QUANTA TECHNOLOGY

REPORT

Deliverable 3: Benefit Cost Analysis of Alternatives

PREPARED FOR

Southern California Edison.
(SCE)

DATE

January 3, 2020
(Version 1.0)

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VERSION HISTORY:

Version	Date	Description
0.1	11/14/2019	First Draft
0.2	12/5/2019	Second Draft
1.0	1/3/2020	Final Report

EXECUTIVE SUMMARY

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for SCE's Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this study is to amend the ASP business case (including benefit-cost analysis) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with SCE to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until year the 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives utilized power flow studies in coordination with quantitative analysis to forecast the impacts of the alternatives under evaluation, including the ASP. The forecasted impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of the alternatives utilized the benefit-cost and risk analysis frameworks to quantify the value of monetary benefits observed over the project horizon.

A total of 13 alternatives, including the ASP, were evaluated within this framework to validate performance and contribution towards project objectives. These alternatives were categorized into Minimal Investment, Conventional, Non-Wire, and Hybrid (Conventional plus Non-Wire) alternatives.

The key findings of this study are summarized as follows:

- Consistent with Industry accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely Conventional and Spatial forecasts[1].
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and the state of California's electrification goals.
  - Across all forecasts the reliability need year was identified as 2022, except for one sensitivity that identified 2021 as the need year.
  - The Effective PV Spatial load forecast is found to be the most consistent with the load-growth trend in the Valley South needs area. This forecast demonstrates a range of load from 1,083 MVA to 1,377 MVA over 2019-2048.
- Several reliability metrics were utilized to quantitatively assess the performance of each alternative under study. An evaluation of alternative performance demonstrated that ASP provides the highest

[1] The load forecasting methodologies and findings are documented in detail within Chapter 2 of this report.

benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resiliency and operational flexibility needs throughout the study period in the Valley South System. Considering the aggregated benefits over the 30-year horizon under normal and emergency[2] conditions, the ASP results in 854 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $6 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following ASP are SCE Orange County, and SDG&E and Centralized BESS in Valley South.

- The benefit-cost analysis framework was implemented to evaluate and compare individual alternative performance.
  - Non-wire alternatives remained cost-effective only under reduced load forecast levels (e.g. Reduced Trend and Low sensitivities of the Conventional forecasts). Under other forecasts, non-wire alternatives accrue sizably additional costs over time due to incremental storage sizing necessary to address the load growth in the Valley South System.
  - Conventional and Hybrid alternatives can better satisfy project objectives and long-term reliability challenges throughout the Valley electric system.
  - Mira Loma, ASP, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Mira Loma and Valley South to Valley North have lower costs relative to ASP; while providing sizably lower benefits than ASP.
- The incremental benefit-cost framework was implemented to select among alternatives, and the results demonstrated that ASP as the preferred alternative. The analysis is indicative of significant unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrates that:
  - The costs associated with the incremental size of the non-wire alternatives (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from non-wire alternatives are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks the most favorable among the considered alternatives over the 30 years period.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available.

[2] N-0, N-1 and Operational flexibility.

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1 INTRODUCTION

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for the Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV System. The overall objective of this analysis is to present a business case (including benefit-cost analysis) justifying the appropriate project solution through data-driven quantitative methods and analysis.

In this section of the report, the project background, scope of work, study objective (including task breakdown), and study process have been outlined.

1.1 Project Background

Valley Substation is a 500/115 kV substation that serves electric demand in southwestern Riverside County. Valley Substation is split into two distinct 500/115 kV electrical systems: Valley North and Valley South. Each is served by two 500/115 kV, 560 MVA, three-phase transformers. The Valley South 115 kV System is not supplied power by any alternative means other than Valley Substation nor does it have system tie-lines to adjacent 115 kV systems. In other words, this portion of the system is radially served by a single point of interconnection with the bulk electric system under jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility[3], and resiliency needs of the Valley South System.

The Valley South 115 kV system Electrical Needs Area (ENA) consists of 14 distribution level substations (115/12 kV substations). During the 2019-2028 forecast developed for peak demand, SCE identified an overload of the Valley South 500/115 kV transformer capacity by the year 2022 under normal operating conditions (N-0) and 1-in-5-year heat storm weather conditions. SCE has additionally identified the need to provide system tie-lines to improve reliability, resiliency, and operational flexibility. To address these needs, the ASP was proposed. Figure 1-1 provides an overview of the project area.

Key features of this project are highlighted below:

- Construction of an 1,120 MVA 500/115 kV substation (Alberhill Substation).
- Construction of two 500 kV transmission line segments to connect the proposed Alberhill Substation by looping into the existing Serrano-Valley 500 kV transmission line.
- Construction of approximately 20 miles of 115 kV subtransmission line to modify the configuration of the existing Valley South System to allow for the transfer of five 115/12 kV distribution substations

[3] Flexibility or Operational Flexibility are used interchangeably in the context of this study. It is considered as the capability of the power system to absorb disturbances to maintain a secure operating state. It is used to bridge the gap between reliability and resiliency needs in the system and overall planning objectives. Typically, system tie-lines allow for the operational flexibility to maintain service during unplanned equipment outages, during planned maintenance and construction activities, and to pre-emptively transfer load to avoid loss of service to affected customers. System tie-lines may effectively supplement transformation capacity by allowing the transfer of load to adjacent systems.

from the Valley South System to the new Alberhill System, and to create 115 kV system tie-lines between the two systems.

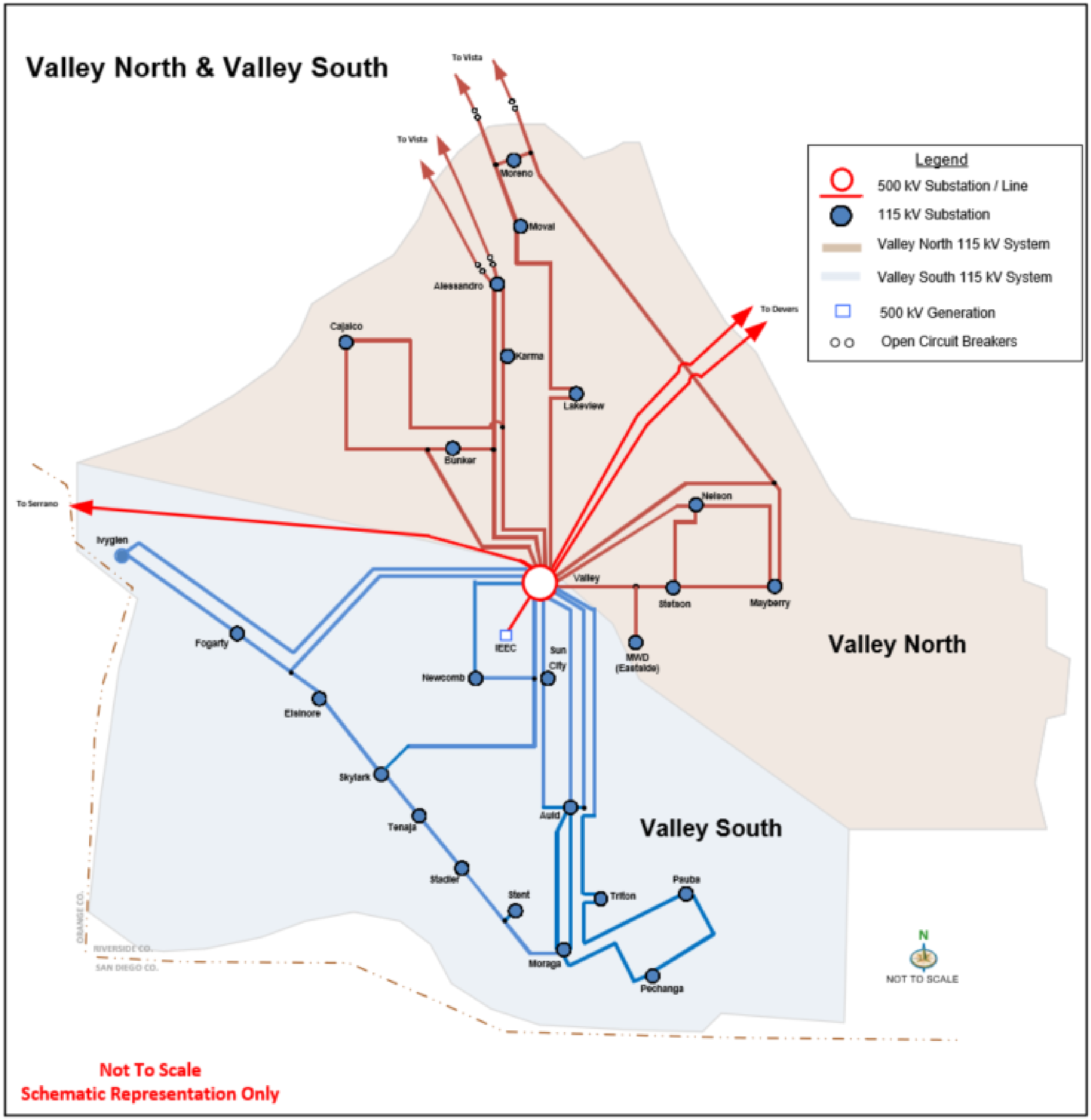


Figure 1-1 Valley Substation service areas[4].

SCE subsequently submitted an application to the CPUC seeking a Certificate of Public Convenience and Necessity (CPCN). During the final stage of the ASP proceeding, the CPUC directed SCE to provide

[4] Valley-Ivyglen and VSSP projects included [3]

additional analyses to justify the peak demand forecasts and reliability cases in support of justifying the project. The CPUC also directed SCE to provide a comparison of the proposed ASP to other potential system alternatives that may satisfy the stated project needs; including but not limited to, energy storage, demand response, and distributed energy resources (DER).

1.2 Scope of Work

Quanta Technology supported SCE in supplementing the existing record in the CPUC proceeding for the ASP with additional analyses including a forecast using industry accepted methods of load forecast and additional alternatives including DERs to address any system needs established by the load forecasts to provide necessary facilities to meet the capacity and reliability needs of the Valley South 500/115 kV System. The key scope items of the Quanta Technology analysis are detailed below:

1. Apply a rigorous, quantitative, data-driven approach to comprehensively present the business case justifying the appropriate project solution. The business case justification included a benefit-cost analysis of the alternatives considered based on the forecasted improvements in service reliability performance of the Valley South System. To this effect, Quanta Technology developed a load forecast for the Valley South System planning area using industry-accepted methods for estimating load growth and incorporating load-reduction programs due to energy efficiency, demand response, and behind-the-meter generation. Quanta Technology's forecasting exercise was developed independent of SCE's current forecasting methodology and practices; however, both SCE's and Quanta's analysis incorporated the CEC's IEPR forecasts for the first 10 years through 2028.
2. Using power flow simulations and quantitative review of project data, the forecasted impact of the proposed Alberhill System Project on service reliability performance was estimated.
3. Identification of capital investments or operational changes to address reliability issues in the absence of construction of the proposed Alberhill System Project or any other major projects requiring CPUC approval, along with the associated costs for such actions.
4. Benefit-cost analysis of several system alternatives (including the proposed ASP, alternative substations and line configurations, energy storage, DER, demand response, and other smart-grid solutions or combinations thereof) for enhancing reliability and providing the required additional capacity.

The primary component of this work statement was to identify a number of system alternatives (e.g., alternative substation and line configurations, energy storage, DER, demand response, other smart-grid solutions, or combinations thereof [hybrid projects]) to satisfy the peak-demand load projections and reliability needs over a 30-year planning horizon. This was followed by a system analysis using data-driven quantitative assessment of project performance, coupled with benefit-cost analysis of the proposed project and several of these alternatives, to allow objective comparison of their costs and benefits. Additionally, all system alternative designs were developed to satisfy the following project objectives[5], as stipulated by the project proceedings:

[5] For purposes of alternatives analysis SCE directed Quanta to refer to the original project objectives identified by SCE in its Proponents Environmental Assessment (PEA) that was filed with SCE's application because the project objectives as listed in the Final Environmental Impact Report (FEIR) identified that a solution must include a new 500/115 kV substation. During the ASP proceeding, the CPUC directing SCE to evaluate additional alternatives that

1. Serve current and long-term projected electrical demand requirements in the SCE Electrical Needs Area.
2. Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations located in the Valley South system).
3. Transfer a sufficient amount of electrical demand from the Valley South system to maintain a positive reserve capacity through the 10-year planning horizon.
4. Provide safe and reliable electrical service consistent with the SCE's Subtransmission Planning Criteria and Guidelines.
5. Increase electrical system reliability by constructing a project in a location suitable to serve the SCE Electrical Needs Area (i.e., the area served by the existing Valley South system).
6. Meet project needs while minimizing environmental impacts.
7. Meet project needs in a cost-effective manner.

1.3 Methodology

In order to accomplish the scope of this project, the following tasks were employed to meet the overall objectives of this effort.

- Task 1: Detailed Project Planning,
- Task 2: Development of Load Forecast for the Valley South System,
- Task 3: Reliability Assessment of ASP,
- Task 4: Screening and Reliability Assessment of Alternatives,
- Task 5: Benefit-Cost Analysis.

The objective of each of the project tasks is detailed in the following subsections.

1.3.1 Task 1: Detailed Project Planning

The objective of this task was to develop a detailed and structured work plan that includes a description of the proposed load-forecasting methodology, overall study process, data needs, interim deliverables, and timeline of activities to meet the project deliverables. The key outcomes of this task were to review and finalize assumptions, methodology, metrics and overall approach for the following key aspects of the project:

- Load forecasting methodology.
- Data-driven, quantitative reliability metrics.
- Reliability Assessment and Benefit-Cost Framework.
- Detailed project plan including interim deliverables and schedule.

included DERs. To comprehensively perform this analysis would have been necessarily constrained by the project objectives as stated in the FEIR, thus reverting back to SCE's project objectives in its PEA (which did not specify a solution as requiring a new 500/115 kV substation) was most suitable to perform the required alternatives analysis.

1.3.2 Task 2: Development of Load Forecast for the Valley South System

The objective of this task was to develop a baseline load forecast representative of the 10-year horizon and long-term forecast to account for the 30-year horizon. Forecasts have been developed for Valley North and Valley South Systems. The long-term forecasts are developed accounting for varying projections around energy efficiency, demand response, and behind-the-meter aggregations.

1.3.3 Task 3: Reliability Assessment of ASP

The objective of this task is to introduce the reliability assessment framework, while describing the tools, formulation and overall methodology. The proposed performance metrics are introduced, and their applicability has been described. Subsequently the reliability framework was applied to the ASP and the overall project performance was evaluated.

1.3.4 Task 4: Screening and Reliability Assessment of Alternatives

The objective of this task was to analyze alternative projects (and their operational considerations) that are be considered to address the reliability needs in the absence of the ASP. Through a screening process, the selected set of the alternatives are evaluated using the reliability framework to quantify their performance.

1.3.5 Task 5: Benefit-Cost Analysis

The objective of this task was to perform a benefit-cost analysis of the ASP along with the list of system alternatives from Task 4. The intent of this analysis was to compare the project alternatives using the quantitative reliability metrics developed in Task 1 along with rigorous cost and risk analysis that will be required to justify the business case of each alternative for meeting the load growth and reliability needs of the Valley South System.

1.4 Report Organization

The report has been organized consistent with the tasks outlined by Section 1.3. The report has been separated into several chapters that individually address each task item. The intent of this breakdown is to capture, in detail, the essential elements of the reliability and benefit-cost framework.

In Chapter 2 of this report, the long-term spatial load forecast is discussed. This chapter is complementary to Quanta Technology's load forecast report [1], which focused on the near-term load forecast and describes the technical details behind spatial load forecasting methodology.

Chapter 3 of this report presents the overall framework for reliability and benefit-cost evaluation. This highlights the study methodology, assumptions and describes key processes involved within the analysis.

In Chapters 4 and 5, the reliability evaluation framework is applied on the ASP and selected alternatives. Each of the forecasts developed in Task 2 are utilized to evaluate the alternative's performance.

Chapter 6 presents the results from benefit-cost analysis and deterministic risk assessment.

The report is concluded with appendices for the glossary and applicable references.

2 LONG-TERM SPATIAL LOAD FORECAST

The spatial load forecast for the Valley North and Valley South Systems of the greater SCE System, was developed for the long-term period of 30 years, covering from 2019 to 2048. The horizon year of 2048 assumed all general plan land use maps for Valley North and Valley South communities are designed for the 30-year horizon. Forecast results up to year 2028 were presented in a separate report[6]. This forecast was constructed from a base load forecast and incorporated DER future developments according to IEPR 2018[7] and SCE's dependable photovoltaic (PV) disaggregation. The result was a disaggregated effective PV forecast that expanded the 10-year PV forecast for the Valley North and Valley South regions, to the 30-year timeframe. This chapter describes the methodology used to develop the additional 20 years of the load forecast (2029-2048) and considers three DER development scenarios.

2.1 Base spatial load forecast

The spatial load forecasting method developed by Quanta Technology was presented in [1], where base forecast results were shown up to year 2028. This spatial forecast methodology is based on 30-year horizon year[8], and results were obtained for the entire period.

These forecast results are representative of the natural load growth resulting from incremental use of electricity by existing customers, and new customer additions as indicated by future land use plans. The sum of these two factors provides the base spatial forecast that does not include the effects of future DER developments. Embedded within these results are the current levels of DER adoption observed by the base forecast. The results are summarized in Table 2-1. Further details on the spatial load forecast methodology, can be found in [1].

Table 2-1 Base spatial load forecast without additional impacts of future DER

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2018	1068	769
2019	1092	787
2020	1116	804
2021	1142	825
2022	1162	845
2023	1181	857
2024	1193	866

[6] Report Alberhill System Project Load Forecast, Quanta Technology, 2019

[7] Integrated Energy Policy Report, published by California Energy Commission: ww2.energy.ca.gov/2018_energypolicy

[8] The 30-year horizon year was selected as a typical long-term planning range that allows accommodating such things as the time required for regulatory licensing and permitting activities as well as lead times and financial budgeting for utility equipment and construction as required.

Year	Spatial Valley South (No added DER) [MVA]	Spatial Valley North (No added DER) [MVA]
2025	1205	874
2026	1217	882
2027	1229	893
2028	1242	904
2029	1254	915
2030	1267	925
2031	1280	938
2032	1293	950
2033	1306	963
2034	1319	975
2035	1331	989
2036	1344	1002
2037	1356	1015
2038	1369	1029
2039	1380	1042
2040	1392	1055
2041	1404	1068
2042	1415	1081
2043	1425	1093
2044	1436	1105
2045	1446	1117
2046	1456	1129
2047	1465	1140
2048	1474	1150

2.2 DER development from 2019 to 2028

Based on IEPR 2018, SCE provided disaggregated DER forecasts to the level of the Valley South and Valley North Systems. These DER forecasts covered from 2019 to 2028, and included Additional Achievable Energy Efficiency (AAEE), Additional Achievable Photovoltaic (AAPV), Electric Vehicles, Energy storage, and Load Modifying Demand Response (LMDR) categories.

2.2.1 AAPV disaggregation

Particularly for AAPV, SCE provided two scenarios: SCE Effective PV and PVWatts; the final load forecast presented in [1] considers the SCE Effective PV scenario as the most likely scenario during the period from

2019 to 2028. AAPV values based on SCE's Effective PV forecast and AAPV values based on PVWatts impacts on peak load reduction are shown in Table 2-2.

Table 2-2 Disaggregated forecasted peak modifying AAPV from 2019 to 2028

	DER Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	AAPV SCE Effective PV [MVA]	-4.9	-4.9	-4.9	-4.9	-4.9	-4.5	-4.0	-3.7	-3.7	-2.9
	AAPV PVWatts [MVA]	-7.7	-7.6	-7.6	-7.5	-7.4	-6.8	-6.2	-5.8	-5.6	-4.3
Valley South	AAPV SCE Effective PV [MVA]	-5.7	-5.0	-4.2	-3.4	-3.0	-2.8	-2.7	-2.4	-2.1	-1.9
	AAPV PVWatts [MVA]	-8.9	-8.7	-8.6	-8.4	-7.8	-7.0	-7.0	-6.3	-5.6	-4.8

2.2.2 Disaggregation of other DER categories

Based on the 2018 IEPR, SCE also provided disaggregated DER forecasts for Additional Achievable Energy Efficiency (AAEE), Electric Vehicles, Energy storage, and Load Modifying Demand Response (LMDR) categories. The forecasted peak-modifying amounts of DER are shown in Table 2-3.

Table 2-3 Disaggregated forecasted peak-modifying DER from 2019 to 2028

	DER Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Electric Vehicle [MVA]	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.2	0.3
	AAEE [MVA]	-2.3	-2.1	-2.6	-2.8	-3.2	-2.9	-2.8	-2.7	-2.8	-2.9
	Energy Storage [MVA]	-0.5	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
	LMDR [MVA]	0.0	-0.5	0.0	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0
Valley South	Electric Vehicle [MVA]	0.8	0.9	0.8	0.6	0.7	0.6	0.6	0.4	0.4	0.4
	AAEE [MVA]	-3.4	-2.9	-3.6	-2.6	-3.0	-2.8	-2.7	-2.5	-2.6	-2.8
	Energy Storage [MVA]	-1.0	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
	LMDR [MVA]	0.6	-1.4	0.0	-0.2	-0.2	-0.1	-0.1	0.0	0.0	0.0

2.3 Forecasted DER development 2029 – 2048

In order to obtain a long-term spatial forecast that considers impacts of DERs, it is required to have DER forecasts which extend to year 2048. The estimation of DER from year 2029 until year 2048 has been done as described in the following subsections.

2.3.1 AAPV growth from 2029 to 2048

Growth rates of generation forecasts for solar and rooftop PV have been taken from the California PATHWAYS[9] model, on its CEC 2050 scenario. The same yearly growth rates for the state of California have

9 https://www.ethree.com/public_proceedings/summary-california-state-agencies-pathways-project-long-term-greenhouse-gas-reduction-scenarios/

been applied to the AAPV forecasts of Table 2-2, starting from year 2029, to generate an estimation of the AAPV in the Valley South and Valley North systems up to year 2048. The estimated AAPV at Valley South and Valley North System level, for the AAPV Effective PV and the AAPV PVWatts scenarios, are shown in Table 2-4 and Table 2-5.

Table 2-4 California (CA) PATHWAYS CEC 2050 case for solar generation [MVA], and estimated AAPV SCE Effective PV [MVA] at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	117	124	132	139	146	152	157	162	167	172	176	179	183
CA PV	29.9	33	36.4	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.3	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	122	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-2.9	-2.7	-2.5	-2.3	-2.2	-2.1	-2.1	-2	-1.9	-1.8	-1.7	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.3	-1.3	-1.2
AAPV Valley South	-1.9	-1.8	-1.6	-1.5	-1.5	-1.4	-1.4	-1.3	-1.2	-1.2	-1.1	-1.1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8

Table 2-5 California (CA) PATHWAYS CEC 2050 case for solar generation [MVA], and estimated AAPV PVWatts [MVA] at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA Solar	75.7	80.6	86	92.1	95.8	100	105	111	118	124	132	139	146	152	157	162	167	172	176	180	183
CA PV	29.9	33	36.5	37.5	38.6	39.7	40.8	41.9	42.9	44	45.1	46.2	47.3	48.4	49.4	50.5	51.6	52.7	53.8	54.8	55.9
CA Total	106	114	123	130	134	140	146	153	160	168	177	185	193	200	207	213	219	225	230	234	239
AAPV Valley North	-4.3	-4	-3.6	-3.4	-3.3	-3.2	-3	-2.9	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.1	-2	-2	-1.9	-1.9	-1.9	-1.8
AAPV Valley South	-4.8	-4.5	-4.1	-3.9	-3.7	-3.6	-3.4	-3.3	-3.1	-3	-2.8	-2.7	-2.6	-2.5	-2.4	-2.3	-2.2	-2.2	-2.1	-2.1	-2.1

As a third scenario for AAPV growth after 2028, a compound annual growth rate of 3% was used, as a reasonable expectation for future AAPV after year 2028. This is based on CEC IEPR PV forecast observations that around 2022 the natural adoption of PV starts to show plateau. The additional growth from zero net energy or new home installations is expected to be relatively flat for every year. That means it will not generate higher growth rates for PV forecast in the longer term. The reasonable growth rate for the disaggregated PV forecast going beyond 2028 is about -3%. The resulting estimations of peak reducing capabilities are shown in Table 2-6.

Table 2-6 Estimated AAPV PVWatts [MVA] at Valley South and Valley North a -3% CAGR

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
AAPV Valley North	-2.9	-2.8	-2.7	-2.6	-2.6	-2.5	-2.4	-2.3	-2.3	-2.2	-2.1	-2.1	-2	-2	-1.9	-1.8	-1.8	-1.7	-1.7	-1.6	-1.6
AAPV Valley South	-1.9	-1.9	-1.8	-1.7	-1.7	-1.6	-1.6	-1.5	-1.5	-1.5	-1.4	-1.4	-1.3	-1.3	-1.2	-1.2	-1.2	-1.1	-1.1	-1.1	-1

Figure 2-1 and Figure 2-2 show the AAPV forecasted growth scenarios for Valley South and Valley North, respectively.

