii) operates the generating and recreational facilities of the Hydroelectric Project. Under a separate FERC-issued license with an expiration date coterminous with the Project No. 2409 license (Project No. 11197), NCPA holds the license and owns the 230 kV Collierville-Bellota and the 21 kV Spicer Meadows-Cabbage Patch transmission lines for Project No. 2409. NCPA also has a separate FERC license for Project No. 11563 (Upper Utica Project), which consists of three storage reservoirs that mainly feed the New Spicer Meadow Reservoir. This license expires in 2033. After the present FERC License for Project No. 2409 expires in the year 2032, NCPA has the option to continue to purchase Hydroelectric Project capacity and energy during a subsequent license renewal period. The purchase option includes all capacity and energy which is surplus to CCWD's needs for power within the boundaries of Calaveras County.

In February 1990, the operating portions of the Hydroelectric Project were declared substantially complete and commercially operable. The Hydroelectric Project has been supplying peak load requirements of the project participants therein and complementing other resources available to them through NCPA. As with any hydroelectric generation project, the operation of the

Hydroelectric Project is determined by consideration of its storage capacity and available stream flows. The Hydroelectric Project has a 104-year record (1913 to 2017) of storage and stream flows. Based upon the record, the Hydroelectric Project's average production is estimated to be 470 GWh annually. The Hydroelectric Project is optimized together with NCPA's other resources as determined by NCPA to economically meet the load requirements of the respective project participants. The load-following characteristics of the Hydroelectric Project give NCPA a great degree of flexibility in meeting the hourly and daily variations which occur in the project participants' loads.

NCPA financed the Hydroelectric Project through the issuance of Hydroelectric Project Number One Revenue Bonds, of which approximately $315.5 million aggregate principal amount was outstanding as of April 15, 2018 (the NCPA Hydroelectric Revenue Bonds). NCPA has sold the capacity of the Hydroelectric Project to certain of its project participants, including Santa Clara, pursuant to "take-or-pay" power sales contracts which require payments to be made whether or not the Hydroelectric Project is operable. Each purchaser is responsible under its power sales contract for paying its entitlement share in the Hydroelectric Project of all of NCPA's costs of the Hydroelectric Project, including debt service on the aforementioned bonds as well as a "step-up" of up to 25 percent in the event of the unremedied default of another project participant. Pursuant to a power sales contract, Santa Clara has purchased from NCPA a 37.02 percent entitlement share in NCPA's Hydroelectric Project (including a 1.16 percent entitlement share laid off to Santa Clara from the cities of Biggs and Gridley). Santa Clara is using its Hydroelectric Project entitlement to serve peak load and to provide capacity to support non-firm purchases of energy at market prices.

3.2.1.2 NCPA Geothermal Project

NCPA has developed a geothermal project (the Geothermal Project) located on federal land in certain areas of Sonoma and Lake Counties, California. In addition to the geothermal leasehold, wells, gathering system and related facilities, the Geothermal Project consists of two electric generating stations (Geothermal Plant 1 and Geothermal Plant 2), each with two 55 MW (nameplate rating) turbine generating units utilizing low pressure, low temperature geothermal steam, and associated facilities. NCPA formed two not-for-profit corporations controlled by its members to own the generating plants of the Geothermal Project. NCPA manages the Geothermal Project for the corporations and is entitled to all the capacity and energy generated by the Geothermal Project. Geothermal Plant 1 and Geothermal Plant 2 were originally developed and operated as separate projects referred to as "Geothermal Project Number 2" and "Geothermal Project Number 3," respectively. Plant 1 and Plant 2 are now operated together as the Project pursuant to the terms of the NCPA Geothermal Operating Agreement. NCPA financed the Geothermal Project with Geothermal Project Number 3 Revenue Bonds, of which $28.8 million were outstanding as of April 15, 2018.

Steam for NCPA's geothermal plants comes from lands in the Geysers Area, which are leased by NCPA from the federal government. NCPA operates these steam-supply areas. The NCPA geothermal plants experienced greater-than-originally anticipated declines in steam production from existing geothermal wells. Operation of the geothermal plants at high generation levels, together with high steam usage by others in the same area, resulted in a decline in the steam production from the steam wells at a rate greater than expected. As a result, an operating plan has been developed that encompasses steam field management, water injection pressure operation and additional water source development, and includes a detailed steam well monitoring system that has enabled a more efficient utilization of the existing steam field resources. NCPA, along with other producers in the Geysers Area, also constructed a pipeline to deliver treated wastewater from Lake

County Sanitation District's treatment plant near the project for injection into the steam field. This wastewater is pumped to the steam field to continue to regenerate its capacity.

NCPA has sold the capacity of the Geothermal Project to some of its members, including Santa Clara, pursuant to a "take-or-pay" power sales contract which requires payments to be made whether or not the project is operable. Each participant is responsible under the power sales contract for paying its capacity share of all of NCPA's costs of the Geothermal Project, including debt service on the aforementioned NCPA bonds, and subject to a "step-up" obligation of up to 25 percent upon the unremedied default of another NCPA Geothermal Project participant. Santa Clara has purchased from NCPA, pursuant to power sales contracts, 54.65 percent and 34.13 percent entitlement shares, respectively, in the capacity of NCPA's Geothermal Project Plant 1 and Plant 2, and is obligated to pay 44.39 percent of the debt service and operating costs associated with such plants and steam field. Santa Clara is currently taking delivery of its share of the capacity and associated energy from the Geothermal Project. Santa Clara's share of the current CAISO maximum rated capacity of the project is 71.7 MW. Current expectations are that the output from the plant will decrease gradually over time. These anticipated decreases are not material to Santa Clara's supply and can be replaced by additional short-term purchases, additional generation or reduced wholesale sales.

Under terms of the federal geothermal leasehold agreements, which became effective August 1, 1974, the leasehold had a 10-year primary term with provision for renewal as long thereafter as geothermal steam is produced or utilized, but not longer than 40 years; however, in 2013, NCPA renewed the leasehold. At the expiration of that period, if geothermal steam is still being produced, NCPA has preferential right to renew the leasehold for a second term. The leasehold also requires NCPA to remove its leasehold improvements including the geothermal plants and steam gathering system when and if NCPA abandons the leasehold. These decommissioning costs are currently estimated to total approximately $59.3 million. NCPA has been collecting monies to pay the expected decommissioning costs since 2007 and holds $16.2 million in a reserve for such purpose as of June 30, 2017. Collections towards future decommissioning costs are expected to be approximately $1.8 million for Fiscal Year 2017-18.

3.2.1.3 NCPA Geysers Transmission Project

In order to meet certain obligations required of NCPA to secure transmission and other support services for the Geothermal Project, NCPA undertook the geysers transmission project (the Geysers Transmission Project). The Geysers Transmission Project includes (i) an ownership interest in PG&E's 230 kV line from Castle Rock Junction in Sonoma County to the Lakeville Substation (the Castle Rock to Lakeville Line), (ii) additional firm transmission rights in the Castle Rock to Lakeville Line and (iii) the Central Dispatch Facility. Santa Clara has a 55 MW share in NCPA's Geysers Transmission Project, which provides a link from the Geysers to PG&E's bulk transmission system. Through a long-term contract with the California Department of Water Resources (CDWR), sufficient additional transmission capability on the same line is available for the balance of Santa Clara's share of the capacity and energy produced by the NCPA Geothermal Project. Santa Clara obtains additional transmission services to Santa Clara for its share of the output of NCPA Geothermal Project from arrangements with PG&E and the CAISO.

3.2.1.4 NCPA Combustion Turbine Project No. 1

NCPA has developed its Combustion Turbine Project Number One (CT 1) (the Combustion Turbine Project), originally consisting of five combustion turbine units, each nominally rated 25 MW, with two of the units are located in the City of Roseville, two are in the City of Alameda and one is in the City of Lodi. Sale of the two units located in Roseville to the City of Roseville was effective on September 1, 2010. Santa Clara purchased a 25 percent entitlement share in NCPA's Combustion

Turbine Project pursuant to a power sales contract with NCPA, which has recently been amended to reflect that Santa Clara's 25 percent share comes specifically from the two Alameda plants and the one Lodi plant.

The Combustion Turbine Project provides capacity (i) that is economically dispatched during the peak load period to the extent permitted by air quality restrictions and (ii) to be used to meet the capacity reserve requirements (e.g., resource adequacy requirements). This resource provides the capacity below current spot market prices for capacity but as is typical of this type of technology, the average cost for power per kWh of power delivered to the participants in the Combustion Turbine Project is comparatively expensive. Such reserve capacity is operated only during emergency periods when other resources are unexpectedly out of service.

Santa Clara uses its NCPA Combustion Turbine Project entitlement for resource adequacy purposes and to meet peak load requirements.

3.2.1.5 NCPA Lodi Energy Center Project

Through NCPA, Santa Clara is a participant in the Lodi Energy Center. The Lodi Energy Center is a natural gas-fired, combined-cycle power generation plant located in the City of Lodi, San Joaquin County, California (Lodi), which was placed into commercial operation on November 27, 2012. The costs of construction of the Lodi Energy Center were approximately $385.7 million. To provide funding for a portion of the costs of the Lodi Energy Center, in June 2010, NCPA issued two series of revenue bonds, its $255.0 million Lodi Energy Center Revenue Bonds, Issue One, issued on behalf of eleven of the thirteen participants in the Lodi Energy Center (being all of the below-named LEC Project Participants other than Modesto and CDWR, such eleven participant the "Indenture Group A Participants") and its $140.8 million Lodi Energy Center Revenue Bonds, Issue Two, issued on behalf of CDWR. Modesto provided its own financing for its share of the estimated costs of construction of the Lodi Energy Center.

Pursuant to the Lodi Energy Center Power Sales Agreement (the LEC Power Sales Agreement), by and among NCPA and (i) the NCPA Member project participants: Santa Clara, the Cities of Biggs, Gridley, Healdsburg, Lodi, Lompoc, Plumas-Sierra, Ukiah and BART; and (ii) the non-NCPA Member project participants: the City of Azusa, Modesto Irrigation District (Modesto), the Power and Water Resources Pooling Authority and CDWR (such entities other than NCPA, collectively the "LEC Project Participants"), NCPA has sold the capacity and energy of the Lodi Energy Center to the thirteen LEC Project Participants, in accordance with their respective generation entitlement shares to the capacity and energy of the Lodi Energy Center.

Pursuant to the LEC Power Sales Agreement, Santa Clara has purchased from NCPA a 25.75 percent generation entitlement share of the capacity and energy of the Lodi Energy Center on an unconditional take-or-pay basis, and is obligated to pay 25.75 percent of NCPA's Lodi Energy Center operating and maintenance expenses and 46.16 percent of the debt service for the Lodi Energy Center Revenue Bonds, Issue One. Santa Clara's obligations to make payments to NCPA under the LEC Power Sales Agreement are not dependent upon the operation of the Lodi Energy Center and are not subject to reduction. Upon an unremedied default by one Indenture Group A Participant (being all of the LEC Project Participants other than MID and CDWR) in making a payment required under the LEC Power Sales Agreement, the non-defaulting Indenture Group A Participants are required (except as lay-offs are made pursuant to the LEC Power Sales Agreement) to increase pro-rata their participation percentage by the amount of the defaulting Indenture Group A Participant's entitlement share, provided that no such increase can result in a greater than 35 percent increase in the participation percentage of the non-defaulting Indenture Group A Participants.

The Lodi Energy Center plant is capable of operating at 302 MW (It has been permitted to operate at this level and it has equipment necessary to operate at this level) but is limited to 280 MW of firm capacity under the terms of the transmission interconnection agreement and full output of the unit as available on the transmission system with the CAISO and PG&E. PG&E has notified NCPA that PG&E intends to complete reconductoring work on the transmission line limiting the LEC Project Participants ability to claim the full capacity for resource adequacy requirements from the Lodi Energy Center in 2018 (actual production from the facility has not been significantly affected by this limitation).

3.3 M-S-R RESOURCES

The City, along with the Modesto Irrigation District (MID) and the City of Redding, is a member of the M-S-R Public Power Agency (M-S-R PPA). The resources that are jointly owned, or procured through power purchase agreements are described below:

3.3.1.1 M-S-R PPA Purchased Power–Big Horn Projects

In 2005, M-S-R PPA entered into a series of power purchase agreements with Avangrid Renewables, Inc. (formerly Iberdrola Renewables, Inc.) (Avangrid), certain of which agreements have been assigned to Avangrid's subsidiary, Big Horn I, LLC, for the purchase of energy from the Big Horn I wind energy project (the Big Horn I Project) located near the town of Bickleton, in Klickitat County, Washington. The 199.5 MW project consists of 133 1.5 MW GE wind turbines. Santa Clara receives 52.5 percent of the power purchased by M-S-R PPA from the Big Horn I Project. Santa Clara's share equates to approximately a 105 MW share of the output at a cost comparable to combined cycle gas-fuel generation. Power deliveries commenced on October 1, 2006 and will continue through September 30, 2026. Through an amendment of the original agreements M-S-R PPA has an obligation to continue to take the same output through September 30, 2031, or if the Big Horn Project is repowered M-S-R PPA will have a right of first offer to negotiate a long-term power purchase for such repowered project. The project interconnects with the high voltage transmission grid through an 11-mile transmission line at Bonneville Power Administration's (BPA) Spring Creek Substation. Through the shaping and firming agreement between Avangrid and M-S-R, Avangrid receives Big Horn energy, as generated, and delivers such energy to M-S-R at the California-Oregon border pursuant to firm pre-established delivery schedules. Santa Clara uses a portion of its transfer capability of the COTP to provide for transmission of the output from the Big Horn I Project from the California-Oregon border.

M-S-R PPA subsequently negotiated a 25-year agreement with Avangrid for the purchase of the output from a 50 MW expansion of the Big Horn I Project, the Big Horn II Project. Santa Clara began receiving deliveries from the Big Horn II Project in November 2010. Santa Clara receives 35 percent of the output from this project, or approximately 17.5 MW of project capacity.

3.3.1.2 M-S-R PPA Purchased Power – San Juan

Santa Clara officially divested from the San Juan Coal Power Plant as of December 31, 2017. Santa Clara is a Member of M-S-R PPA and purchased from M-S-R PPA a 35 percent Participation Percentage entitlement in the M-S-R PPA San Juan Ownership Interest pursuant to the Power Sales Agreement. M-S-R PPA financed the acquisition of the M S R PPA San Juan Ownership Interest through the issuance of San Juan Project revenue bonds, of which $136.1 million principal amount was outstanding as of April 15, 2018. M S R PPA divested its San Juan Ownership Interest effective as of December 31, 2017. Following the divestiture, M-S-R PPA still retains certain liabilities for a share of the costs of plant decommissioning and mine reclamation.

Pursuant to the Power Sales Agreement, Santa Clara is unconditionally obligated thereunder to pay its Participation Percentage share of all of M-S-R PPA's costs associated with the M-S-R PPA San Juan Ownership Interest, including debt service on M-S-R PPA's San Juan Project revenue bonds which were issued to finance the acquisition of the M-S-R PPA San Juan Ownership Interest and any remaining liabilities for decommissioning and mine reclamation of the plant associated with the M-S-R PPA San Juan Ownership Interest. Santa Clara's obligations to make payments to M-S-R PPA under the Power Sales Agreement are not dependent upon the operation of the San Juan Unit No. 4 and are not subject to reduction. Pursuant to the Power Sales Agreement, upon failure of any M-S-R PPA Member to make any payment thereunder which failure constitutes a default under the Power Sales Agreement, the participation percentage of each non-defaulting Member automatically shall be increased for the remaining term of the Power Sales Agreement in proportion to its participation percentage; provided, however, that the sum of such increase for any non-defaulting Member shall not exceed 25 percent of its original participation percentage. Santa Clara's payments under the Power Sales Agreement constitute an operating expense of the electric system.

3.4 RENEWABLE ENERGY RESOURCES SUMMARY

A significant portion of the energy received by Santa Clara customers is generated from renewable energy resources. Santa Clara's power mix in Calendar Year 2017 consisted of 38 percent eligible renewable resources. When large hydroelectric resources are included, Santa Clara's power mix consisted of 72 percent renewable and large hydroelectric power. On December 6, 2016, the Santa Clara City Council adopted revisions to Santa Clara's Environmental Stewardship and Renewable Portfolio Standard Policy Statement (City of Santa Clara Resolution 16-8392), and adopted a new RPS Enforcement Program, to conform to the standards and timetable set forth in SBX1-2, signed by the Governor on October 6, 2016. Santa Clara satisfied the RPS target for Compliance Period 1 (from 2011 through 2013), with an average of approximately 20 percent of Santa Clara's energy portfolio supplied from renewable resources over such period, which has been verified and approved by the State of California. Santa Clara has also satisfied the RPS target for Compliance Period 2 (from 2014 through 2016), meeting the compliance requirement of 20 percent of retail sales in 2014 and 2015, and 25 percent of retail sales in 2016. In the first year of Compliance Period 3 (from 2017 through 2020) Santa Clara satisfied the RPS target, meeting the requirement of 27 percent of retails sales. Santa Clara expects to fulfill the RPS requirement under Compliance Period 3 by procuring eligible renewable energy resources (not including "large hydro") amounting to 33 percent of total retail sales by 2020. SB 350 will require that the amount of electricity generated each year from eligible renewable energy resources be increased to at least 50 percent of total retail sales by December 31, 2030. SB 100 now requires 60 percent eligible renewable energy compliance by December 31, 2030. Santa Clara is well positioned to meet the new renewable energy compliance requirements of SB 100.

Due to SVP's long position in renewables, SVP will either sell excess renewable generation to other entities or accumulate RECs that exceed RPS requirements as excess procurement to be utilized in future years in case of unplanned curtailment, plant interruptions, and unexpected load growth, future project delays or as needed to ensure compliance with the RPS. Excess procurement allows SVP to evaluate additional eligible renewable resources projects, other generation and potential battery storage projects that will optimize the value for the customers. SVP starts new procurement processes for a forecasted need at a minimum 3-5 years before the resource is needed. SVP is fully compliant with the State requirement that 65 percent of eligible renewables are under long term contracts.

3.5 RESOURCE ADEQUACY

Every year, the CEC publishes the Monthly Coincident Peak for every Load Serving Entity (LSE) in CAISO, which is based on the LSE's load forecast. From that coincident peak number, the CEC and CAISO require LSE's to provide enough capacity to meet each LSE's needs. The CEC and CAISO then provides the LSE's Local and System Requirements for the upcoming year. The Local Requirement is the amount of capacity that is required to be satisfied by local resources that are classified as being able to meet that LSE's Local Requirement. The remaining amount can be satisfied with system resources which are generation units that are not tied to a specific location. Although SVP is a non-CPUC Load Serving Entity, SVP has adopted the reserve margin of 115 percent with a goal to procure sufficient capacity to meet 115 percent of the Coincident Peak. Table 3-3 lays out SVP's 2019 capacity reserve requirement. It is assumed that SVP has sufficient local and system resources to meet the reserve margin and any shortfall shall be addressed through capacity market purchases.

Per CAISO Tariff Section 40, Load Serving Entities are required to submit Annual (in October for the upcoming year) and Monthly (45 Days prior to the first day of the month covered by the plan) Resource Adequacy (RA) plans to provide the CAISO with all the information of where the supply is coming from to be available for the LSE.

Table 3-3 SVP's Capacity Reserve Requirement 2019

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Sys Peak (as published by the CEC)	473.53	494.85	470.79	515.67	534.87	558.67	583.45	566.43	614.95	600.69	562.25	542.82
Sys Peak +115% (Capacity Reserve Requirement)	544.56	569.08	541.41	593.02	615.1	642.47	670.97	651.39	707.19	690.79	646.59	624.24
System Requirement	236.72	261.24	233.57	285.18	307.26	334.63	363.13	343.55	399.35	382.95	338.75	316.4
Local Requirement	307.84	307.84	307.84	307.84	307.84	307.84	307.84	307.84	307.84	307.84	307.84	307.84

3.5.1 Supply

On the supply side, the CAISO publishes a Net Qualifying Capacity (NQC) for each participating generator in the CAISO. This NQC is the amount of capacity that is available to be claimed or sold as capacity to an LSE. SVP has many Local and System generation units to meet the load requirements, and any excess is available to be sold to other LSEs. During months that the generation units are not available, SVP may engage in agreements with other suppliers to purchase the capacity to meet the 115 percent required capacity. Supply plans are also required to be submitted, and have the same timeline as the RA Plans.

3.5.2 Penalties

The CAISO exercises a Resource Adequacy Availability Incentive Mechanism (RAAIM) to determine the availability of the resources providing Local and/or System Resource Adequacy Capacity and Flexible RA Capacity during the Availability Assessment Hours each month and then assess the resultant Availability Incentive Payments and Non-Availability Charges through the CAISO's settlements process. RAAIM penalties will be assessed if the generator was not available during periods that the units were claimed by an LSE, or can issue credits to Generators that were available during periods where the system was short.