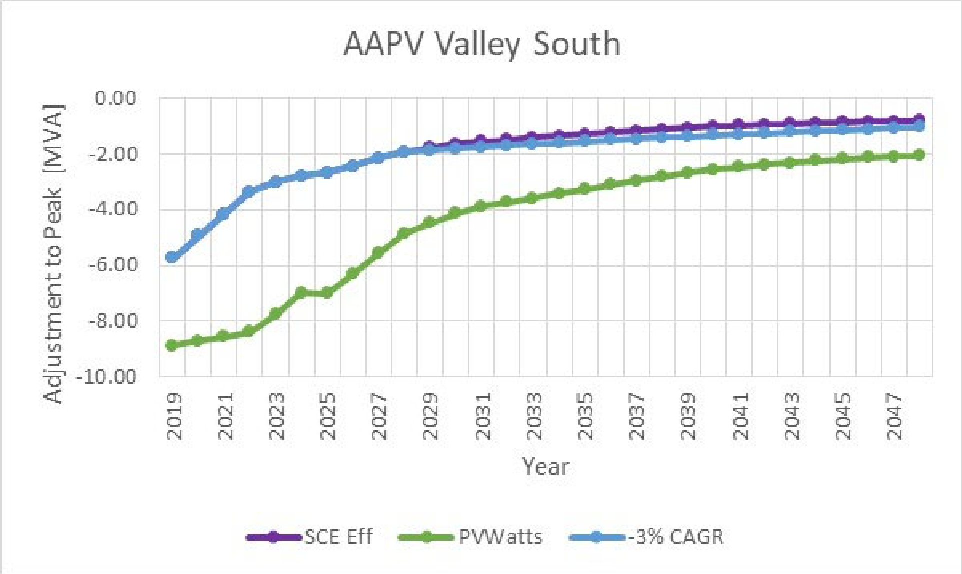


Figure 2-1 AAPV forecasted growth scenarios for Valley South

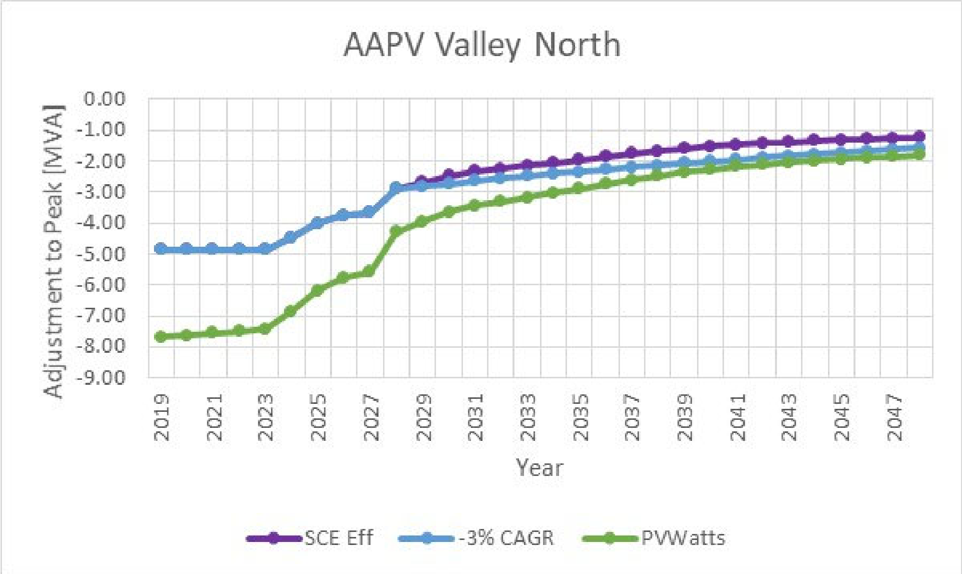


Figure 2-2 AAPV forecasted growth scenarios for Valley North

2.3.2 EV growth from 2029 to 2048

The electric vehicle disaggregated forecast of Table 2-3 was extended until year 2048 by using Growth rates of subsector electric demands for light-duty vehicles, taken from the California PATHWAYS model, on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the electric vehicle forecast of Table 2-3, starting from year 2028. The estimated Electric Vehicle load at Valley South and Valley North System level are shown in Table 2-7.

Table 2-7 California PATHWAYS CEC 2050 case for light EV load [MVA], and estimated EV [MVA] at Valley South and Valley North

DER	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
CA EV	10.1	11.8	14	16.5	19.4	22.5	25.5	28.3	30.8	33.2	35.5	37.5	39.4	41.3	43	44.5	45.8	46.9	47.7	48.4	48.8
EV Valley North	0.28	0.32	0.38	0.45	0.53	0.62	0.7	0.78	0.85	0.91	0.97	1.03	1.08	1.13	1.18	1.22	1.26	1.29	1.31	1.33	1.34
EV Valley South	0.43	0.5	0.6	0.7	0.83	0.96	1.09	1.2	1.31	1.42	1.51	1.6	1.68	1.76	1.83	1.9	1.95	2	2.03	2.06	2.08

Figure 2-3 and Figure 2-4 show the forecasted amounts of peak-enhancing electric vehicle loads for Valley South and Valley North.

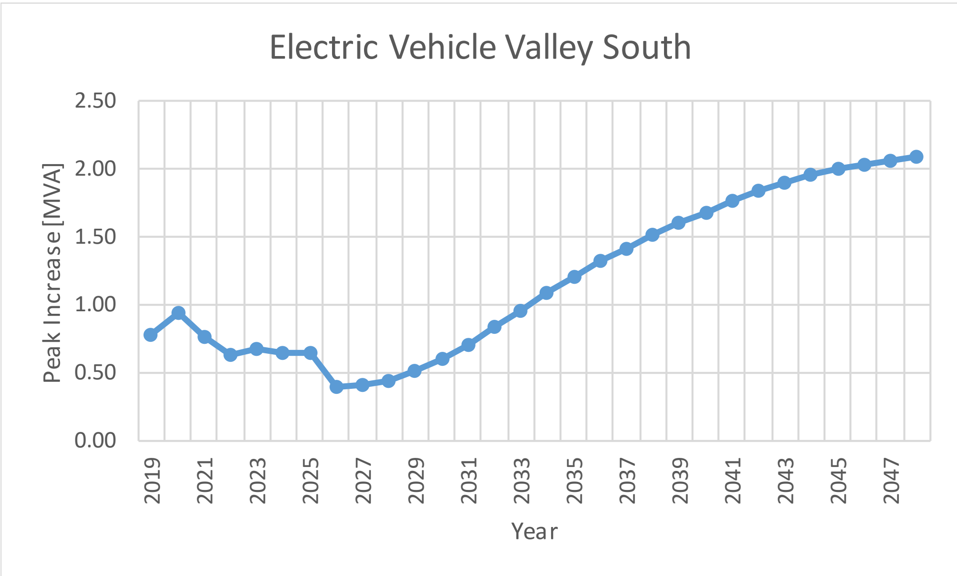


Figure 2-3 Electric vehicle forecasted growth for Valley South

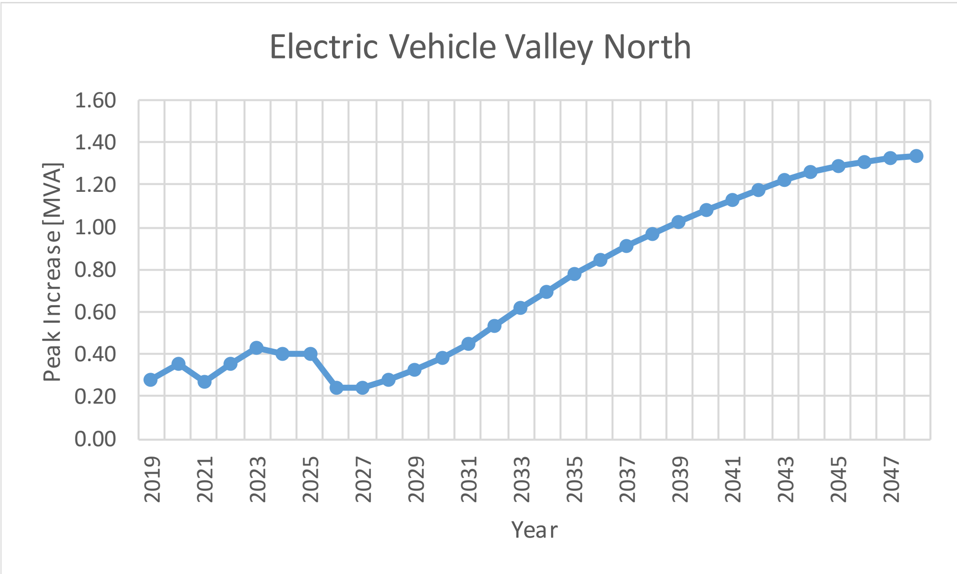


Figure 2-4 Electric vehicle forecasted growth for Valley North

2.3.3 Energy Efficiency growth from 2029 to 2048

The Energy Efficiency disaggregated forecast of Table 2-3 was extended until year 2048 based on the criteria that after 2028 the load reductions in energy efficiency are expected to be close to 21% of the forecasted load growth of each year. Additionally, it is considered that energy efficiency load reductions will predominantly take place in residential loads, which are approximately 40% of the Valley South System load and approximately 36% of the Valley North System load. The resulting extended forecast for Energy Efficiency is shown in Table 2-8.

Table 2-8 Estimated growth of peak-reducing Energy Efficiency at Valley South and Valley North [MVA]

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
EE Valley North	-0.8	-0.9	-0.9	-0.9	-0.9	-1	-1	-1	-1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8
EE Valley South	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1	-1	-1	-1	-0.9	-0.9	-0.9	-0.9	-0.7	-0.7	-0.7

Figure 2-5 and Figure 2-6 show the forecasted amounts of peak-reducing Energy Efficiency effect for Valley South and Valley North.

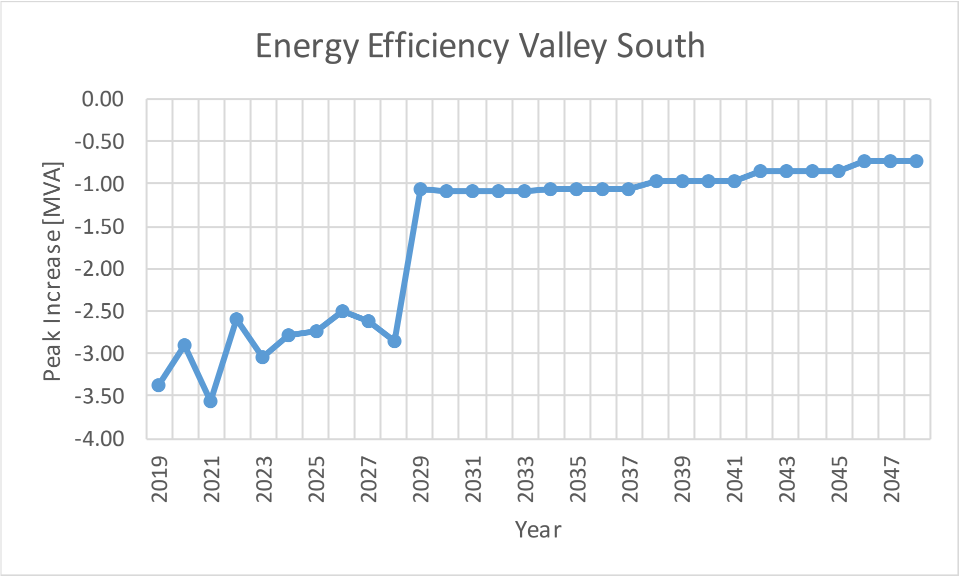


Figure 2-5 Energy Efficiency forecasted growth for Valley South

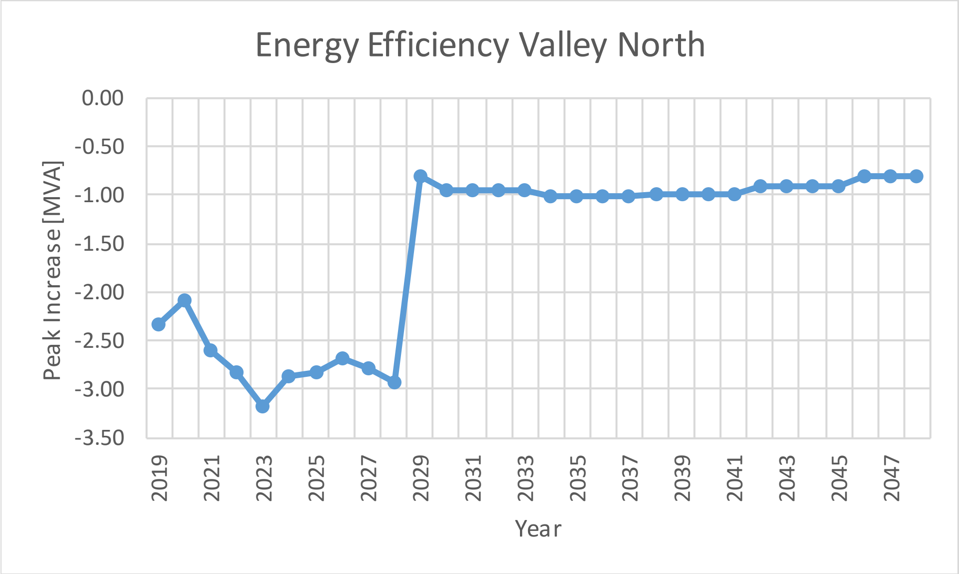


Figure 2-6 Energy Efficiency forecasted growth for Valley North

2.3.4 ES growth from 2029 to 2048

SCE provided an energy storage outlook for the entire SCE service territory. This outlook estimated an approximated total of 4,300 MVA of energy storage by year 2048. By SCE criteria it was estimated that 60% of this storage would be associated to residential customers, of which approximately 5% would be located in the Valley South System and approximately 20% of it would have a peak reduction effect. These considerations lead to an estimated peak-reducing amount of cumulated energy storage of 26 MVA (or additional 23.6 MVA after 2028) by 2048 for the Valley South System. Similar considerations lead to additional cumulated 15.5 MVA of peak reducing Energy Storage for the Valley North System.

A constant compound annual growth rate (CAGR) of energy storage was identified for each area (North and South), so that the 2048 estimated values were achieved. The resulting CAGR for the Valley South System is 17.98%, and the same for Valley North is 14.39%. Table 2-9 summarizes the resulting estimated peak-reducing amounts of energy storage for the Valley South and Valley North Systems.

Table 2-9 Estimated growth of peak-reducing Energy Storage at Valley South and Valley North [MVA]

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Storage Valley North	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.5	-0.6	-0.7	-0.8	-0.9	-1.1	-1.2	-1.4	-1.6	-1.8	-2.1
Storage Valley South	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.4	-0.5	-0.6	-0.7	-0.8	-1	-1.2	-1.4	-1.6	-1.9	-2.3	-2.7	-3.2	-3.7

Figure 2-7 and Figure 2-8 show the forecasted amounts of peak-reducing Energy Storage effect for the Valley South and Valley North Systems.

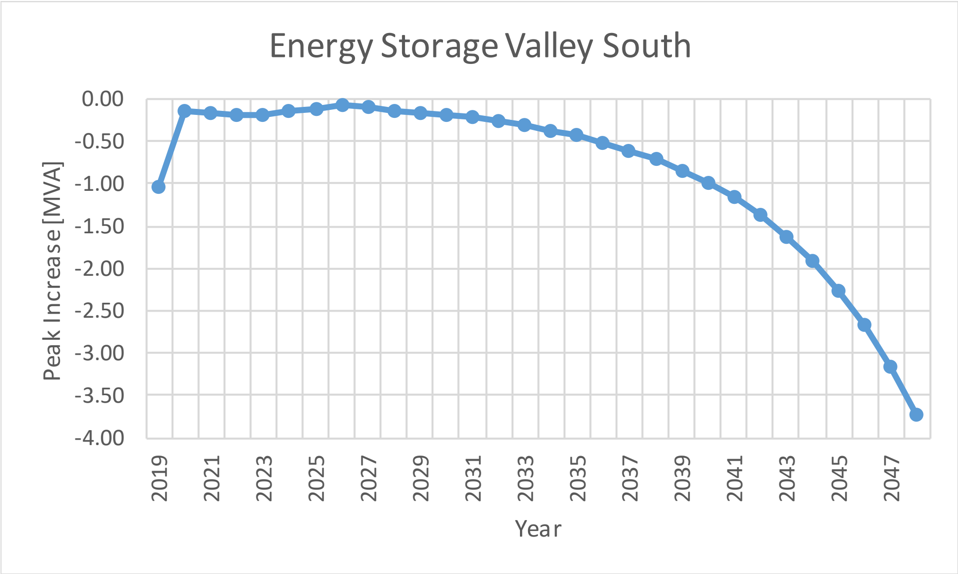


Figure 2-7 Energy Storage forecasted growth for Valley South

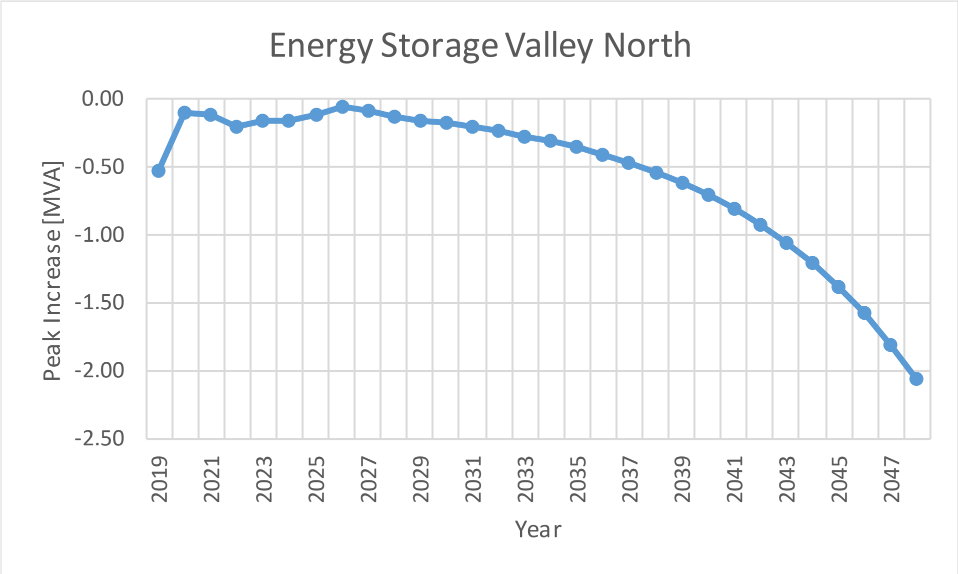


Figure 2-8 Energy Storage forecasted growth for Valley North

2.3.5 Demand Response growth from 2029 to 2048

According to the demand response trends extracted from Table 2-3, the effects of Demand response were considered negligible after year 2028.

2.4 Valley South and Valley North long-term forecast results

The peak modifying effects for future DER discussed in the previous sections were aggregated and applied to the base spatial load forecast of Section 2.1, to develop long term load forecast results for Valley South and Valley North. The resulting forecast scenarios are summarized in Table 2-10 and Figure 2-9 for the Valley South System, and in Table 2-11 and Figure 2-10 for the Valley North System.

Table 2-10 Final results of spatial forecast for Valley South, considering three AAPV growth alternatives after year 2028

Year	Spatial Valley South (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	1068	1068	1068	1068
2019	1092	1083	1083	1083
2020	1116	1099	1099	1099
2021	1142	1118	1118	1118
2022	1162	1132	1132	1132
2023	1181	1146	1146	1146
2024	1193	1152	1152	1152
2025	1205	1159	1159	1159
2026	1217	1166	1166	1166
2027	1229	1174	1174	1174
2028	1242	1183	1183	1183
2029	1254	1193	1177	1193
2030	1267	1203	1172	1203
2031	1280	1214	1166	1213
2032	1293	1225	1175	1224
2033	1306	1236	1184	1235
2034	1319	1247	1193	1246
2035	1331	1258	1202	1257
2036	1344	1269	1211	1267
2037	1356	1280	1221	1278
2038	1369	1291	1230	1289
2039	1380	1302	1239	1299
2040	1392	1312	1248	1309
2041	1404	1322	1256	1319
2042	1415	1333	1265	1329
2043	1425	1341	1272	1337
2044	1436	1350	1280	1346
2045	1446	1358	1287	1354
2046	1456	1366	1293	1361
2047	1465	1372	1298	1367
2048	1474	1378	1302	1373

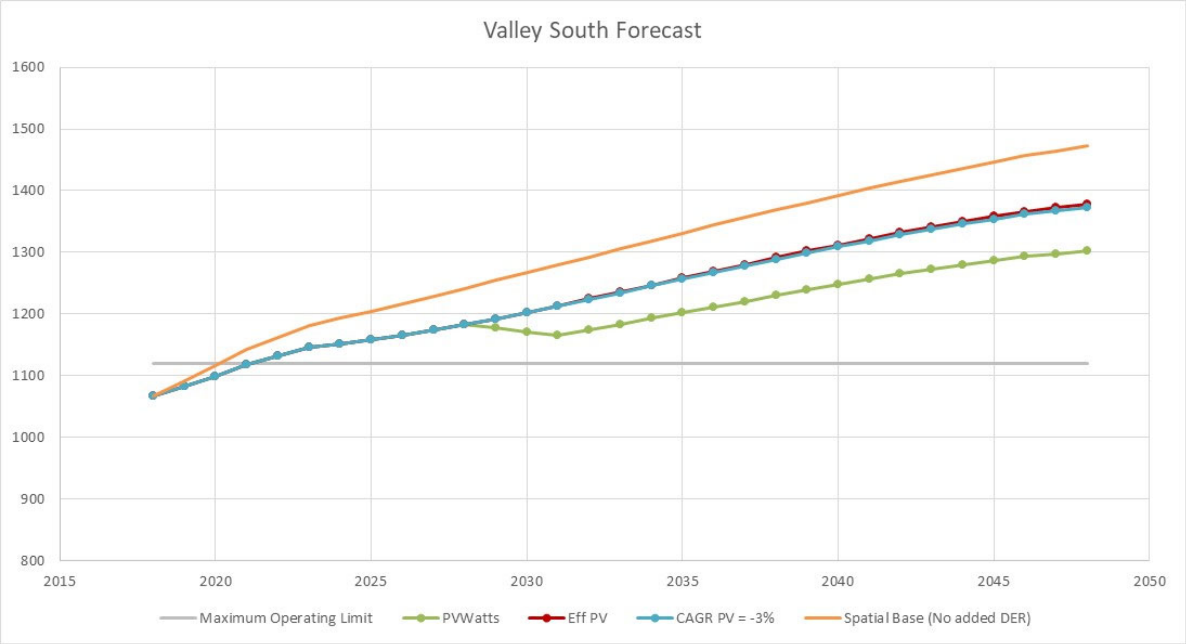


Figure 2-9 Final results of spatial forecast for Valley South, considering three AAPV growth alternatives after year 2028

Table 2-11 Final results of spatial forecast for Valley North, considering three AAPV growth alternatives after year 2028

Year	Spatial Valley North (No added DER) [MVA]	Spatial Forecast AAPV SCE's Effective PV Scenario [MVA]	Spatial Forecast AAPV PVWatts Scenario [MVA]	Spatial Forecast AAPV -3% CAGR [MVA]
2018	769	769	769	769
2019	787	779	779	779
2020	804	789	789	789
2021	825	803	803	803
2022	845	816	816	816
2023	857	820	820	820
2024	866	821	821	821
2025	874	823	823	823
2026	882	825	825	825
2027	893	829	829	829
2028	904	834	834	834
2029	915	842	834	842
2030	925	849	833	849
2031	938	859	832	858
2032	950	868	840	867
2033	963	878	849	877
2034	975	888	858	886
2035	989	899	868	897
2036	1002	910	878	907
2037	1015	921	888	918
2038	1029	932	898	928
2039	1042	943	908	939
2040	1055	954	919	949
2041	1068	964	929	960
2042	1081	975	939	970
2043	1093	985	948	980
2044	1105	995	958	989
2045	1117	1005	967	998
2046	1129	1015	976	1008
2047	1140	1023	983	1015
2048	1150	1031	991	1023

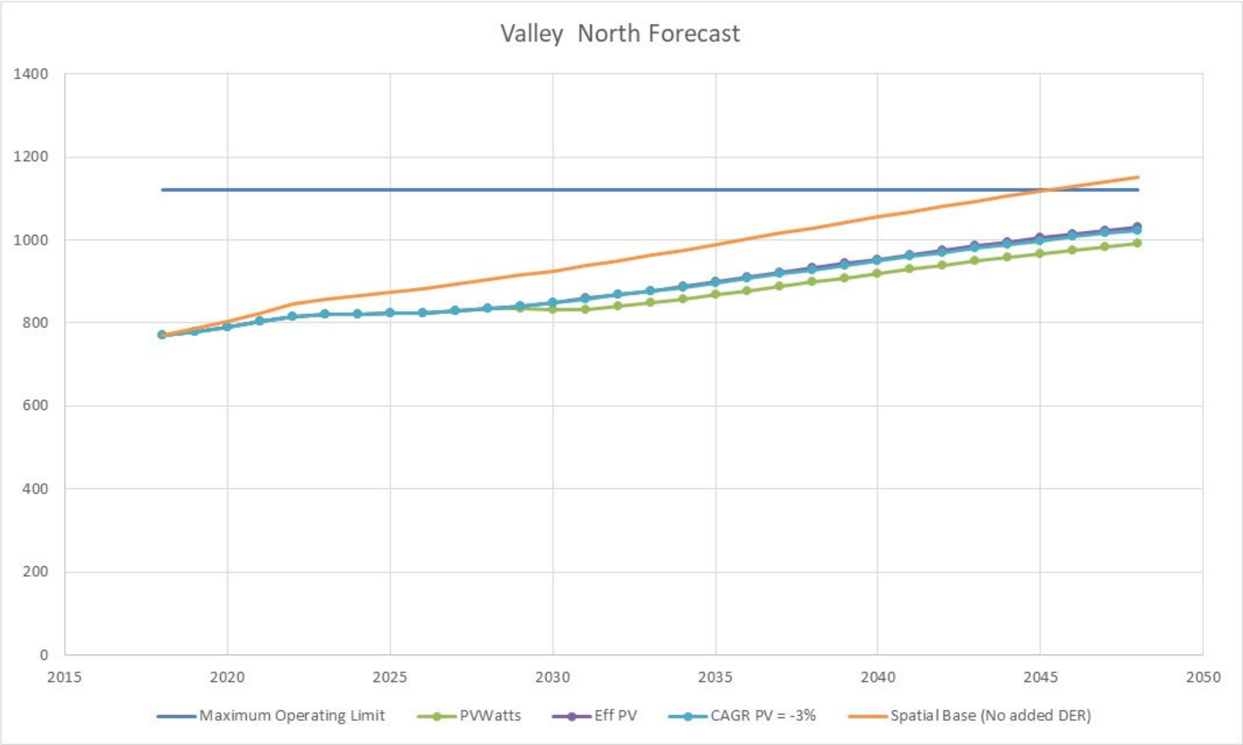


Figure 2-10 Final results of spatial forecast for Valley North, considering three AAPV growth alternatives after year 2028

3 RELIABILITY ASSESSMENT & BENEFIT COST FRAMEWORK

3.1 Introduction

The objective of this framework is to facilitate the evaluation of project performance and benefits relative to the baseline scenario (i.e., no project in service). The projects under consideration include the ASP and proposed alternatives which are further discussed in Chapters 4 and 5. Within the framework of this analysis, reliability, capacity, operational flexibility and resiliency benefits have been quantified.

In order to successfully evaluate the benefit of a potential project in the Valley South System, the project's performance must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to baseline scenario (no project in service),
3. To establish a basis to value the performance of projects against overall objectives,
4. To take into consideration benefits or impacts of operational flexibility and resiliency (high-impact, low-probability events), and
5. To provide guidance for comparing the relative performance of each alternative as compared to others.

Within the scope of the developed metrics, the key project objectives presented earlier, are categorized and reviewed.

- **Capacity**
  - Serve current and long-term projected electrical demand requirements in the SCE Electrical Needs Area.
  - Transfer a sufficient amount of electrical demand from the Valley South System to maintain a positive reserve capacity on the Valley South System through not only the 10-year planning horizon, but also that of a longer-term horizon that identifies needs beyond 10 years, which would allow for an appropriate comparison of alternatives that have different useful lifespan horizons.

- **Reliability**
  - Provide safe and reliable electrical service consistent with the SCE's Subtransmission Planning Criteria and Guidelines.
  - Increase electrical system reliability by constructing a project in a location suitable to serve the Electrical Needs Area (i.e., the area served by the existing Valley South System).

- **Operational flexibility and Resiliency**
  - Increase system operational flexibility and maintain system reliability (e.g., by creating system tie-lines that establish the ability to transfer substations from the current Valley South System and to address system operational capacity needs under normal and contingency (N-1) conditions.

3.2 Reliability Framework and Study Assumptions

In order to develop a framework to effectively evaluate the performance of a project, the overall study methodology was broken down into the following elements:

1. Develop metrics to establish project performance,
2. Quantify the project performance using commercial power flow software,
3. Establish platform to evaluate monetized and non-monetized project benefits,
4. Utilize tools such as benefit-cost ratio, incremental benefit-cost analysis and $/Unit Benefit to substantiate alternative selection and conclusions.

Each of the above areas are further detailed throughout this chapter.

3.2.1 Study Inputs

SCE provided Quanta Technology with information pertinent to the Valley South, Valley North, and the proposed ASP systems. This information encompassed the following data:

1. GE PSLF power flow models for Valley South and North Systems.
   a. 2018 system configuration (current system).
   b. 2021 system configuration (Valley-Ivyglen[10] and VSSP[11] projects modeled and included).
   c. 2022 system configuration (with the ASP in service).
2. Substation layout diagrams representing the Valley Substation.
3. Impedance drawings for the Valley South and Valley North Systems depicting the line ratings and configurations.
4. Single-line diagram of the Valley South and Valley North Systems.
5. Contingency processor tools to develop relevant study contingencies to be considered for each system configuration
6. 8,760 load shape of the Valley South System.
7. Advanced Metering Infrastructure (AMI) data for metered customers in the Valley South and North Systems with circuit and substation association, annual consumption amount, and peak demand use.

The reliability assessment utilizes the load forecasts developed for Valley South and Valley North System service territories to evaluate the performance of the system for future planning horizons. The developed forecasts are detailed in Chapter 2 of this report. The primary forecasts under consideration for reliability analysis is the Effective PV (§2.4) along with associated sensitivities, the Spatial Base Forecast (§2.4) and PVWatts (§2.4). The Effective PV forecast is expected to most closely resemble the levels of growth anticipated in the Valley system. The developed forecasts take into consideration the variabilities in future developments of Photovoltaic, Electric Vehicles, Energy Efficiency, Energy Storage, and Load Modifying Demand Response.

[10] Valley-Ivyglen project CPUC Decision 18-08-026 (issued August 31, 2018).
[11] VSSP (Valley South 115 kV Subtransmission Project) CPUC Decision 16-12-001 (issued December 1, 2016).

The load forecasts for Valley South are presented in Figure 3-1, which demonstrate system deficiency in (need) year 2022 (Effective PV and PVWatts) and 2021 (Spatial Base), where the loading on the Valley South transformers exceeds maximum operating limits (1,120 MVA). Figure 3-2, presents the representative load forecast for Valley North where the loading on the Valley South transformers exceeds maximum operating limits (1,120 MVA) by 2045 in the Spatial Base forecast.

Benefits begin to accrue coincident with the project need year. For purposes of this assessment, it is assumed that the project will be in service by this year, and benefits accrue from need year to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

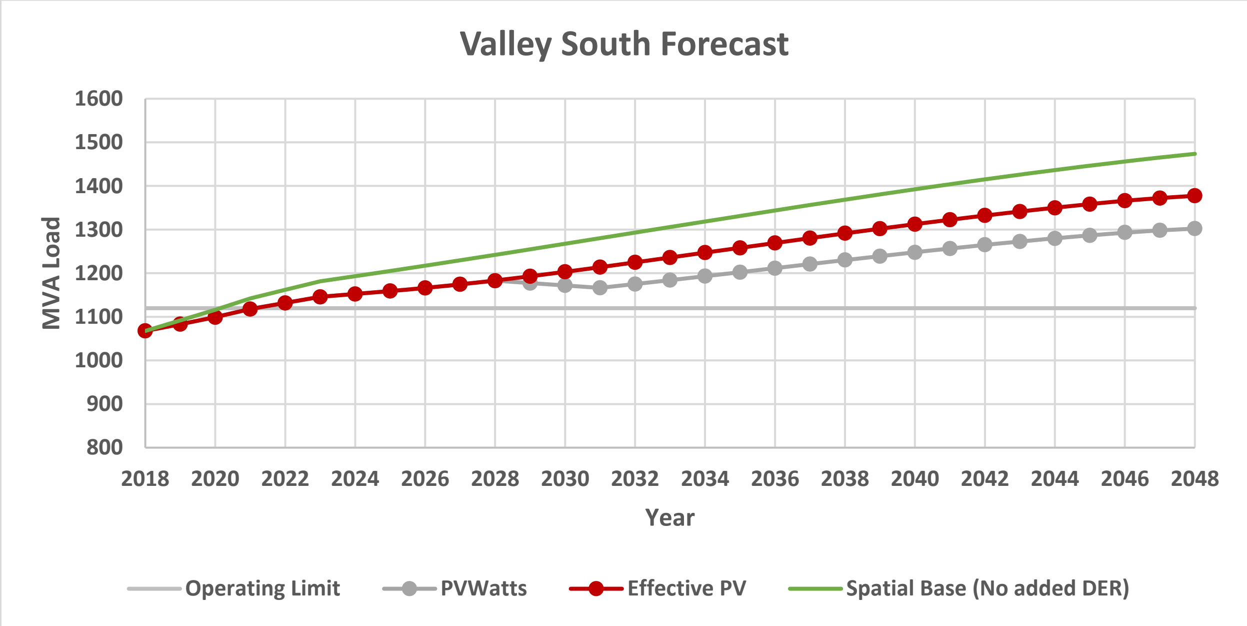


Figure 3-1 Valley South Load Forecast (Peak)

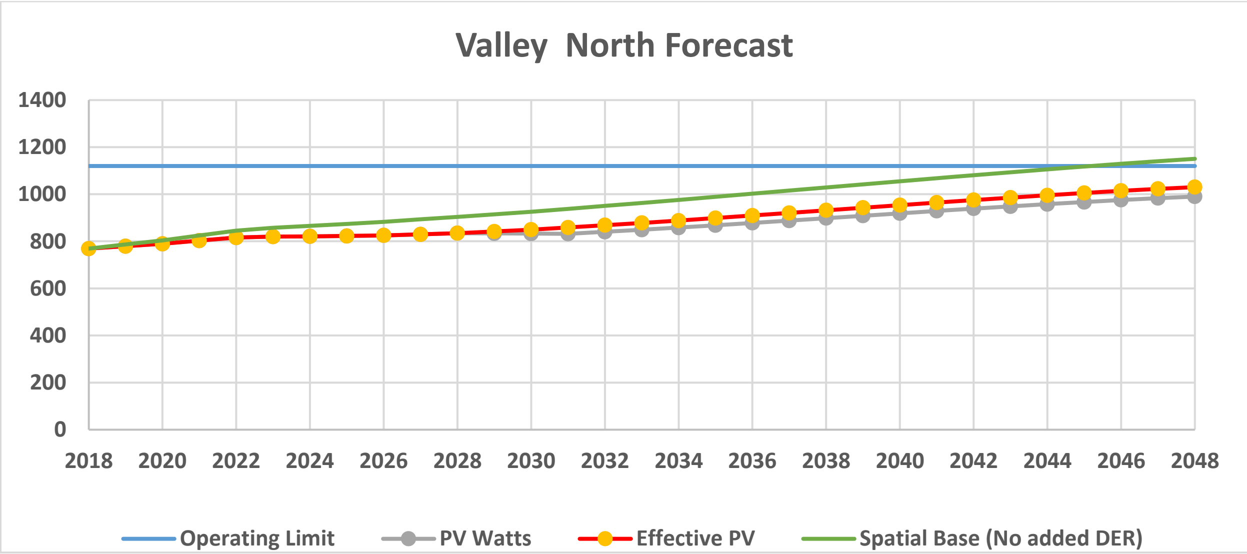


Figure 3-2 Valley North Load Forecast (Peak)

System configuration for the years 2018, 2021, and 2022 are depicted in Figure 3-3 through Figure 3-5.

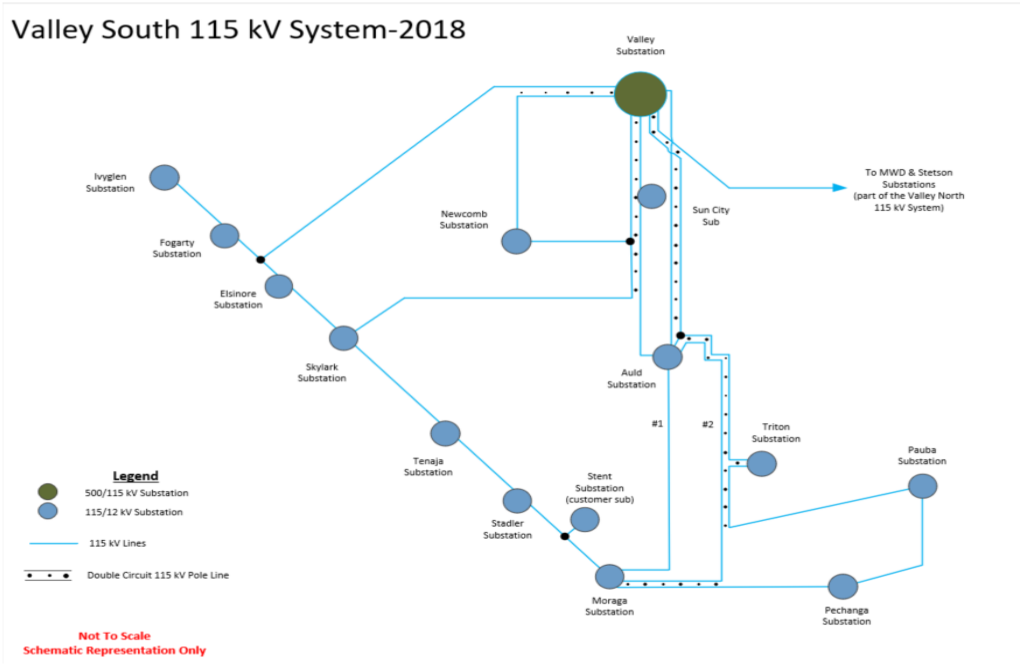


Figure 3-3 Valley South System Configuration (2018)

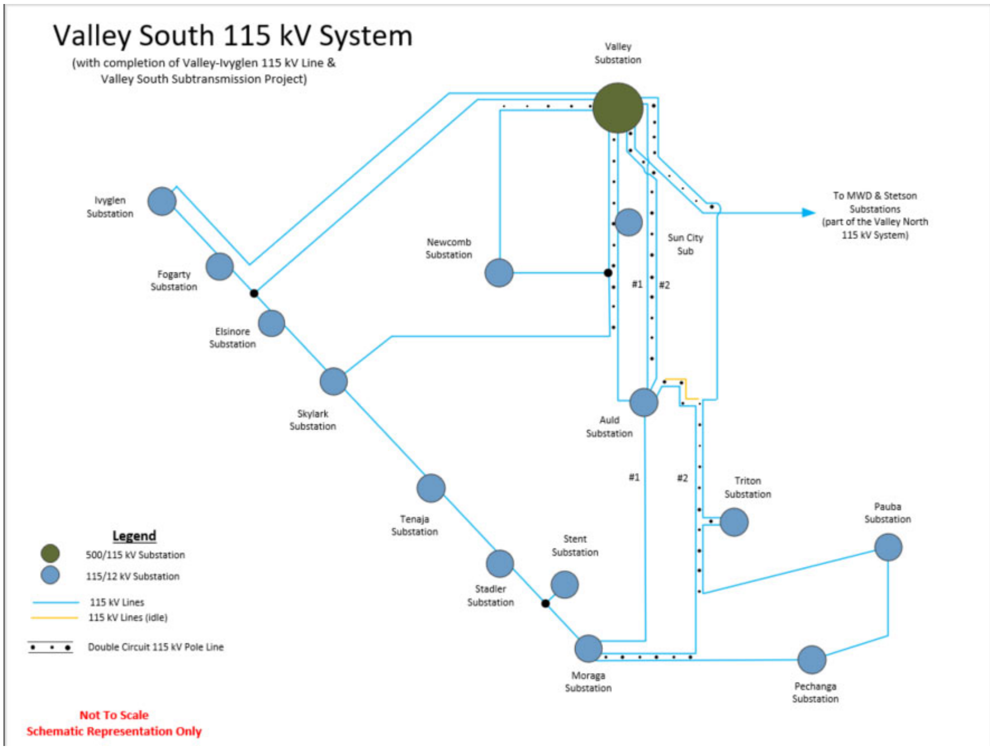


Figure 3-4 Valley South System Configuration (2021)

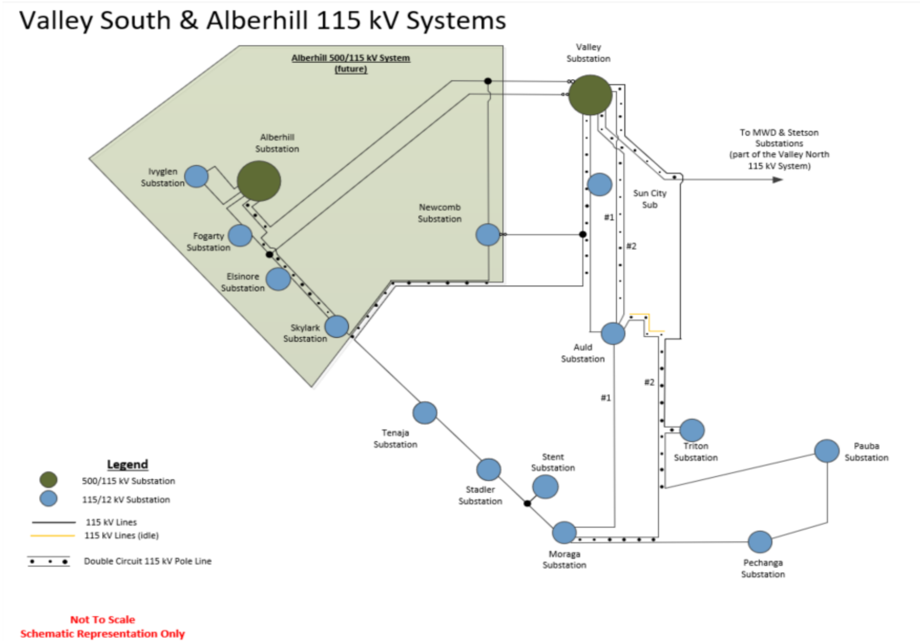


Figure 3-5 Valley South System Configuration (2022 with ASP in-service)

The load shape of the year 2016 was selected for this study. This selection was made because it demonstrated the largest variability among available records[12]. This load shape is presented in Figure 3-6.

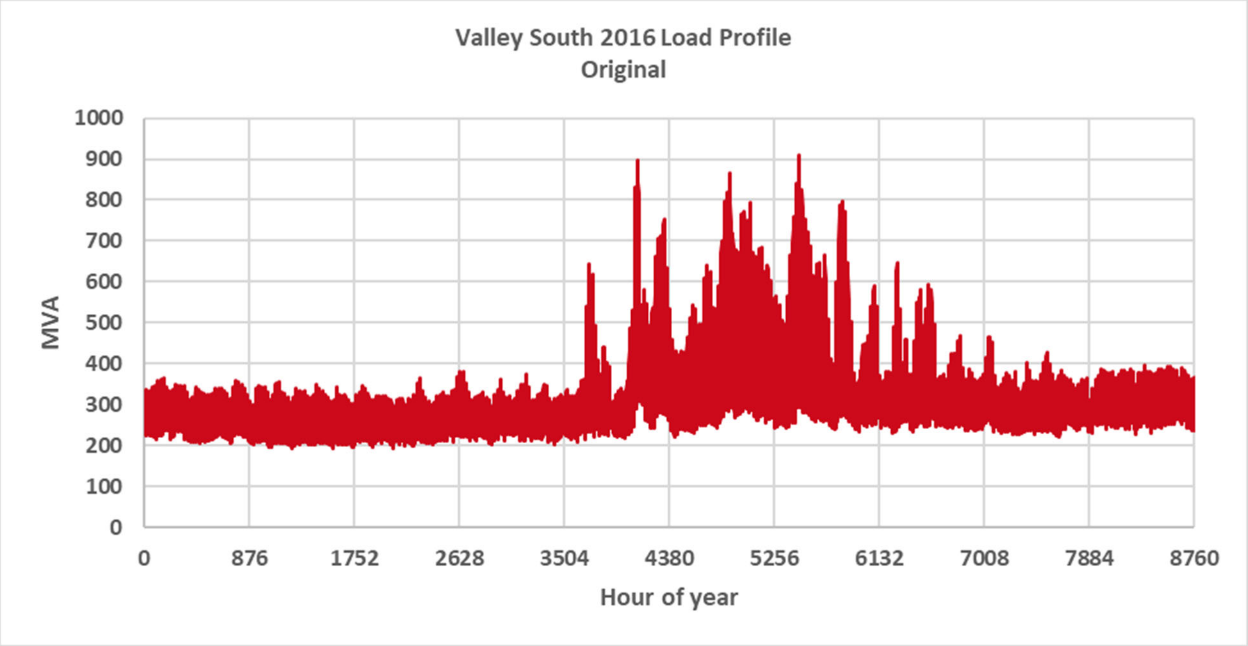


Figure 3-6 Load Shape of the Valley South System

3.2.2 Study Criteria

The following guidelines have been used through the course of this analysis to ensure consistency with SCE planning practices:

- The study and planning of projects adhered to SCE's Subtransmission Planning Criteria and Guidelines. Where applicable, North American Electric Reliability (NERC) and Western Electricity Coordinating Council (WECC) standards were referenced when considering any potential impacts on the bulk electric system (BES) and the non-radial parts of the system under CAISO control.
- Transformer overload criteria established per SCE Subtransmission Planning Criteria and Guidelines for AA banks have been utilized.
- Thermal limits (i.e., ampacity) of conductors are maintained for N-0 and N-1 conditions.
- Voltage limits of 0.95–1.05 per unit under N-0 and N-1 operating configurations.
- Voltage deviation within established limits of ±5% post contingency.

3.2.3 Reliability Study Tools and Application

A combination of power flow simulation tools has been utilized for this analysis, such as General Electric's Positive Sequence Load Flow (PSLF) and PowerGem TARA. PSLF has been used for base-case model

[12] Note that the load shapes of years 2017 and 2018 were skewed due to the use of the AA-bank spare transformers as overload mitigation. Therefore, the load shape for year 2016 was adopted. Its shape is representative only and does not change among years.

development, conditioning, contingency development, and system diagram capabilities. TARA has been used to perform time-series power-flow analysis.

Time-series power-flow analysis is typically used in distribution system analysis to assess variation of quantities over time with changes in load, generation, power-line status, etc. It is now finding common application even in transmission system analysis, especially when the system under study is not heavily meshed (radial in nature).

In this analysis, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each future year under study. This is represented by Figure 3-7 for the Valley South System as an example. The MVA peak load is then distributed amongst the various distribution substations in the Valley System in proportion to their ratio of peak load to that of the entire Valley South System in the base case. Distribution substations under consideration in this analysis of the Valley South and Valley North Systems are listed in Table 3-1.

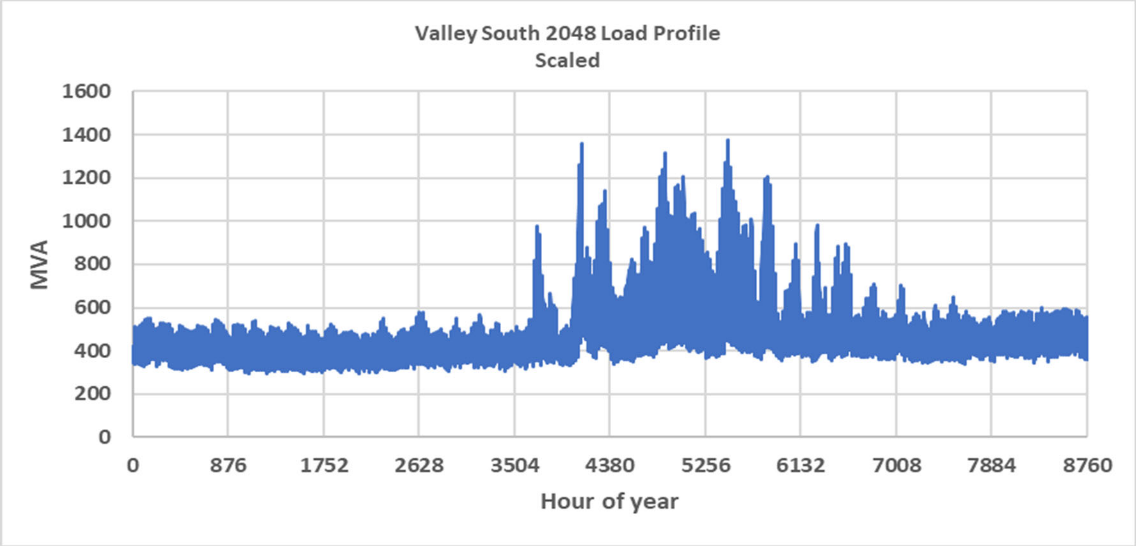


Figure 3-7 Scaled Valley South Load Shape Representative of Study Years

Table 3-1 Distribution Substation Load Buses

Valley South	Valley North
Auld	Alessandro
Elsinore	Bunker
Fogarty	Cajalco
Ivyglen	ESRP_MWD
Moraga	Karma
Newcomb	Lakeview
Pechanga	Mayberry

Valley South	Valley North
Pauba	Moreno
Skylark	Moval
Stadler	Nelson
Stent	Stetson
Sun City	
Tenaja	
Triton	

Hourly study (8,760 simulations per year) was conducted in selected years (5-year period) starting from the year 2022 or 2021 where transformer capacity need exceeds its operating limit. The results for the years in between were interpolated. At each simulation, the alternating current power-flow solution was solved, relevant equipment was monitored under N-0 conditions (using equipment ratings under normal conditions) and N-1 conditions (using equipment ratings under emergency conditions), potential reliability violations were recorded, and performance reliability metrics (as described in Section 3.2.4) were calculated. A flowchart of the overall study process is presented in Figure 3-8.

The N-1 contingency has been evaluated for every hour of the 8,760 simulation; outages were considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for Valley South System. This tool generates single-circuit outages for all subtransmission lines within the system. Whenever an overload or voltage violation was observed, the binding constraint was applied to compute relevant reliability metric(s). When the project under evaluation has system tie-lines that can be leveraged, they were engaged to minimize system impacts. The list of binding constraints is provided for demonstration purposes in this section of the report. The losses are monitored every hour and aggregated across the existing and new transmission lines in the service area.