3.6 TRANSMISSION ASSETS AND ADEQUACY

Santa Clara's service area is surrounded by a portion of PG&E's service area and the two systems are interconnected at two Santa Clara-owned 115 kV receiving stations – Northern Receiving

Station (NRS) and Kifer Receiving Station (KRS), each located within Santa Clara's city limits. In addition, Santa Clara has a 230-kV interconnection with PG&E at PG&E's Los Esteros Substation (LES) in the City of San Jose. Power received at LES is transmitted by Santa Clara approximately six miles to NRS. Santa Clara owns facilities for the distribution of electric power within its city limits (approximately 19.3 square miles), which includes approximately 27 miles of 60 kV power lines, approximately 500 miles of 12 kV distribution lines (approximately 64 percent of which are underground), and 27 stations. Santa Clara's electric system experiences approximately 0.5 to 1.5 hours of outage time per customer per year. This compares favorably with other utilities in California with reliability factors ranging from 1.0 to 2.5 hours outage per customer per year.

Historically, PG&E provided interconnection, partial power and other support services to Santa Clara under an interconnection agreement. Beginning March 31, 1998, the operation of the transmission facilities owned by California's investor-owned utilities, including PG&E, was undertaken by the CAISO. In July 2002, FERC approved a series of agreements between Santa Clara, PG&E, the CAISO and NCPA (which acts as scheduling coordinator for Santa Clara), including Santa Clara's MSS Agreement with the CAISO, to replace Santa Clara's interconnection agreement with PG&E and to allow Santa Clara to operate within the CAISO control area.

To the extent Santa Clara requires transmission/ancillary/power services beyond those contained in other existing contracts or from Santa Clara's own generating resources, Santa Clara will procure such transmission/ancillary/power services from the CAISO or via the CAISO's markets.

Santa Clara is unable to predict how future industry changes, especially those concerning resource adequacy requirements, renewable fuels, greenhouse gas limitations and new transmission facilities to serve potential renewable energy projects, will affect future costs for the purchase of services under its interconnection, scheduling and CAISO agreements.

The transmission facilities owned or contracted for by SVP are described in this section. SVP's transmission facilities are shown in Figure 3-2. SVP participates in the CAISO transmission system to move electricity from generators to load. SVP owns 230 and 115kV lines in and around the City of Santa Clara.

3.6.1.1 TANC California–Oregon Transmission Project

Santa Clara is a member of TANC and has executed Project Agreement No. 3 for the California-Oregon Transmission Project (the TANC Agreement and the COTP, respectively) for a participation percentage of TANC's entitlement of the COTP transfer capability. Pursuant to the TANC Agreement, Santa Clara's participation percentage was 20.4745 percent of TANC's share of COTP transfer capability (approximately 278 MW net of third party layoffs of TANC). Effective July 1, 2014, Santa Clara laid-off 147 MWs of this entitlement to MID, Turlock Irrigation District (TID) and SMUD under a 25-year agreement. During the term of this agreement, the parties taking on the entitlement will assume responsibility for all associated debt service, operations and maintenance costs and all administrative and general costs. As a result of the layoff agreement, Santa Clara is currently responsible for paying approximately 10.01 percent of the operating and maintenance expenses of the COTP and approximately 9.81 percent of TANC's COTP debt service. Santa Clara remains contractually obligated for its full participation share. Santa Clara's payments to TANC under the TANC Agreement, including debt service on TANC's revenue bonds, constitute an operating expense of Santa Clara's electric system. Santa Clara is using a portion of its share of the project transfer capability of the COTP to provide transmission of energy generated from the Big Horn Projects and Santa Clara's share of the SCL-NCPA Exchange Agreement

3.6.1.2 TANC Tesla–Midway Transmission Service

TANC and certain TANC Members have arranged for PG&E to provide TANC and such TANC Members with 300 MW of firm, bi-directional transmission capacity on its transmission system between PG&E's Midway Substation and the electric systems of the TANC Members or the COTP (the Tesla-Midway Service) under a long-term agreement known as the South of Tesla Principles. Santa Clara's share of Tesla–Midway Transmission Service is 81 MW. Santa Clara utilizes its share of the TANC Tesla–Midway Transmission Service to provide access to power supplies located in the southwest.

3.6.1.3 SVP Transmission Projects

On September 1st, 2017 SVP set a system peak load of 586 MW. With recent load growth of 5 to7 percent and increasing demand from data centers, SVP is looking to increase the capacity of its existing system. Currently the following projects have been approved to increase the capacity or enhance reliability of the transmission system:

3.6.1.3.1 Scott Receiving Station Upgrades

SVP's Scott Receiving Station currently is fed by 115 kV lines and transformers to reduce the voltage to 60 kV. Due to system load growth, SVP is currently evaluating breaker upgrades and installing larger transformers. This project is projected to be completed by mid-2020.

3.6.1.3.2 Northern Receiving Station Upgrades

SVP's Northern Receiving Station currently is fed by 230 kV and 115 kV lines and transformers reduce the voltage to 60 kV. Due to system load growth, SVP is currently evaluating breaker upgrades and installing larger transformers. This project is projected to be completed by end of 2021.

SVP is investigating installation of an additional 230kV transformer to provide redundancy to the existing 230 kV transformer. This is scheduled for installation to be complete in 2026.

During the spring of 2018, SVP completed a breaker replacement project which enabled increased loading for the existing system.

3.6.1.3.3 South Loop Expansion

SVP's 60 kV transmission system is arranged in various circuit loops within The City. There are five loops, Northeast Loop, Northwest Loop, South Loop, East Loop, and Center Loop. Based on load growth in its South Loop, SVP is in the design phase of reconfiguring and reconstructing the South Loop. Construction should be completed by end of 2020.

3.6.1.3.4 Northern Receiving Station and Scott Receiving Station Lines #1 and #2

These lines (115kV) are scheduled to be upgraded to allow for higher capacity. Design has been completed and construction is scheduled to be complete by April, 2019.

3.7 DISTRIBUTION ASSETS AND ADEQUACY

3.7.1 Distribution Assets

SVP's distribution service area is approximately 19 square miles. SVP distribution assets consists of electric system with nominal system voltage equal or less than 12,000 volts. The City owns facilities for the distribution of electric power in its limits which includes approximately 500 miles of 12 KV distribution lines (64 percent of which are underground). SVP owns 21 distribution substations out of which 14 are general distribution substations and 7 single customer dedicated substations.

3.7.2 Distribution System Adequacy

Based on 2017 peak summer loading data, the typical maximum loading on the distribution transformer bank is approximately 50 percent of the highest rating of the transformers. All the distribution feeders have sufficient capacity and operate within the thermal capability ratings. The distribution planning study which includes the load forecast and distribution area capacity study ensures adequacy of the capacity in the distribution system and identifies upgrades and construction of new distribution systems including substation. The following distribution projects have been identified for implementation:

- Serra Substation replacement: This involves removing existing single transformer Bank substation and replacing with 2-transformer bank Substation.
- Homestead Substation: This involves removing existing 2-transformer bank substation and replacing with 2-higher capacity transformer bank substation.
- Parker Substation: This will be new substation dedicated to single customer.
- Fairview Substation expansion: This involves adding third transformer bank in existing 2 bank substation.
- Oaks Junction (RW) Substation: This will be new substation dedicated to single customer.
- Laurelwood Substation: This will be new substation dedicated to single customer.
- Freedom Circle Junction Substation: This will be new substation dedicated to single customer.
- Esperanca Substation: This will be new general distribution substation to serve new developments proposed around Levi's stadium.

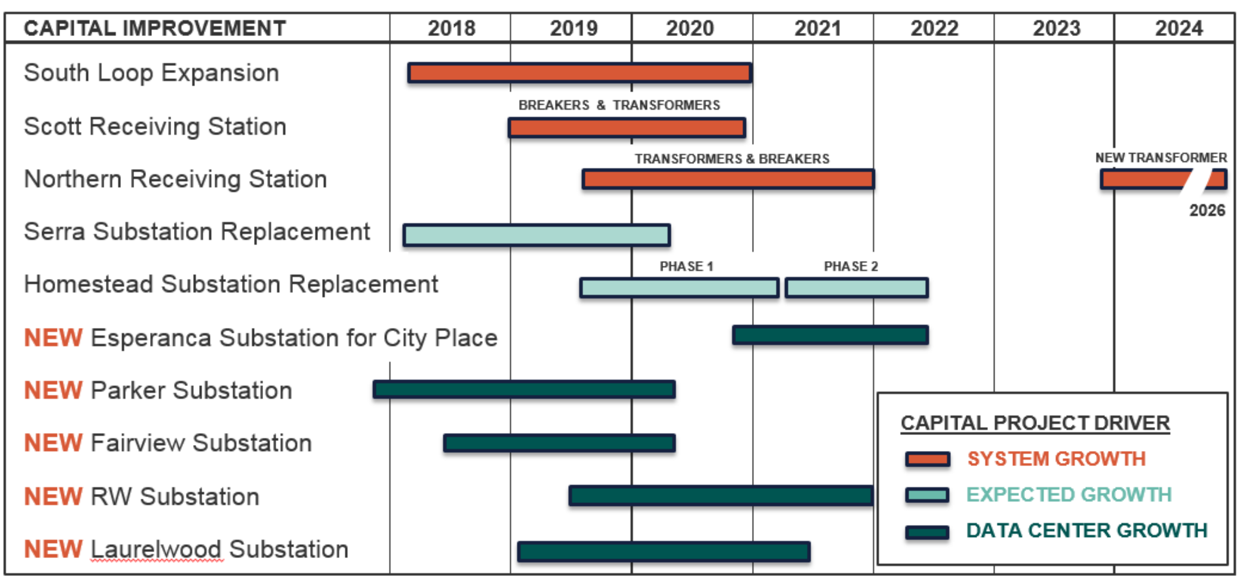

Figure 3-4 SVP's Capital Projects

Table 3-4 SVP's Reliability Statistics

DESCRIPTION	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ASAI (%)	99.978	99.995	99.988	99.994	99.991	99.989	99.986	99.993	99.979	99.992
CAIDI (Long) (min)	160.00	75.00	90.61	61.32	96.58	118.29	126.32	72.06	106.34	104.14
SAIDI (Long) (min)	117.50	26.87	61.58	29.34	47.33	56.6	73.96	36.29	109.08	42.61
SAIFI (Long) (ints/tot cust)	0.73	0.36	0.68	0.48	0.49	0.48	0.59	0.5	1.03	0.41
SAIFI (Short) (ints/tot cust)	0.23	0.18	0.15	0.21	0.08	0.19	0.09	0.32	0.83	0.27
Total Outages	110	78	62	67	69	80	123	123	195	132
Unplanned Outages*										89
Planned Outages*										33
Momentary Outages*										10

Notes:
*New Metrics as of 2018

Definitions:
ASAI (%) Average Service Availability Index - (customer minutes available / total customer minutes, as a %)
CAIDI (minutes) Customer Average Interruption Duration Index -(average minutes interrupted per interrupted customer)
SAIDI (minutes) System Average Interruption Duration Index - (average minutes interrupted per customer for all customer)
SAIFI (number) System Average Interruption Frequency Index - (number of interruptions per customer for all customers)

3.8 NATURAL GAS COMMODITY, TRANSPORTATION AND STORAGE

SVP owns several gas-fired power plants in its portfolio. Through the gas pre-pay agreement described below, SVP aims to hedge the impact of gas supply and price volatility on its customers.

Natural gas is the primary fuel and the primary variable operating cost of Santa Clara's cogeneration plant, Gianera Generating Station and Don Von Raesfeld Power Plant. These plants can require delivery of up to 49,000 million British Thermal Units (MMBtu) of natural gas per day, with current average daily requirements of 24,400 MMBtu per day. Santa Clara has developed a comprehensive natural gas program to both manage supply and price volatility. This includes the procurement of a supply of natural gas at a discount from the monthly index price pursuant to a gas prepayment arrangement and several fixed price contracts for 15,000 MMBtu per day from 2016 to 2019 and 10,000 MMBtu in 2020.

3.8.1.1 M-S-R Energy Authority – Gas Prepay

In 2009, Santa Clara participated in the M-S-R EA Gas Prepay Project. The Gas Prepay Project provides, through a Gas Supply Agreement between M-S-R EA and Santa Clara, for a secure and long-term supply of natural gas of 7,500 MMBtu daily (or 2,730,500 MMBtu annually) through December 31, 2012, and 12,500 MMBtu daily (or 4,562,500 MMBtu annually) thereafter until September 30, 2039. The Gas Supply Agreement provides this supply at a discounted price below the monthly market index price (the PG&E Citygate index) over the 30-year term. M-S-R EA entered into a prepaid gas purchase agreement with Citigroup Energy, Inc. (CEI) to provide this gas supply, and issued $500.2 million of its Gas Project Revenue Bonds to finance the prepayment for Santa Clara, all of which were outstanding as of April 15, 2018. Under the terms of the Gas Supply Agreement, M-S-R EA will bill Santa Clara for actual quantities of natural gas delivered each month on a "take-and-pay" basis. Moreover, any default by CEI or the other participants in M-S-R EA's Gas Prepay Project, MID and Redding, is non-recourse to Santa Clara.

3.9 WHOLESALE ENERGY TRADING

For several years, Santa Clara has used its energy and transmission resources together with its power scheduling capabilities to buy and sell energy in the western North American market. As deregulation unfolded, a greater need to manage resources on a day-to-day basis evolved, resulting in a more comprehensive approach to trading operations at Santa Clara. The principal reason for wholesale power trading is to optimize the value of the utility's assets and cost-effectively serve its retail load. Since a substantial portion of Santa Clara's energy needs are being met through contracts, SVP uses its energy, Resource Adequacy and transmission resources to buy and sell actively in five established wholesale power trading market zones: Mid-Columbia (MID-C), California-Oregon Border (COB), North of Path 15 (NP15), South of Path 15 (SP15) and Palo Verde Hub (PV). Trades may be directly with counterparties or through clearinghouses, such as the ICE Clear Europe on InterContinental Exchange (ICE).

4.0 Energy and Demand Forecast

A fundamental element of an IRP analysis is the development of the long-term (2019-2038) system peak demand and energy forecasts. The forecast results in a projection of the capacity and energy requirements on the SVP system that the utility must plan to meet through self-owned generation or purchase arrangements.

The amount of capacity procured is intended to cover SVP's projected peak annual demand as well as its reserve requirement. Reserves are an amount over and above the projected system peak that utility's will plan to maintain in the event that the forecasted demand is higher than anticipated due to extreme weather conditions or higher than expected load growth, or in the event that capacity resources are not available due to a forced outage, a transmission line failure, or another unexpected event. As described in the Resource Adequacy section earlier, SVP uses a planning reserve margin of 15 percent in its planning based on the requirement set forth for the region by the North American Electric Reliability Council (NERC).[6]

4.1 HISTORICAL ENERGY USE AND PEAK DEMAND

Due to SVP's predominantly industrial customer base, its energy use and peak demand profile is relatively flat on a monthly basis as illustrated in Figure 4-1. However, SVP has historically experienced sudden increases in electricity demand at times as customers move into new facilities. Data Center loading can cause SVP's load growth profile to be "lumpy," due to new connections of substantial blocks of power-consuming facilities or equipment by industrial customers. This profile is reflective of the high intensity of industrial energy use in SVP's service area, which is heavily weighted toward high-technology manufacturing and data management facilities.

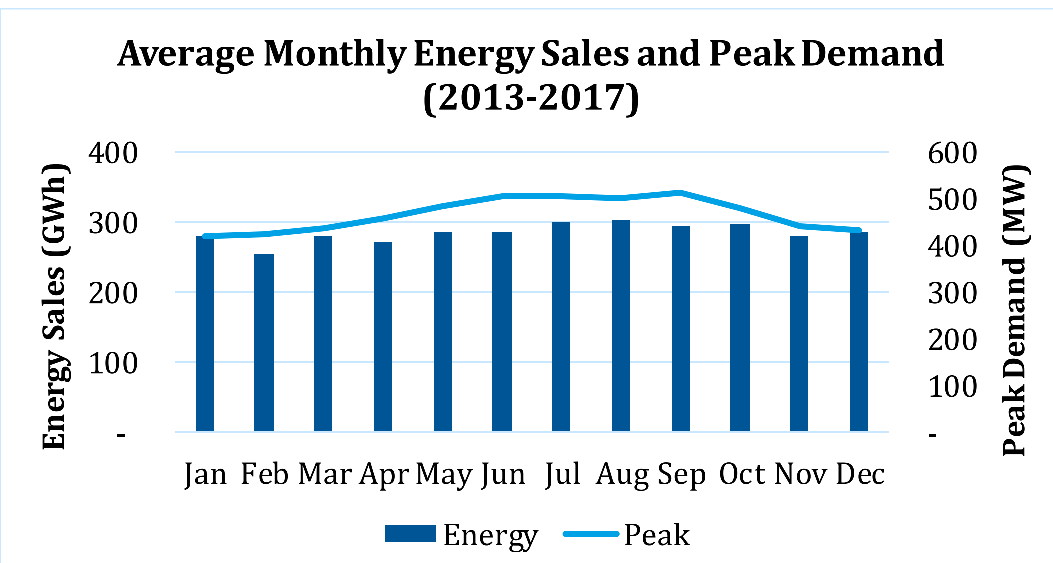

Figure 4-1 5-Year Average Monthly SVP Energy Sales and Peak Demand (2013-2017)

[6] Overall SVP must meet a system level Resource Adequacy (RA) requirement of 15 percent of the monthly peak demand as.

Table 4-1 lists historical data over SVP's past five Fiscal Years. Both energy and peak demand has been consistently increasing over the years and this trend is forecasted to continue going forward. SVP has set a new peak each year, the latest on September 1, 2017 at 586 MW.

Table 4-1 SVP Historic Customer, Sales, and Demand Data August 2017

YEAR [1]	2013	2014	2015	2016	2017
Number of Customers					
Residential	44,540	44,758	45,139	45,655	46,707
Commercial	6,188	6,218	6,266	6,261	6,184
Industrial	1749	1735	1688	1660	1660
Municipal	180	180	183	184	187
Other	380	382	382	382	363
Total Customers	**53,037**	**53,273**	**53,658**	**54,142**	**55,101**
Kilowatt-Hour Sales					
Residential	241,831,995	230,930,319	228,952,046	224,053,245	235,643,830
Commercial	92,613,838	93,602,762	92,484,237	94,660,690	95,259,889
Industrial	2,622,287,369	2,706,549,120	2,861,043,888	3,089,679,178	3,192,880,627
Municipal	21,091,693	20,968,645	19,194,762	17,408,698	19,834,539
Total kWh	**2,977,824,895**	**3,052,050,846**	**3,201,674,933**	**3,425,801,811**	**3,543,618,885**
Peak Demand (kW)	**478,900**	**482,440**	**523,680**	**534,310**	**586,580**

Source: SVP

4.2 FORECAST METHODOLOGY AND ASSUMPTIONS

The City of Santa Clara is growing both from residential high-density development and large industrial/commercial customers redevelopment projects. The load forecast for the IRP planning is based on future loads derived from historical base data and assessment of future system load growth potential. SVP works through the City of Santa Clara's Community Development project clearance process, as well as, engaging large customers directly to assess impacts of the large development projects, and the timing of those projects to SVP's system, to model the load forecast. Data Centers submit projected load forecasts in a block load format, usually in 12 to 60 month forecasts. SVP manages the large customers through dedicated Key Account Representatives who track and update the loads. The load forecast for the IRP planning builds upon SVP's baseline projection, and applies a growth rate to the base load energy trend, and projects a forecasted growth rate that is tied to each additional load segment. Each segment is analyzed separately to differentiate between growth patterns and load profiles. In the near-term SVP's growth is dependent on mixed-use growth and data center growth, but in later years it is more heavily weighted to data centers due to their much higher potential in energy usage density.

In total the three segments include: 1. existing load in which growth is determined as a function of temperature, and new block loads divided into two segments: 2. commercial and mixed-use segment, 3. and hyper-scale and mid-tier data centers. SVP assumes the block loads from data centers are temperature agnostic. SVP applies different load factors to each of the segments, and monthly specific load factors to adjust for each end-user type.

SVP utilizes PLEXOS for IRP and budget case forecasting.

Table 4-2 Load Forecast Assumptions and Input Considerations

CATEGORY	DESCRIPTION
Weather	▪ Normal Weather for Energy and Peak
Economics	▪ Average load factors: City of Santa Clara Development Projects ▪ High, Mid and Low growth cases ▪ Data Center Block Load Forecast
End Use Equipment Saturation & Efficiency/ New Technology	▪ Energy Efficiency and Demand Response Forecast ▪ Distributed Generation Adoption Forecast

Source: SVP

4.3 FORECAST RESULTS

The peak and energy forecast results are presented in this section. The capacity and energy requirement forecast is also carried forward to the four required CEC tables in Appendix A.

4.3.1 Peak and Energy Forecast

SVP's energy and peak demand forecast is shown in Table 4-3. The energy demand is projected to increase from 3,887 GWh in 2019 to 4,951 GWh in 2038. The annual average growth rate for this period is forecasted to be 2.1 percent. Peak demand is projected to grow from 582 MW in 2019 to 872 MW in 2038 at an annual average growth rate of 1.9 percent.