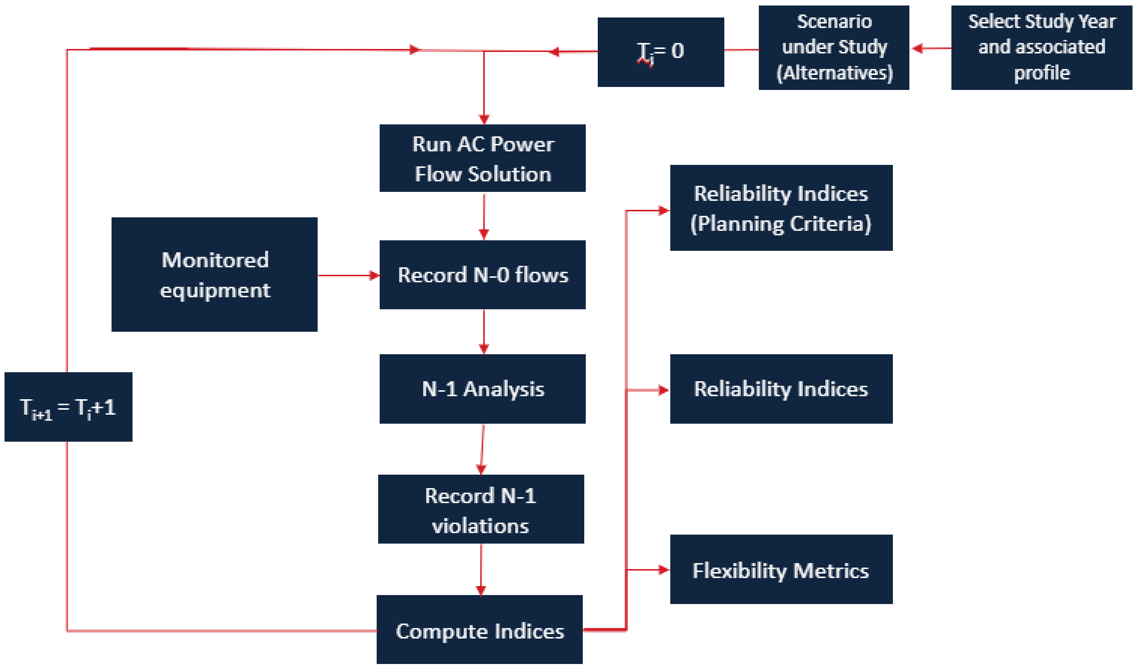


Figure 3-8 Flowchart of Reliability Assessment Process

Several operational flexibility metrics were developed to evaluate the incremental benefits of system tie-lines under emergency including planned and unplanned outages, and High Impact Low Probability (HILP) events in the Valley South System.

Flexibility Metric 1 evaluates the system under N-2 (double-circuit outages) representative of combinations of two transmission lines out for service. The contingencies were generated using the SCE contingency processor tool for Valley South System. This tool generates double-circuit outages for all subtransmission lines within the system. The objective of this metric is to gauge the incremental benefits that projects provide for events that would traditionally result in unserved energy in the Valley South System. The flow chart in Figure 3-9 presents the overall process. The analysis is initiated taking into consideration the peak loading day (24-hour duration) for a year and applying the N-2 contingencies at each hour. Whenever an overload or voltage violation was observed, the binding constraint is used to determine the MWh load at risk, and to calculate the weighted amount using the associated contingency probabilities. The contingency probabilities were derived from a review of the historic outage data in the Valley South system. The results for the peak day were compared against the baseline system and utilized as the common denominator to scale other days of the year for aggregation into the flexibility metric. During the course of the analysis, it was observed that the system is vulnerable to N-2 events at load levels greater than 900 MW. This also corresponds to the Valley South operating limit wherein the spare transformer is switched into service to maintain transformer N-1 security. Thus, for purposes of scaling, only days with peak load greater than 900 MW were selected where there is a potential for EENS to accumulate in the system. When the project under evaluation has tie-lines, they are considered to minimize system impacts.

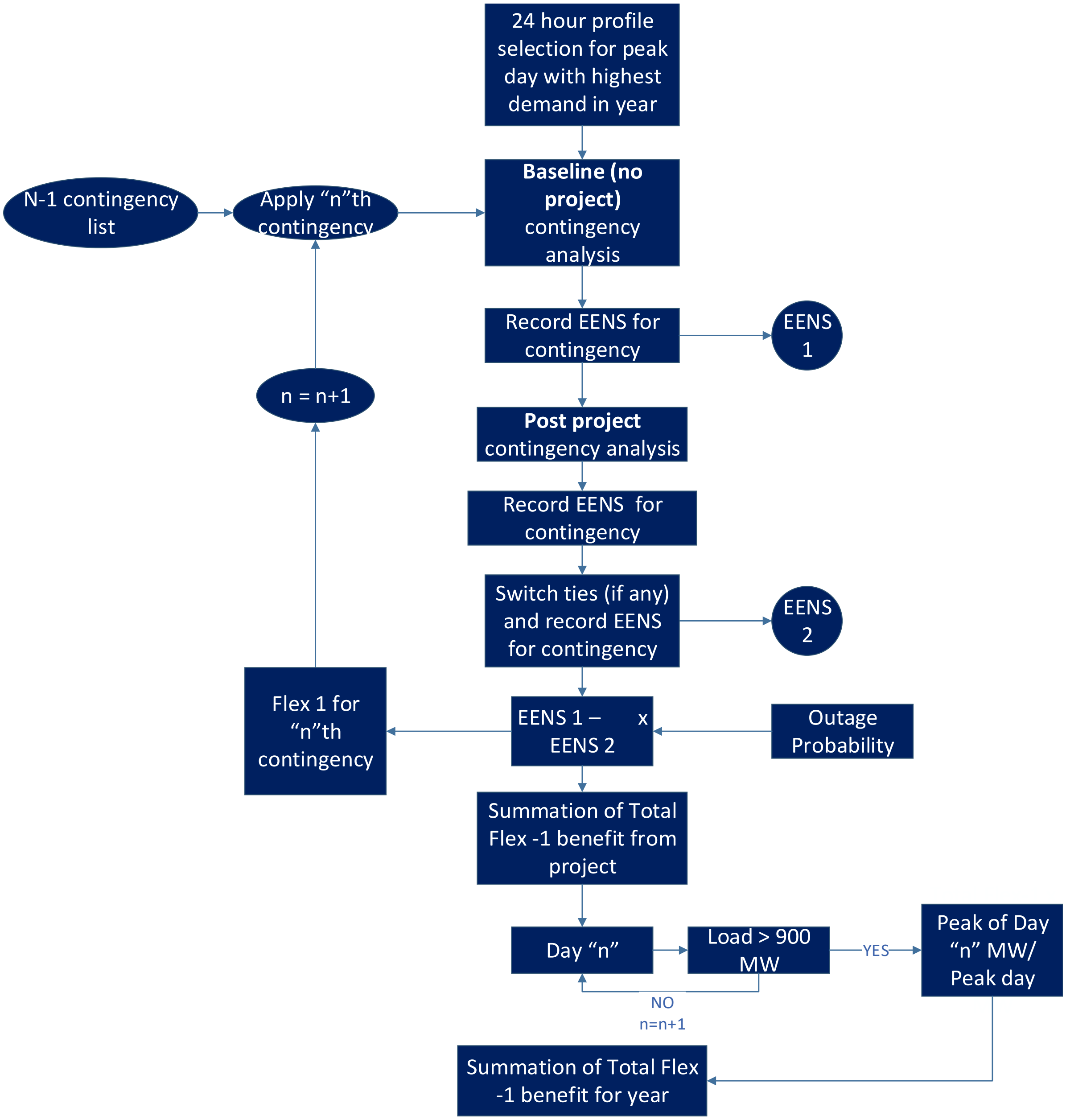


Figure 3-9 Flowchart of Flex-1 Calculation Process

Flexibility Metric 2 evaluates the project performance under HILP events in the Valley South System. This has been broken down into two components that consider different events impacting the Valley South service area. Both components utilize a combination of power flow and load profile analysis to determine the amount of load at risk.

- Flexibility Metric 2-1 evaluates the impact of the entire Valley Substation out of service, wherein all electric load served by Valley Substation is at risk. Considering a two-week event (assumed minimum substation outage duration to fully recover from an event of this magnitude) around the peak loading day in the system, the amount of load at risk is determined. A threshold is established using power-flow simulations to evaluate the maximum load that can be transferred by projects with system tie-lines. The threshold is compared against the load profile of the two-week period to estimate the amount of load that can be recovered.

- Flexibility Metric 2-2 evaluates a condition wherein the Valley South service area is served by a single transformer; i.e., the second transformer is out of service with no spare available. Utilizing the 8,760 load shape and the transformer Short-Term Emergency Loading Limits (STELL) and Long-Term Emergency Loading Limits (LTELL), the amount of MWh load at risk is estimated and aggregated for the study year. The threshold is applied as a maximum limit for load that can transferred with system tie-lines. The analysis accounts for the incremental relief offered by alternatives with permanent and temporary load transfer using system tie-lines.

3.2.4 Reliability Metrics

Prior to introducing reliability metrics, key elements of the overall project objectives must be outlined to provide direction and to guide further analysis. The following key concepts are revisited using applicable NERC guidelines and standards for Bulk Electric System (BES).

- Reliability has been measured with reference to equipment rating (thermal overload) and voltage magnitude (low voltages).
- Capacity represents the need to have adequate resources to ensure that the demand for electricity can be met without service outages. Capacity is evaluated under normal and emergency system conditions, and normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address emergency, maintenance, and planned outage conditions. Therefore, it is expected to operate the system radially and to accommodate flexibility by employing normally open system tie-lines.
- Resiliency has been viewed as an extension of the Flexibility benefits, wherein system tie-lines are leveraged to recover load under High Impact Low Probability events.

Building on the overall project objectives, the following reliability metrics have been established to address reliability, capacity, flexibility, and resiliency needs of the system.

- **Expected Energy Not Served (EENS)**
  a. This is quantified by the amount of MWh at risk from each of the following elements:
     i. For each thermal overload, the MW amount to be curtailed to reduce loading below equipment ratings multiplied by the number of hours of overload. This includes both transformers and power lines serving the Valley South System.
     ii. For voltage violations, the MW amount of load to be dropped based on voltage sensitivity of the bus to bring voltage to within established operating limits. The sensitivity study established ranges of load drop associated with varying levels of post contingency voltage. For deviations in bus voltage from 0.95 per unit limit, the amount of load drop to avoid the violation was determined and multiplied by the number of hours of violations.
  b. EENS was computed for N-0 and N-1 events. The focus of analysis is on the Valley South System. However, under N-0 condition EENS recorded on the Valley North System was also accumulated during the simulation.

   c. For N-1 events, system tie-lines are used where applicable to minimize the amount of MWh at risk.

- **Maximum Interrupted Power (IP)**
   a. This is quantified as the maximum amount of load in MW dropped to address thermal overloads and voltage violations. In other words, it is representative of the peak MW overload observed among all overloaded elements.
   b. IP was computed for N-0 events and N-1 events.

- **Valley South System SAIDI metrics** – A rough proxy approach to estimate the SAIDI metrics have been considered. These are reported for reference purposes only[13]. For each Valley South System distribution substation, the total MWh is uniformly distributed by the customer count. Using this principle, the amount of interrupted power is associated with proportional loss of customer count. These metrics are calculated at each substation and then aggregated to the system level.
   a. Sum of total customers interrupted per outage multiplied by the number of outage hours divided by the total number of customers served.

- **Valley South System SAIFI metrics** – Similar to the approach used to calculate SAIDI metrics, these metrics are calculated at each substation and then aggregated to the system level. These are reported for reference purposes only.
   - Sum of total customers interrupted due to outage/ total number of customers served.

- **Valley South level CAIDI**
   a. Calculated as SAIDI/SAIFI.

- **Losses** – Losses (MWh) are treated as the active power losses in the Valley South System. New transmission lines, introduced by the scope of a project, have also been included in the loss computation.

- **Availability of Flexibility in the system** – Measure of the availability of flexible resources (system tie-lines, switching schemes) to serve customer demand. It provides a proxy basis for the amount of flexibility (MWh) that an alternative project provides during maintenance operations, emergency events, and other operational issues. Two flexibility metrics are considered:
   a. Flexibility Metric 1: Capability to recover load during maintenance and outage conditions.
      i. Calculated as the amount of energy not served for N-2 events. Measure of capability of the project to provide flexibility to avoid certain overloads and violations observable under traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served using flexibility attributes of the project.
      ii. Probabilities associated with the combined outage of two transmission lines have been used to account for the MWh energy not served. The probabilities are presented in Table 3-3.

[13] Distribution reliability indices including SAIDI and SAIFI are traditionally calculated using historical outage information. However, in this context they are calculated using simulated outages and thus the results are mainly presented for information only.

b. Flexibility Metric 2: Recover load for emergency condition: Single point of failure Valley South substation and transformer banks.
   i. Flex-2-1: Calculated as the energy unserved when the system is impacted by high-impact, low probability event such as loss of the entire Valley Substation. Projects that establish system tie-lines or connections to an adjacent network can support the recovery of load during these events. This metric is calculated over a two-week period (average restoration duration for events of this magnitude) around the summer peak condition in the Valley System. Probabilities associated with an event of this magnitude have been selected as 0.01, signifying a 1-in-100 year event, adopted from NERC treatment of events of similar magnitude[14].

      Flex-2-2: Calculated as the amount of MWh load at risk when the system is operating with a single transformer at Valley Substation (second transformer out of service and the spare transformer is unavailable). Projects that establish system tie-lines to adjacent networks can support the recovery of load during these events. Probabilities associated with this event have been adopted from NERC TADS[15] data for transformer outages on the 500/115 kV system and treated as a 1-in-60 year event (0.0169), occurring once during the average lifetime of the asset.

- **Period of Flexibility Deficit** – The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) were insufficient and resulted in energy not-being served for a given time horizon.

The above list has been iteratively developed to successfully translate project objectives into quantifiable metrics and provides a basis for project performance evaluation.

3.3 Benefit-Cost Framework and Study Assumptions

Each of the projects have been evaluated using a Benefit-Cost framework that derives the value of project performance (and benefits) using a combination of methods. This framework provides an additional basis for comparison of project performance while justifying the business case of each alternative to meet the load growth and reliability needs of the Valley South System.

Benefit-Cost analysis is a commonly used tool in public policy discussion and decisions. Benefit is defined as a value of the impact of a project to a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like EENS, SAIDI, and SAIFI among other considerations. Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a Net Present Worth using a discount rate, and an inflation rate, over the project lifetime or horizon of interest.

The overall process associated with the detailed alternatives analysis framework has been presented in Figure 3-10.

[14] https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_Research_Work_Plan_Apr_17_2018.pdf

[15] https://www.nerc.com/pa/RAPA/tads/Pages/ElementInventory.aspx

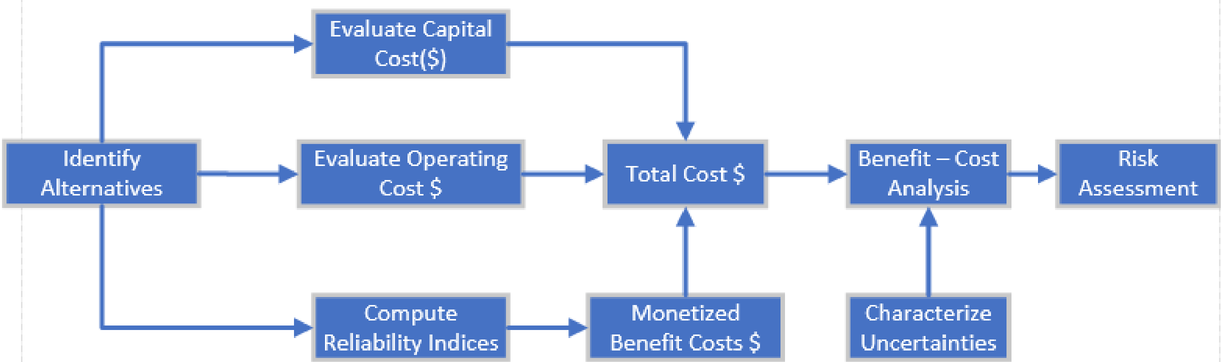


Figure 3-10 Benefit-Cost analysis framework

The project costs have been developed by SCE as the Present Value of Revenue Requirements (PVRR) over the lifetime of the asset to include the rate of return on investment, initial capital investments, Operations & Maintenance (O&M) and equipment specific costs. These are reflective of the direct costs used in the analysis. Due to the differences in equipment life of the projects under consideration, the present worth of costs has been utilized over the period of study horizon. The PVRR costs are offset for incremental revenues generated by battery energy storage system (BESS) assets through market participation. Table 3-2 presents the financial assumptions considered in this analysis. Further details pertinent to each of the assumptions are elaborated in upcoming sections of this report.

In the scope of this assessment, the benefits for considered metrics (3.2.4) are derived by a comparison of system performance with and without project in service. Depending on the benefit category, a distinction is made between monetized and non-monetized benefits. The benefits in combination with costs PVRR have been used at different capacities to develop a comprehensive view of project performance. This evaluation framework includes traditional benefit-cost comparison of alternatives to characterize the risks associated with load sensitivities.

Table 3-2 Financial and Operating Costs

Parameters	Value	Source
Discount Rate (Weighted Aggregate Cost of Capital: WACC)	10%	SCE
Customer price (Locational Marginal Price)	40 $/MWh	CAISO
Inflation Rate (Price Escalation)	2.5%	Quanta
Load distribution: Residential	90%	SCE
Load distribution: Commercial	10%	SCE
Annual Outage rate for Flexibility-2-2 events	0.0169	NERC
Annual Outage rate for High Impact Low Probability Event (Flexibility-2-1 events)	0.01	NERC

The non-monetized benefits have been presented in two different formats. From the perspective of Reliability Analysis (Chapters 4 & 5), they are described as the sum or cumulative of the benefits of the project over the project study horizon. In the Cost Benefit Framework (Chapter 6), the non-monetized benefits are calculated as the present worth of benefits discounted at the weighted aggregate cost of capital (WACC) over the period of study horizon. An example of the latter, EENS benefits of the ASP under normal system condition (N-0) and their present worth using discount rate of WACC are presented in Figure 3-11.

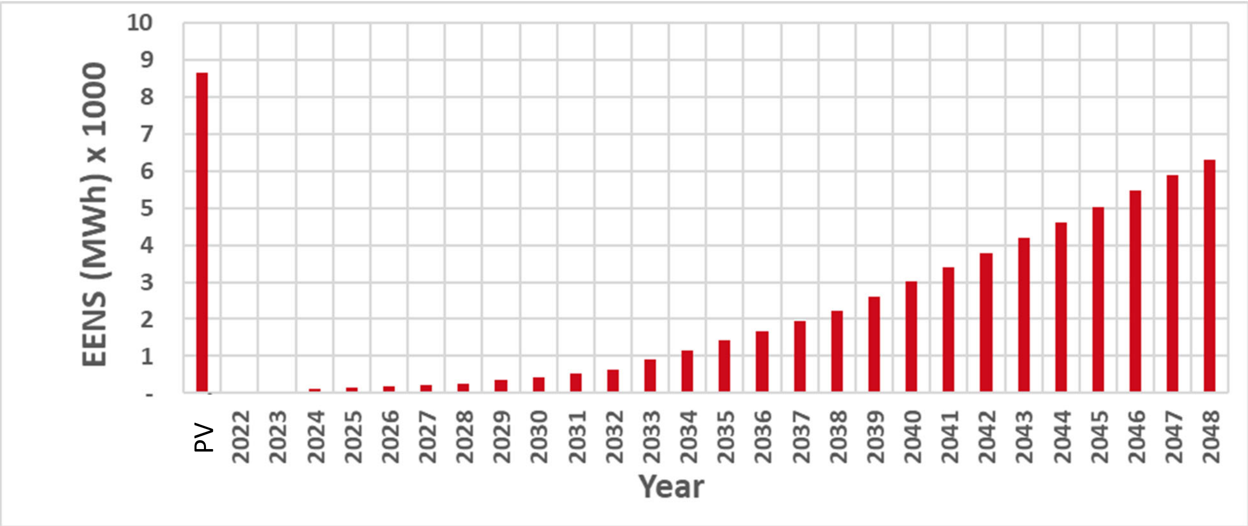


Figure 3-11 EENS (N-0) benefits accumulated for ASP over the study horizon

EENS (N-0, N-1), and flexibility indices (Flex-1, Flex-2-1 and Flex-2-2) were monetized using the $/kWh for unserved energy (load) from the customer perspective as provided by SCE[16]. These costs are separated into residential and commercial in $/kWh. Figure 3-12 below presents the costs over a 24-hour duration as applied to this assessment.

[16] SCE Value of Service Study, 2018.

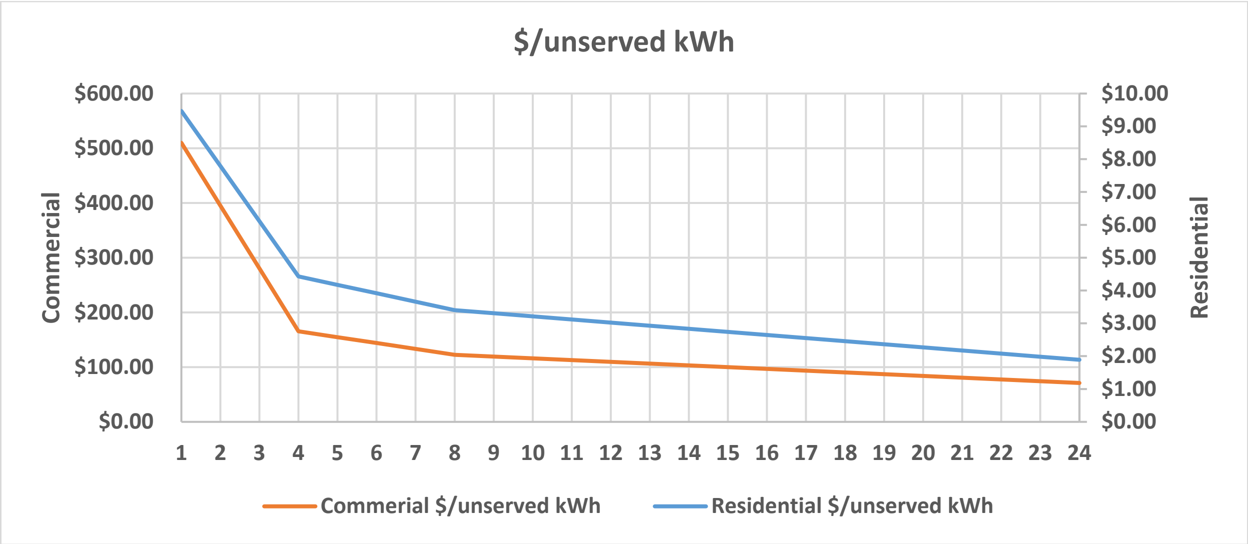


Figure 3-12 Value of Unserved kWh

The formulation below describes the monetized benefits, and are complemented by the assumptions detailed in Table 3-2

- Expected Energy Not Served (EENS) under N-0 conditions:
  - EENS (MWh) for the year multiplied by the Cost of lost load ($/MWh) associated with duration of overload,
  - Costs derived based on duration of continuous overload from Figure 3-12.

- Expected Energy Not Served (EENS) under N-1 conditions:
  - EENS (MWh) for the year multiplied by the Cost for lost load ($/MWh) associated with average outage duration multiplied by the Outage probability,
  - 4-hour average outage duration was determined from analysis of historic outage event data in Valley South. Costs associated with this duration have been utilized from Figure 3-12,
  - Probabilities of circuit outages have been derived from historic event data in Valley South. The outage probabilities associated with N-1 circuits are presented in Table 3-3. For new lines in the project, probabilities associated with circuits of comparable length have been utilized.

Table 3-3 N-1-line outage probabilities in Valley South

Line name	Line outage Probability index
Auld-Moraga #1 and #2	0.050978418
Auld-Sun City	0.029792582
Elsinore-Skylark	0.038329638
Fogarty-Ivyglen	0.022758222
Moraga-Pechanga	0.031558068
Moraga-Stadler-Stent	0.050418216
Pauba-Pechanga	0.021081301

Line name	Line outage Probability index
Pauba-Triton	0.043695787
Skylark-Tenaja	0.011498891
Stadler-Tenaja	0.026009397
Valley-Auld #1 and #2	0.095584534
Valley-Elsinore-Fogarty	0.241237156
Valley-Newcomb	0.038688978
Valley-Newcomb-Skylark	0.102813616
Valley-Sun City	0.019861721
Valley-Auld-Triton	0.029130525

- Flexibility-1 Metric
  - EENS (MWh) for the year multiplied by the Cost for lost load ($/MWh) associated with average outage duration multiplied by the Outage probability,
  - Costs associated with 5-hour average outage duration were utilized from Figure 3-12. The 5-hour duration was derived from analysis of the average number of hours that the system is operating above 900 MW threshold,
  - Probabilities of circuit outages were derived from historic event data in Valley South. The product of outage probabilities associated the combination of individual circuits in the N-2 outage definition have been utilized.

- Flexibility-2-1 Metric
  - EENS (MWh) over two-week duration multiplied by the Cost of lost load ($/MWh) associated with assumed a two-week outage duration multiplied by the Outage Probability,
  - The outage duration for this event is considered to be two weeks, reflective of the minimum restoration duration for an event of this magnitude. The cost has been derived as the average cost of lost load over 24-hour duration from Figure 3-12,
  - Probabilities associated with an event of this magnitude have been adopted as 0.01, signifying a 1-in-100 year event, adopted from NERC treatment of events of similar magnitude[17].

- Flexibility-2-2 Metric
  - EENS (MWh) for the year multiplied by the Cost of lost load ($/MWh) associated with duration of overload multiplied by the Outage Probability,
  - Costs derived from duration of continuous overload from Figure 3-12,
  - Probabilities associated with this event have been adopted from NERC TADS data for transformer outages on the 500/115 kV system and treated as a 1-in-60 year event (0.0169[18]), occurring once during the average lifetime of the asset.

[17] https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_Research_Work_Plan_Apr_17_2018.pdf

[18] https://www.nerc.com/pa/RAPA/tads/Pages/ElementInventory.aspx

- Losses
  - Losses (MWh) for the year multiplied by the Average LMP at Valley 500 kV bus
  - The average LMPs are obtained from production simulation of the CAISO model for year 2021 and 2022.
  - The loss reduction is treated as a benefit and aggregated to the monetized EENS and Flex benefits.

3.3.1 Benefit-Cost Methodology

As described in earlier sections of this report, all costs and benefits have been evaluated over the study horizon from in-service year[19] to 2048 which cover the 30-year horizon. The benefits associated with each project have been calculated as the present worth of each benefit category.

Following the quantification of present worth of costs and benefits, three different types of analysis have been considered to select the most suitable project among pool of alternatives. The proposed methodologies utilize the benefits in their non-monetized and monetized representation.

3.3.1.1 Benefit Cost Analysis

The Benefit-Cost analysis is the most straight forward and commonly used metric for project comparison. However, it requires both benefits and costs to be treated on a common unit basis ($). Due to this, only monetized benefits are considered for this assessment. With the monetized benefits, a ratio is derived of the cost of the project to aggregate benefits introduced by the project.

The relevant benefit categories are monetized consistent with the discussion in Section 3.3.1. The benefits are derived as differences in monetized costs with and without project in service, which directly translates into cost savings from the Customers' perspective. For example, without a project in service, customers in the Valley South System are vulnerable to 50 MWh of EENS in the year 2026 under normal system condition (N-0), which translates into $6.6M cost to customers. However, with a project such as ASP in service, the 50 MW of EENS is completely eliminated, and $6.6M cost to customers will be avoided.

3.3.1.2 Levelized Cost Analysis

This evaluation is most suited for non-monetized metrics and their benefit evaluation. For each of the projects under consideration:

- The benefits have been quantified using the difference between project and baseline scenario.
- The benefits of each category from N-0 and N-1 are normalized as the ratio of $/Unit benefit using their present worth over the horizon using WACC discount rate.
- This index primarily provides insight into the investment value ($) from each project to achieve a unit of benefit improvement from baseline.

For example, the Present worth of the ASP project cost is $545M, and the present worth of N-0 EENS benefit from the ASP (in comparison to baseline) is 8,657 MWh. The ratio of $545M/8,657 MWh suggests that this project would require an investment of $62,954 to achieve 1 MWh of N-0 EENS benefit.

[19] 2022 or 2021, depending on need year from forecast under study

3.3.1.3 Incremental Benefit-Cost Analysis

Incremental benefit cost analysis is commonly used to rank and value the overall benefits attributed to an alternative project, while providing an advantage to the most cost-effective solution that provides maximum benefit. The procedure is outlined as follows.

Considering that the proposed project solutions are mutually exclusive alternatives (MEA), the MEAs are ranked based on their cost in an increasing order. The do-nothing or least cost MEA is selected as baseline. The incremental benefit-cost ratio $\left(\frac{\Delta B}{\Delta C}\right)$ for the next expensive alternative is evaluated. Provided that the ratio is equal or above unity, this alternative will be selected, and replaces the baseline to evaluate the next expensive MEA. For ratio below unity, the last baseline alternative is maintained. The incremental benefit-cost analysis will continue and iterate between the baseline and next alternative. The selection will stop once the incremental benefit-cost ratio becomes unfavorable or the list is exhausted. The flowchart in Figure 3-13 provides an overview of the overall process.

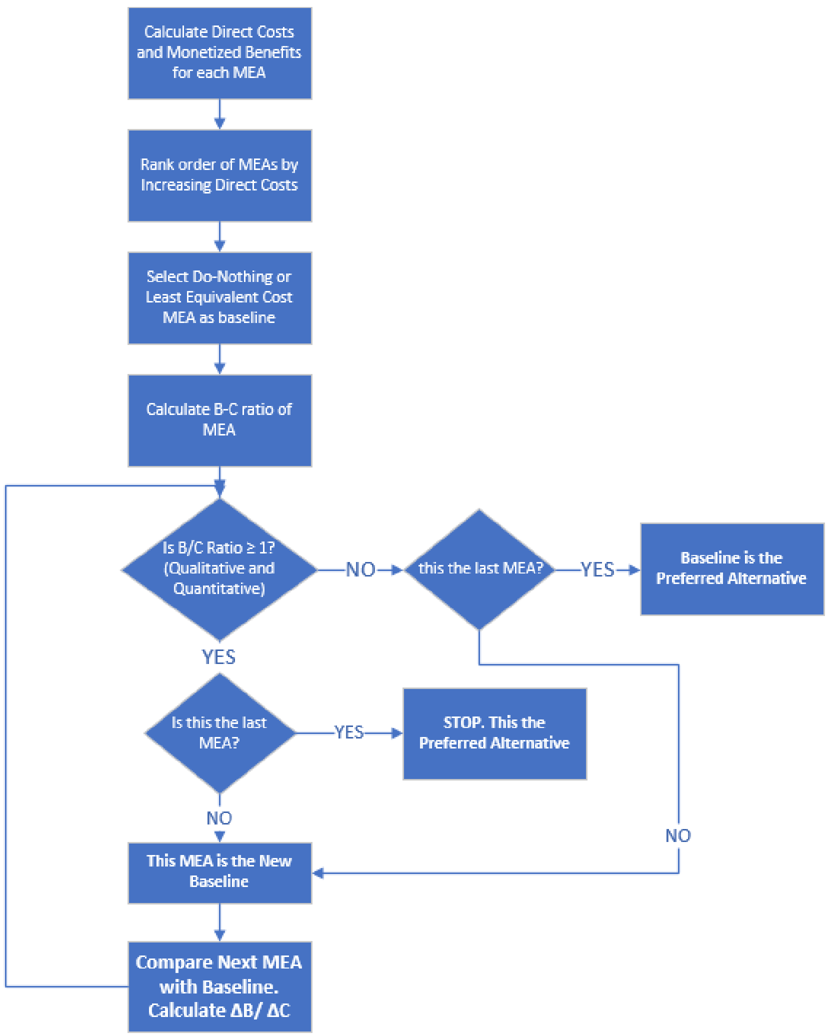


Figure 3-13 Incremental benefit cost analysis flowchart.

3.3.2 BESS Revenue Stacking

Revenue stacking describes a situation where the battery energy storage system (BESS) is used for more than one domain of applications. When wholesale market and Transmission & Distribution (T&D) applications are allowed to be performed by the same BESS, the BESS accesses and participates in wholesale markets in addition to its primary function (T&D applications). T&D applications always take priority over wholesale market participation. This means, the function of the BESS always first ensures reliable operation of the T&D system as needed before consideration for market participation. Needed capacity and required dispatch levels must be considered as constraints to market participation.

In the Valley South planning area, batteries primarily provide local reliability, capacity, and flexibility benefits by supporting N-0, N-1 and N-2 needs in the system (primary application). To leverage the benefits from BESS-based solutions in each of these categories, the available capacity is reserved during summer months (peak demand period) from June to October (i.e., the BESS is only allowed to participate in the wholesale market outside the summer operating period).

During the period of the year when the BESS is not required for the primary application, it can time-shift the energy by participating in wholesale energy markets (i.e., market participation). This service results in ratepayer savings when the asset is assumed to be utility owned with all energy cost savings passed on to ratepayers. “Shared application” or “hybrid application” is also investigated. This means that the storage is also used for ancillary services provision.

For applicable solutions that include BESS (Non-wire alternatives or Hybrid), additional potential benefits of BESS participating in CAISO wholesale and ancillary service (AS) markets are determined. The optimization uses the Day-Ahead (DA) prices for charging and discharging, to simulate the strategy in which charging load and discharging is offered into DA market. For this purpose, 2018-2019 DA for the node at the Valley South System is used. Energy storage also offers Regulation Up (RegUp) and Regulation Down (RegDown) services into the CAISO ancillary service markets. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints.

An Energy Credit is calculated under each scenario using the discharging revenues less the charging payments when only wholesale energy participation is considered. These energy credits in the wholesale and regulation cases also include an estimate of the settlement of regulation revenues at AS clearing prices. Generally, energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage. Table 3-4 summarizes data inputs that have been utilized for market analysis. This includes data name, data type, and duration of the extracted data (applicable for time-series data).

Table 3-4 Data Inputs for Market Analysis

Input Name	Input Data Type (Source)	Value
Hourly Load Data (MW)	Time-series (SCE)	Data provided for 01/01/2016 – 01/01/2017
Load Threshold (MW)	Parameter (SCE)	1120 MW
Battery VO&M Cost ($/kWh)	Parameter (QT)	0.005 $/kWh
Battery min/max Allowable State of Charge (SOC)	Parameter (QT)	Min/Max: 5/100%
Start/ End of Day SOC	Parameter (QT)	50%
BESS Charging Efficiency	Parameter (QT)	92%
Wholesale Day-ahead LMP Data ($/kWh)	Time-series (ISO)	Data extracted for 01/01/2018 – 01/01/2019
BESS Discharging Efficiency	Parameter (QT)	98%
Regulation Up and Down Clearing Market Prices ($/kW)	Time-series (ISO)	Data extracted for 01/01/18 – 01/01/2019
LMP Price Escalation/yr	Time-series (QT)	2.5%

This evaluation was carried out using a proprietary optimization tool developed by Quanta Technology for evaluating storage projects economics. This tool methodology and mathematical formulation are developed for solution as a Mixed Integer Programming (MIP) problem. The co-optimization of storage resource participation in energy and ancillary service markets is similar to that performed by the CAISO in its market clearing. The tool computes the optimal allocation of BESS capacity to the different markets each hour, while observing constraints imposed by the BESS characteristics and capabilities. This is done for the 8,760 hours of the year and the total revenues computed.

For the storage sizes established under each project, a bidding strategy of offering both charging and discharging into the DA markets was evaluated. As an additional step, the strategy of also offering RegUp and RegDown services into the CAISO ancillary service markets was evaluated. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. The prices were escalated at 2.5%/yr. to cover the horizon until 2048. Annual market benefits are calculated as a summation of energy, Regulation Up and Regulation Down Capacity less the variable O&M (VOM). Note: VOM of $0.00579/kWh is considered for both charging and discharging of the battery. A low-order VOM cost is assumed to account for external costs including bidding, scheduling, metering, and settlement. Figure 3-14 exhibits a sample from the optimized BESS schedule over 24-hour duration.

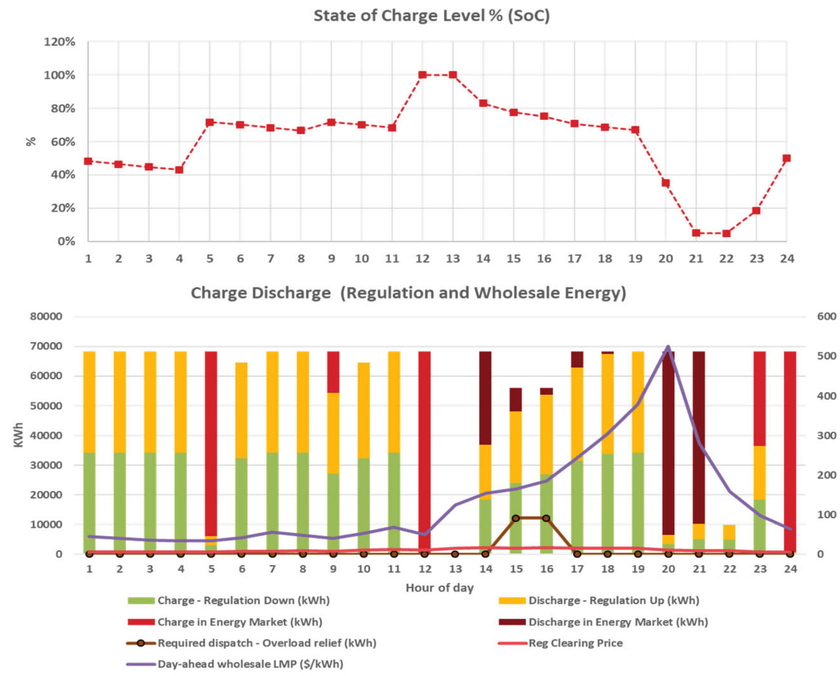


Figure 3-14 Daily Scheduling Example

3.3.3 Risk Assessment

Load forecast uncertainty has been treated in the risk assessment. The range of load variability associated with the three main forecasts considered in this study are presented in Figure 3-15 and Table 3-5.

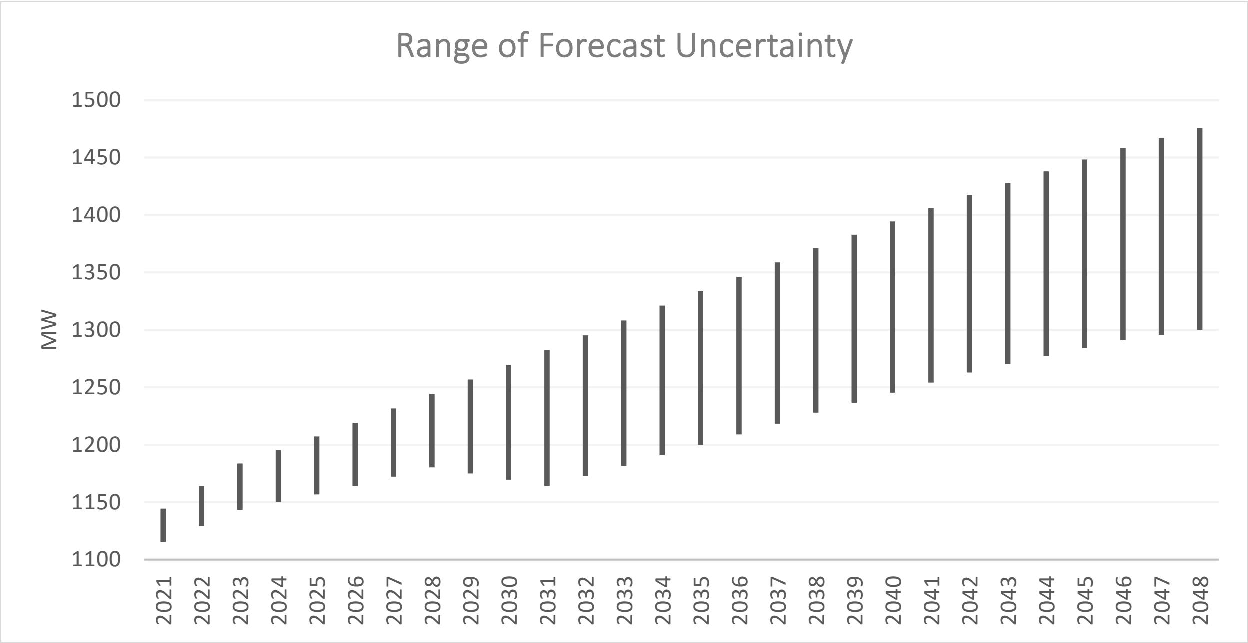


Figure 3-15 Load forecast range.

Table 3-5 Statistics Associated with Load Forecast

MW	Low	High
2023	1145	1181
2028	1182	1241
2038	1230	1368
2048	1302	1473

Considering the spectrum of the alternative projects under analysis, a deterministic risk analysis has been performed. The deterministic risk analysis provides insight into the capabilities of alternatives to meet the incremental demands of the system in the future, and characterizes the risks associated with load sensitivities. Within the scope of the deterministic risk analysis, the performance of project alternative is investigated under various forecast trends and compared using Benefit-Cost metrics.

4 RELIABILITY ASSESSMENT OF ALBERHILL SYSTEM PROJECT

4.1 Introduction

The objective of the analysis in this chapter is to apply the reliability assessment framework on the ASP. The performance and benefits of the ASP are computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The performance of the baseline system is initially presented, followed by the ASP for all considered load forecasts (PVWatts, Effective PV, and Spatial Base).

In order to successfully evaluate the benefits of potential projects in the Valley South System, the performance of each project must be effectively translated into quantitative metrics. These metrics serve the following purposes:

1. To provide a refined view of the future evolution of the Valley South System reliability performance,
2. To compare project performance to baseline scenario (no project in service),
3. To establish a basis to value the performance of the ASP against overall project objectives,
4. To take into consideration benefits or impacts of flexibility and resiliency (high-impact, low-probability events), and
5. To provide guidance for comparing projects against alternatives.

Within the framework of this analysis, reliability, capacity, flexibility, and resiliency benefits have been quantified.

4.2 Reliability Analysis of the Baseline System

The baseline system is the no-project scenario within this analysis. It depicts a condition wherein the load grows to levels established by the forecast under study, without any project in service to address the shortfalls in transformer capacity. This scenario forms the primary basis for comparison against alternatives performance to evaluate the benefits associated with the project.

The baseline system has been evaluated under need year[20], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

[20] 2022 and 2021, depending on need year from forecast under study

4.2.1 System Performance under Normal Conditions (N-0)

Findings from system analysis under N-0 conditions in the system are presented in Table 4-1 for the Effective PV Forecast, Table 4-2 for the Spatial Base Forecast, and Table 4-3 for the PVWatts Forecast.

Table 4-1 Baseline N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	22	13	0	0	2	2	49,667
2028	250	65	2	0	7	7	52,288
2033	905	120	23	1	18	23	54,472
2038	2,212	190	87	2	37	37	56,656
2043	4,184	246	236	4	53	53	58,840
2048	6,310	288	517	7	77	77	61,024

Table 4-2 Baseline N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	50	22	0	0	4	4	50,082
2022	129	42	1	0	5	5	50,888
2028	908	131	18	1	19	19	54,467
2033	2,844	205	145	3	42	48	57,450
2038	5,741	280	422	6	69	69	60,432
2043	9,888	348	1,073	11	102	102	63,415
2048	14,522	411	2,195	15	142	142	66,397

Table 4-3 Baseline N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	22	13	0	0	2	2	49,667
2028	250	65	2	0	7	7	52,288
2033	292	67	3	0	8	10	52,859
2038	740	117	11	1	14	14	54,310
2043	1,504	155	13	0	26	28	55,761
2048	2,659	199	102	3	37	37	57,211

4.2.2 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions in the system are presented in Table 4-4 for the Effective PV Forecast, Table 4-5 for the Spatial Base Forecast, and Table 4-6 for the PVWatts Forecast.

Table 4-4 Baseline N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	10	2	0.08	0.01	14	5,446	192,865	57,814	14
2028	67	11	0.73	0.05	32	16,219	201,538	74,821	13
2033	249	21	6.12	0.21	54	25,196	210,603	94,913	29
2038	679	35	24.37	0.59	88	34,173	220,085	118,576	41
2043	1,596	45	93.41	1.41	120	43,151	228,568	141,697	66
2048	2,823	68	253.88	2.53	153	52,128	234,771	159,823	100

Table 4-5 Baseline N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	18	4	0.20	0.01	18	6,327	194,613	61,014	15
2022	40	6	0.46	0.03	28	9,591	197,970	67,510	15
2028	231	23	4.51	0.19	60	29,172	211,637	97,361	24
2033	989	40	54.14	0.87	98	45,489	222,543	125,103	62
2038	2,435	62	197.46	2.18	147	61,807	233,279	155,356	91
2043	5,263	71	738.14	4.78	204	78,125	242,925	185,398	154
2048	9,236	128	1,934.23	8.45	261	94,442	251,122	212,823	229

Table 4-6 Baseline N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	10	2	0.08	0.01	14	5,446	192,865	57,814	14
2028	67	11	0.73	0.05	32	16,219	201,538	74,821	13
2033	75	11	0.97	0.06	33	16,913	201,766	75,302	16
2038	182	20	2.98	0.15	51	21,504	209,643	92,677	20
2043	454	29	93.41	1.41	79	26,095	216,849	110,238	66
2048	805	35	31.66	0.71	94	30,685	221,946	123,501	45

In the baseline system analysis, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).
In Table 4-7 only thermal violations associated with each constraint are reported.

Table 4-7 List of Baseline System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG -Newcomb-Skylark	2033	2043	
Tap 39-Elsinore	N-1	Valley EFG -Newcomb-Skylark	2028	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2048	
Valley EFG-Sun City	N-1	Skylark-Tenaja	2048		
Moraga-Tap 150	N-1	Skylark-Tenaja	2048		
Skylark-Tap 22	N-1	Valley EFG -Elsinore-Fogarty	2028	2033	2038
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2038	2043	
Valley EFG-Auld #2	N-1	Valley EFG -Auld #1	2048		
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2038	2048	
Valley EFG-Auld #2	N-1	Valley EFG -Sun City	2043		
Valley EFG-Tap 22	N-1	Valley EFG -Newcomb	2038	2043	
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2038	2048	
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	
Valley EFG-Tap 39	N-1	Valley EFG -Ivyglen	2048	-	
Auld-Moraga #1	N-1	Valley EFG-Triton	2032	2043	2048
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2038	2043
Valley EFG-Auld #1	N-1	Valley EFG-Triton	2048		
Valley EFG-Sun City	N-1	Valley EFG-Triton	2043		

4.2.3 Key Highlights of System Performance

The key highlights of system performance for baseline system are as follows:

1. Without any project in service, the Valley South System transformers projected to overload in the year 2022. Sensitivity scenario using Spatial Base forecast demonstrates a need year by 2021.
2. In the Effective PV forecast by year 2028, 250 MWh of EENS is observable in the system under N-0 conditions. This extends to 6,309 MWh by 2048 with no project in service. Through the range of

forecast sensitivities, the potential load at risk ranges from 2,600 MWh to 14,500 MWh in 30-year horizon

3. In the Effective PV forecast between 2028 and 2048, the flexibility deficit in the system increases from 7 hours to 77 hours under N-0 condition. Considering the range of forecast uncertainties, the number of hours of deficit in the system under N-0 range from 37 hours to 147 hours in year 2048.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasing challenging to maintain system N-1 security.
5. In the Effective PV forecast by year 2028, 67 MWh of EENS is observable in the system under N-1 conditions. This extends to 2,800 MWh by 2048 with no project in service. Through the range of forecast sensitivities, the potential load at risk ranges from 805 MWh to 9,200 MWh in 30-year horizon.

4.3 Reliability Analysis of the Alberhill System Project (Project A)

The Alberhill System Project has been evaluated under need year[21], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

4.3.1 Description of Project Solution

The Alberhill System Project would be constructed in Riverside County and includes the following components:

1. Construction of a new 1,120 MVA 500/115 kV substation to increase the electrical service capacity to the area presently served by the Valley South 115 kV system. Two transformers installed, one of which is a spare.
2. Construction of two new 500 kV transmission line segments to connect the new substation to SCE's existing Serrano-Valley 500 kV transmission line.
3. Construction of new 115 kV subtransmission lines and modifications to existing 115 kV subtransmission lines to transfer five existing 115/12 kV distribution substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb) presently served by the Valley South 115 kV System to the Alberhill 115 kV System.
4. Installation of telecommunications improvements to connect the new facilities to SCE's telecommunications network.

Figure 4-1 presents an overview of the project layout and schematic.

[21] 2022 and 2021, depending on need year from forecast under study

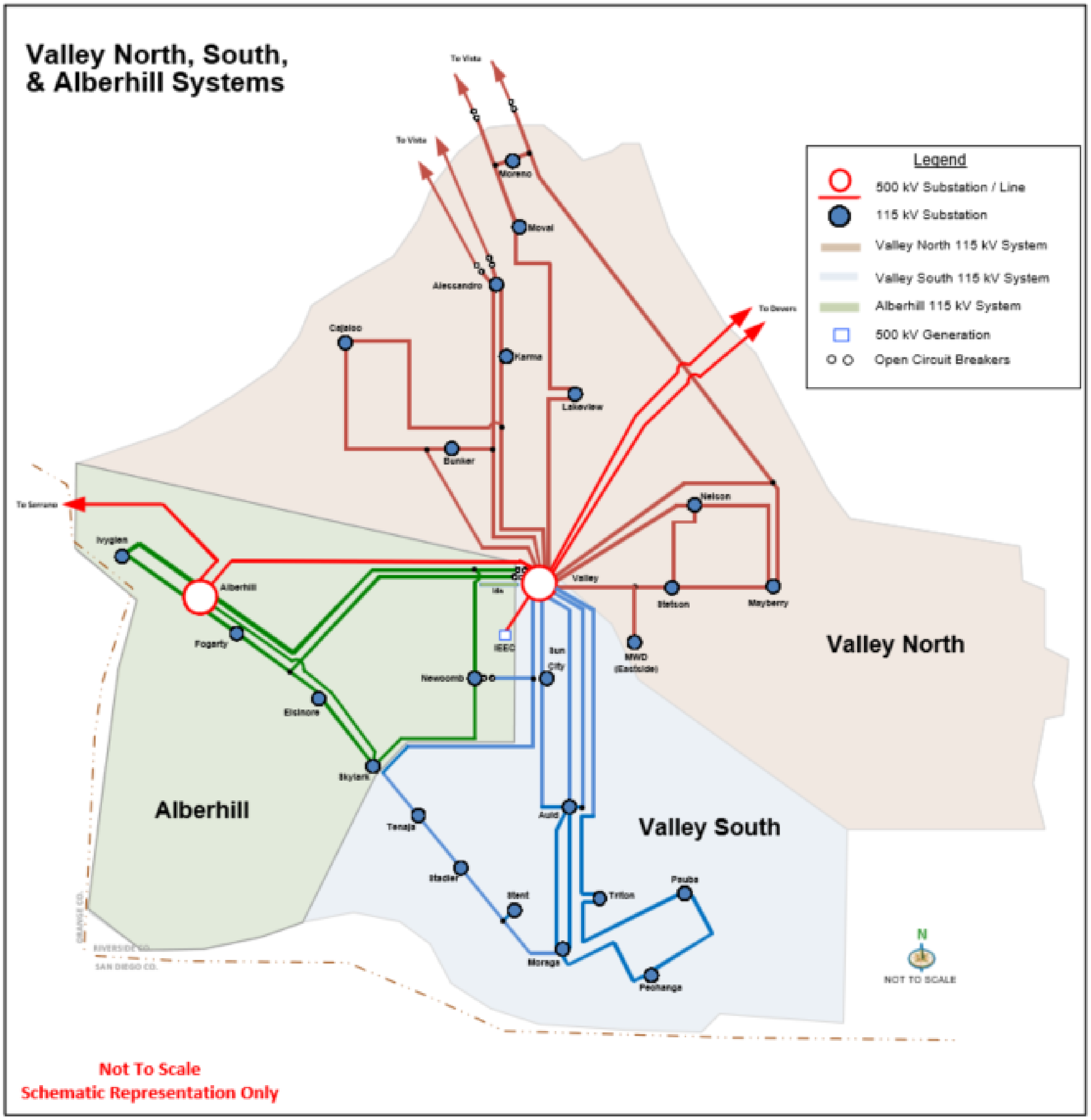


Figure 4-1 Alberhill System Project and Resulting Valley North and South Systems.