4.3.2 SVP System Load Factor

As described earlier, industrial customers are the largest component of SVP's customer base. As a result, SVP's load factor is significantly higher compared to other utilities at over 70 percent as outlined in Table 4-3. A load factor is a measure of the variability in utility load over time. A load factor measures total energy requirements on a utility system as a percentage of the theoretical maximum energy requirements that would result if the energy requirements at the time of peak demand were required all hours of the year.

The near-term accelerated growth observed in the load forecast is primarily due to the growth from data centers which are already in the City's planning and development processes and secondarily due to commercial and residential mixed-use housing growth. Numerous data centers have been established in SVP's service territory to support the data needs of corporate offices and internet-related businesses. Starting around 2021, SVP's growth is more heavily weighed to data centers due to interest and demand from this consumer base to locate in SVP's service territory and because of technological advances which allow for a higher potential energy usage density. The data centers in SVP's service area are categorized into two tiers, hyper-scale and mid-tier data centers. These data centers operate with a load factor of 85 percent or greater. Significant energy efficiency improvements in the design and operation of data centers over the past decade has allowed data center energy use to remain nearly constant while simultaneously meeting a drastic increase in demand for data center services. Because of the large percentage of server farm load, which is by nature almost unity load factor, the delta between off-peak and peak loads is much lower than a typical utility. Of the total retail load, approximately 47 percent was driven by data centers. The concentration of data centers and their high load factor in SVP's service territory contributes to the high forecasted load factor for the utility.

Table 4-3 Projected SVP Net Energy Requirements, Peak Demand Forecast, and Load Factor

YEAR	NET ENERGY REQUIREMENTS		PEAK DEMAND		LOAD FACTOR (%)
	GWH	PERCENT CHANGE (%)	MW	PERCENT CHANGE (%)	
2017 (actual)	3,727.2		586.6		73%
2018	3,694.31	-0.87%	554.8	-5.41%	71%
2019	3,887.76	5.24%	582.6	5.00%	73%
2020	4,067.26	4.62%	611.7	5.00%	75%
2021	4,235.73	4.14%	637.0	4.14%	75%
2022	4,339.03	2.44%	652.6	2.44%	76%
2023	4,440.03	2.33%	667.8	2.33%	76%
2024	4,553.10	2.55%	684.8	2.55%	79%
2025	4,621.26	1.50%	695.0	1.50%	78%
2026	4,676.25	1.19%	703.3	1.19%	79%
2027	4,687.38	0.24%	705.0	0.24%	78%
2028	4,710.82	0.50%	708.5	0.50%	78%
2029	4,734.37	0.50%	712.0	0.50%	78%
2030	4,758.04	0.50%	715.6	0.50%	78%
2031	4,781.83	0.50%	814.0	0.50%	78%
2032	4,805.74	0.50%	822.2	0.50%	78%
2033	4,829.77	0.50%	830.4	0.50%	78%
2034	4,853.92	0.50%	838.7	0.50%	78%
2035	4,878.19	0.50%	847.1	0.50%	78%
2036	4,902.58	0.50%	855.6	0.50%	78%
2037	4,927.09	0.50%	864.1	0.50%	78%
2038	4,951.73	0.50%	872.8	0.50%	78%
AAGR 2018-2038		1.58%		1.17%	

Source: SVP

4.4 COMPARISON TO CEC FORECAST

The SVP energy requirements forecast used in this IRP can be compared to the forecast published by the CEC in its document *California Energy Demand 2018-2030,* which is developed annually as part of the CEC's Integrated Energy Policy Report.

As seen in Figure 4-2, the CEC forecasts of SVP energy requirements are significantly lower with steady to declining growth. On February 7, 2018, SVP provided comments on Docket 17-IEPR-03 to CEC outlining an explanation on the variances between SVP and the CEC's load forecast.[7] As described earlier, the nature of SVP's load growth and customer base is not typical compared to

[7] Letter to the CEC Re: Docket 17-IEPR-03: Silicon Valley Power Comments on the California Energy Demand 2018-2030 Revised Forecast and LSE and BA Forecasts

other utilities in California. The high density of data centers in SVP's territory and the planned addition of new data centers drive the higher energy demand and load factor for the utility.

SVP has collaborated with the CEC and participated in the CEC's Energy Demand Forecast public comment process to provide feedback on SVP's unique load. In 2018, the CEC agreed to adopt SVP's load forecast, and will be updating the CEC's published LSE load forecast to reflect SVP's revised forecast in the revised IEPR forecast published in 2019.

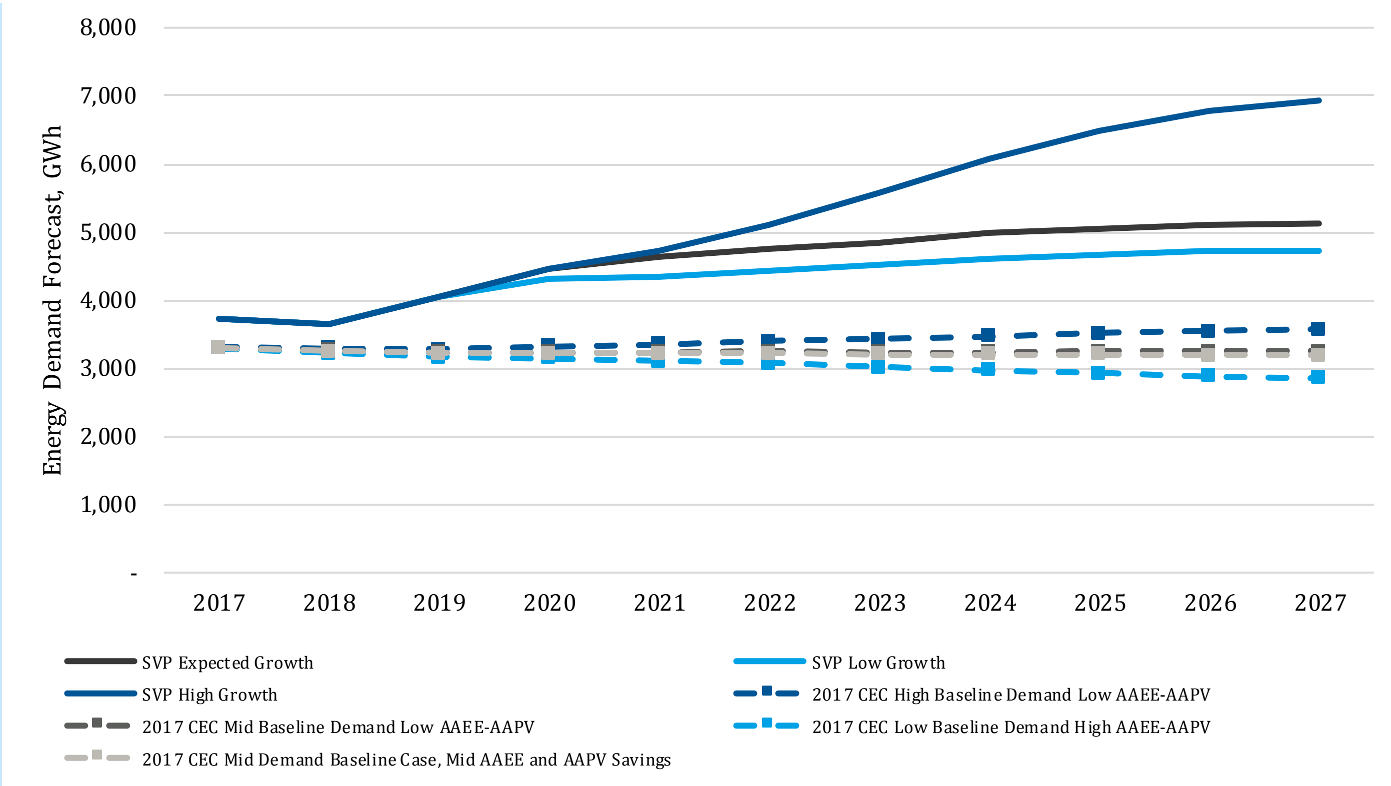

Figure 4-2 Energy Requirements Comparison: SVP Forecast vs. CEC Forecast for SVP

5.0 Customer Programs, Energy Efficiency and Demand Response Resources

5.1 ENERGY EFFICIENCY PROGRAM BACKGROUND

Targets for energy efficiency programs (and established under PUC section 9505) are based on the net market potential estimated in the Navigant study.[8] The net market potential provides a forecast of market potential for specific utility energy efficiency programs. The net market potential is a subset of the total economic potential and technical potential and recognizes that not all of the impacts that are technically or economically achievable will be realized.

Santa Clara's energy efficiency programs are separated into residential and business programs, with the majority of funding toward its largest customer segment - the business sector. Total Public Benefits Charge (PBC) funds are about $11 million per year. Residential programs include rate assistance for low-income customers, energy efficiency rebates (ceiling fans, clothes dryers, heat pumps, water heaters, attic insulation, and variable speed pool pumps), energy audits, and programs for schools and libraries. Business programs include energy audits, installation management for small companies, rebates for a wide variety of equipment (lighting, air conditioning systems, chillers, motors, new construction, food service equipment and customized installations, etc.), and design and construction assistance.

The goals and objectives of the programs are as follows:

- Implement cost-effective energy efficiency programs to lower energy use. The cost to implement energy efficiency programs should be lower than the capital cost to build new generation and benefits of the total programs should exceed costs under the Total Resource Cost (TRC) test under the methodology reviewed and approved by the Northern California Public Agency (NCPA) Public Benefits Committee, of which Silicon Valley Power is a member.
- Provide the PBC programs in a manner that creates value to the community and meets all applicable legal requirements.
- Assist Divisions and City Departments in achieving optimal energy efficiency at City facilities and assist in implementing new energy related technologies for the benefit of the City and community.
- Implement programs to support renewable power generation that increase resource diversity and minimize adverse environmental impacts from electric generation and operation of the electric system.
- Support emerging technologies to speed up market acceptance therefore, allowing energy efficiency services and products to compete in the open market.
- Assist low-income residents in helping them to pay their electric bills and in installing energy efficient appliances and other measures.
- Determine the best energy programs to offer Santa Clara customers by collecting input from community organizations, businesses and other City departments.

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[8] California Public Utilities Commission. Energy Efficiency Potential and Goals Study for 2018 and Beyond. June 15, 2017, ftp://ftp.cpuc.ca.gov/gopherdata/ energy_division/EnergyEfficiency/DAWG/2018andBeyondPotentialandGoals%20StudyDRAFT.pdf.

SVP participated in the California Municipal Utilities Association (CUA) Energy Efficiency Potential Forecasting Study conducted in 2016 by Navigant Consulting, Inc. The most recent study was adopted by the Santa Clara City Council in 2017. Results are presented in Table 5-1.

Table 5-1 Results of Energy Efficiency Potential Forecasting Study

CUMULATIVE SAVINGS	UTILITY SPECIFIED FEASIBLE GOAL IN MWH
2017-2018	12,851
2018-2019	13,032
2019-2020	14,015
2020-2021	14,928
2021-2022	15,129
2022-2023	14,565
2023-2024	13,333
2024-2025	12,192
2025-2026	11,528
2026-2027	10,590

5.2 CURRENT ENERGY EFFICIENCY INITIATIVES

SVP maintains a robust suite of energy efficiency programs that will contribute to the state's goal of doubling statewide energy efficiency savings as codified in SB 350. Energy efficiency programs are intended to offer maximum benefit to the community while meeting all regulatory requirements. The regulatory requirements include the following:

- Public Utilities Code § 385 requires that the utilities collect and spend a percentage of their base retail electric revenues on qualified Public Benefits Programs. The customary amount collected by public utilities in California is a minimum 2.85 percent of annual base retail electric revenues. The funds must be spent on programs in four categories including energy efficiency, research and development, renewable energy resource development and low-income assistance.
- Public Utilities Code § 386 requires each local, publicly-owned utility to ensure that low-income families have access to affordable electricity, and the level of assistance reflects the level of need. Furthermore, utilities shall ensure that low-income families have access to low-cost, no-cost measures that reduce energy consumption.
- Public Utilities Code § 454.5 and Public Utilities Code § 9615 both require utilities to address unmet resource needs through energy efficiency and demand response prior to procuring new sources of power.
- Public Utilities Code § 9505 requires each local, publicly-owned utility to annually report investments and achievements in energy efficiency and demand reduction programs. Furthermore, utilities must identify all potentially achievable cost-effective electricity efficiency saving and report savings targets to the CEC.

- Public Resources Code § 25305.2 requires the CEC to report to the Legislature a comparison of the annual energy savings targets versus the actual energy efficiency savings and demand reduction for each local POU.
- Public Resources Code § 25310 (c)(1) requires the CEC to set goals that will double statewide energy efficiency savings in California by 2030 and will require specific targets for SVP.

A comprehensive list of energy efficiency projects and programs under consideration is described below.

5.2.1 Proposed New and Modified Programs for Fiscal Year 2018/2019 to 2022/2023

- Data Center Efficiency Program – This program targets data centers with IT server load greater than 350 kW or cooling load greater than 100 tons. The incentive is paid as a performance incentive, where the customer will receive five annual payments based on actual measured energy savings, with the first payment made three months after project completion. The incentive payment is $0.03 per kWh in energy savings. The project cap was raised to $750,000 for projects completed in FY 2017/2018 and that cap will be extended for projects completed in FY 2018/2019.
- Customer Directed Rebate – This program provides incentives based on actual energy saved for energy efficiency measures that do not fall into SVP's standard business rebate programs. Lighting with network lighting controls will be removed from the Customer Directed rebate program and will now be covered under the standard lighting rebate. The incentive will be $0.15 per kWh for all custom projects incentivized by the Customer Directed Rebate Program. The project cap was raised to $750,000 for projects completed in FY 2017/2018 and that cap will be extended for projects completed in FY 2018/2019. A peak demand incentive of $150 kW was introduced in FY 2017/2018, but it did not result in any additional project applications, so this will be removed for simplicity.
- Commercial Lighting Rebates – The lighting rebate will be increased to $0.25 per kWh for the installation of network lighting control systems. This incentive applies to lighting retrofits only and helps to cover the customer's additional cost of measurement and verification of the energy savings.

5.2.2 Programs Ending or On Hold Third Party Programs for Business Customers

- City Revolving Energy Efficiency Loan Program – The City established a revolving loan fund for qualifying energy efficiency measures at City owned and occupied facilities. The funds were repaid on utility bills through the energy savings achieved by the project. Utilization of the program was low. City energy efficiency projects will still be eligible for rebates through its standard programs, but loan funds will no longer be available.
- Residential Solar Electric Rebate – the state legislation that required utilities to provide solar electric rebates expired on December 31, 2016. SVP continued to offer rebates for commercial solar installations through June 30, 2017. Residential Solar rebates end June 30, 2018 under the current program design. Staff will evaluate options for solar programs in future years, with emphasis on a possible low income program.

5.2.3 Ongoing Programs

- Residential Electric Dryer Rebate Program: This program provides a rebate of $100 for any ENERGY STAR -qualified electric clothes dryer having a Combined Energy Factor (CEF) of 4.3-5.4. For Energy Star-qualified clothes dryers with a CEF of 5.5 or greater, the rebate is $200.

- Residential Pool Pump Rebate: This program provides a $100 rebate to residential customers installing a new variable speed pool pump with a qualifying controller.
- Energy Star Ceiling Fan: Residents who purchase Energy Star qualified ceiling fans (limit 3 per household) will be able to receive a $35 rebate per ceiling fan. The program will encourage customers to use ceiling fans to help cool their homes instead of using air conditioning.
- ENERGY STAR Residential Heat Pump Electric Water Heater Rebate – SVP offers a maximum rebate of $500 per household for the purchase of an ENERGY STAR-qualified electric heat pump water heater.
- Residential In-Home Energy Audits, Education, and Hot Line: The program encourages residents to become more energy efficient and reduce their energy bills. Staff members visit homes and provide information and energy saving items. Also, the SVP information booth will continue to be displayed at several City events, providing education on energy efficiency and solar electric generation systems to residents.
- Residential Attic Insulation Rebate – This program pays $0.10/square foot for attic insulation of R-38 over conditioned space in single family homes or in multifamily homes where the attic space is completely separated from that of the other multifamily units. Eligible customers must have electric heat either in the form of a heat pump or electric resistance heat and no more than R19 existing attic insulation.
- Financial Rate Assistance Program (FRAP) – This program provides a 25 percent discount on the electric portion of utility bills for income-qualified residential customers, up to the first 800 kWh of use per month.
- Residential Blower Door and Duct Testing Pilot Program: In an attempt to help customers improve the efficiency and comfort of their homes through the reduction of leaks, this pilot program will be available to residential customers in single family homes who have central air conditioning. A free SVP audit will be required to determine if the home is a good candidate for the blower door test. Duct testing is a much more involved process and will be offered to those customers who are a good candidate for reducing the leaks in their air conditioning duct system, who demonstrate an interest in taking action to improve the duct work, and who are not already doing an air conditioning system upgrade where a duct test is required by building code. The service will be free to eligible customers under the pilot program. At the time of this report, this pilot program is still in the design phase and has not yet been launched.
- Low Income EV Charging Station Grant for Multi-family properties – Under its low income programs, SVP will offer a grant of up to $1,000 per charging station for multi-family properties where 15 percent of customers residing at the property qualify for SVP's low income programs. The utility will provide charging station rebates for all eligible customers as described in section 5.6.
- Medical Rate Assistance Program: Customers receive a 25 percent discount on their electric bill if they qualify due to high electric use for medical reasons. The programs are managed in-house.
- Deep Energy Retrofit Pilot Program – This pilot is targeted at customers who are interested in deep energy retrofits and able to make a commitment to a multi-year effort in reaching an energy savings of at least 30 percent. Incentives match the levels offered for the same measures incentivized under SVP's other programs, with a range from $0.02-$0.20 per kWh in first year savings. The program target is to enroll three customers.

- Enhanced Ventilation Controls Demonstration Projects –The program is targeted at smaller customers with rooftop package units of 15 tons or smaller. This customer segment is not at the forefront of adopting new technology. In order to educate customers on the technology and validate the energy savings, SVP aims for demonstration projects at customers' facilities and will fund up to the lesser of 100 percent of the project cost or $3,500. The customers are required to allow SVP to install metering equipment to validate energy savings and to write a case study on the project. The case study will be used in promoting the rebate program to other customers and educating them on the energy savings and payback of the project.
- Emerging Technologies Grant: The program provides grants to encourage businesses to develop new energy-related technologies. The incentive is $0.35/kWh, paid in two payments. The first payment of 50 percent of the incentive will be paid upon completion of the project and the second payment of 50 percent will be paid upon verification of energy savings. This is intended to encourage customers to implement innovative energy efficiency projects and minimize some of the risks involved if the savings do not materialize as expected, which has been one of the barriers to program adoption. SVP is actively researching emerging technologies and reaching out to customers to inform them about the program and appropriate emerging technologies for their business.
- Commercial New Construction Rebate: This program provides a rebate to customers who exceed Title 24 by 10 percent for the measure being incentivized, in line with other prescriptive rebates for retrofit projects. A Design Team Incentive matching the Investor Owned Utilities' program is provided as follows: at 10 percent savings, the incentive rate is $0.033/kWh. The incentive rate increases as the savings increase, up to 30 percent savings and $0.10/kWh. The incentive rate remains at $0.10/kWh until the project savings exceed 40 percent. At 40 percent and above, the incentive rate is $0.13/kWh. The Design Team Incentive, capped at $50,000, also includes an incentive of $33 per peak kW reduction.
- Business Energy Audits: Provides free energy efficiency audits to business customers. Energy and Resource Solutions administers this and other business PBC programs.
- Business Rebates: Encourages businesses to install energy efficient lighting, air conditioners, motion sensors, programmable thermostats, food service equipment, etc. The programs are occasionally changed to match statewide programs.
- Enhanced Ventilation Controls Rebate: This program provides an incentive of $160/ton for adding enhanced ventilation controls to HVAC rooftop packaged units 15 tons or smaller.
- Small Business Efficiency Services Program – This program is targeted at small business customers, and provides assistance in identifying energy efficiency projects, selecting and managing contractors, and help with filling out rebate application paperwork. The program also provides a 35 percent incentive for lighting and HVAC rebates, provided that customers to install the lighting measures within 6 months of program enrollment and HVAC measures within 12 months of enrollment in order to receive the additional incentive.
- Controls Program – This program is available for projects where at least 80 percent of the savings come from the control strategies. Incentives are paid on a performance basis with 6 payments made over 5 years at a rate of $0.02/kWh saved annually, capped at 65 percent of total project cost, which is above the statewide program cap of 50 percent. The first payment is made upon project completion and each additional annual payment will be subject to commissioning of the controls system and validation of persistent energy savings.
- Public Facilities' Energy Efficiency Program: SVP provides technical assistance and financial incentives for the expansion, remodel, and new construction of City of Santa Clara buildings.

Included in this program are higher levels of rebates for qualifying equipment and energy management assistance.

5.2.1 Third Party Programs for Business Customers

As one of the ways to enhance energy savings through the PBC programs and meet kilowatt hour and kilowatt demand reduction goals, SVP periodically embarks on an RFP process to add third party energy efficiency programs to its Public Benefit Program offering. Of the responses received each cycle, a review team selects responses that are both cost-effective and the most likely to help customers without overlapping with programs already being provided. The most recent RFP was issued in April 2018. The following are being offered:

- **Compressed Air Management Program** was run from 2007-2010 and provided successful implementation of energy efficiency measures in compressed air systems. It was reintroduced in FY 2015/2016, following an RFP issued in December 2013, and is ongoing.
- **Keep Your Cool**, which focused on replacement of refrigeration gaskets and use of strip curtains in commercial refrigeration facilities was launched in 2007. A second version of this program ran in FY 2014/2015 and focused on strip curtains, efficient refrigeration motors, and LED case lighting. The latest version was launched in April 2017 and adds additional energy efficiency measures.
- **Specialized Commercial and Industrial Operational Optimization Program** - This program provides engineering support and analysis to large customer facilities to effectively engage these customers in taking a long-term view of developing energy savings strategies geared towards implementing measures that will continually optimize the operations of their facilities. The program also provides project management support to customers during the implementation phase to make the recommended energy efficiency improvements and data analytics support to assist with ongoing savings validation.
- **Energy Efficient Water Systems Program** - This program provides engineering support and analysis to large customer facilities with cooling towers, significant wastewater systems, and significant pumping loads to assist in implementing energy efficiency measures which will also likely result in water conservation. The program provides an audit of the facilities and project management support to customers during the implementation phase to make the recommended energy efficiency improvements and validate the energy savings.
- **Small Business Exterior Lighting Program** – This program provides a free snapshot audit of exterior lighting efficiency opportunities. It then provides free LED exterior lights to eligible small businesses. The businesses are responsible for the installation cost and can use their own staff, the contractor of their choice, or one of the contractors working with the program provider.

5.2.2 Complementary Programs

- **Low-Income Programs**: SVP's low income programs include a Rate Assistance Program, where qualified low-income customers receive a 25 percent discount on their electric bill (low-income program), as well as a Low Income Direct Install Program, which is described in the energy efficiency programs section.
- **Renewable Energy Programs**:
  - <u>Santa Clara Green Power Program</u>: Residents can purchase 100 percent renewable energy through this voluntary program. The cost for residents and small businesses is a penny and

a half per kWh. Larger companies who do not wish to purchase 100 percent renewable energy may purchase in 1,000 kWh blocks. Block pricing can vary depending on the location of the resources (CA vs. Western U.S), the size of the purchase, and the duration of the purchase commitment.

- **Research, Development, and Demonstration**:
  - Emerging Technologies Grant: This program encourages businesses to demonstrate new products and product applications not yet commercially viable in today's marketplace, install energy efficient technologies not generally known or widely accepted, yet show potential for successful market growth, successfully apply energy efficiency solutions in new ways, or introduce energy efficiency into industries or businesses that are resistant to adopting new technologies or practices.
  - APPA DEED Program: Silicon Valley Power is a paying member of the American Public Power Association (APPA) Demonstration of Energy and Efficient Design (DEED) and currently occupies a seat on the DEED Board. This program funds grants, internships and student scholarships to further R&D in the electric utility industry and support innovative applications of energy efficient or renewable technologies. Over the years, SVP has applied for and received several DEED grants. Most recently, SVP has received grants for additional research of duct-less mini split HVAC units and for commercial food preparation appliance energy savings.
  - California Lighting Technology Center (CLTC): SVP provides financial support to the CLTC to further research and testing of emerging technologies in the area of lighting.
  - Super-Efficient Dryer Initiative (SEDI): SVP provides financial support to SEDI to further research and testing of emerging technologies in clothes dryers, such as the Energy Star Emerging Technology Award-winning Clothes Dryers, which came on the market within the last three years, and the Heat Pump Clothes Dryer, which became commercially available in the United States in 2015, and holds significant promise for energy savings.

5.3 DEMAND RESPONSE PROGRAMS

The CEC encourages POUs to include in the IRP Filing the expected quantitative impacts of planned price-sensitive demand response measures that are proposed, or being considered for future implementation (for example, time-of-use rates), including discussion of POU demand response programs.

Silicon Valley Power is unique in its mix of customers. While 84 percent of the customers are residential, over 90 percent of the utility retail sales are to commercial and industrial customers. Approximately 74 percent of electric load is attributable to the largest "Key" Customers. Over 46 percent comes from data centers. Analysis of large customers has been conducted to determine if any have the ability to shift load during periods of high demand. SVP industrial customers have an average load factor of 85 percent, and perform almost at unity load factor, meaning most large customers are on 24/7 and observe minimal differences between peak and off-peak load, therefore do not have the ability to load shift. In 2017, SVP's load factor was 76 percent inclusive of residential, commercial and industrial customers. SVP does offer incentivizes for customers that can participate in an interruptible program. To date, SVP has one customer that can provide an 8 MW reduction of load.

Advanced Metering Infrastructure: SVP will complete the installation of their advanced metering infrastructure in 2019, time-of-use rates may be offered to residential and non-residential customers; however, the expected impact of new time-of-use rates on peak load are expected to be negligible given the current limited ability of large customers to shift significant amounts of energy load.

Electric Vehicle (EV) Demand Response Programs: As EV adoption grows, SVP will offer programs to encourage EV charging when it is most beneficial to the grid.

5.4 DISTRIBUTED GENERATION AND COMBINED HEAT AND POWER

There are four distributed generation types deployed by SVP's customers: Solar (PV), Fuel Cell (Natural Gas), Micro-turbines, as outlined in Table 5-2.

Table 5-2 Distributed Generation Types deployed by SVP's customers

GENERATOR TYPE	INSTALLED CAPACITY 2017	COMING ON LINE 2018
Solar (PV)	16 MW	1 MW
Fuel Cell (Natural Gas)	6 MW	8 MW
Micro-Turbine (Natural Gas)	0.450 MW	0
Wind (Micro-Turbine)	0.014 MW	0

Since, SVP discontinued commercial solar installation rebates as of June 30, 2017, there has been a decline of interconnection application. SVP discontinued the residential solar rebates on June 30, 2018. Staff will evaluate options for solar programs in future years, with emphasis on a possible low income program and/or a deployable battery storage program.

5.5 STORAGE

In 2013, AB2514 codified Public Utilities Code Section 2836(B) that requires the governing board of each local publicly owned electric utility to determine appropriate targets for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014 as part of their supply plan. The statute also requires each governing board to reevaluate the determinations made pursuant to this subdivision not less than once every three years, where the first three-year period ended October 1, 2017.

The CEC is required by AB 2514 to review the plans and reports submitted by POUs. This review should include consideration of the integration of technologically viable and cost-effective energy storage technologies with other programs, including demand side management and other means to result in the most efficient use of electricity generation and load management resources. The CEC must report to the Legislature regarding the progress made by each local POU serving end-use customers in meeting the requirements of AB 2514. The CEC staff and Commission have been clear that they value the importance of using energy storage to help in meeting the State's environmental goals and plan to act early to ensure energy storage procurement plans are implemented statewide.

In order to meet these requirements SVP must develop cost-effective energy storage options and adopt energy storage system procurement targets, if appropriate. SVP was required to open an energy storage system procurement proceeding by March 1, 2012 and adopted an energy storage procurement target by October 1, 2014, with the first report submitted to the CEC by December 31, 2016 and the second to be submitted by December 31, 2021. SVP must report to the CEC regarding individual progress toward meeting this goal. This report meets the requirement of adopting an energy storage procurement targets to be achieved by December 31, 2021. Below is SVP's current Energy Storage focus.

In SVP's 2017 SVP Storage Procurement Plan submitted to the CEC, the utility proposed proposing to explore three potential projects/use cases to be deployed before January 1, 2021, if found to be cost effective. First, a transmission battery storage application - a black start battery hybrid project. And than other two potential activities are Research and Development (R&D) projects. Of the R&D projects, one is with a Class A commercial customer to explore a battery storage deployment that may provide multiple benefits or dual value streams to both the utility system and the end customer. The second R&D project is a hybrid distribution and customer-end-use project/solution with a large data center that could maximize different value streams and incremental benefits to SVP's distribution system and the customer.

To satisfy SVP's obligations under state law, SVP proposes the energy storage procurement targets as outline in Table 5-3.

Table 5-3 SVP Proposed Energy Storage Procurement Targets

CATEGORY	AMOUNT (KW) / USE CASE	STATUS
Transmission	2.5 MW Black Start Battery Hybrid Project at a Generation Facility in Santa Clara. SVP proposed using a Battery Energy Storage System (BESS) to provide black start capabilities. SVP submitted a proposal to the CAISO to be part of the network of generators that brings the electric grid back on-line after a system failure also known as Black Start.	Project was not selected by the CAISO. Project was terminated
Distribution	50 MW Research and Development (R&D) project with a new data center development to explore multiple value streams/stackable benefits to the customer and the utility. Potential benefits; demand response, frequency support, ancillary services, a non-wires solution to potential system constraints.	Modified due to cost
Customer	▪ Developing a 0.75-1.5 MW Commercial R&D program for Commercial Customers to benefit both utility (demand response) and customer deployment (peak shaving) and potentially other multi-purpose uses ▪ Continuing a 30 kW – Green Charge Networks project at Tasman Drive Parking Structure	In Process

5.5.1 Opportunity Behind-the-Meter/Customer Sided

SVP is spearheading an R&D project through the support from Bay Area Air Quality Management District (BAAQMD) grant funding to implement a behind-the-meter battery storage project with a data center and energy storage technology provider. The project will demonstrate the economic viability and flexibility of a 2 MW/5 MWh duration Battery Energy Storage System (BESS) used for critical need backup power to delay and potentially offset the activation of traditional diesel generators as backup power, while also using the BESS as a demand response product to reduce peak load and providing the opportunity for net revenue by energy arbitrage. The demonstration project combines multiple use storage applications to reduce the operational time and need of diesel generation, optimize GHG reductions through the increased use of renewable energy on the grid to charge the battery, and to reduce the need for combined cycle natural gas generation dispatch during the evening peak demand hours, through the cycling of a fully dispatchable battery. The project will reduce greenhouse gas emissions and particulate matter in vulnerable communities in the City of Santa Clara. In the mid-to-long-term, the investment in the project aims to demonstrate a pilot program to be used for new data center builds that can scale greenhouse gas emission and particulate matter reductions in the City of Santa Clara, and be used as a case study across other service territories.

SVP will also evaluate the potential of multiple stacking benefits that a deployment of this size could bring to the market. Benefits include the following below but are not limited to[9]:

- Ancillary Services - Provide spin / non-spin reserves

  Operation of an electric grid requires reserve capacity that can be called upon when some portion of the online supply resources become unavailable unexpectedly. Generally, reserves are sized to be at least as large as the single largest supply resource (e.g., the single largest generation unit) serving the system and reserve capacity is equivalent to 15 percent to 20 percent of the normal electric supply capacity. Spinning Reserve refers to generation capacity that is online (and synchronized to the grid system) but unloaded and that can respond within 10 minutes when needed to compensate for generation or transmission outages. Non-Spinning Reserve refers to generation capacity that may be offline or that comprises a block of curtailable and/or interruptible loads and that can be ramped to the required level (and synchronized to the grid system) within 10 minutes.

- Provide ramping

  Conventional generation-based load following resources will increase output to follow demand up as system load increases and decreases output to follow demand down as system load decreases. To enable ramping service, a generation unit must be operated at partial load, which is inefficient and requires more fuel per MWh, resulting in increased emissions per MWh relative to the generation unit operated at its design output level. Varying the output of generators will also increase fuel use and air emissions, as well as the need for more generator maintenance and thus higher variable operations and maintenance costs. Storage is a well-suited alternative resource to provide ramping because it can operate at partial output levels with relatively modest performance penalties and respond very quickly when output modulation is needed for load following.

- Shift energy

  At the transmission and distribution level, electric energy time-shift involves purchasing inexpensive electric energy, available during periods when prices or system marginal costs are low, to charge the storage system so that the stored energy can be discharged or sold at a later time when the prices or costs are high. Alternatively, storage can provide similar time-shift service by storing excess energy production, which would otherwise be curtailed, from renewable sources such as wind. Operationally, this application is similar to avoiding curtailing excess energy as energy shifting on the transmission scale is performed during periods of over-generation.

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[9] DNV KEMA Cost Effectiveness Methodologies Report 2017

- Provide capacity

  Capacity refers to making power and energy available to given an electric market to serve current and future demand. Resource adequacy capacity requirements ensure sufficient resources are available in the CASIO market for safe and reliable operation of the grid in real time. Resource adequacy capacity is also designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. For a given capacity resource, the net qualifying capacity is the qualifying capacity of a resource adjusted, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. Flexible capacity is defined as the quantity of resource capacity as specified by CAISO to meet maximum three hour ramping and contingency reserves. Depending on the circumstances in a given electric supply system, energy storage can be used as an alternative to buying new central station generation capacity and/or purchasing capacity in the wholesale electricity marketplace.

  The storage system could perform in utility or ISO capacity dispatch programs such as Demand Response, Local Capacity Resource (LCR), or Forward Capacity Market (FCM). Under these programs, the storage system would be notified ahead of time of the volume and duration of capacity required and the price of that service. Capacity dispatch may involve storage discharging (equivalent to load reduction) during peak or congested hours of the day such as early or late evening.

- Improve distribution system operation (Voltage Support/VAR Support)

  Utilities regulate voltage within specified ANSI standard limits by installing and operating tap changing transformers and voltage regulators at the distribution substation and by switching feeder capacitors downstream to follow load changes. This need is pronounced on long, radial lines with high loading or on feeders with high penetration of intermittent residential PV systems which may be causing unacceptable voltage deviations for neighboring customers. Placing distributed storage closer to load can improve network voltage profile, mitigate fluctuations, and reduce network power losses. Though this may be valuable to SVP system operations it may harder to implement if competing with market opportunities. Staff will determine if this value can be stacked with others for maximum benefit.

- Provide uninterruptible power supply

  Even momentary outages or power quality events can result in large-scale customer financial losses when sensitive electronic or process equipment loads are present. The electric supply to these pieces of equipment can be backed up to an uninterruptible power supply which can seamlessly switch from the utility power supply to energy storage backup when a power quality event or momentary outage occurs. For long-term outages, the UPS enables ride-through capability ensuring continuous supply of power to critical loads while other conventional back-up generation is brought on-line. This value is realized and valued by the end-use customer and is part of their business continuity strategy.

Key project highlights are listed below:

- Target: 2 MW/ 5 MWh duration
- Goal: Creating a Battery Storage design that can be replicated to other Data Centers.
- Cost-Effectiveness:

- Utility: To be determined -depends on the value extracted stacking benefits and the CAISO marketplace
- Customer: Provide additional revenue stream and/or cost recovery mechanism. Emissions reduction.

- Deployment Target Date: 2019/2020

5.5.2 Commercial Solar and Storage Pilot

The primary benefit for cost-effective deployment of behind-the-meter use cases is customer bill reduction through the reduction of demand charges that are applicable to some commercial and industrial customers, also known as "peak shaving." In addition to customer bill savings, energy storage could potentially provide capacity dispatch revenue from the utility as part of a Demand Response program. The storage system would be notified ahead of time of the volume and duration of capacity required and the price of that service. Capacity dispatch may involve storage discharging (equivalent to load reduction) during peak or congested hours of the day such as early or late evening.

SVP is working with a vendor who currently deploys Solar + Storage on large Class-A office buildings. SVP is proposing a R&D project to determine the cost-effectiveness of deploying smaller scale storage systems and co-optimized the benefits that the storage operation can provide. This also allows the utility to test the accuracy of customer control systems and the integration of battery storage into a defined operational strategy.

Key project highlights are listed below:

- Proposed Size: 0.75MW – 1.5MW
- Goal: Reduce customer and utility peak through demand response management thus creating a win/win scenario for both the utility and end use customer without impacts to other rate payers.
- Cost-effectiveness:
  - Utility: To be determined.
  - Customer: the deployment is dependent on the California Self Generation Incentive Program (SGIP) and the Federal Investment Tax Credit (FITC), applicable to energy storage and PV and potentially SVP's determined grid value.
- Deployment Target Date: 2019/2020

5.5.3 Continuing Project -SVP Pilot Project with Green Charge Networks

SVP is continuing to pilot an energy storage project at the Tasman Drive Parking Structure through a CEC grant program to reduce customer-side peak demand charges due to high energy electric vehicle fast charging. The City's Streets Department is SVP's customer at this parking structure. Green Charge Networks, a Santa Clara based energy storage company, approached SVP to install a 30 kW "GreenStation" battery energy storage system along with an electric vehicle DC fast charger station at this location. The cost of the energy storage system, the DC fast charger and the installation is covered by a California Energy Commission grant program, resulting in no costs to Santa Clara or SVP. The GreenStation is installed behind-the-meter and dampens the demand spikes that occur when the DC fast charging station is used. This helps the Streets Department avoid higher electricity bills due to the increased demand charges that would otherwise occur from use of the DC fast charging station.

5.5.4 Energy Storage Opportunity at the Transmission/Distribution and Generation System Level

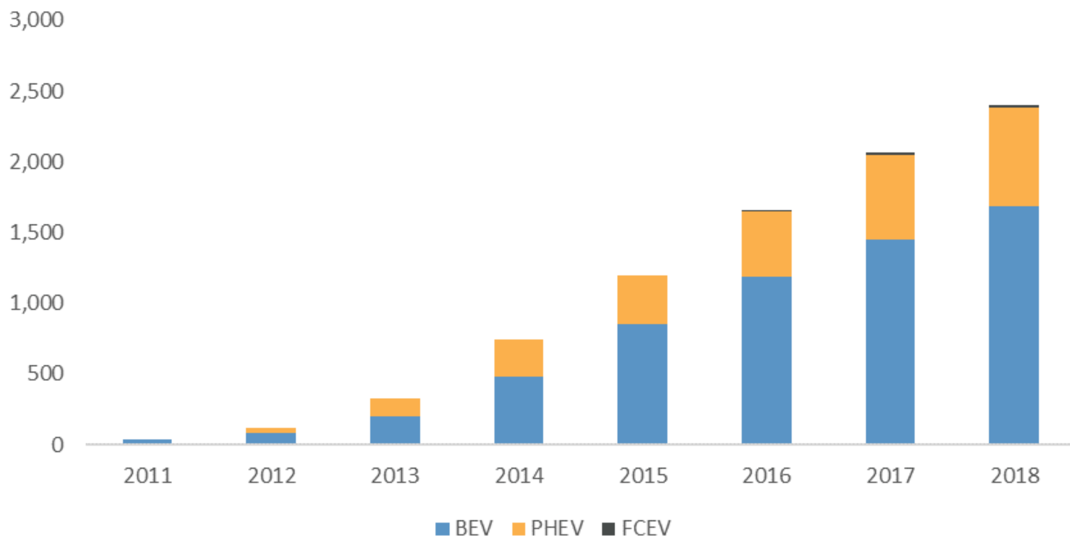
SVP designed a techno-economic model to simulate the performance of a utility-scale lithium-ion battery, which incorporated a discounted cash flow analysis to evaluate the financial feasibility of a battery energy storage system over the life of the system. The model discounts project costs, savings and revenues generated to present value to assess the payback period of the project required to recover the total installed cost of the battery energy storage system. Furthermore, a break-even point analysis is determined to understand how subsidies, and future battery energy storage costs required can improve project viability. The analysis provides case studies on battery capacity over time, efficiency losses through system components, the useful life of the system, total system costs over time, and various cost savings achieved through the participation in the wholesale market and other multi-use application for the battery energy storage system. When the model indicates, SVP will evaluate large scale battery deployment at utility scale renewable projects.

5.6 TRANSPORTATION ELECTRIFICATION

California calls for a 40% reduction in GHG emissions from 1990 levels by 2030 and an 80% reduction by 2050 per Executive Order S-3-05 (2005). Air quality goals include a 90% reduction in emissions of nitrogen oxide gases ($NO_{x)}$ from 2010 levels by 2032. In January 2018, Executive Order B-48-18 called for 5 million ZEVs by 2030. In December 2018, CARB passed the "Innovative Clean Transit" policy stating that by 2023, one quarter of purchased transit buses need to be zero emission, and by 2029, 100% of new buses purchased need to be zero emission.

Using CARB's Clean Vehicle Rebate Project (CVRP), which began tracking rebates for purchased zero-emission vehicles (ZEVs) in 2011 through 2018, there were 2,427 vehicle to date registered with in the City. Note that not all plug-in hybrid, all-battery, and fuel cell electric vehicles sold/leased in the state are captured in this database. Not every eligible vehicle owner applies to the CVRP, and not every clean vehicle is eligible for the rebate. Over the first five years of the program, owners of about 75% of eligible vehicles participated in the rebate project. If available, using Department of Motor Vehicle (DMV) registration data is a preferred source for a more accurate estimate of current PEV adoption within a city; that data can also provide information on vehicle class for commercial vehicles. However, neither of these sources forecast vehicle ownership trends or inflow of traffic from surrounding areas.