4.3.2 System Performance under Normal Conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 4-8 for the Effective PV Forecast, Table 4-9 for the Spatial Base Forecast and Table 4-10 for the PVWatts Forecast.

Table 4-8 Alberhill N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	40,621
2028	0	0	0	0	0	0	42,671
2033	0	0	0	0	0	0	44,380
2038	0	0	0	0	0	0	46,089
2043	0	0	0	0	0	0	47,797
2048	3	1.9	0.021	0.010	2	2	49,506

Table 4-9 Alberhill N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	40,954.00
2022	0	0	0	0	0	0	41,590.29
2028	0	0	0	0	0	0	43,417.04
2033	0	0	0	0	0	0	44,939.32
2038	1	1	0.004	0.002	1	0	46,461.61
2043	28	8	0.582	0.097	6	0	47,983.89
2048	93	14	5.141	0.321	10	16	49,506.18

Table 4-10 Alberhill N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	40,621
2028	0	0	0	0	0	0	42,671
2033	0	0	0	0	0	0	42,310
2038	0	0	0	0	0	0	43,725
2043	0	0	0	0	0	0	45,140
2048	0	0	0	0	0	0	46,555

4.3.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 4-11 for the Effective PV Forecast, Table 4-12 for the Spatial Base Forecast and Table 4-13 for the PVWatts Forecast.

Table 4-11 Alberhill N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2038	21	8	0.21	0.05	4	0	14,803	0	4
2043	84	17	2.34	0.21	8	0	17,351	44	11
2048	202	24	9.06	0.51	14	0	19,302	138	18

Table 4-12 Alberhill N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2033	33	11	0.42	0.08	5	0	15,530	0	5
2038	163	22	6.30	0.41	12	0	18,826	109	15
2043	530	34	45.27	1.35	6	0	22,009	353	34
2048	1,080	43	152.00	2.69	43	0	24,853	803	56

Table 4-13 Alberhill N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2043	7	4	0.03	0.02	2	0	13,876	0	2
2048	30	10	0.38	0.08	5	0	15,352	0	5

In analyzing the ASP, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 4-14 only thermal violations associated with each constraint are reported.

Table 4-14 List of ASP Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Alberhill-Fogarty	N-0	N/A (base case)	2038	2046	-
Alberhill-Fogarty	N-1	Alberhill-Skylark	2033	2038	2043
Alberhill-Skylark	N-1	Alberhill–Fogarty	2038	2043	-
Auld-Moraga #1	N-1	Valley EFG-Newcomb-Tenaja	2038	2048	-
Alberhill-Fogarty	N-1	Alberhill-Newcomb-Valley EFG	2048	-	-

4.3.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the ASP to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and the ASP for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 4-15 below for all three forecasts.

Table 4-15 Cumulative Benefits – Alberhill System Project

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV Forecast	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	275,699.00	277,608.08	362,675.60
N-1	EENS (MWh)	6,281.90	20,649.30	66,741.95
N-1	IP (MW)	428.40	601.15	953.65
N-1	SAIDI (hr)	584.15	1,344.27	10,083.74
N-1	SAIFI	10.24	16.27	48.65
N-1	PFD (hr)	1,300.00	1,907.00	3,276.50
N-1	Flex-1 (MWh)	515,204.08	777,346.52	1,410,772.49
N-1	Flex-2-1 (MWh)	5,282,485.78	5,426,238.65	5,837,736.21
N-1	Flex-2-2 (MWh)	2,365,561.84	2,872,775.50	3,799,083.71
N-0	EENS (MWh)	22,750.50	56,574.70	140,565.53
N-0	IP (MW)	2,713.40	4,052.60	6,212.65
N-0	SAIDI (hr)	445.38	3,267.57	14,793.79
N-0	SAIFI	16.61	60.20	148.70
N-0	PFD (hr)	410.50	811.00	1,558.87

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizon by the ASP. The robustness of the project is justified through benefits accrued across all forecast sensitivities. The results for each category of benefits demonstrate the merits of the ASP to complement the increasing reliability, capacity, flexibility, and resiliency needs in the Valley South service area.

4.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the ASP in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. EENS of 3 MWh is recorded under N-0 condition (Effective PV Forecast) in year 2048 due to an observed overload of the Alberhill-Fogarty 115 kV line. Across all sensitivities, the benefits range between 22.7 to 140.5 GWh of avoided EENS.
2. Considerable reduction in N-1 overloads are observed in the near-term and long-term horizons for all forecasts. With the ASP in service, the N-1 EENS benefits in the system range from 6.2 to 66.7 GWh through all forecasts. In the Effective PV Forecast by year 2038, overloads due to N-1 events are observed on the Alberhill-Fogarty 115 kV line, the Alberhill-Skylark 115 kV line, and the Auld – Moraga 115 kV line.
3. The project provides significant flexibility to address planned, unplanned, and emergency outages throughout the system while also providing significant benefits to address needs under high-impact, low-probability (HILP) events that occur in the Valley South System. The ASP addresses the full range of flexibility needs identified by the baseline system across all forecast sensitivities.
4. Following a HILP event, the ASP is able to recover approximately 400 MW of load in Valley South leveraging capabilities of its system tie-lines.
5. Overall, the ASP demonstrated robustness to address the needs identified in the Valley South System service territory. The project design offers several advantages that can also overcome the variability and uncertainty associated with load uncertainties. The available flexibility through system tie-lines provide relief to system operations under N-1, N-2, and HILP events that affect the region.

5 SCREENING AND RELIABILITY ASSESSMENT OF ALTERNATIVES

5.1 Introduction

The objective of this analysis is to identity and screen potential alternatives that meet the project objectives detailed in Section 1.2. Each of these alternatives are evaluated using the criteria established in Section 3.2.4.

The considered alternatives are evaluated for their capability to address system capacity and reliability needs. The alternatives are categorized as Minimal Investment Alternatives, Conventional, Non-Wire Alternatives (NWA) and Hybrid solutions.

Minimal Investment Alternatives can also be referred to as a "do nothing" scenario in which no large project is implemented to address the needs of the system. These include spare equipment investments, re-rating or equipment upgrades, component hardening, vegetation management, undergrounding T&D, reinforcement of poles and towers and emergency operations like load shedding relays. Conventional solutions include alternative substation or transmission line configurations. NWA's include energy storage, demand response, energy efficiency programs, distributed energy resources, and other smart grid investments like smart meters. Hybrid solutions are a combination of Conventional and Non-Wire Alternatives.

The solution alternatives are organized into four primary categories, as outlined in Figure 5-1.

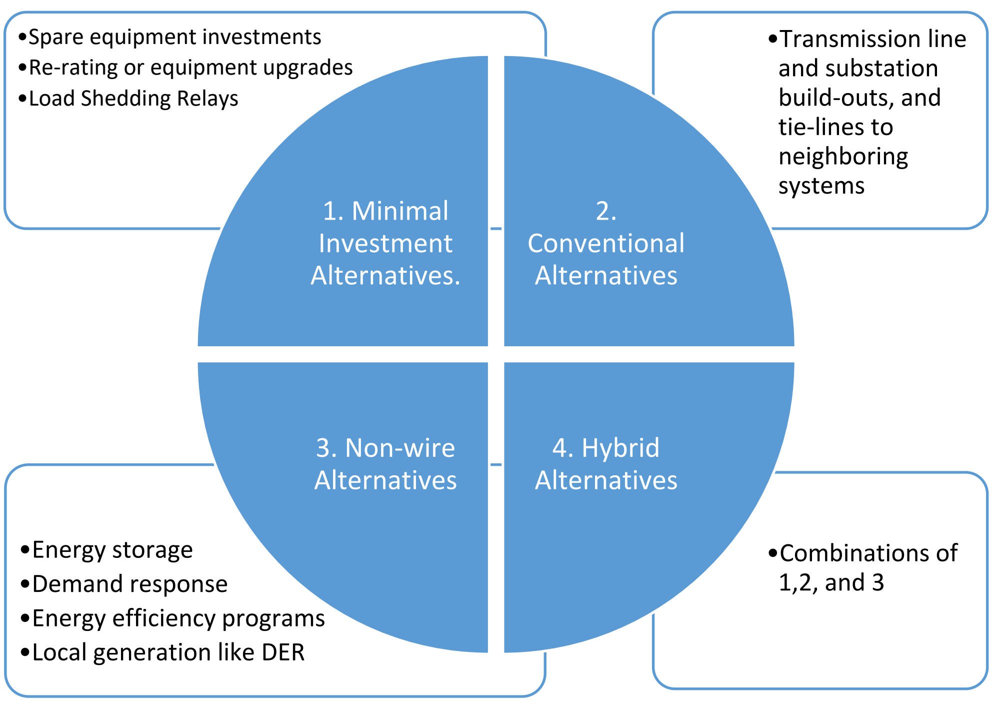


Figure 5-1 Categorization of considered alternatives.

The highlights of the procedure used to identify potential alternative projects are presented as follows.

- Use reliability analysis results with no project in service and available reports detailing layout of the Valley South System to establish Minimum Investment Alternatives to mitigate and meet the objectives.
- An exhaustive search (brute force) approach was used to establish system tie-lines between the Valley South System and neighboring systems. Tie-lines performance were evaluated under the most constraining conditions identified from the "No Project" scenario results. Figure 5-2 provides a description of the Valley South System relative to neighboring electrical systems.
- Seek guidance from the EENS metrics to provide the viability of alternatives. For example, the identified MWh need is significantly large and predominantly occurs during off-peak hours of the day that PV-DER type solutions might not be available.

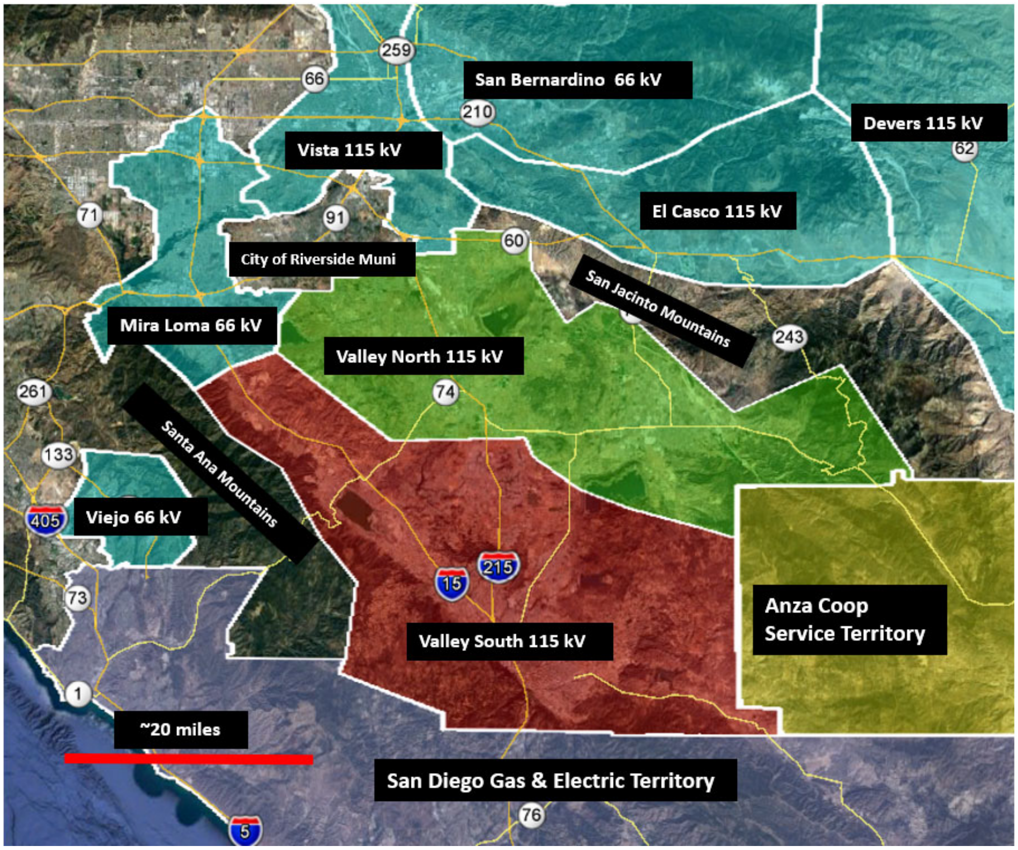


Figure 5-2 Valley System and neighboring electrical systems

5.2 Project Screening and Selection

The initial screening process resulted in a total of 17 alternatives. These included all categories of options outlined in Figure 5-1. The 17 alternatives were preliminarily screened through a fatal flaw analysis driven by the overall project objectives. Through this process four alternatives were dropped from further consideration. The dropped alternatives included 1- utilization of spare transformer for the Valley South System, 2- upgrading transformer ratings, 3- investing in load shedding relays, and 4- installation of two additional 500/115kV transformer banks. Upon further inspection and analysis, these four alternatives were determined to not satisfy all project objective needs or were not feasible from an implementation or constructability perspective.

The final list of 13 alternatives included a combination of conventional, non-wire and hybrid solutions. These alternatives are presented below. Further details pertinent to the scope, design and project performance are described in upcoming sections of this chapter. Note that ASP and project alternatives are identified using an alphabetic character, A through M, which is used throughout this report to refer each alternative.

Conventional Alternatives

The considered conventional transmission alternatives are detailed below.

A. Alberhill System Project
B. San Diego Gas & Electric Project
C. SCE Orange County Project
D. Menifee Project
E. Mira Loma Project
F. Valley South to Valley North Project
G. Valley South to Valley North to Vista Project

Non-Wire Alternatives

The following non-wire alternatives have been considered:

H. Centralized BESS in Valley South Project

Hybrid Solutions

The following hybrid solutions that involve a combination of conventional and hybrid solutions have been considered in this analysis:

I. Valley South to Valley North and Distributed BESS in Valley South Project
J. San Diego Gas & Electric and Centralized BESS in Valley South (Alternatives B + H)
K. Mira Loma and Centralized BESS in Valley South (Alternatives E + H)
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North (Alternatives F + H)
M. Valley South to Valley North to Vista and Centralized BESS in Valley South (Alternatives G + H)

5.3 Detailed Project Analysis

In the detailed project analysis, the reliability assessment framework was applied to all 13 considered alternatives. The performance and benefits of each alternative were computed in comparison to the baseline scenario (i.e., no project in service) following the methodology detailed in Section 3.2. The results of baseline scenario are presented in Section 4.2 and the ASP (Alternative A) in Section 4.3. The performance of each alternative is presented for the range of load forecast sensitivities (PVWatts, Effective PV, and Spatial Base).

5.3.1 San Diego Gas & Electric (Project B)

The original premise for this project is to construct a new 230/115 kV substation that provides power by San Diego Gas & Electric System and to transfer some of SCE's distribution substations to this new 230/115 kV system. This project has been evaluated under need year[22], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

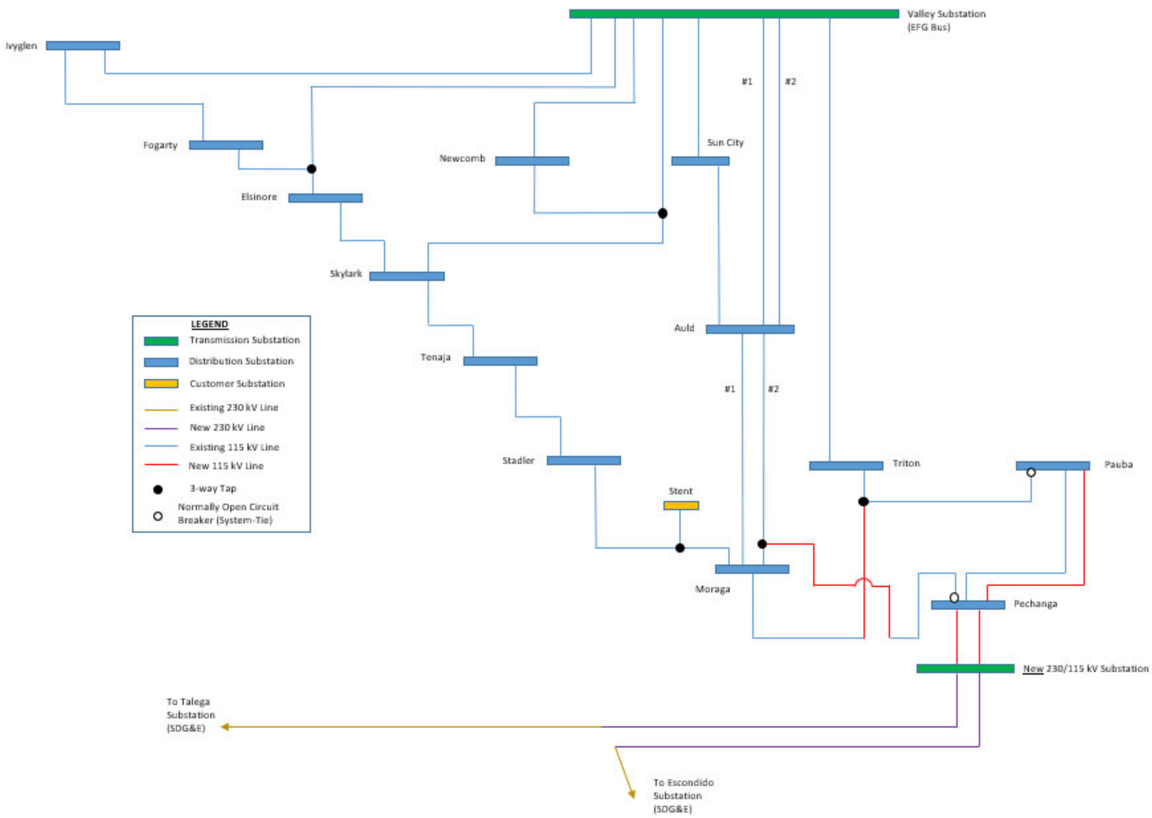
5.3.1.1 Description of Project Solution

The proposed project would transfer SCE's Pechanga and Pauba 115/12 kV distribution substations to a new 230/115 kV transmission substation provided service from the SDG&E electric system. The proposed project would include the following components:

1. Point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega-Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega-Escondido 230 kV transmission line.
3. New 115 kV line construction to allow transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally-open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.

Figure 5-3 presents a high-level representation of the proposed configuration.

[22] 2022 and 2021, depending on need year from forecast under study



Schematic Representation. Not to scale.

Figure 5-3 SDG&E Project Scope

5.3.1.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-1 for the Effective PV Forecast, Table 5-2 for the Spatial Base Forecast and Table 5-3 for the PVWatts Forecast.

Table 5-1 SDG&E N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	44,182
2028	0	0	0	0	0	0	46,553
2033	0	0	0	0	0	0	48,529
2038	0	0	0.000	0.000	0	0	50,505
2043	82	31	0.284	0.071	4	0	52,481
2048	244	63	1.482	0.212	7	7	54,457

Table 5-2 SDG&E N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	44,182.40
2022	0	0	0	0	0	0	44,715.01
2028	0	0	0	0	0	0	46,963.17
2033	0	0	0	0	0	0	48,836.64
2038	199	56	1.040	0.173	6	0	50,710.11
2043	655	112	6.832	0.569	12	0	52,583.58
2048	1,499	152	36.481	1.303	28	28	54,457.06

Table 5-3 SDG&E N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	44,182
2028	0	0	0	0	0	0	46,553
2033	0	0	0	0	0	0	45,310
2038	0	0	0	0	0	0	46,470
2043	0	0	0	0	0	0	47,630
2048	3	3	0.003	0.003	1	1	48,791

5.3.1.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-4 for the Effective PV Forecast, Table 5-5 for the Spatial Base Forecast and Table 5-6 for the PVWatts Forecast.

Table 5-4 SDG&E N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,680	57,104	12,006	0
2028	0	0	0	0	0	8,859	63,631	17,792	0
2033	0	0	0	0	0	14,842	70,782	25,448	0
2038	0	0	0	0	0	20,824	78,642	35,134	0
2043	0	0	0	0	0	26,806	85,866	45,192	0
2048	0	0	0	0	0	32,789	91,166	53,403	0

Table 5-5 SDG&E N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	0	0	0	0	0	3,718	58,391	13,056	0
2022	0	0	0	0	0	5,825	60,909	15,232	0
2028	0	0	0	0	0	17,287	71,622	26,413	0
2033	0	0	0	0	0	26,838	80,726	37,913	0
2038	0	0	0	0	0	36,390	89,892	51,367	0
2043	30	7	0.25	0.03	4	45,941	98,133	65,515	8
2048	196	18	4.75	0.20	8	55,492	105,137	79,230	24

Table 5-6 SDG&E N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,680	57,104	12,006	0
2028	0	0	0	0	0	8,859	63,631	17,792	0
2033	0	0	0	0	0	9,532	63,808	17,964	0
2038	0	0	0	0	0	13,100	70,007	24,567	0
2043	0	0	0	0	0	16,669	75,927	31,653	0
2048	0	0	0	0	0	20,238	80,218	37,223	0

In analyzing the SDG&E project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-7 only thermal violations associated with each constraint are reported.

Table 5-7 List of SDG&E Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (basecase)	2034	2040	2048
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG - Newcomb-Skylark	2043	-	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22	N-1	Valley EFG -Elsinore-Fogarty	2043	-	-
Valley EFG-Tap 22	N-1	Valley EFG - Newcomb	2043	-	-

5.3.1.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the SDG&E Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-8 below for all three forecasts.

Table 5-8 Cumulative Benefits – San Diego Gas & Electric

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	200,878.85	214,200.02	249,116.75
N-1	EENS (MWh)	6,374.80	21,683.80	72,687.55
N-1	IP (MW)	466.50	780.05	1,320.75
N-1	SAIDI (hr)	585.07	1,379.19	10,716.14
N-1	SAIFI	10.48	18.89	64.67
N-1	PFD (hr)	1,320.00	1,999.00	3,431.50
N-1	Flex-1 (MWh)	208,172.17	312,015.50	579,269.57
N-1	Flex-2-1 (MWh)	3,750,849.98	3,785,438.88	3,975,283.83
N-1	Flex-2-2 (MWh)	1,747,226.49	2,043,804.58	2,581,138.88
N-0	EENS (MWh)	22,747.50	55,563.10	132,226.50
N-0	IP (MW)	2,710.40	3,725.50	4,978.00
N-0	SAIDI (hr)	445.38	3,262.81	14,661.31

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	SAIFI	16.61	59.33	142.42
N-0	PFD (hr)	409.50	775.00	1,443.50

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E Project. In particular, the range of benefits are substantial in the N-1 category. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. The project also provides overall loss reduction primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel longer distances from source to delivery. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.1.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near-term horizon. This trend is observable across all forecast sensitivities. Under N-0, EENS of 240 MWh is recorded in the Effective PV forecast for 2048 and 1,500 MWh under Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 132.2 GWh of avoided EENS.
2. With the SDG&E Project in service, the N-1 EENS benefits in the system range from 6.3 to 72.6 GWh through all forecasts. The design of SDG&E Project displaces two relatively large load centers located at the southern border of the Valley South System. By the nature of radial networks, all flows were originally moving in the direction of these loads. With load transfer and circuit reconfiguration, significant benefits are gained under N-1 outage conditions in Valley South System. In the Spatial Base forecast, by year 2043 overloads due to N-1 events are observed in the system.
3. The project provides considerable flexibility to address planned, unplanned or emergency outages in the system while also providing benefits to address needs under high impact, low probability (HILP) events that occur in the Valley System. However, these benefits are not as significant in comparison to the ASP.
4. Following a HILP event, the SDG&E Project is able to recover approximately 280 MW of load from the Valley South System, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, SDG&E did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near-term horizon and under lower range of forecast sensitivities.