Figure 5-1 shows the cumulative growth of ZEV rebates within SVP territory, by vehicle type, from 2011-2018. A slight decline in annual rebates is most likely to occur in 2019 due to popular rebate-eligible vehicles sold in the U.S. reaching 200,000. Any of those specific vehicles purchased after that point no longer qualifying for the federal PEV rebates.



Source: CARB CVRP

Figure 5-1 Cumulative SVP ZEV Rebates by ZEV Type, 2011-2018

For the service area, the electric vehicle (EV) forecast involves a significant increase in the number of vehicles through 2026. Figure 5-2 shows the cumulative number of electric vehicles, including EVs and plug-in electric vehicles (PEVs) that are projected to increase from approximately 2,200 in 2018 to more than 24,000 by 2030 based on the CEC EV model.

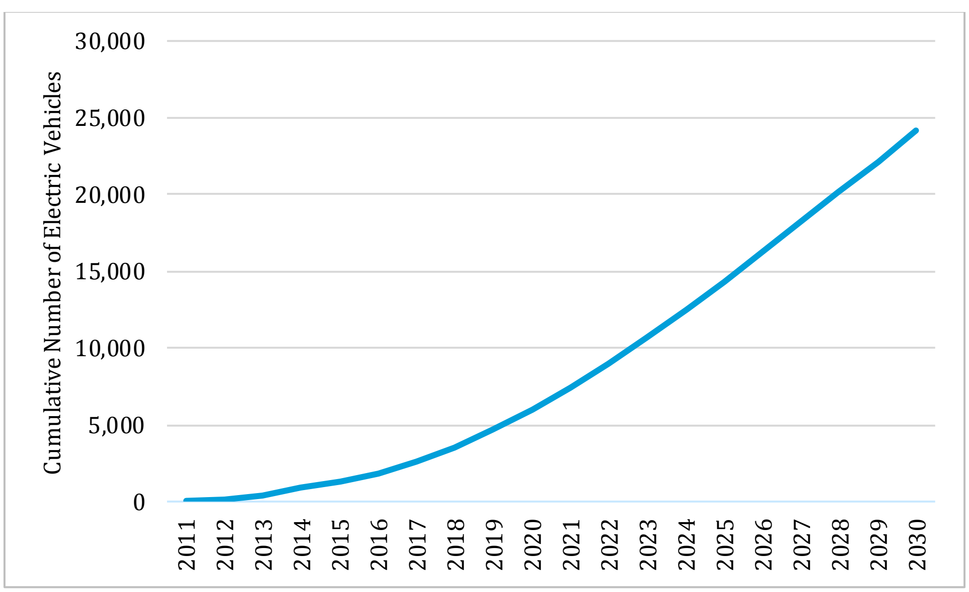
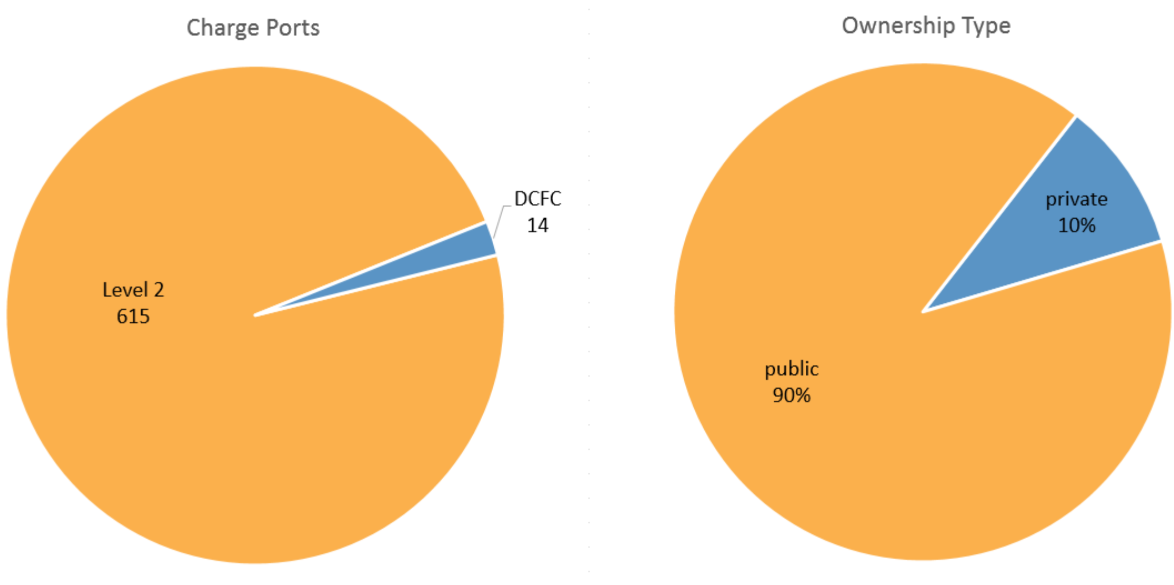


Figure 5-2 CEC Projected EV Adoption (cumulative)

5.6.1 Current Electric Vehicle Charge Connectors

By 2016, The City and its businesses had installed 376 PEV charging connectors. Note that a typical charging station contains multiple charging connectors to plug into multiple vehicles. In Santa Clara, the average charging station has six charging connectors. Using the Alternative Fuels Data Center (AFDC), The City tracks installation of public and private charge connectors.[10] Through 2018, there were 629 charge ports; 615 ports were Level 2 (L2) chargers and 14 were DCFC chargers in the City. This information, as well as ownership type, is detailed in Figure 5-3.

Figure 5-3 Current Charger Port Installations by Type and Ownership



Source: Siemens; AFDC

The 629 public and private charge ports currently within The City are found in 106 different locations, for an average of six charge ports per location. However, specifically for DCFC, there are only one or two charge ports per location. Most of the charging infrastructure is in the northern part of The City, zip code 95054, with 93% of all L2 charge ports and 57% of all DCFC charge ports. The location with the most accessible charge ports is 2910 Tannery Way – a parking garage – with 158 L2 charge ports open 24 hours, 7 days a week. The City currently has a total of 70 city-installed public charge ports located at Central Park Library, Santa Clara Convention Center, Tasman Garage, City Hall, and, most recently, the Northside Library. Two DCFC ports at the Central Park Library have been identified for replacement. Figure 5-4 maps where PEV chargers are located within The City, based on city permitting data.

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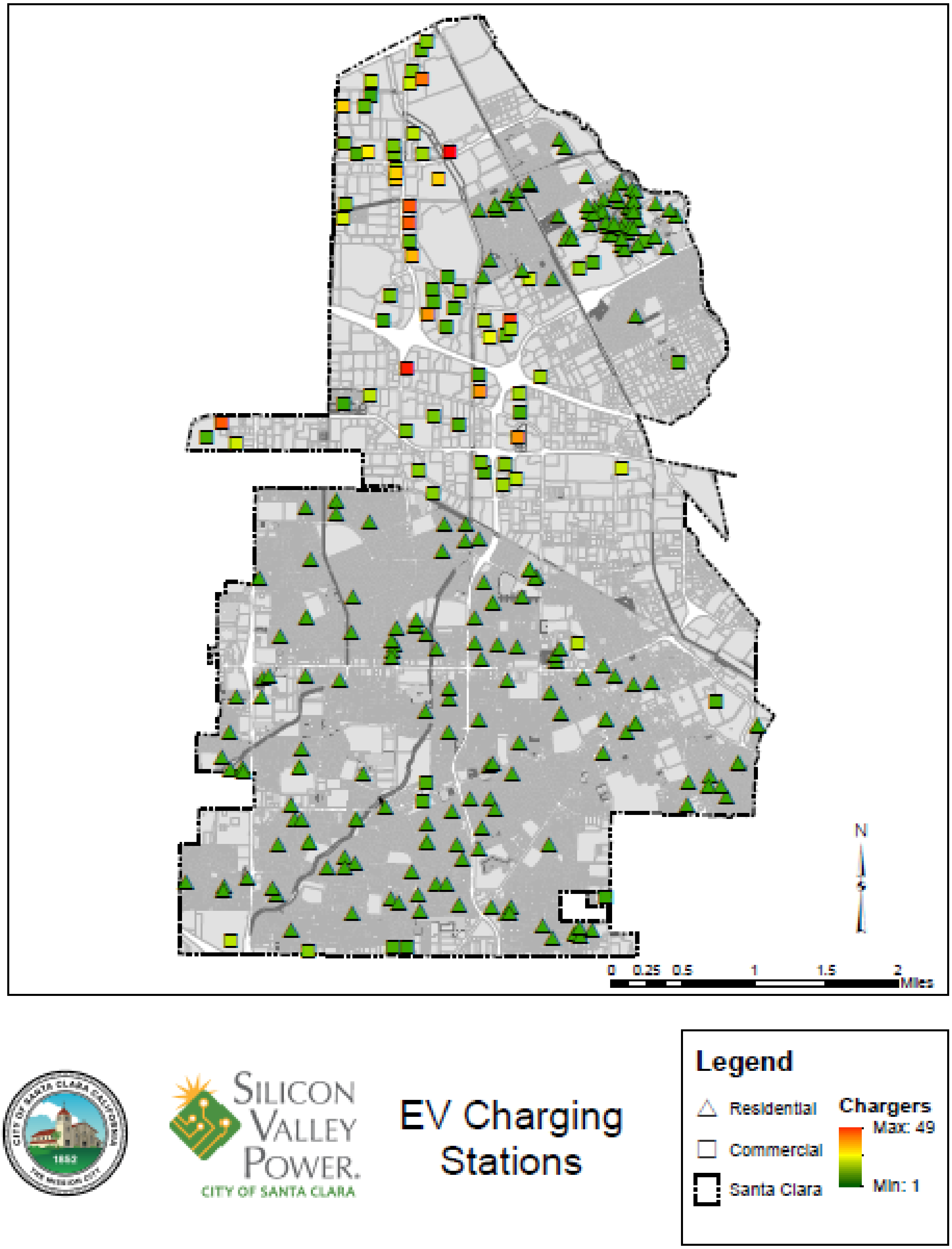
[10] https://afdc.energy.gov/fuels/electricity_locations.html#/find/nearest?fuel=ELEC

Figure 5-4 Map of PEV known Chargers within The City



Source: EV Blueprint team

5.6.2 Grid Impacts

SVP's primary responsibility is to provide safe, reliable power, while limiting future cost increases and complying with city core values. PEV adoption poses both risks and opportunities to utilities as summarized in Figure .

Figure 5-5 Utility Risks and Opportunities from PEV Adoption

Increased Planning Cost and Decreased Effectiveness	Waiting to plan for inevitable Plug-in Electric Vehicle (PEV) growth will result in reactive uncoordinated efforts to study and upgrade systems to meet system/circuit stresses caused by local charging. Such ad hoc efforts will prove more costly and less effective than a planned systemic business approach to prepare the grid for PEVs.
Scramble to Keep Pace with Other Agendas	The current reactive approach to transport electrification allows interveners and new market entrants to drive the public debate and steer political responses resulting in utilities trying to catch-up with state regulators.
Missed Load and Business Opportunities	The PEV market will grow and affect utilities whether they want it to or not. Active engagement provides opportunities to counter declining load, test new business models, and reduce negative grid impacts. However, without a strategy, utilities have been ceding these opportunities to new market entrants, which are taking the low hanging fruit.
Precedents and Funding Available	While the PEV market is new, the risk that growth will slow or stop is lower than many think. With state policymakers funding charging infrastructure and another $2.4 billion in Volkswagen settlement funds available, the lack of available charging infrastructure will cease being a barrier to consumers considering PEVs.

Source: Siemens[11]

Utilities have the opening to approach electrification of the transportation sector not just as a business opportunity, but an entry point for grid modernization. Therefore, whether a city-owned or investor-owned utility, their understanding of the electrical infrastructure within a city and data to evaluate impacts of PEV adoption on the grid are a crucial part of any EV Blueprint.

Since SVP's customer base is primarily commercial/industrial, its energy use and peak demand profile is relatively flat monthly. However, SVP has historically experienced sudden increases in electricity demand at times, as customers move into new facilities. Data center loading can cause SVP's load growth profile to be "lumpy," due to new connections of substantial blocks of power-consuming facilities or equipment by industrial customers. This profile is reflective of the high intensity of industrial energy use in SVP's service area, which is heavily weighted toward high-technology manufacturing and data management facilities.

Unlike many cities, which experience lower than expected load growth due to energy efficiency programs, and distributed energy resources (DER), The City is experiencing consistent growth in energy and peak demand. Both energy and peak demand have been consistently increasing over the years and this trend is forecasted to continue going forward. Current forecast for PEV energy

[11] http://www.paceglobal.com/wp-content/uploads/2017/12/Electrification_Transportation_Sector_Flyer_FINAL.pdf

demand by 2030 is an additional 52 GWh to 143 GWh based on preliminary modeling. Overall anywhere from a 0.70% to 2.61% of SVP's total load demand.

5.6.3 Low Carbon Fuel Standard

In October of 2016, SVP entered a voluntary California Air Resources Board (CARB) program called the Low Carbon Fuel Standard (LCFS) Program. The LCFS Program was created through AB 32, California Global Warming Solutions Act of 2006 and Governor's Executive Order S-01-07. The LCFS Program is a key part of a comprehensive set of programs in California to cut greenhouse gas emissions and other smog-forming and toxic air pollutants by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options. The LCFS Program is designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable-powered alternatives. The goal of this program is to reduce by at least 10 percent the carbon intensity of California's transportation fuels by 2020.

Through compliance with the LCFS Program, SVP receives LCFS credits. These credits are sold in an exchange and these funds are to be used to comply with Title 17 of the California Code of Regulations Section 95483(e) (1) (A-D), LCFS program proceeds may only be used in accordance with the following requirements.

Regulated Parties for Electricity

For electricity used as a transportation fuel, the party who is eligible to generate credits is determined as specified below:

For on-road transportation fuel supplied through electric vehicle (EV) charging in a single- or multi-family residence, the Electrical Distribution Utility is eligible to generate credits in its service territory. To receive such credits, the Electrical Distribution Utility SVP must:

- Use all credit proceeds to benefit current or future EV customers;
- Educate the public on the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline);
- Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid; and
- Include in annual compliance reporting the following supplemental information: an itemized summary of efforts to meet requirements (A) through (C) above and costs associated with meeting the requirements

The LCFS combined with other programs, enables SVP to create an EV program that include the following initiating activities in fiscal year 2018/19:

- Electric Vehicle Charging Equipment Rebate:
  - Residential: $750 rebate per installed electric vehicle charger equipment
  - Multi-Family: $3,000 rebate per installed public electric vehicle charger equipment
  - Schools & Non-Profit entities: $5,000 per installed electric vehicle charger equipment

- Electric Vehicle Public Access Charging:
  - Placing public electric vehicle chargers at City owned facilities, such as at the new Reed and Grant Sports Park (8 charging ports) and Raymond G. Gamma Dog Park (6 charging ports)

SVP believes that with convenient, publicly accessible EV charging incentives to promote EV charging in the community, and with community outreach and engagement, SVP can influence the City's residents and businesses will accelerate the deployment of transportation electrification and reduce carbon emissions from the transportation sector.

5.6.4 CEC Electric Vehicle Ready Communities Challenge Blueprint Plan

In July 2018, Council approved a Grant Agreement with the California Energy Commission and approved the appropriation of those grant funds to complete the Electric Vehicle Ready Communities Challenge Blueprint Plan to help the City achieve electric vehicle readiness, and understand current gaps and implementation barriers. The EV Blueprint will be completed by June 1, 2019 and relevant parts will be incorporated into the utility planning process and into future IRPs. Staff anticipates this EV Blueprint in combination with the proposed use of LCFS Program funds for charger rebates and other incentives will accelerate deployment of transportation electrification within Santa Clara.

6.0 The Need for Additional Resources and Resource Options

SVP's load forecast was used to determine the gap between SVP's existing and contracted resources and customer load requirements during the 2019-2038 planning period. SVP has sufficient resources to meet the RPS requirements through 2030 to meet the 50 percent mandate. However, given the recent approval of SB 100, SVP modeled the IRP based on a 60 percent target by 2030.

The need for additional renewable resources established in this section leads to the development of two expansion planning scenarios that are modeled and presented from an economic cost and renewable energy perspective in Section 8.

6.1 SVP'S EXISTING SYSTEM

Simulations for the IRP planning were used to identify, under the Base Case, when additional renewable resources are needed to meet RPS targets. Initial modeling was performed to meet the 50 percent renewable target stipulated by SB 350. However, with the recent passing of SB 100, additional analysis was performed to ensure sufficient renewable additions to meet the 60 percent target by 2030 were identified. Table 6-1 provides additional information about the adequacy of SVP's existing system through 2030 to meet renewable targets of 60 percent by 2030.

The table indicates through 2024 that the existing system has sufficient renewable generation to add to the banked RECs, with the exception of one withdrawal in the year 2020. Starting in 2025, SVP begins to withdraw from the banked RECs to meet renewable targets. The table does not include any generic renewable resources added to the mix post 2020. SVP can comply with the targets using a combination of existing resources and banked RECs. However, for the IRP Base Case, SVP considered commencing renewable additions in 2030 to be more proactive and flexible in renewable additions through years 2020-2029 and less reliant on the use of RECs to meet the target for that year. This is further described in Section 8.

As described in Section 1, since the completion of the modeling, SVP has made updates to the assumptions underlying the IRP. These updates are reflected in the Standardized Tables RPT 60 (60%) in addition to RPT 50 (50%) and are to take precedence over the numbers provided in this report. The change includes a reduction in the generation from a few RPS-eligible facilities, which results in increased market purchases and additional withdrawals from banked RECs. The additional withdrawals occur during the same years as modeled at an increased volume of 1 to 3 percent of the 60 percent renewable target. In total, SVP continues to maintain an adequate REC balance for the duration of the planning period. Modeling included signed contracts, those resources in process were not included in the modeling scenarios of the document but are included in the Standardized Tables.

Table 6-1 SVP Existing System Renewables Sufficiency

Renewable Energy Achieved (GWh) and Renewable Energy Credits (1,000)													
Silicon Valley Power													
Technology	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Solar		62	62	158	157	157	157	156	155	155	155	154	153
Wind		453	454	1,022	1,422	1,422	1,423	1,416	1,416	1,416	1,417	1,417	1,417
Small Hydro		544	544	544	544	544	308	307	307	307	308	307	307
Landfill Gas		98	98	98	98	98	98	98	98	95	96	84	84
Geothermal		342	336	329	322	316	310	303	297	291	285	280	274
Total RECs Generated		**1,499**	**1,494**	**2,150**	**2,543**	**2,536**	**2,295**	**2,280**	**2,274**	**2,265**	**2,260**	**2,242**	**2,235**
RPS Target, %		31%	33%	36%	39%	42%	45%	48%	50%	53%	55%	58%	60%
RPS Target		1,190	1,394	1,584	1,758	1,937	2,128	2,304	2,429	2,556	2,705	2,856	3,010
REC Sales Obligation		(111)	(111)	(111)	(111)	(72)	(72)	(72)	(72)	(72)	-	-	-
RECs Available for compliance		**1,387**	**1,382**	**2,039**	**2,432**	**2,464**	**2,223**	**2,208**	**2,202**	**2,193**	**2,260**	**2,242**	**2,954**
Historical Banked RECs	2,856												
Deposits		198	-	455	674	527	94	-	-	-	-	-	-
Withdrawals		-	12	-	-	-	-	96	227	363	445	615	775
REC Bank Balance		**3,054**	**3,042**	**3,497**	**4,170**	**4,697**	**4,791**	**4,695**	**4,468**	**4,105**	**3,660**	**3,045**	**2,271**
Renewable Generation and REC withdrawals		**1,499**	**1,506**	**2,150**	**2,543**	**2,536**	**2,295**	**2,376**	**2,501**	**2,629**	**2,705**	**2,856**	**3,010**
Renewable and RECs as a % of retail sales		**39%**	**36%**	**49%**	**56%**	**55%**	**49%**	**50%**	**51%**	**54%**	**55%**	**58%**	**60%**

SVP developed and evaluated two expansion plans as part of the IRP process. One expansion plan assessed the addition of 50 percent solar and 50 percent wind to address the renewable shortfall. The second expansion plan assessed the addition of 80 percent wind and 50 percent solar to address the renewables shortfall. Additionally SVP evaluated multiple sensitivity cases. These scenarios and sensitivities are presented in Section 8.

In order to evaluate the best resource options for SVP, cost and performance assumptions were developed for candidate renewable resources that could be part of SVP's resource expansion plan. The cost and performance of supply side resources considered in the expansion planning analysis are developed and presented in the following subsections.

6.2 SUPPLY SIDE RESOURCE TECHNOLOGY COSTS AND CHARACTERISTICS

In consideration of the objective of achieving long-term reliability, low electric costs, and fuel diversity to lower risk of dependence on a single fuel source, SVP developed a list of multiple resource options to serve as candidates for consideration to serve SVP's future needs. All incremental options considered in the analysis were renewable energy solar or wind resources. These options are discussed further in this section.