5.3.2 SCE Orange County (Project C)

The SCE Orange County Project was evaluated under need year[23], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

5.3.2.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection is a new substation with 220/115 kV transformation, southwest of SCE's Tenaja and Stadler Substations in the Valley South System.
2. Looping the San Onofre-Viejo 220 kV line in to the new 220/115 kV substation. This configuration would include the construction of new 230 kV double-circuit transmission line.
3. The proposed solution would transfer SCE's Tenaja and Stadler 115/12 kV Substation to the new 220/115 kV system through construction of new 115 kV lines.
4. Normally-open circuit breakers at Skylark and Stadler Substations would create system tie-lines providing operational flexibility to accommodate future load transfers.

Figure 5-4 presents a high-level representation of the proposed configuration.

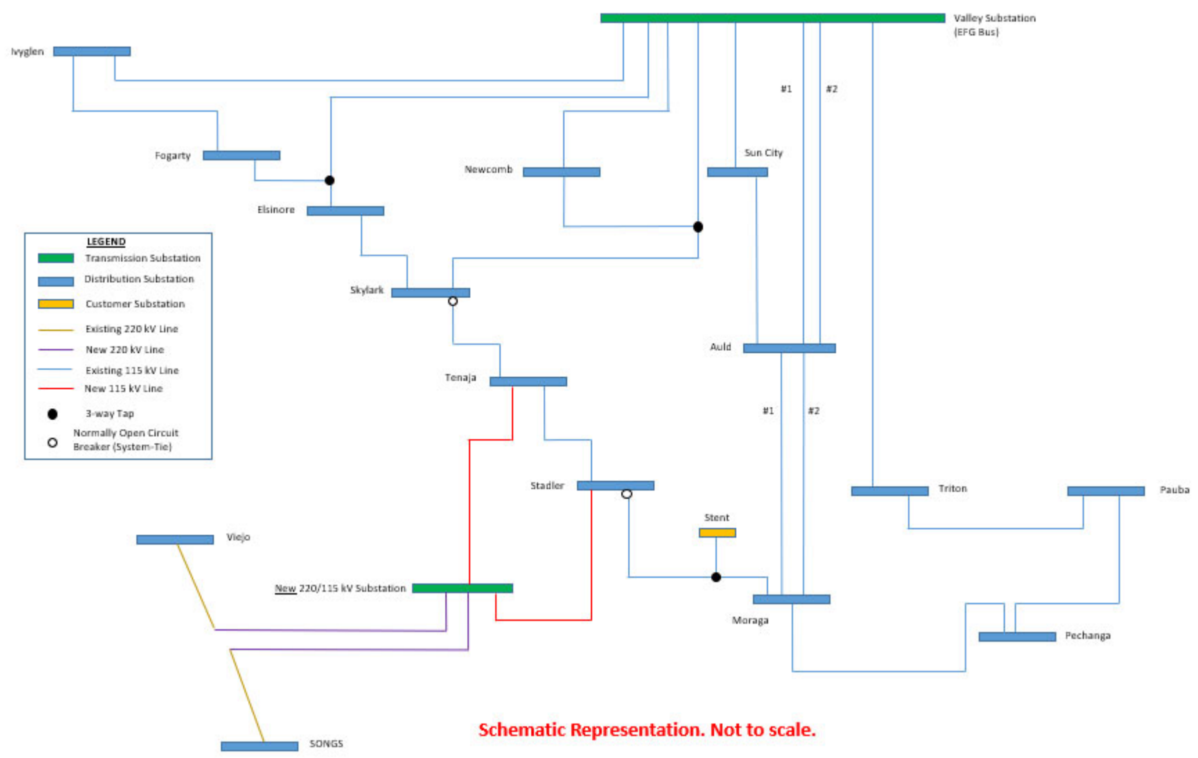


Figure 5-4 SCE Orange County Project Scope

[23] 2022 and 2021, depending on need year from forecast under study

5.3.2.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-9 for the Effective PV Forecast, Table 5-10 for the Spatial Base Forecast and Table 5-11 for the PVWatts Forecast.

Table 5-9 SCE Orange County N-0 System Performance (Effective PV Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
SCE Orange County	2022	0	0	0	0	0	0	43,189
	2028	0	0	0	0	0	0	45,593
	2033	0	0	0	0	0	0	47,596
	2038	0	0	0.000	0.000	0	0	49,599
	2043	72	31	0.639	0.080	4	8	51,602
	2048	232	65	3.588	0.256	7	14	53,605

Table 5-10 SCE Orange County N-0 System Performance (Spatial Base Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
SCE Orange County	2021	0	0	0	0	0	0	43,573.71
	2022	0	0	0	0	0	0	44,329.83
	2028	0	0	0	0	0	0	41,444.40
	2033	0	0	0	0	0	0	45,671.60
	2038	183	55	1.013	0.203	5	5	49,898.80
	2043	536	111	6.523	0.593	11	11	54,125.99
	2048	1,426	159	42.554	1.576	27	27	58,353.19

Table 5-11 SCE Orange County N-0 System Performance (PVWatts Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
SCE Orange County	2022	0	0	0	0	0	0	43,189
	2028	0	0	0	0	0	0	45,593
	2033	0	0	0	0	0	0	45,187
	2038	0	0	0	0	0	0	46,843
	2043	0	0	0	0	0	0	48,500
	2048	0	0	0	0	0	0	50,156

5.3.2.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-12 for the Effective PV Forecast, Table 5-13 for the Spatial Base Forecast and Table 5-14 for the PVWatts Forecast.

Table 5-12 SCE Orange County N-1 System Performance (Effective PV Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
SCE Orange County	2022	0	0	0.00	0.00	0	835	54,765	9,568	0
	2028	12.5	2.5	0.06	0.01	5	2,486	61,060	14,527	5
	2033	35.3	3.3	0.22	0.04	2	3,861	67,960	21,155	5
	2038	129.9	14	1.68	0.15	7	5,237	75,558	29,763	11
	2043	313.1	26	5.51	0.37	14	6,613	82,604	38,800	15
	2048	578.2	36.3	16.98	0.68	28	7,989	87,813	46,210	25

Table 5-13 SCE Orange County N-1 System Performance (Spatial Base Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
SCE Orange County	2021	5	3	0	0	2	994	56,008	10,473	2
	2022	10	3	0	0	2	1,506	58,427	12,328	4
	2028	38	5	0	0	4	4,581	68,769	22,013	6
	2033	176	17	3	0	8	7,143	77,581	32,256	13
	2038	497	32	13	1	24	9,706	86,560	44,365	22
	2043	1,179	46	47.83	1.37	37	12,268	94,664	57,027	35
	2048	2,275	74	146.10	2.63	56	14,831	101,550	69,422	56

Table 5-14 SCE Orange County N-1 System Performance (PVWatts Forecast)

	Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
SCE Orange County	2022	0	0	0	0	0	835	54,765	9,568	0
	2028	12.5	2.5	0.05	0.01	5	2,486	61,060	14,527	5
	2033	15	2.5	0.08	0.01	6	2,503	61,231	14,673	6
	2038	31.6	2.5	0.24	0.03	10	3,262	67,215	20,377	7
	2043	94.7	9.9	1.30	0.10	21	4,021	72,923	26,624	12
	2048	159.1	16	2.18	0.18	23	4,779	77,088	31,642	12

In analyzing the SCE Orange County Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-15 only thermal violations associated with each constraint are reported.

Table 5-15 List of SCE Orange County Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2034	2040	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2043	-	-
Auld-Moraga #1	N-1	Auld-Moraga #2	2033	2038	2048
Valley EFG-Triton	N-1	Moraga-Pechanga	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #1	2043	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Sun City	2048	-	-
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2043	-	-
Valley EFG-Sun City	N-1	Valley EFG -Auld #2	2043	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2043	2048	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.2.4 Evaluation of Benefits

The established performance metrics were compared between baseline and SCE Orange County Project to quantify the overall benefits accrued over 30-year study. The benefits are quantified as the difference between baseline and the ASP for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-16 below for all three forecasts.

Table 5-16 Cumulative Benefits – SCE Orange County

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	193,424.47	187,601.40	203,637.40
N-1	EENS (MWh)	5,163.50	17,520.20	57,040.45
N-1	IP (MW)	336.50	447.15	660.65
N-1	SAIDI (hr)	570.28	1,291.03	9,973.44
N-1	SAIFI	9.13	14.00	46.39

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-1	PFD (hr)	1,055.00	1,785.00	2,922.50
N-1	Flex-1 (MWh)	436,349.40	658,231.80	1,189,234.45
N-1	Flex-2-1 (MWh)	3,824,376.05	3,863,817.70	4,062,666.89
N-1	Flex-2-2 (MWh)	1,852,440.22	2,172,509.74	2,753,551.92
N-0	EENS (MWh)	22,750.50	55,560.40	133,064.00
N-0	IP (MW)	2,713.40	3,724.30	4,986.10
N-0	SAIDI (hr)	445.38	3,253.98	14,644.32
N-0	SAIFI	16.61	59.09	141.29
N-0	PFD (hr)	410.50	776.00	1,456.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SCE Orange County Project. In particular, the range of benefits are substantial in the N-1 category and Loss reduction. The projects contribution to loss reduction is primarily because it displaces loads at the southern border of the Valley South service territory, thereby reducing the need for power to traverse longer distances from source to deliver. Additionally, this project displaces loading on subtransmission lines with significant contribution to overall system losses (namely, Tap 22-Skylark and Skylark-Tenaja) in the Valley South System. However, it is observed that the solution does not completely address the N-0 overload condition on Valley South System transformers. Also, the flexibility benefits offered by the solution are limited in comparison to the ASP.

5.3.2.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformer is avoided only in the near-term horizon. Under N-0, EENS of 230 MWh is recorded in the Effective PV forecast for 2048 and 1,400 MWh under Spatial Base Forecast for 2048. Across all sensitivities, the benefits range between 22.7 to 133 GWh of avoided EENS.
2. Considerable reduction in N-1 overloads are observed in the near-term and long-term horizons for all forecasts. With SCE Orange County Project in service, the N-1 EENS benefits in the system range from 5.1 to 57 GWh through all forecasts.
3. The project provides reasonable flexibility to address planned, unplanned or emergency outages in the system while also providing benefits to address needs under high impact, low probability events that occur in the Valley System. However, these benefits are not as significant in comparison to the ASP.
4. Under peak loading conditions, the SCE Orange County Project would be able to approximately serve 280 MW of load from Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.

5. Overall, the SCE Orange County project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in the near-term horizon and under lower range of forecast sensitivities.

5.3.3 Menifee (Project D)

The Menifee Project would construct a new substation located approximately 0.5 miles west of Valley Substation. Scope would include 500/115 kV transformation and associated 500 and 115 kV switch racks. Power would be supplied by looping in SCE's existing Serrano-Valley 500 kV line. SCE's existing Newcomb and Sun City distribution substations would be transferred to this new system providing relief on the Valley South System transformers. The project has been evaluated under need year[24], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

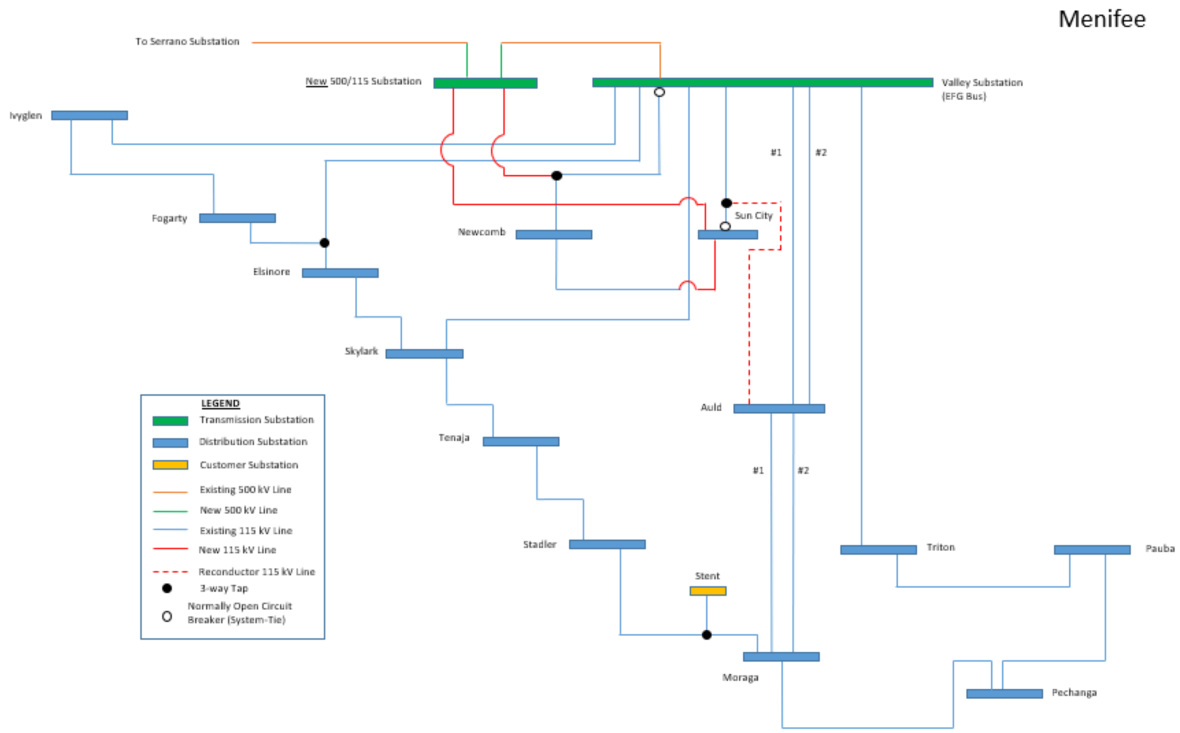
5.3.3.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be a new substation with two 500/115 kV transformers (including spare) and associated facilities located approximately 0.5 miles west of Valley Substation. It would be provided power by looping in SCE's existing Serrano-Valley 500 kV line.
2. The proposed solution would transfer the loads at Newcomb and Sun City Substations in the Valley South System.
3. The 115 kV lines currently serving Newcomb and Sun City substations would be transferred to the new system involving a combination of new 115 kV lines and circuit reconfiguration.
4. Creates two system ties between the new system and the Valley South System through an open circuit breaker at Sun City and Valley Substations to provide operational flexibility.
5. Reconductor existing Auld-Sun City 115 kV line which would become the Valley-Auld-Sun City 115 kV line.

Figure 5-5 presents a high-level representation of the proposed configuration.

[24] 2022 and 2021, depending on need year from forecast under study



Schematic Representation. Not to scale.

Figure 5-5 Menifee project scope.

5.3.3.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-17 for the Effective PV Forecast, Table 5-18 for the Spatial Base Forecast and Table 5-19 for the PVWatts Forecast.

Table 5-17 Menifee N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,898
2028	0	0	0	0	0	0	51,308
2033	0	0	0	0	0	0	53,316
2038	0	0	0	0	0	0	55,324
2043	3	3	0.000	0.004	1	0	57,332
2048	114	39	1.008	0.126	4	8	59,341

Table 5-18 Menifee N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,287
2022	0	0	0	0	0	0	50,035
2028	0	0	0	0	0	0	53,305
2033	0	0	0	0	0	0	56,030
2038	73	29	0.482	0.080	4	6	58,754
2043	417	83	7.824	0.460	8	17	61,479
2048	985	130	34.775	1.087	14	32	64,204

Table 5-19 Menifee N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,898
2028	0	0	0	0	0	0	51,308
2033	0	0	0	0	0	0	50,553
2038	0	0	0	0	0	0	52,316
2043	0	0	0	0	0	0	54,079
2048	0	0	0	0	0	0	55,855

5.3.3.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-20 for the Effective PV Forecast, Table 5-21 for the Spatial Base Forecast and Table 5-22 for the PVWatts Forecast.

Table 5-20 SCE Menifee N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	5	3	0.00	0.01	2	3,549	71,622	15,864	2
2028	64	14.7	0.57	0.07	8	11,342	78,874	22,946	8
2033	196	28	4.09	0.22	19	17,620	86,454	32,011	19
2038	617	38.1	25.98	0.66	39	23,898	94,382	43,191	39
2043	1,408	50.1	90.83	1.46	65	30,194	101,475	54,727	62
2048	2,430	87	213.16	2.49	92	36,649	106,662	64,235	86

Table 5-21 Menifee N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	16	6	0	0	4	4,257	73,084	17,164	4
2022	35	11	0	0	5	6,453	75,891	19,844	5
2028	226	28	6	0	23	19,627	87,318	33,148	23
2033	789	42	36	1	44	30,605	96,438	46,386	43
2038	2,117	80	176	2	86	41,583	105,415	61,842	81
2043	4,510	78	557.37	4.54	129	52,562	113,479	78,185	123
2048	7,745	145	34.77	1.09	178	63,540	120,333	93,441	32

Table 5-22 Menifee N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	5.8	3	0.016	0.005	3	3,808	71,622	15,864	3
2028	57.9	14.5	0.423	0.053	8	11,342	78,874	22,946	8
2033	61.1	15.1	0.446	0.056	8	11,732	79,065	23,155	8
2038	167.5	25.9	2.595	0.153	17	15,334	85,651	30,979	17
2043	430.1	35.5	11.513	0.396	30	18,936	91,677	39,179	29
2048	733.1	40.9	28.006	0.678	44	22,538	95,938	45,597	41

In analyzing the Menifee project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-23 only thermal violations associated with each constraint are reported.

Table 5-23. List of Menifee Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Auld-Moraga #1	N-0	N/A (base case)	2037	2045	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2043	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2033	2043	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.3.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Menifee to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and the ASP for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-24 below for all three forecasts.

Table 5-24 Cumulative Benefits – Menifee

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	41,267.70	33,102.00	41,919.84
N-1	EENS (MWh)	600.25	2,963.80	12,978.35
N-1	IP (MW)	-118.05	-154.10	-205.55
N-1	SAIDI (hr)	426.51	134.91	6,816.96
N-1	SAIFI	5.16	-0.63	24.19
N-1	PFD (hr)	863.50	1,061.00	1,555.00
N-1	Flex-1 (MWh)	146,671.17	233,606.39	461,612.05
N-1	Flex-2-1 (MWh)	3,335,750.17	3,368,622.29	3,542,647.48
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,420.75	2,322,663.11
N-0	EENS (MWh)	22,750.50	56,228.50	135,608.80
N-0	IP (MW)	2,713.40	3,929.80	5,370.90
N-0	SAIDI (hr)	445.38	3,264.59	14,664.29
N-0	SAIFI	16.61	59.83	144.11
N-0	PFD (hr)	410.50	800.00	1,519.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Menifee Project. The project by design includes permanent transfer of relatively large load centers in the Valley South System during initial years. This provides significant N-0 system relief, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. The solution does not offer relief to address N-1 violations in the system. This is primarily because the topological changes do not significantly alter the configuration of Valley Substation. In fact, several overloads are aggravated in the system post project in service.

5.3.3.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided only in the near-term horizon. Under N-0, EENS of 115 MWh is recorded in the Effective PV Forecast for 2048 and 1,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range between 22.7 to 135.6 GWh of avoided EENS.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 0.6 to 12.9 GWh through all forecast sensitivities.

3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Following a HILP event, the Menifee Project is able to serve approximately a total of 160 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Menifee did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.4 Mira Loma (Project E)

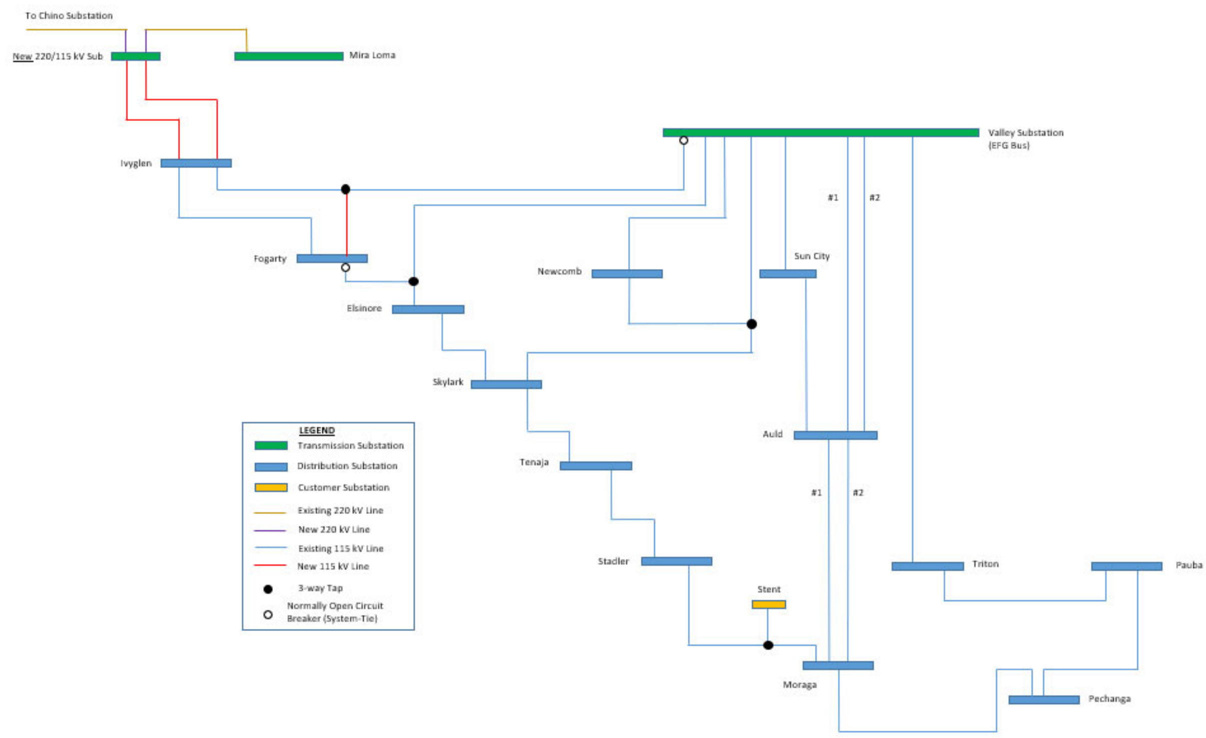
The objective of this alternative is to take advantage of the Mira Loma System to provide a new source of supply into the Valley South service area. The project has been evaluated under need year[25], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

5.3.4.1 Description of Project Solution

1. Construct new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV system created.
3. Creates two system tie-lines between Valley South and new system at Valley Substation and Fogarty Substation respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from new 220/115 kV substation to Ivyglen Substation in the Valley South System.

Figure 5-6 presents a high-level representation of the proposed configuration.

[25] 2022 and 2021, depending on need year from forecast under study



Schematic Representation. Not to scale.

Figure 5-6 Tie-line to Mira Loma Project Scope

5.3.4.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-25 for the Effective PV Forecast, Table 5-26 for the Spatial Base Forecast and Table 5-27 for the PVWatts Forecast.

Table 5-25 Mira Loma N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,453
2028	0	0	0	0	0	0	50,945
2033	82	30.7	0.557	0.082	4	7	53,021
2038	314	84.2	2.808	0.312	9	9	55,097
2043	807	138	17.630	0.801	22	22	57,173
2048	1,905	184	56.774	1.892	30	30	59,250

Table 5-26 Mira Loma N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	48,849
2022	0	0	0	0	0	0	49,618
2028	106	38	0.423	0.106	4	4	42,629
2033	607	104	10.225	0.603	12	17	48,041
2038	1,449	172	41.743	1.439	29	29	53,453
2043	3,382	238	164.624	3.360	45	49	58,864
2048	4,994	294	441.584	4.962	69	89	64,276

Table 5-27 Mira Loma N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,453
2028	0	0	0	0	0	0	50,945
2033	0	0	0	0	0	0	53,021
2038	58	24	0	0	4	4	55,097
2043	273	69	1.896	0.271	7	7	57,173
2048	526	184	56.774	1.892	30	30	59,250

5.3.4.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-28 for the Effective PV Forecast, Table 5-29 for the Spatial Base Forecast and Table 5-30 for the PVWatts Forecast.

Table 5-28 Mira Loma N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	2,180	139,483	18,208	0
2028	29	10	0.15	0.03	5	6,493	147,439	25,978	5
2033	149	22	2.53	0.15	12.5	10,087	155,755	35,786	16
2038	416	33	10.83	0.43	30	13,680	164,453	47,823	25
2043	1,125	44	42.76	1.10	48	17,274	172,235	60,210	39
2048	2,009	53	112.29	1.91	76	20,868	177,925	70,501	59

Table 5-29 Mira Loma N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	1	1	0	0	2	3,292	141,086	19,647	2
2022	11	4	0	0	4	4,990	144,166	22,589	4
2028	146	22	2	0	13	15,177	156,703	37,006	12
2033	694	36	26	1	37	23,667	166,708	51,240	37
2038	1,715	50	92	2	67	32,156	176,557	67,935	56
2043	4,151	68	335.59	3.76	107	40,646	185,405	85,284	89
2048	7,216	120	855.62	6.42	153	49,136	192,924	101,463	133

Table 5-30 Mira Loma N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	2,180	139,483	18,207	0
2028	29	10	0.15	0.03	5	6,493	147,439	25,978	5
2033	27	11	0.14	0.03	5	5,964	147,648	26,202	5
2038	92	20	0.92	0.10	10	7,539	154,875	34,677	10
2043	297	34	6.11	0.30	24	9,213	161,485	43,499	20
2048	553	102	5.22	0.52	10	10,888	166,160	50,404	10

In analyzing the Mira Loma Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-31 only thermal violations associated with each constraint are reported.