6.2.1 Renewable Energy

To obtain indicative renewable energy PPA pricing, representative wind and solar projects were identified in the Northern California region. The solar project was assumed to consist of single axis tracking systems (SAT). SAT systems tend to have better output in the late afternoons when generation is often the most valuable. The representative project was assumed to have a capacity factor of 30 percent, similar to those currently in SVP's portfolio.

The wind project evaluated was sized at 100 MW or more in line with recent trends of sizing wind farm. It was assumed, however, that SVP could purchase less than the full output of a large wind farm. Wind capacity factor was assumed to be 40 percent based on units currently in SVP's portfolio.

Table 6-2 summarizes the two representative projects.

Table 6-2 Renewable Systems and Modeled Performance

SITE	LOCATION	PROJECT CAPACITY [MWAC]	MODULE CAPACITY [MWDC]	CAPACITY FACTOR (AC)
1	North CA Solar	10	13	30.0%
2	North CA Wind	100		40.0%

6.2.1.1 Cost Assumptions

Renewable energy project costs vary depending on system size and location costs. The capital costs provided represents an all-in installed cost or total capital expenditures (CAPEX), including EPC, owner's costs, developer fees, interconnection, financing fees, and construction interest. [12] This total cost is used as the capital cost when calculating the busbar levelized cost of energy (LCOE). Table 6-3 summarizes the 2020 Cost Assumptions in nominal dollars.

Table 6-3 2020 Cost Assumptions for Renewable Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	INTER-CONNEC-TION COST ($M)	CAPITAL COST [$/KWAC]	CAPITAL COST [$/KWDC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALA-TION (ANNUAL)
1	North CA Solar	10	$0.5	$1,770	$1,362	$26	2.5%
2	North CA Wind	100		$1,700		$35	2.5%

To determine the estimated cost of 2030 projects, it was assumed that capital costs would decline 1 percent per year in real terms for wind and solar technologies amid an inflationary environment of 2.5 percent per year. The escalated technology costs for 2030 are shown in Table 6-4.

[12] EPC stands for "engineer, procure, and construct". Additional trade tariffs were imposed on imported solar cells in January of 2018, resulting in increases in module costs. However, the new tariffs are set to decline over the next four years, and module costs are expected to continue to fall. Thus, module costs are assumed to be similar to 2017 levels by 2020.

Table 6-4 2030 Cost Assumptions for Renewable Systems (Nominal$)

SITE	LOCATION	PROJECT CAPACITY [MWAC]	INTER-CONNEC-TION COST ($M)	CAPITAL COST [$/KWAC]	CAPITAL COST [$/KWDC]	FIXED O&M COSTS [$/KWAC]	FIXED O&M ESCALATION (ANNUAL)
1	North CA Solar	10	$0.64	$2,049	$1,576	$33	2.5%
2	North CA Wind	100		$1,968		$45	2.5%

6.2.1.2 Levelized Cost of Energy (LCOE)

To model the LCOE of each of the representative projects, Black & Veatch assumed a third-party independent power producer (IPP) structure where PPA pricing is based on the LCOE. A number of financial incentives were incorporated into the modeling, as discussed below. As a tax exempt entity, SVP cannot directly use the investment tax credit, however, by contracting with an IPP under a PPA, SVP can share in the tax credit through the PPA pricing.

6.2.1.3 Financial Assumptions

The 2018 Tax Reform bill changed the federal corporate tax rate from 35 percent to 21 percent while still allowing state income taxes to be tax deductible, resulting in the composite income taxes for California are shown in Table 6-5.

Table 6-5 Assumed Federal and State Income Tax Rates

	CALIFORNIA
Federal Income Tax	21%
State Income Tax	8.84%
Composite Income Tax	28.0%

6.2.1.4 Tax Credits

The Consolidated Appropriations Act, signed in December 2015, extended the investment tax credits (ITC) that apply to solar technologies and wind. Wind project owners can opt for the ITC in lieu of the production tax credit (PTC), which was also extended, but wind typically benefits more from PTC at better wind sites. The credits do decline over time, as shown in Table 6-6. The availability of tax credits shapes the SVP strategy of purchasing wind and solar from private developers through a PPA instead of self-building since SVP is a tax exempt municipal utility.

- ITC is a credit taken as a percentage against the capital cost of a renewable energy system. The capital cost basis allowed is defined by the IRS. If the project owner opts for the ITC, the depreciation basis will need to be reduced by 50 percent of the ITC (e.g., 30 percent ITC => Depreciation Basis would be 85 percent of the capital cost)
- PTC is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service.

For 2020, solar projects can receive a 30 percent ITC against the total capital cost of their project, if the project "begins constructions" by the end of 2019. For this analysis, it was assumed that the solar projects begin construction in 2019 and come on-line in 2020 to take advantage of the 30 percent ITC. Otherwise the incentive drops to 26 percent in 2020. By 2030, the ITC drops to 10 percent.

While wind project owners can select between the ITC and the PTC, the drop in the benefits of the ITC occur sooner, so by 2020, there are no incentives available for wind, unless construction started in 2019. In this case, it was assumed that construction starts in 2019 and wind owners take advantage of the PTC at a rate of $9 per MWh, escalated at inflation, for the first 10 years of the project. By 2030, wind does not receive any production tax credits.

Table 6-6 Tax Credit Assumptions

TECHNOLOGY (CONSTRUCTION START)	12/31/19	12/31/20	12/31/21	12/31/22	FUTURE YEARS
Solar PV	30%	26%	22%	10%	10%
Large Wind (Estimated PTC per MWh)	$9	N/A	N/A	N/A	N/A

6.2.1.5 Accelerated Depreciation

Historically, solar and wind projects have been able to utilize a 5-year accelerated depreciation schedule (MACRS) that helped improve project economics. The 2018 Tax Reform bill now allows renewable energy projects to take 100 percent tax depreciation on the total cost of the project in year 1. Industry experts believe, while quite generous, few investors would be able to take full advantage of this new depreciation schedule, so the modeling in the analysis assumed a 5-year MACRS schedule, where approximately 90 percent of the total capital cost would be depreciable.

6.2.1.6 Cost of Capital

IPPs have multiple methods of funding renewable energy projects. For modeling purposes, it was assumed that the debt/equity structure for both solar and wind projects would be as shown Table 6-7. In recent years, the cost of capital for renewable energy projects has dropped substantially in terms of lower interest rates on debt as well as lower equity return requirements by investors. The debt term was modeled for 20 years while the life of the project was 25 years in the analysis performed.

Table 6-7 Cost of Capital Assumptions for Solar and Wind

FINANCIAL FACTOR	SOLAR	WIND
Debt Percentage	50	60
Debt Interest Rate (percent)	4.5	4.5
Debt term (Years)	20	20
Economic life (Years)	25	25
Cost of equity (after tax) (percent)	10	10

6.2.1.7 Levelized Cost of Energy

The LCOE for the renewable projects with commercial on-line dates in 2020 and 2030 resulting from the input assumptions and analysis are shown in Table 6-8 and Table 6-9. The LCOE represents that assumed to be in a fixed price, 25-year PPA.

Table 6-8 Renewable Energy Projects LCOE (Nominal$) 2020 COD

SITE	TECH-NOLOGY	PROJECT CAPACITY [MWAC]	CAPACITY FACTOR (AC)	CAPITAL COST [$/KWAC]	ITC OR PTC	NOMINAL LCOE RESULT ($/MWH)
1	North CA Solar	10	27.9%	$1,770	30%	**$53**
2	North CA Wind	100	30.0%	$1,700	$9/MWh	**$60**

Table 6-9 Renewable Energy Projects LCOE (Nominal$) 2030 COD

SITE	TECH-NOLOGY	PROJECT CAPACITY [MWAC]	CAPACITY FACTOR (AC)	CAPITAL COST [$/KWAC]	ITC OR PTC	NOMINAL LCOE ($/MWH)
1	North CA Solar	10	27.9%	$2,049	10%	$85
2	North CA Wind	100	33.1%	$1,968	$0	$75

Since the ITC and PTC vary year by year, the following table shows the year by year LCOE for projects that come on-line for that year, assuming construction start dates of the previous year.

Table 6-10 Project Nominal LCOE 2020 to 2030 ($/MWH)

YEAR	PROJECT 1	PROJECT 2
	Solar SAT	**Wind**
	North CA	**North CA**
2020	$53	$60
2021	$58	$70
2022	$65	$70
2023	$75	$71
2024	$77	$71
2025	$78	$72
2026	$79	$72
2027	$81	$73
2028	$82	$73
2029	$83	$74
2030	$85	$75

7.0 Modeling Assumptions, Tools, and Methodology

7.1 MODELING ASSUMPTIONS

7.1.1 Load forecasts

The SVP load forecast used for the IRP analysis was bases on the following forecast:

YEAR	NET ENERGY REQUIREMENTS GWH	NET ENERGY REQUIREMENTS PERCENT CHANGE (%)	PEAK DEMAND MW	PEAK DEMAND PERCENT CHANGE (%)	LOAD FACTOR (%)
2017 (actual)	3,727.2		586.6		73%
2018	3,647.5	-2.1%	585.8	-0.1%	71%
2019	4,039.5	10.7%	646.6	10.4%	73%
2020	4,447.6	10.1%	693.7	7.3%	75%
2021	4,631.8	4.1%	716.3	3.3%	75%
2022	4,744.8	2.4%	731.2	2.1%	76%
2023	4,855.2	2.3%	745.6	2.0%	76%
2024	4,978.9	2.5%	760.0	1.9%	79%
2025	5,053.4	1.5%	771.8	1.6%	78%
2026	5,113.6	1.2%	778.4	0.9%	79%
2027	5,125.7	0.2%	782.3	0.5%	78%
2028	5,177.0	1.0%	790.1	1.0%	78%
2029	5,228.8	1.0%	798.0	1.0%	78%
2030	5,281.0	1.0%	806.0	1.0%	78%
2031	5,333.9	1.0%	814.0	1.0%	78%
2032	5,387.2	1.0%	822.2	1.0%	78%
2033	5,441.1	1.0%	830.4	1.0%	78%
2034	5,495.5	1.0%	838.7	1.0%	78%
2035	5,550.4	1.0%	847.1	1.0%	78%
2036	5,605.9	1.0%	855.6	1.0%	78%
2037	5,662.0	1.0%	864.1	1.0%	78%
2038	5,718.6	1.0%	872.8	1.0%	78%
AAGR 2018-2038		2.1%		1.9%	

7.1.2 Natural Gas and Average Market Prices

The economic analysis required a projection of natural gas fuel prices and power energy prices per Table 7-1.

Table 7-1 Average Natural Gas and Market Energy Prices Assumed in the SVP IRP

YEAR	AVERAGE GAS PRICE ($/MMBTU)	AVERAGE ENERGY PRICE ($/MWH)
2019	$ 3.22	$ 31.83
2020	$ 3.42	$ 32.51
2021	$ 3.47	$ 31.99
2022	$ 3.68	$ 32.59
2023	$ 3.96	$ 32.91
2024	$ 4.10	$ 33.64
2025	$ 4.23	$ 34.72
2026	$ 4.36	$ 35.94
2027	$ 4.37	$ 35.32
2028	$ 4.40	$ 35.22
2029	$ 4.54	$ 35.44
2030	$ 4.52	$ 35.46
2031	$ 4.69	$ 37.09
2032	$ 4.88	$ 38.79
2033	$ 5.06	$ 40.40
2034	$ 5.27	$ 42.09
2035	$ 5.48	$ 43.86
2036	$ 5.72	$ 45.78
2037	$ 6.01	$ 47.93
2038	$ 6.31	$ 50.25

7.1.3 Discount Rate

The analysis utilized a 4.5 percent discount rate. This discount rate was applied to future costs and revenues to determine estimated future SVP net costs of serving load on a net present value basis.

7.2 PLEXOS MODELING TOOL AND METHODOLOGY

The IRP utilized the PLEXOS production cost modeling software tool to model SVP's power system to compare the various scenarios in terms of present value cost as well as determining if a portfolio achieves other requirements such as GHG and renewable energy goals.

PLEXOS is one of the leading production cost model simulation software and uses state-of-the-art mathematical optimization to provide extensive simulation capabilities across electric power, water and gas systems. PLEXOS is used extensively by utilities, ISOs, consultants, and government agencies for Renewable Integration studies, Market design, Integrated Resource Planning, portfolio planning and risk management. PLEXOS has been used by SVP to model SVP electric portfolio and provide 10-year budget forecast.

For the IRP, PLEXOS was used to develop 20-year integrated resource plan that satisfies system reliability constraint and RPS targets and minimizes the Net Present Value (NPV) of investment cost and operation cost over 20-year planning horizon.

The Long-Term Plan module in PLEXOS, was used to develop the least cost expansion plan. The objective function of the Long-Term Plan module is the NPV of the sum of capital costs, fixed costs, and variable operation costs of the system over the planning period of 2019 to 2038. Key inputs to the model include:

- System load forecast
- Existing and planned resources and expected retirements
- Operating parameters of the existing resources and costs
- Future candidates, operating parameters, and associated capital cost, fixed and variable operating cost
- System reliability constraint
- Annual RPS target
- System discount rate

It was assumed that SVP has sufficient local and system resource to meet local and system Resource Adequacy constraints or through short-term capacity market purchases. For RPS target, the system assumes the RPS target of 60 percent by 2030 and 100 percent by 2045, in line with the requirements of SB 100.

Initial simulation shows that without additional renewable resources, SVP is short in 2032 to meet the annual RPS target. However, given the renewable target requirement in 2030, SVP pulled forward the addition of renewable resources to 2030 to be more proactive and flexible in renewable additions, and to be less reliant on the use of RECs to meet the targets. Given the cost and performance parameters of potential wind and solar projects, the PLEXOS Long Term Plan was then used to find the best combination of new solar and wind resources to meet the RPS targets and minimize the NPV of the investment and operating cost.

8.0 Evaluation and Results

This section lays out the economic analysis performed for the SVP system. In general, the analysis is aimed at minimizing SVP total system costs while also meeting the several targets that have resulted from the state RPS and environmental policies described in Section 2, including the following goals for SVP:

- Low cost and reliability
- 60 percent renewable energy by 2030 and meet intermediate goals per SB 100
- Increased energy efficiency per SB 350
- 2030 GHG within the July, 2018 CARB staff recommended targets (low of 275,000 MTCO2e and high of 485,000 MTCO2e)

Additionally, SVP believes that it is important to achieve a balance in solar and wind resources over the planning horizon, since a balanced portfolio may reduce risks associated with over-reliance on a single technology. Also, a balanced wind and solar energy generation combination is deemed to be a better fit to SVP's hourly system energy demand profile than a plan heavily weighted toward either wind or solar.

8.1 ECONOMIC EVALUATION FRAMEWORK

The objective of the economic analysis is to meet the requirements identified above, while minimizing the long-term present worth cost of incremental power to customers. This cost is commonly called the cumulative present worth cost (CPWC) of an expansion plan. The CPWC includes "incremental" costs, which refers to the power supply costs incurred by SVP directly or indirectly through interaction with the market and power producers during the 2019-2038 evaluation period. Incremental costs do not include existing fixed costs or common costs such as general and administrative costs, as these are considered sunk costs or costs common to all future expansion plans. However, the capital costs associated with new resources are included, as are variable costs incurred by SVP (directly or indirectly) in a resource plan. Additionally, since SVP is an active participant in the power markets, a projection of costs and revenues associated with purchases from, or sales into, the market have also been included. A plan that relies heavily on assumed market purchases may incur risks associated with future power energy market prices increasing at a rate higher than assumed in the analysis.

As part of the CPWC calculation, the annual costs associated with an expansion plan are determined, then discounted to the start of the evaluation period and summed with all other years in the planning horizon to derive the "cumulative" present worth costs of a plan. The CPWC is a single, dollar figure that can be easily compared among alternative expansion plans.

8.2 SCENARIO ANALYSIS

The SVP IRP evaluated five separate cases. Two expansion plans were explored along with three sensitivity cases for 2030 and beyond. Only solar and wind resources were evaluated as future resources due to SVP's need for additional renewable energy resources and SVP's customer desire for additional renewable energy at a reasonable cost. The list of projects considered for inclusion in the expansion plans is shown in Table 8-1 and the details of the modeling assumptions are laid out in Section 6 and Section 7. All cases include the addition of a new contract for a wind resource, Viento Loco in 2022 with an installed capacity of 200MW.

Table 8-1 RPS Project Definitions

	PROJECT 1	PROJECT 2
Name	Local PV w/Bat	NorCal/ OR Wind
Location	Local	OR/ NorCal
Type	PV	Wind
Capacity (MW)	10	100
Scalable	No	Yes
AC Capacity Factor (%)	30%	40.0%
Annual Energy (MWh)	26,280	350,400
Energy Storage? (Yes/No/Maybe)	Not included	Not included
ES Capacity (MW, %)	Not included	Not included
ES Duration (Hrs)	4	Not included
Transmission Requirements	None	To COTP, WAPA
LMP Market Location (To Value)	NP15	NP15
Transmission & VERBS Costs (2018-$/kW/mo)	0.000	2.258
Transmission Costs (2018-$/MWh)	0.000	0.000
Transmission Escalation Rate		5.00%

8.3 CONSOLIDATED RESULTS

The following five scenarios were evaluated as part of the IRP analysis.

- Base Case: Existing system with a renewable target of 60 percent by 2030. Note: based on the recent signing of SB 100, SVP has decided to model the renewable target of 60 percent by 2030. This case, assumes expected load growth a balanced procurement scenario adding an equal amount of wind and solar to the portfolio.
- High Wind Case: Base Case with an 80 percent wind and 20 percent expansion plan
- High Load Case: Base Case with high load growth assumptions. Renewable additions to this case were at 50 percent solar and 50 percent wind
- Low Load Case: Base Case with low load growth assumptions
- High GHG Price Case: Base Case with high carbon price forecast

While the CEC guidelines only require the expansion planning studies to extend to 2030, consideration of additional years beyond 2030 were encouraged. SVP developed a 20-year expansion plan through 2038. All the five cases were optimized to meet the 60 percent renewable target under SB 100. As shown in Table 8-2, of the two expansion plans evaluated, the High Wind procurement case is the lowest in terms of CPWC.

The Base Case, while it has a CPWC that is 6 percent higher than the High Wind Case, is the preferred plan. This is because SVP believes that it is important to achieve a balance in solar and wind resources over the planning horizon, since a balanced portfolio may reduce risks associated with over-reliance on a single technology. Also, a balanced wind and solar energy generation combination is deemed to be a better fit to SVP’s hourly system energy demand profile than a plan heavily weighted toward either wind or solar.

As described in Section 1, since the completion of the modeling, SVP has made updates to the assumptions underlying the IRP. These updates are reflected in the Standardized Tables and are to take precedence over the numbers provided in this report. The change includes a reduction in the generation from a few RPS-eligible facilities, which results in increased market purchases and additional withdrawals from banked RECs. In total, SVP continues to maintain a healthy REC balance for the duration of the planning period. Since this change is common to all cases and sensitivities modeled, the relative ranking of the results presented on in this report is not expected to change.

Table 8-2 CPWC and RE Results for Scenarios and Sensitivities

CASE	DESCRIPTION	CPWC ($1,000s)	% HIGHER THAN LOWEST CPWC	2030 RENEWABLE % OF RETAIL SALES	INTERMEDIATE MILESTONE RENEWABLES MET?
Base Case	Expected Load Growth with 50/50 solar and wind additions	$1,682,712	6%	60%	Yes
High Wind Case	Expected Load Growth with 80/50 wind and solar additions	$1,583,361	0%	60%	Yes
High GHG Sensitivity	Base Case and high GHG price forecast	$1,833,029	16%	60%	Yes
High Load Sensitivity	High Load Growth with 50/50 solar and wind additions	$2,888,563	82%	60%	Yes
Low Load Sensitivity	Low Load Growth with 50/50 solar and wind additions	$1,342,780	-15%	60%	Yes

8.4 DETAILED RESULTS OF THE PREFERRED AND RECOMMENDED CASE

8.4.1 Capacity and Energy Adequacy of Preferred and Recommended Case

Table 8-3 and Figure 8-1 lays out the capacity balance in the preferred and recommended case (Base Case). The information in this table is simplified but reflects the comprehensive CRAT table included in Appendix A. Table 8-4 and Figure 8-2 lays out the energy balance in the preferred and recommended case.

As can be seen in the bottom of Table 8-4, SVP's IRP modeling was optimized to meet load requirements and the 60 percent renewable target by 2030. To meet these requirements, the modelling included the addition of 670 MWs of solar and 500 MWs of wind in terms of installed capacity to the portfolio. The additions are made in 2030, 2032, 2033, 2034, 2035 and 2037. The additions translate into a 50/50 split of generation between the two resource types. Table 8-3 shows that while the energy demand is met, there is a shortfall in terms of peak dependable capacity to meet reserve margin. SVP may cover these capacity requirements through short-term capacity purchases, or other economically feasible alternatives.

The EBT Standardized Table includes an update to the energy output from some of SVP-owned RPS-eligible facilities. The output from Solar Geo Unit 1 and 2 and Stony Creek Hydro was reduced from the modeling results by approximately 148 GWh through 2032, with the difference narrowing past 2033. It was assumed that this reduction will be made up through market purchases. The updates the Standardized Tables are to take precedence over the numbers provided in this report.

Table 8-3 Capacity Balance in the Preferred and Recommended Case

Capacity Balance of Loads and Resources

Silicon Valley Power

Description		Technology	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
System Peak Demand (MW)			634	680	702	715	730	723	736	742	747	754	762	770	778	786	794	803	811	820	828	837
System Energy (GWh)			4,040	4,448	4,632	4,745	4,855	4,979	5,053	5,114	5,126	5,177	5,229	5,281	5,334	5,387	5,441	5,495	5,550	5,606	5,662	5,719
System Load Factor (%)			73%	75%	75%	76%	76%	79%	78%	79%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%
System Capacity Responsibility (Peak Demand plus Reserve Margin)			729	782	808	823	839	831	846	854	859	867	876	885	895	904	914	923	933	942	952	962
SVP Owned Units - peak dependable capacity, MW																						
SVP Owned Units (not-RPS Eligible)	Collierville (NCPA Joint Powers Agency Resource)	Large Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
	Donald Von Raesfeld (DVR)	Natural Gas	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
	Gianera Generating Station	Natural Gas	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
	Lodi Energy Center (NCPA Joint Powers Agency Resource)	Natural Gas	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
	NCPA CT (NCPA Joint Powers Agency Resource)	Natural Gas	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
	Santa Clara Cogeneration	Natural Gas	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
SVP Owned Units (RPS Eligible)	Big Horn 1 (M-S-R JPA resource)	Wind	39	39	39	39	39	39	39	39	39	39	39	39	39	-	-	-	-	-	-	-
	Big Horn 2 (M-S-R JPA resource)	Wind	6	6	6	6	6	6	6	6	6	6	6	6	-	-	-	-	-	-	-	-
	Geo 1-4 (NCPA Joint Powers Agency Resource)	Geothermal	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Grizzly Hydro	Small Hydro	18	18	18	18	18	18	18	18	18	18	18	18	18	18	-	-	-	-	-	-
	Jenny Strand	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NCPA Solar Hydro	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NewSpicr (NCPA Joint Powers Agency Resource)	Small Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	Solar Geo Unit 1 (NCPA Joint Powers Agency Resource)	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar Geo Unit 2 (NCPA Joint Powers Agency Resource)	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Stony Creek Hydro Project	Small Hydro	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total SVP Owned Units, MW			**524**	**524**	**524**	**524**	**524**	**524**	**524**	**524**	**524**	**524**	**524**	**524**	**517**	**478**	**460**	**460**	**460**	**460**	**460**	**460**
Long term contracts - peak dependable capacity, MW																						
Long Term Contracts (not-RPS Eligible)	Tri-Dam Donnells	Large Hydro	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WAPA	Large Hydro	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
	Graphics Packaging	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	San Juan	Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Long Term Contracts (RPS Eligible)	Ameresco FWD	Landfill Gas	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-
	Ameresco Landfill	Landfill Gas	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
	Ameresco VASCO	Landfill Gas	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	-	-	-	-	-
	Central 40 Solar	Solar	-	-	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
	Friant 1	Small Hydro	17	17	17	17	17	17	17	17	17	17	17	17	17	17	-	-	-	-	-	-
	Friant 2	Small Hydro	7	7	7	7	7	7	7	7	7	7	7	7	7	7	-	-	-	-	-	-
	G2 Landfill	Landfill Gas	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	24	24	24	24	24	24	24	24	24	24	24	24	24	24	-	-	-	-	-	-
	Recurrent Solar	Solar	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Rooney Ranch	Wind	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	San Hill A	Wind	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	San Hill B	Wind	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Tioga Solar	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-
	Tri Dam Southern	Small Hydro	13	13	13	13	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	7	7	7	7	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Tulloch	Small Hydro	18	18	18	18	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Viento Loco	Wind	-	-	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
	WAPA (Small Hydro)	Small Hydro	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Total Long term contracts, MW			**315**	**315**	**399**	**399**	**399**	**289**	**289**	**289**	**288**	**288**	**287**	**287**	**287**	**287**	**238**	**229**	**229**	**229**	**229**	**229**
New Resource Additions - peak dependable capacity, MW																						
New Resource	Generic Solar	Solar	-	-	-	-	-	-	-	-	-	-	-	27	27	53	80	80	106	106	133	133
	Generic Wind	Wind	-	-	-	-	-	-	-	-	-	-	-	57	57	111	164	168	221	221	275	275
Total new resource additions, MW			-	-	-	-	-	-	-	-	-	-	-	**84**	**84**	**164**	**244**	**248**	**327**	**327**	**407**	**407**
Total System Capacity			**839**	**839**	**923**	**923**	**923**	**813**	**813**	**813**	**812**	**812**	**810**	**894**	**888**	**928**	**941**	**937**	**1,017**	**1,017**	**1,097**	**1,097**
Capacity Balance Surplus/(Deficit) to be addressed with capacity purchases			**109**	**56**	**115**	**100**	**84**	**(19)**	**(34)**	**(41)**	**(47)**	**(55)**	**(66)**	**9**	**(7)**	**24**	**28**	**14**	**84**	**74**	**144**	**134**

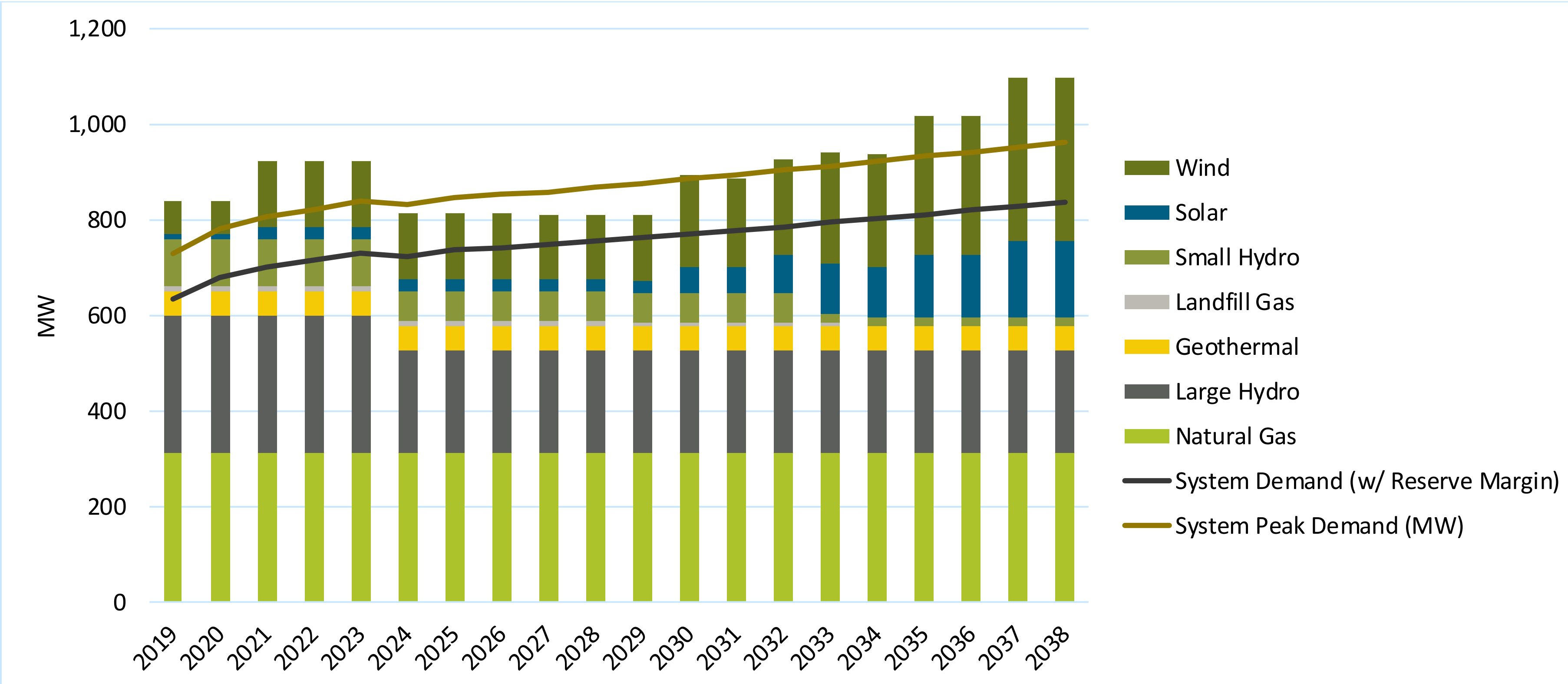


Figure 8-1 Capacity Balance in the Preferred and Recommended Case

Table 8-4 Energy Balance in the Preferred and Recommended Case

Annual Energy Balance of Loads and Resources Silicon Valley Power																						
Description		**Technology**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
System Energy Demand (GWh)			**4,040**	**4,448**	**4,632**	**4,745**	**4,855**	**4,979**	**5,053**	**5,114**	**5,126**	**5,177**	**5,229**	**5,281**	**5,334**	**5,387**	**5,441**	**5,495**	**5,550**	**5,606**	**5,662**	**5,719**
Generation																						
SVP Owned Units (not-RPS Eligible)	Collierville (NCPA Joint Powers Agency Resource)	Large Hydro	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	203	202
	Donald Von Raesfeld (DVR)	Natural Gas	835	839	777	711	670	727	720	728	716	701	685	660	669	653	606	616	530	536	467	470
	Gianera Generating Station	Natural Gas	8	12	5	4	3	7	5	5	3	3	2	2	1	0	0	0	0	-	-	-
	Lodi Energy Center (NCPA Joint Powers Agency Resource)	Natural Gas	394	418	337	288	280	364	367	371	363	359	352	319	318	291	263	281	224	228	190	195
	NCPA CT (NCPA Joint Powers Agency Resource)	Other	0	0	0	0	0	0	0	0	-	-	0	0	-	-	-	-	-	-	-	-
	Santa Clara Cogeneration	Natural Gas	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
SVP Owned Units (RPS Eligible)	Big Horn 1 (M-S-R JPA resource)	Wind	281	282	281	281	281	282	275	275	275	275	275	275	275	-	-	-	-	-	-	-
	Big Horn 2 (M-S-R JPA resource)	Wind	42	42	42	42	42	42	42	42	42	42	42	42	-	-	-	-	-	-	-	-
	Geo 1-4 (NCPA Joint Powers Agency Resource)	Geothermal	342	336	329	322	316	310	303	297	291	285	280	274	269	263	258	253	248	243	238	233
	Grizzly Hydro	Small Hydro	43	43	43	43	43	43	43	43	43	43	43	43	43	43	-	-	-	-	-	-
	Jenny Strand	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
	NCPA Solar Hydro	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NewSpicr (NCPA Joint Powers Agency Resource)	Small Hydro	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Solar Geo Unit 1 (NCPA Joint Powers Agency Resource)	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Solar Geo Unit 2 (NCPA Joint Powers Agency Resource)	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	Stony Creek Hydro Project	Small Hydro	163	164	163	163	163	164	163	163	163	164	163	163	163	164	163	163	163	164	163	163
Total Generation from SVP Units, GWh			**2,369**	**2,395**	**2,236**	**2,114**	**2,057**	**2,199**	**2,179**	**2,184**	**2,155**	**2,132**	**2,101**	**2,039**	**1,998**	**1,673**	**1,550**	**1,572**	**1,424**	**1,429**	**1,318**	**1,321**
Long Term Contracts (not-RPS Eligible)	Tri-Dam Donnells	Large Hydro	298	298	298	298	298	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	WAPA	Large Hydro	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254
Long Term Contracts (RPS Eligible)	Ameresco FWD	Landfill Gas	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	-	-	-	-	-
	Ameresco Landfill	Landfill Gas	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
	Ameresco VASCO	Landfill Gas	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	-	-	-	-	-
	Central 40 Solar	Solar	-	-	96	95	95	95	94	94	93	93	92	92	91	91	90	90	89	89	88	88
	Friant 1	Small Hydro	58	58	58	58	58	58	58	58	58	58	58	58	58	58	-	-	-	-	-	-
	Friant 2	Small Hydro	29	29	29	29	29	29	29	29	29	29	29	29	29	29	-	-	-	-	-	-
	G2 Landfill	Landfill Gas	11	11	11	11	11	11	11	11	11	11	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	130	130	130	130	130	130	130	130	130	130	130	130	130	130	-	-	-	-	-	-
	Recurrent Solar	Solar	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	Rooney Ranch	Wind	-	-	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67	67
	San Hill A	Wind	-	-	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
	San Hill B	Wind	-	-	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
	Tioga Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-
	Tri Dam Southern	Small Hydro	86	86	86	86	86	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	56	56	56	56	56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Tulloch	Small Hydro	95	95	95	95	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Viento Loco	Wind	-	-	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
	WAPA (Small Hydro)	Small Hydro	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Generation from Contracts, GWh			**1,170**	**1,170**	**1,835**	**2,235**	**2,234**	**1,699**	**1,698**	**1,698**	**1,695**	**1,695**	**1,683**	**1,682**	**1,682**	**1,682**	**1,464**	**1,379**	**1,379**	**1,379**	**1,378**	**1,377**
New Resource Additions	Generic Solar	Solar	-	-	-	-	-	-	-	-	-	-	-	368	368	712	1,051	1,077	1,419	1,423	1,761	1,761
	Generic Wind	Wind	-	-	-	-	-	-	-	-	-	-	-	350	350	704	1,051	1,051	1,402	1,408	1,752	1,752
Total New Resource Additions, GWh			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**718**	**718**	**1,416**	**2,102**	**2,129**	**2,821**	**2,831**	**3,513**	**3,513**
Market Purchases			607	949	675	568	722	1,119	1,207	1,259	1,298	1,368	1,460	878	960	663	473	546	326	355	241	261
Market Sales			(106)	(67)	(114)	(172)	(158)	(39)	(31)	(27)	(23)	(18)	(15)	(36)	(24)	(41)	(113)	(103)	(324)	(326)	(724)	(701)
Net Market Purchases, GWh			**501**	**882**	**561**	**396**	**564**	**1,081**	**1,177**	**1,232**	**1,275**	**1,350**	**1,445**	**842**	**936**	**622**	**360**	**443**	**2**	**30**	**(483)**	**(441)**
Net System Energy, GWh			**4,040**	**4,448**	**4,632**	**4,745**	**4,855**	**4,979**	**5,053**	**5,114**	**5,126**	**5,177**	**5,229**	**5,281**	**5,334**	**5,393**	**5,476**	**5,523**	**5,625**	**5,669**	**5,726**	**5,770**

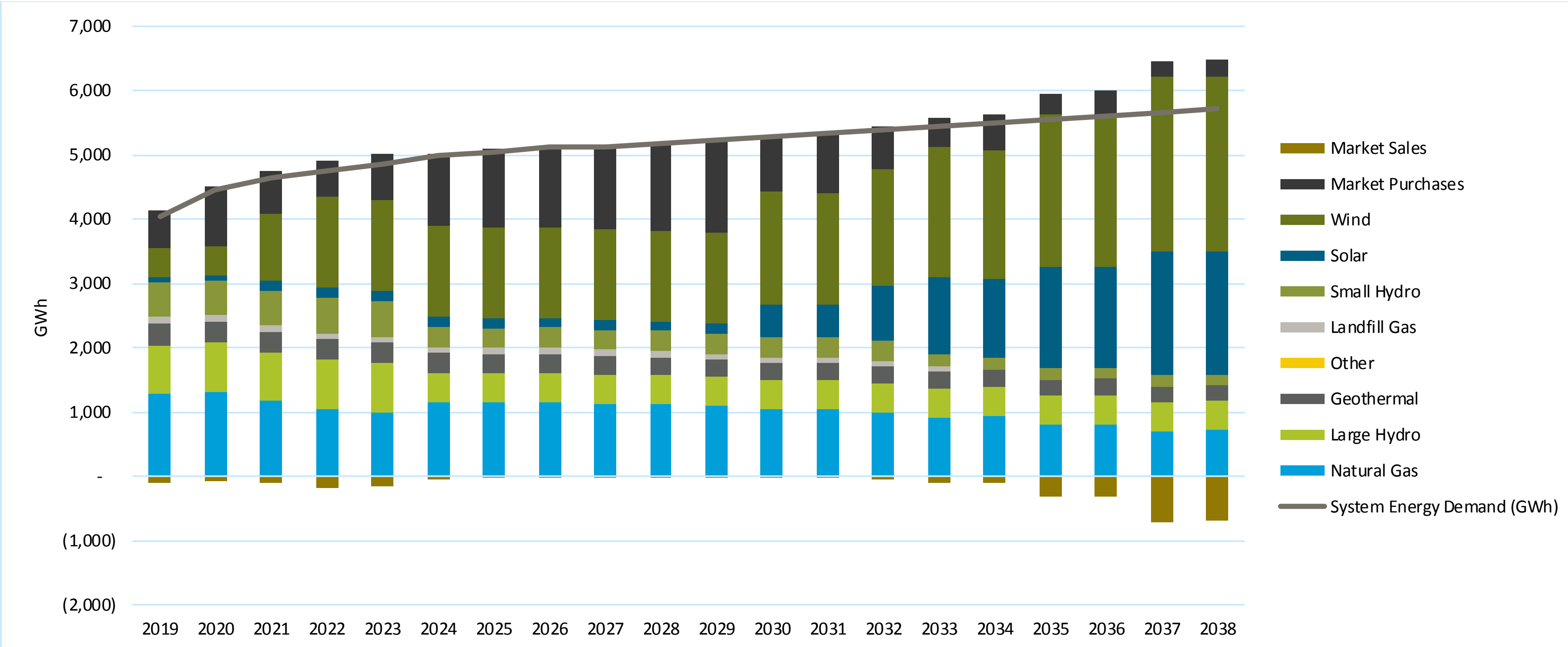


Figure 8-2 Energy Balance for the Preferred and Recommended Case

8.4.2 Renewable Energy and GHG Emissions of Preferred and Recommended Case

Under the Base Case preferred scenario, a total of five 100 MW wind projects and sixty-seven 10 MW solar projects were added starting in 2030. As shown in Table 8-5 these additions, along with RECs were used to meet the RPS targets. Also shown in the table is the REC balance which remains positive through the planning period. The table shows that the RPS targets are met through the duration of the planning period.

The RPT Standardized Table is based on the 50 percent renewable target. In this IRP, SVP has focused on attaining the 60 percent by 2030 target under SB 100. SVP is ahead of the renewable requirements per the CEC guidelines. Additionally, the update to the energy output after the completion of the modeling and the corresponding impact to the REC balance is reflected in the RPT Standardized Table. SVP continues to maintain a healthy REC balance through the duration of the planning period.

Table 8-6 shows a projection of GHG emissions for the planning period under the Base Case. These numbers are represented in MTCO2e. Based on the portfolio currently owned by SVP, the GHG emissions in 2030 are projected to be 404,487MTCO2e. This is just under SVP's High 2030 target of 485,000 MTCO2e. SVP finds that the generic emissions rate of 0.428 Mt CO2e/MWh for spot market purchases per the CEC guidelines to be too high. If unspecified resources are withdrawn from the grid in a given hour, the emissions associated with the unspecified resource should reflect the emissions of the grid at that given hour. Additionally, when SVP sells resources in excess of load both SVP and the unspecified purchaser should not carry the carbon numbers into the portfolio emission. This leads to a double counting of GHG emissions on the grid. Recommendation to CARB is to develop seasonal hourly grid emissions for the different Balancing Areas or utilize the CAISO's real time emissions tracking. Section 2.4.1.2 describes SVP's approach to the accounting of carbon emissions.

8.4.3 Detailed CPWC Sheet for Preferred and Recommended Case

The annual cost breakdown of the Base Case is provided in Table 8-7. Since the model is run based on nominal dollars, a 4.5 percent discount rate is used in the calculations. The CPWC of this case is presented in 2017 dollars. The CPWC takes into account the cost of generation which includes fuel costs, variable O&M and emissions cost for existing resources. The calculations also include the cost of new renewable generation build. The total system cost at the end of the 20-year IRP period is $1,682 million.

Table 8-5 Renewable Energy and REC Adequacy in the Preferred and Recommended Case

Renewable Energy Achieved (GWh) and Renewable Energy Credits (1,000)																					
Silicon Valley Power																					
Technology	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Solar		62	62	158	157	157	157	156	155	155	155	154	521	521	864	1,203	1,228	1,569	1,574	1,910	1,910
Wind		453	454	1,022	1,422	1,422	1,423	1,416	1,416	1,416	1,417	1,417	1,767	1,725	1,803	2,021	2,021	2,371	2,377	2,721	2,721
Small Hydro		544	544	544	544	544	308	307	307	307	308	307	307	307	308	177	177	177	177	177	177
Landfill Gas		98	98	98	98	98	98	98	98	95	96	84	84	84	84	84	-	-	-	-	-
Geothermal		342	336	329	322	316	310	303	297	291	285	280	274	269	263	258	253	248	243	238	233
Total RECs Generated		1,499	1,494	2,150	2,543	2,536	2,295	2,280	2,274	2,265	2,260	2,242	2,954	2,905	3,323	3,742	3,679	4,365	4,371	5,046	5,041
RPS Target, %		31%	33%	36%	39%	42%	45%	48%	50%	53%	55%	58%	60%	63%	65%	68%	71%	73%	76%	79%	81%
RPS Target		1,190	1,394	1,584	1,758	1,937	2,128	2,304	2,429	2,556	2,705	2,856	3,010	3,175	3,344	3,515	3,689	3,867	4,047	4,231	4,419
REC Sales Obligation		(111)	(111)	(111)	(111)	(72)	(72)	(72)	(72)	(72)	-	-	-	-	-	-	-	-	-	-	-
RECs Available for compliance		1,387	1,382	2,039	2,432	2,464	2,223	2,208	2,202	2,193	2,260	2,242	2,954	2,905	3,323	3,742	3,679	4,365	4,371	5,046	5,041
Historical Banked RECs	2,856																				
Deposits		198	-	455	674	527	94	-	-	-	-	-	-	-	-	227	-	498	323	815	623
Withdrawals		-	12	-	-	-	-	96	227	363	445	615	56	270	21	-	11	-	-	-	-
REC Bank Balance		3,054	3,042	3,497	4,170	4,697	4,791	4,695	4,468	4,105	3,660	3,045	2,989	2,719	2,698	2,925	2,915	3,413	3,736	4,551	5,174
Renewable Generation and REC withdrawals		1,499	1,506	2,150	2,543	2,536	2,295	2,376	2,501	2,629	2,705	2,856	3,010	3,175	3,344	3,742	3,689	4,365	4,371	5,046	5,041
Renewable and RECs as a % of retail sales		39%	36%	49%	56%	55%	49%	50%	51%	54%	55%	58%	60%	63%	65%	72%	71%	83%	82%	94%	93%

Table 8-6 SVP's GHG Emissions in the Preferred and Recommended Case

Generating Plant Emissions																				
Silicon Valley Power																				
Generator	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Donald Von Raesfeld (DVR)	153,883	363,084	345,651	305,793	300,914	311,868	308,318	310,590	308,543	303,778	296,941	284,776	283,291	282,701	272,286	262,115	246,175	228,029	216,245	200,940
Gianera Generating Station	161	7,545	9,916	3,050	2,674	3,478	5,691	4,137	3,224	2,363	2,100	1,267	1,308	455	85	289	120	-	-	-
Lodi Energy Center (NCPA)	52,708	148,370	150,271	102,952	104,739	118,228	133,115	134,604	133,411	132,080	128,081	122,086	115,039	112,653	101,236	99,646	93,527	81,285	77,197	71,375
Santa Clara Cogeneration	20,491	40,757	40,643	40,643	40,643	40,757	40,643	40,643	40,643	40,757	40,643	40,643	40,643	40,757	40,643	40,643	40,643	40,757	40,643	40,643
NCPA CT	-	152	101	101	51	101	101	25	51	-	-	25	51	-	-	-	-	-	-	-
Total Emissions (Metric Tons CO2e)	227,243	559,906	546,583	452,540	449,021	474,431	487,869	490,000	485,872	478,978	467,766	448,797	440,332	436,566	414,251	402,693	380,466	350,071	334,085	312,958

Table 8-7 CPWC Results for the Preferred and Recommended SVP Case

Year	$2017						Present Worth, $2017 at 4.5% discount rate						
	Generation Cost ($000)	New Resource Additions		Market Activity		Total System Cost ($000)	Generation Cost ($000)	New Resource Additions		Market Activity		Total System Cost ($000)	Cumulative Present Worth ($000)
		New Build Cost ($000)	Fixed O&M ($000)	Market Purchases ($000)	Market Sales ($000)			New Build Cost ($000)	Fixed O&M ($000)	Market Purchases ($000)	Market Sales ($000)		
2019	51,684	-	-	23,109	5,096	69,697	49,458	-	-	22,114	4,877	66,696	66,696
2020	56,447	-	-	38,997	3,458	91,987	51,690	-	-	35,711	3,167	84,235	150,931
2021	50,875	-	-	22,535	6,116	67,294	44,582	-	-	19,747	5,359	58,970	209,901
2022	48,359	-	-	18,042	9,002	57,399	40,552	-	-	15,129	7,549	48,132	258,033
2023	48,899	-	-	22,484	8,661	62,722	39,239	-	-	18,042	6,950	50,331	308,364
2024	58,223	-	-	41,973	2,270	97,927	44,709	-	-	32,231	1,743	75,197	383,561
2025	59,807	-	-	47,815	1,830	105,792	43,948	-	-	35,136	1,345	77,739	461,300
2026	62,365	-	-	52,611	1,636	113,340	43,854	-	-	36,995	1,151	79,699	540,999
2027	61,960	-	-	52,958	1,376	113,543	41,693	-	-	35,636	926	76,403	617,402
2028	62,248	-	-	55,939	1,101	117,087	40,084	-	-	36,021	709	75,396	692,798
2029	62,899	-	-	60,736	893	122,742	38,758	-	-	37,425	550	75,634	768,432
2030	60,282	34,856	6,963	34,903	2,147	134,856	35,546	20,553	4,106	20,581	1,266	79,520	847,952
2031	62,914	34,856	6,963	41,679	1,457	144,954	35,501	19,668	3,929	23,518	822	81,793	929,745
2032	62,461	68,235	13,711	32,095	2,029	174,472	33,727	36,845	7,403	17,330	1,096	94,210	1,023,955
2033	59,915	101,614	20,384	28,184	3,265	206,831	30,959	52,506	10,533	14,563	1,687	106,874	1,130,829
2034	64,232	103,090	20,636	34,667	2,774	219,852	31,761	50,975	10,204	17,142	1,372	108,710	1,239,539
2035	56,918	136,470	27,347	24,057	8,588	236,204	26,932	64,574	12,940	11,383	4,064	111,766	1,351,305
2036	59,964	136,470	27,422	26,772	8,944	241,682	27,152	61,793	12,416	12,122	4,050	109,434	1,460,739
2037	54,938	169,849	34,057	20,450	20,219	259,075	23,805	73,596	14,757	8,861	8,761	112,258	1,572,996
2038	58,159	169,849	34,057	22,992	20,453	264,603	24,115	70,427	14,122	9,533	8,481	109,716	1,682,712

8.5 HIGH WIND AND SENSITIVITY CASES

SVP evaluated a High Wind case and three sensitivities in addition to the Base Case. The expansion plan for each of these cases are laid out in Table 8-8. The High Wind case was an alternative expansion plan to the Base Case considered by SVP. This included the addition of 80 percent wind and 20 percent solar resources. As laid out in Table 8-2, while this scenario had the lowest CPWC, this case was not considered due to its high reliance on a single technology. Under this case a total of 400 MWs of solar and 1,200 MWs of wind were added to the portfolio starting in 2030.

Using the base case with a balanced procurement of solar and wind resources the following three sensitivities were evaluated. In all the cases, the goal was to attain the 60 percent RPS target by 2030 and the addition of resources were modeled accordingly.

- Balanced procurement with high GHG Price forecast: This scenario assumed the high GHG prices as published in the Revised 2017 IEPR GHG Price Projections. Under the high GHG scenario, the total amount of renewable resource additions is the same as the Base Case preferred scenario, i.e., 670 MWs of solar and 500 MWs of wind which translate into a 50/50 split of wind and solar generation. The additions commenced in 2030, however due to the high GHG forecast, the additions in the later years were pulled forward as compared to the Base Case.
- Balanced procurement with high load growth: due to the assumed high load growth, the additions now begin in 2026. A total of 940 MWs of solar and 700 MWs of wind resources were added to the portfolio.
- Balanced procurement with low load growth: due to the assumed low load growth, the additions are pushed back to 2032. A total of 540 MWs of solar and 400 MWs of wind were added to this scenario.

Table 8-8 Expansion Plan for High Wind Case and Sensitivities (MW)

CASE	RESOURCE TYPE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
High Wind	Solar					100		40	30	30	40	40	60	60
	Wind					300		100	100	100	100	100	200	200
High GHG	Solar					140	130		130	140			130	
	Wind					100	100		100	100			100	
High Load	Solar	60	80			260	10	130	130	130	140			
	Wind		100			200		100	100	100	100			
Low Load	Solar							140	130		130	10		130
	Wind							100	100		100			100

Table 8-9 SVP's High and Low Load Forecast

YEAR	LOW LOAD SENSITIVITY		HIGH LOAD SENSITIVITY	
	ENERGY REQUIREMENTS, GWH	PEAK DEMAND, MW	ENERGY REQUIREMENTS, GWH	PEAK DEMAND, MW
2019	4,040	647	4,040	647
2020	4,305	671	4,448	694
2021	4,353	679	4,717	732
2022	4,438	690	5,110	788
2023	4,521	701	5,581	848
2024	4,616	712	6,068	909
2025	4,670	721	6,472	959
2026	4,717	726	6,783	994
2027	4,724	728	6,932	1,014
2028	4,743	731	7,070	1,034
2029	4,762	734	7,212	1,055
2030	4,781	737	7,356	1,076
2031	4,800	740	7,503	1,097
2032	4,819	743	7,653	1,119
2033	4,838	746	7,806	1,142
2034	4,858	749	7,962	1,164
2035	4,877	752	8,122	1,188
2036	4,897	755	8,284	1,211
2037	4,916	758	8,450	1,236
2038	4,936	761	8,619	1,260

8.6 RETAIL RATES AND THE RECOMMENDED EXPANSION PLAN

Power portfolio costs (excluding debt service and fixed O&M for existing power plants) are estimated to increase by approximately $215 million in nominal dollars over the 20 year forecast horizon, or approximately 4% per year. Approximately 1.9% per year of this cost increase is attributable to the forecast annual sales increases over this period, and the remaining 2.1% per year of this cost increase is attributable to forecast higher prices for natural gas (which continues to be required, albeit in lesser amounts as renewable projects are brought on line) and to the higher forecast prices of the wind and solar resources that are expected to come on line beginning in 2030.

Assuming that all other SVP costs escalate at approximately 2% per year, then, in concert with the above 2.1% average cost escalation above, overall retail rates would also escalate at about 2% per year. It is imperative to note that these escalation rates could be higher, perhaps significantly higher, if the ability of market participants to add wind and solar generation as needed to meet statewide objectives should become limited by market, environmental, technical or system reliability constraints.

8.7 THE RECOMMENDED PLAN IN CONSIDERATION OF FUTURE CONDITIONS AND RISKS

A number of factors could emerge in the energy industry or in the economy that could impose new conditions or risks not contemplated in this analysis. Some of these factors include new legislation and regulations that impact utility operation and could include the following:

- **AB 813 (Electric Regionalization) -** The bill would open the door for the CAISO to expand its membership to include other balancing authorities across the 14 western states. This regionalization bill would require approval from the state before any California transmission owner, retail seller, or local publicly owned utility joins a multistate regional transmission system organization. Bill proponents believe regionalization would reduce rates and costs, ensure consistent reporting and tracking of renewable energy targets and achievements, and reduce transmission rates. Opponents believe that the bill would harm the independence of state policy including the progress made in California toward its renewable energy standards, which are generally more aggressive than in other states.

- **SB 1110 (Safeguarding Public Utility Ratepayers from Bond Debt authored by Senator Bradford)** – This bill protects the City of Santa Clara and some other local POU's from construction debt of power plants built in the early 2000's in response to the energy crisis. In the early 2000's, when many California cities were struggling with how to serve their communities with electricity and experiencing brown outs; Santa Clara's.21.

  With construction of these safe, efficient, and reliable power generating facilities, debt was incurred. To date, SVP has bond indebtedness of approximately $51 million dollars; which is scheduled to be paid in full by 2028.

  SB 1110 would protect SVP's investment as our state moves down the path of 100% renewable energy mandates by 2040, and allow SVP to continue to operate these effective facilities at a level that would allow us to pay our debt off without financial harm to our community.

- Re-introduction of the Clean Power Plan or the equivalent at the federal level in future years.

With potential changes in the legislative landscape, the impact to SVP's decision making and planning is constantly evolving. The IRP developed provides SVP with the flexibility to adapt to potential changes in the future. Additionally, the balanced portfolio approach helps mitigate the impact of technology specific changes such as cost, incentives, favorability, etc.

8.8 THE RECOMMENDED PLAN WITH CONSIDERATION OF LOCALIZED AIR POLLUTANTS AND DISADVANTAGED COMMUNITIES

Santa Clara's defined Disadvantaged Community (DAC) is comprised of Industrial and Commercial customers with few residential and even fewer lower income FRAP (Federal rate assistance program customers) residential customers residing within the borders as shown in Figure 8-3. SVP's DAC border's highway 101 and the San Jose Airport and is comprised of 24/7 manufacturing, SVP's DVR power plant, data centers, high tech companies and small industrial. The city of Santa Clara has kept this area of the city zoned for heavy industrial and commercial and has kept infill of housing at a minimum except where it makes sense.

SVP purchased 11 acres of industrial land in the heart of the DAC to build a state of the art energy center. Instead, SVP sold the 11 acres to the City to create the Reed & Grant Street Sport Park. This park will feature five lighted soccer fields and other park amenities including EV charging.

SVP is only 19 square miles and land is at a premium and in most cases utilized to maximum densities. In working with the City as they update their General Plan, there is an opportunity to maximize infill building potential with whole building electrification and maximize potential of distributed energy, such as PV and energy storage. There is not land available to build large scale PV projects (>10MW) within our City but ample opportunity throughout California, keeping with SVP's positions on having a diversified portfolio, both geographically and by fuel source. Adding renewable generation to SVP's portfolio is beneficial to the disadvantaged community as well as to SVP's service area. In selecting the Base Case, both the low CPWC and the benefit of a balanced portfolio was taking into account while selecting the case as the preferred scenario.

SVP offers a number of customer programs and rebate to all of their customers, as outlined in Section 5. On the energy efficiency side, one of the many goals of the programs is to assist low-income residents in helping them pay their electric bills and in installing energy efficient appliances. The following programs are offered by SVP to specifically support low-income and disadvantaged communities:

- Financial Rate Assistance Program (FRAP) – This program provides a 25 percent discount on the electric portion of utility bills for income-qualified residential customers, up to the first 800 kWh of use per month.
- Low Income EV Charging Station Grant for Multi-family properties – Under its low income programs, SVP will offer a grant of up to $1,000 per charging station for multi-family properties where 15 percent of customers residing at the property qualify for SVP's low income programs. This program was approved in FY 2016/2017 but has not launched as of the time of this report. The utility is looking at providing charging station rebates for all eligible customers.
- Medical Rate Assistance Program: Customers receive a 25 percent discount on their electric bill if they qualify due to high electric use for medical reasons. The programs are managed in-house.

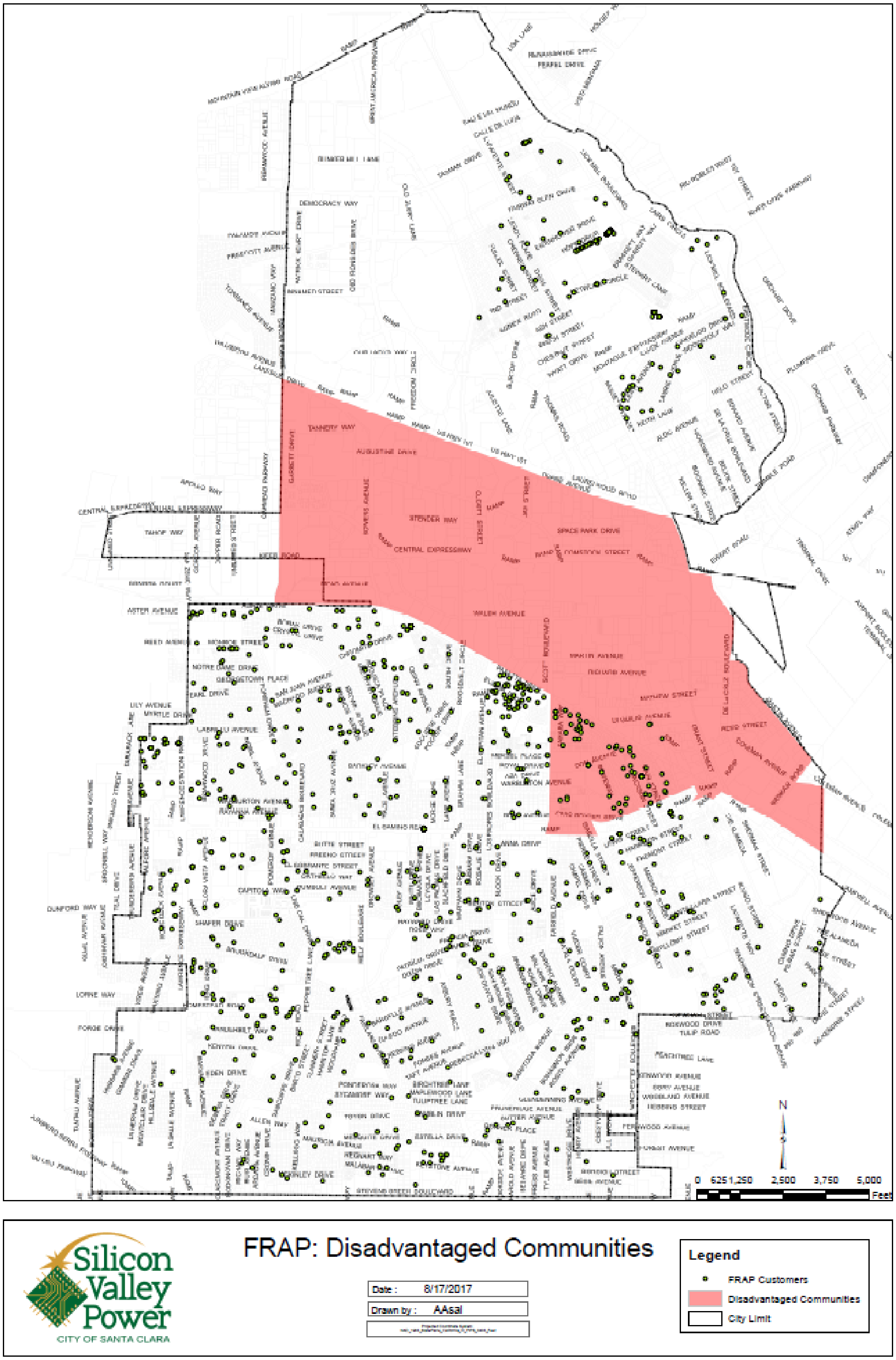


Figure 8-3 SVP's Disadvantaged Community

9.0 Conclusions and Recommended Expansion Plan

This report documents the IRP planning process undertaken by SVP and presents the results. The plan was developed in collaboration with SVP staff and Black & Veatch. SVP in a separate process also engaged their stakeholders to solicit feedback on the planning process.

The Base Case is selected as the preferred scenario. Under this case, all the existing generation and known contracts that are currently in place and planned to be delivered in the future were included in the modeling. SVP's IRP modeling was optimized to meet load growth requirements and the 60 percent renewable target by 2030. In order to meet these requirements, the modelling included the addition of 670 MWs of solar and 500 MWs of wind in terms of installed capacity to the portfolio. The additions translate into a 50/50 split of generation between the two resource types. The energy demand is met with the appropriate amount of renewables to meet SB 100. There is a shortfall in the peak dependable capacity to meet the reserve margin. SVP will cover these capacity requirements through short-term capacity purchases.

Based on SVP's current portfolio of owned assets, the GHG emissions in 2030 are projected to be 404,487 $MTCO_2e$. This is just under SVP's High 2030 target of 485,000 $MTCO_2e$. Meeting the GHG targets is based on the assumption that only SVP-owned resources count towards the emissions target. SVP finds that the generic emissions rate of 0.428 Mt CO2e/MWh for spot market purchases per the CEC guidelines can be either too high or too low based on the mix of hourly dispatched resource on the grid. If this rate is applied, SVP's portfolio emissions could exceed the GHG target. Section 2.4.1.2 describes SVP's approach to the accounting of carbon emissions. Also, the GHG methodology must not double count carbon emissions in the generic emissions rate that are accounted under another utilities ownership.

The details of the Base Case preferred scenario are outlined in Section 8 along with accompanying tables and graphs. The four tables required in the CEC Guidelines are provided in Appendix A. These tables support the conclusion that the Base Case is a viable plant that meets the objectives and requirements of a POU integrated resource plan. SVP intends to update this IRP plan as conditions warrant.

Appendix A. CEC Standardized Tables for the Adopted Resource Scenario

The *CEC Guidelines* require four standardized tables to be part of the IRP Filing. The standardized tables presented in this Appendix for the recommended SVP's Scenario are as follows:

- Capacity Resource Accounting Table (CRAT): Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.
- Energy Balance Table (EBT): Annual total energy demand and annual estimates for energy supply from various resources.
- RPS Procurement Table (RPT): A detailed summary of a POU resource plan to meet the RPS requirements.
- GHG Emissions Accounting Table (GEAT): Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate.

Appendix B. SVP's Stakeholder Input Results