Table 5-31 List of Mira Loma Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2026	2031	2036
Valley EFG-Sun City	N-0	N/A (base case)	2044	-	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #1	N-0	N/A (base case)	2039	-	-
Tap 39-Elsinore #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2023	2023

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2032	2038	2043
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2028	2033	2038
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #1	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG-Sun City	2038	2045	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2038	2043	-
Valley EFG-Auld #1	N-1	Valley EFG -Auld #2	2038	2043	-
Valley EFG-Sun City	N-1	Valley EFG-Auld #2	2038	2043	-
Auld-Moraga #1	N-1	Pauba-Triton	2048	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2028	2033	2038
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.4.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Mira Loma Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and Mira Loma for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-32 below for all three forecasts.

Table 5-32 Cumulative Benefits – Mira Loma

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	48,851.33	40,333.27	47,003.50
N-1	EENS (MWh)	2,573.83	7,195.25	18,318.70
N-1	IP (MW)	41.65	98.45	129.45
N-1	SAIDI (hr)	533.21	764.27	5,908.99
N-1	SAIFI	6.72	4.71	14.95
N-1	PFD (hr)	1,084.00	1,308.50	1,869.00
N-1	Flex-1 (MWh)	327,945.64	466,197.68	676,792.59
N-1	Flex-2-1 (MWh)	1,472,688.43	1,489,270.72	1,569,278.78

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-1	Flex-2-2 (MWh)	1,490,804.78	1,735,029.08	2,174,923.33
N-0	EENS (MWh)	18,949.53	42,092.15	85,890.15
N-0	IP (MW)	1,720.20	2,269.70	2,648.50
N-0	SAIDI (hr)	264.65	2,993.28	12,406.82
N-0	SAIFI	9.35	48.67	107.54
N-0	PFD (hr)	269.50	553.50	922.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma Project. Although the project demonstrates N-0 benefits in the short-term horizon, the project does not completely address the N-0 overload condition on the Valley South System transformers. In the Spatial Base forecast, the project fails to satisfy needs in the short-term horizon as well, resulting in 106 MWh of EENS by 2028. The availability of system tie-lines does provide incremental flexibility to support emergency and maintenance conditions in the system. However, these benefits are limited in comparison to other solutions like the ASP.

5.3.4.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, limited relief is available to overload conditions on the Valley South System transformers. Under N-0, EENS of 1,905 MWh is recorded under the Effective PV Forecast for 2048. Similarly, EENS of 5,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range between 18.9 to 85.8 GWh of avoided EENS.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 2.5 to 18.3 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Following a HILP event, Mira Loma is able recover approximately 110 MW of load in Valley South, beyond the permanent transfers leveraging capabilities of its tie-lines.
5. Overall, Mira Loma did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system

5.3.5 Valley South to Valley North project (Project F)

The objective of this project is to transfer Newcomb and Sun City Substations from the Valley South System to the Valley North System. Under normal conditions, the Valley North System does not approach its transformer rated capacity until 2045 in the Spatial Base Forecast. In all other forecasts, the loading does not exceed transformer capacity. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however transformer loading would be at risk of exceeding rated capacity. Due to this, only the EENS (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on Valley North system have not been considered in the metrics.

The project was considered to leverage capabilities of tie-lines to move loads between the Valley South System and the Valley North System. However, this transfer would not satisfy short-term and long-term objectives of the projects. No incremental benefits are provided to Valley South System in this configuration, because no additional load can be transferred to Valley North during emergency or maintenance conditions in the network. The project has been evaluated under need year[26], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

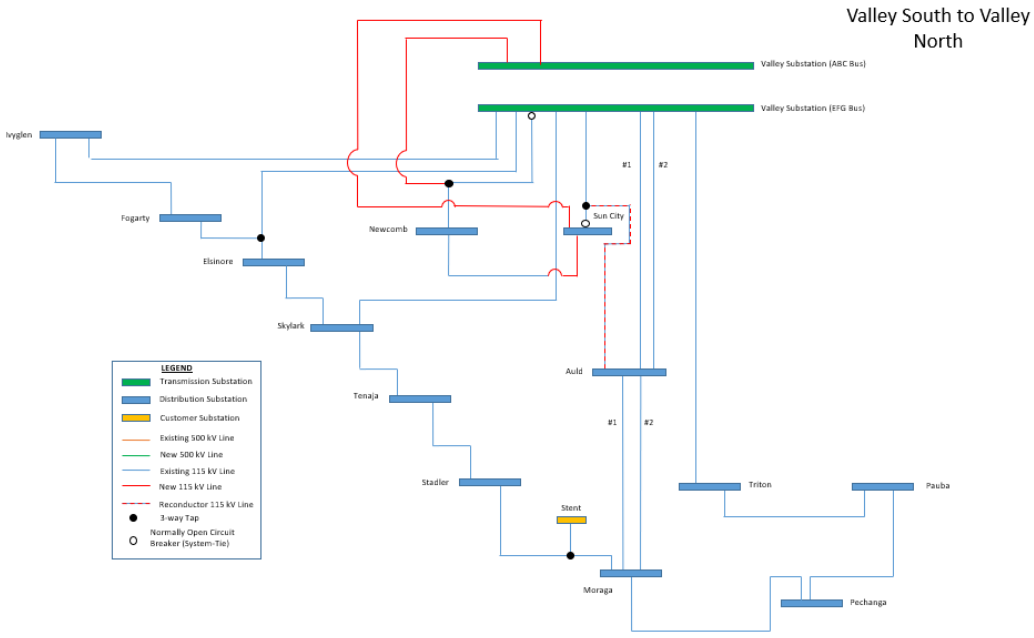
5.3.5.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through construction of new 115 kV lines.
2. Normally open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld-Sun City 115 kV line which would become the Valley-Auld-Sun City 115 kV line.

Figure 5-7 presents a high-level representation of the proposed configuration.

[26] 2022 and 2021, depending on need year from forecast under study



Schematic Representation. Not to scale.

Figure 5-7 Tie-lines between Valley South and Valley North project scope.

5.3.5.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-33 for the Effective PV Forecast, Table 5-34 for the Spatial Base Forecast and Table 5-35 for the PVWatts Forecast.

Table 5-33 Valley South to Valley North N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	51,777
2033	0	0	0.0	0.000	0	0	53,817
2038	136	14	2.891	0.160	4	18	55,858
2043	779	44	17.299	0.914	20	19	57,898
2048	2,680	192	141.685	2.197	55	64	59,939

Table 5-34 Valley South to Valley North N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,723
2022	0	0	0	0	0	0	50,479
2028	0	0	0.000	0.000	0	0	53,801
2033	305	56	4.652	0.607	13	8	56,568
2038	2,468	173	140.694	2.875	56	49	59,336
2043	8,146	310	876.910	9.434	104	93	62,104
2048	16,818	433	2,797.272	13.803	165	203	64,872

Table 5-35 Valley South to Valley North N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	50,960
2033	0	0	0	0	0	0	51,342
2038	0	0	0	0	0	0	53,028
2043	94	49	0.706	0.118	6	6	54,713
2048	750	202	17.871	0.941	19	19	56,399

5.3.5.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-36 for the Effective PV Forecast, Table 5-37 for the Spatial Base Forecast and Table 5-38 for the PVWatts Forecast.

Table 5-36 Valley South to Valley North N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	192	28	18.68	0.18	19	17,620	210,603	32,011	106
2038	610	38	21.12	0.56	39	23,898	220,085	43,191	37
2043	1,416	50	71.97	1.31	62	30,176	228,568	54,727	55
2048	2,500	87	180.25	2.32	89	36,454	234,771	64,235	78

Table 5-37 Valley South to Valley North N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	12	6	0	0	4	4,239	194,613	17,164	4
2022	32	10	0	0	5	6,425	197,970	19,844	5
2028	216	28	4	0	23	19,544	211,637	33,148	23
2033	778	42	29	1	44	30,477	222,543	46,386	41
2038	2,144	58	155	2	87	41,409	233,279	61,842	78
2043	4,517	77	504.31	4.25	129	52,342	242,925	78,185	119
2048	7,683	135	1,170.70	7.25	178	63,274	251,122	93,441	161

Table 5-38 Valley South to Valley North N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	61	15	0.45	0.06	8	11,732	201,766	23,155	8
2038	168	26	2.60	0.15	17	15,334	209,643	30,979	17
2043	430	36	11.51	0.40	30	18,936	216,849	39,179	29
2048	733	41	28.01	0.68	44	22,538	221,946	45,597	41

In analyzing the Valley North to Valley South Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-39 only thermal violations associated with each constraint are reported.

Table 5-39 List of Valley South to Valley North Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Auld-Moraga #1	N-0	N/A (base case)	2037	2045	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2043	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2033	2043	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.5.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Valley South to Valley North Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and the Valley South to Valley North Project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-40 below for all three forecasts.

Table 5-40 Cumulative Benefits – Valley South to Valley North

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	26,508.24	19,220.96	26,468.48
N-1	EENS (MWh)	600.25	2,752.65	11,817.15
N-1	IP (MW)	-118.05	-149.80	-91.15
N-1	SAIDI (hr)	426.51	277.20	3,748.24
N-1	SAIFI	5.16	1.39	7.53
N-1	PFD (hr)	863.50	1,077.50	1,485.50
N-1	Flex-1 (MWh)	146,671.17	233,804.50	465,583.98
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,420.75	2,322,663.11
N-0	EENS (MWh)	20,123.90	45,491.88	40,848.32
N-0	IP (MW)	1,909.80	3,211.43	2,380.48
N-0	SAIDI (hr)	388.94	2,747.38	2,889.80
N-0	SAIFI	13.32	48.56	43.94
N-0	PFD (hr)	327.50	536.50	287.77

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North Project. The project by design includes permanent transfer of large load centers in the Valley South System during initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. Additionally, the transformer overload condition is propagated to the Valley North System transformers starting from year 2030 in the Spatial Base forecast and 2036 in Effective PV forecast. The solution does not offer relief to address N-1 violations in the system. This is primarily because the topological changes do not significantly alter the configuration of Valley Substation. In fact, several overloads are aggravated in the system post project in service.

5.3.5.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near term and long-term horizon till year 2043. However, the transfer of loads result in overloads on the Valley North transformer by year 2037. EENS of 2,600 MWh is recorded under N-0 condition in the PV Effective forecast and 16,800 MWh in the Spatial Base Forecast in year 2048. Across all sensitivities, the benefits range between 20.1 to 45.4 GWh of avoided EENS.

2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 0.6 to 11.8 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. During potential HILP events impacting Valley Substation, the project is unable to serve incremental load in the Valley South System.
5. Overall, Valley South to Valley North Project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system.

5.3.6 Valley South to Valley North to Vista (Project G)

The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to the Valley North System (identical to Project F). Additionally, the load at Moreno Substation in the Valley North System would be transferred to the Vista 220/115 kV System. The premise of this methodology is to relieve loading on the Valley North System to accommodate a load transfer from the Valley South System. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however transformer loading would be at risk of exceeding rated capacity. Due to this, only the EENS (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on Valley North system have not been considered in the metrics. The project has been evaluated under need year[27], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3

5.3.6.1 Description of Project Solution

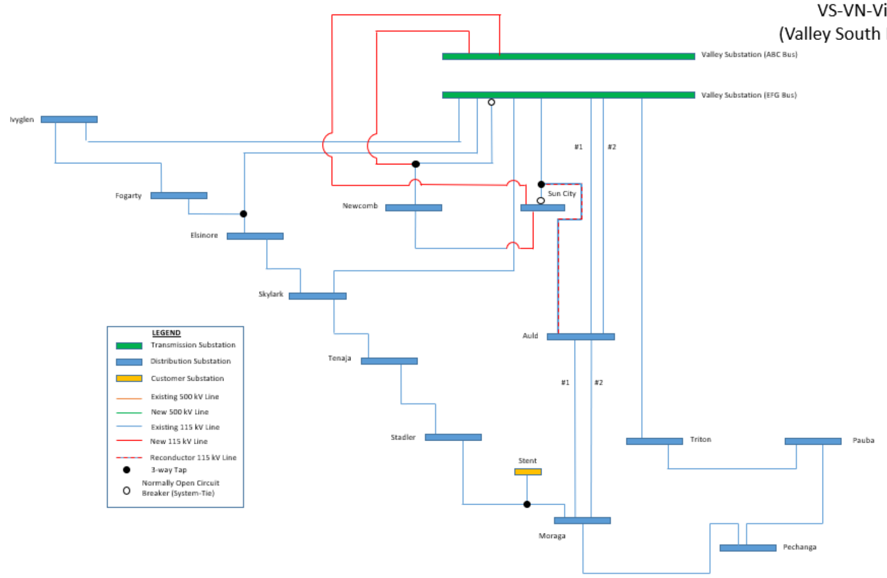
The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following transfer of Moreno Substation.
3. Normally open circuit breaker at Moreno Substation to provide a system tie-line between the Vista System and the Valley North System.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through construction of new 115 kV lines (see Project F).
5. Normally open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system tie-lines between the Valley North System and the Valley South System for transfer flexibility.
6. Reconductor existing Auld-Sun City 115 kV line which would become the Valley-Auld-Sun City 115 kV line.

Figure 5-13 presents a high-level representation of the proposed configuration.

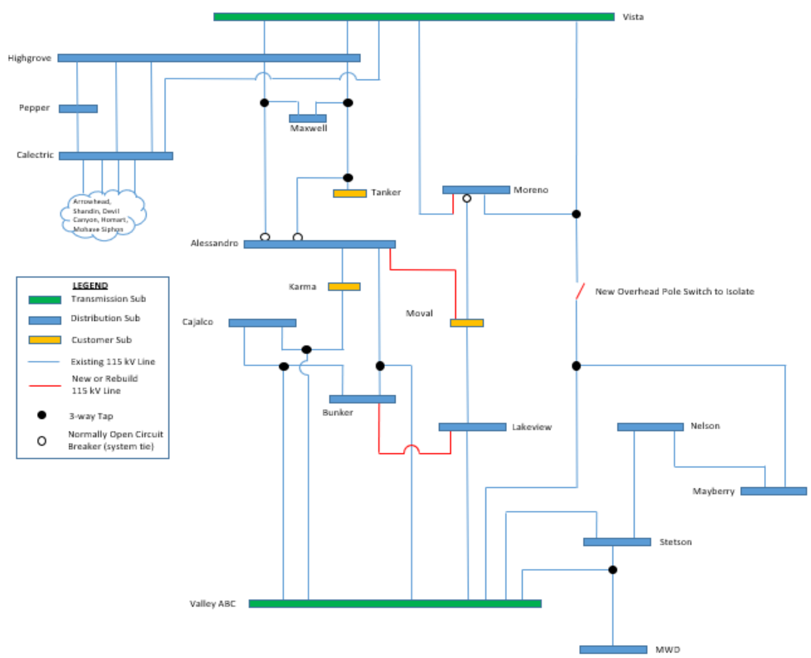
[27] 2022 and 2021, depending on need year from forecast under study

VS-VN-Vista
(Valley South Portion)



Schematic Representation. Not to scale.

VS-VN-Vista (Vista Portion)



Schematic Representation. Not to scale.

Figure 5-8 Tie-lines between Valley South to Valley North to Vista

5.3.6.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-41 for the Effective PV Forecast, Table 5-42 for the Spatial Base Forecast and Table 5-43 for the PVWatts Forecast.

Table 5-41 Valley South to Valley North to Vista N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	51,777
2033	0	0	0	0	0	0	54,225
2038	0	0	0	0	0	0	55,858
2043	83	31	0.004	0.004	6	1	57,898
2048	852	121	2.275	0.101	22	22	59,939

Table 5-42 Valley South to Valley North to Vista N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,723
2022	0	0	0	0	0	0	50,479
2028	0	0	0	0	0	0	53,801
2033	0	0	0	0	0	0	56,568
2038	756	112	10.403	0.657	23	16	59,336
2043	3,843	246	178.497	3.340	66	53	62,104
2048	9,003	365	789.798	8.260	119	96	64,872

Table 5-43 Valley South to Valley North to Vista N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	50,960
2033	0	0	0	0	0	0	51,342
2038	0	0	0	0	0	0	53,028
2043	0	0	0	0	0	0	54,713
2048	68	37	0.295	0.059	5	5	56,399

5.3.6.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-44 for the Effective PV Forecast, Table 5-45 for the Spatial Base Forecast and Table 5-46 for the PVWatts Forecast.

Table 5-44 Valley South to Valley North to Vista N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	192	28	18.68	0.18	19	17,620	210,603	32,011	106
2038	610	38	21.12	0.56	39	23,898	220,085	43,191	37
2043	1,416	50	71.97	1.31	62	30,176	228,568	54,727	55
2048	2,500	87	180.25	2.32	89	36,454	234,771	64,235	78

Table 5-45 Valley South to Valley North to Vista N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	12	6	0	0	4	4,239	194,613	17,164	4
2022	32	10	0	0	5	6,425	197,970	19,844	5
2028	216	28	4	0	23	19,544	211,637	33,148	23
2033	778	42	29	1	44	30,477	222,543	46,386	41
2038	2,144	58	155	2	87	41,409	233,279	61,842	78
2043	4,517	77	504.31	4.25	129	52,342	242,925	78,185	119
2048	7,683	135	1,170.70	7.25	178	63,274	251,122	93,441	161

Table 5-46 Valley South to Valley North to Vista N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	61	15	0.45	0.06	8	11,732	201,766	23,155	8
2038	168	26	2.60	0.15	17	15,334	209,643	30,979	17
2043	430	36	11.51	0.40	30	18,936	216,849	39,179	29
2048	733	41	28.01	0.68	44	22,538	221,946	45,597	41

In analyzing the Valley North to Valley South to Vista Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-47 only thermal violations associated with each constraint are reported.

Table 5-47 List of Valley North to Valley South to Vista Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Auld-Moraga #1	N-0	N/A (base case)	2037	2045	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	2043	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	2048	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Tap 22	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	-	-
Valley-Auld #3	N-1	Valley EFG-Auld #1	2048	-	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2033	2043	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.6.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Valley South to Valley North to Vista Project to quantify the overall benefits accrued over 30-year study horizons. The benefits are quantified as the difference between baseline and the Valley South to Valley North to Vista Project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-48 below for all three forecasts.

Table 5-48 Cumulative Benefits – Valley South to Valley North to Vista

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	26,508.24	19,220.96	26,468.48
N-1	EENS (MWh)	600.25	2,752.65	11,817.15
N-1	IP (MW)	-118.05	-149.80	-91.15
N-1	SAIDI (hr)	426.51	277.20	3,748.24
N-1	SAIFI	5.16	1.39	7.53
N-1	PFD (hr)	863.50	1,077.50	1,485.50
N-1	Flex-1 (MWh)	146,671.17	233,804.50	465,583.98
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,420.75	2,322,663.11
N-0	EENS (MWh)	22,612.50	53,699.90	91,348.65
N-0	IP (MW)	2,637.80	3,568.80	3,422.00
N-0	SAIDI (hr)	444.79	3,260.78	11,500.94
N-0	SAIFI	16.49	59.90	105.53
N-0	PFD (hr)	398.50	725.00	824.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista Project. The project by design includes permanent transfer of large load centers in Valley South during initial years. This provides significant N-0 system relief in Valley South, but at the expense of limited operational flexibility. However, it is observed that the solution does not completely address the N-0 overload condition on the Valley South System transformers. However, the transformer overload condition is propagated to the Valley North System transformers starting from year 2041 in the Effective PV forecast. The project also includes transfer of load from the Valley North System to Vista System. This temporarily remedies the system overload but does not provide relief over the long-term horizon. The solution does not address N-1 violations in the system. This is primarily because the topological changes do not significantly alter the configuration of Valley Substation. In fact, several overloads are aggravated in the system post project in service.

5.3.6.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided in the near-term and long-term horizons until the year 2043. However, the transfer of loads result in overloads on the Valley North System transformers in year 2041, with transfer of loads to Vista system. Under N-0, EENS of 852 MWh is recorded in the Effective PV Forecast for 2048 and 9,000

MWh in the Spatial Base Forecast. Across all sensitivities, the benefits range between 22.6 to 91.3 GWh of avoided EENS.

2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 0.60 to 11.8 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. During potential HILP events affecting Valley Substation, the design of this project does not provide the ability to recover load in the Valley South System through leveraging capabilities of its system tie-lines.
5. Overall, Valley South to Valley North to Vista did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system

The project does not satisfy all project objectives, has a low project capital cost, and low implementation difficulty.

5.3.7 Centralized BESS in Valley South Project (Project H)

The premise of this solution is to utilize battery energy storage systems (BESS) to be appropriately sized for meeting the reliability needs of the system. Storage has been separately sized for each of the forecasts under consideration and their performance has been evaluated. Two locations in the Valley South System are considered, near SCE's existing Pechanga and Auld Substation respectively, with a maximum capacity to accommodate 200 MW each. The project has been evaluated under need year[28], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3

5.3.7.1 Description of Project Solution

The proposed project would include the following components:

1. Point of interconnection would be near Pechanga and/or Auld Substations following construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
2. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.
3. In order to meet the future needs of the Valley South System from 2021/2022 to 2048, the following storage sizes have been established. Sizing analysis has been performed for all forecasts on a 5-year outlook i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026. The incremental storage sizes are presented in Table 5-49 and Table 5-51.

[28] 2022 and 2021, depending on need year from forecast under study

4. Due to the radial design of the Valley South System under study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
5. In the Valley South system, a contingency reserve is maintained of 10 MW,50 MWh in accordance with SCE planning criteria and guidelines for N-1 conditions.

Table 5-49 Storage Sizing and Siting – Spatial Base Forecast

Storage MW and MWh				
	Pechanga		Auld	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2021	110	433		
2026	64	436		
2031	36	279	28	227
2036			61	485
2041			54	491
2046			18	191
Total Battery Size (including contingency)	**371 MW/ 2542 MWh**			

Table 5-50 Storage Sizing and Siting – Effective PV Forecast

Storage MW and MWh				
	Pechanga		Auld	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2022	71	216		
2027	47	281		
2032	57	377		
2037	34	264	18	153
2042			46	375
Total Battery Size (including contingency)	**273 MW/ 1666MWh**			

Table 5-51 Storage Sizing and Siting – PVWatts Forecast

Storage MW and MWh - PVWatts		
	Pechanga	
Year	Total Battery Size	
	MW	MWh
2022	68	216
2027	5	31
2032	46	237
2037	45	286
2042	38	299
Total Battery Size (including contingency)	**202 MW/ 1069 MWh**	

Figure 5-9 presents a high-level representation of the proposed configuration. The proposed configuration would loop into or tap along the Pechanga to Pauba circuit and Auld to Moraga circuit.

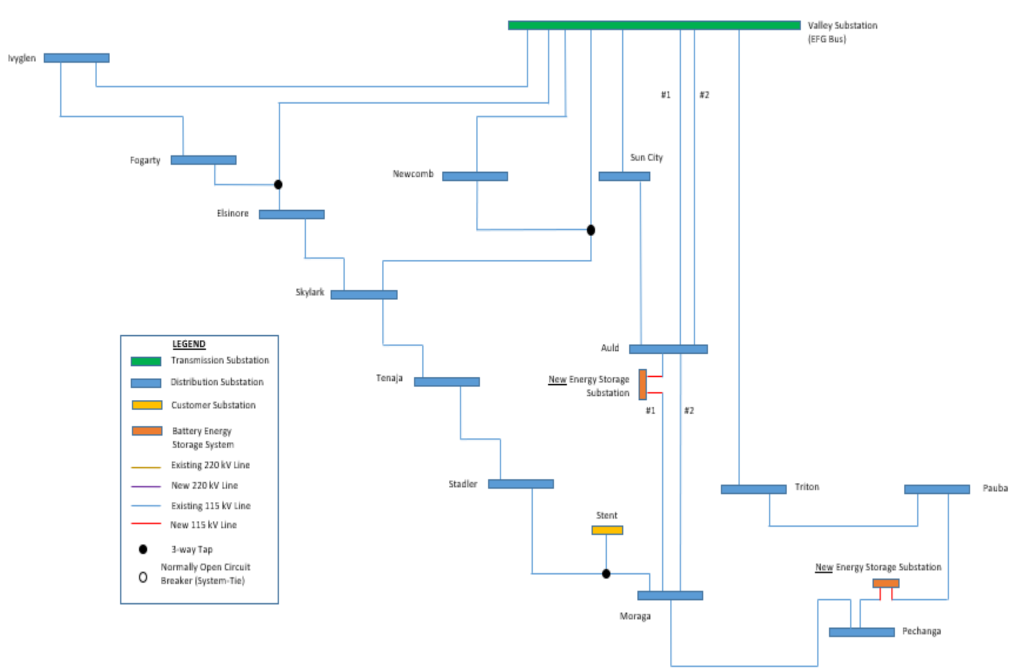


Figure 5-9 Energy storage at Pechanga and/or Auld Substation as part of the Centralized BESS in Valley South project scope.

5.3.7.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-52 for the Effective PV Forecast, Table 5-53 for the Spatial Base Forecast and Table 5-54 for the PVWatts Forecast.

Table 5-52 Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,531
2028	0	0	0	0	0	0	50,808
2033	0	0	0	0	0	0	52,705
2038	0	0	0	0	0	0	54,602
2043	0	0	0	0	0	0	56,499
2048	0	0	0	0	0	0	58,396

Table 5-53 Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	48,908
2022	0	0	0	0	0	0	49,636
2028	0	0	0	0	0	0	52,664
2033	0	0	0	0	0	0	55,188
2038	0	0	0	0	0	0	57,711
2043	0	0	0	0	0	0	60,235
2048	0	0	0	0	0	0	62,758

Table 5-54 Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,531
2028	0	0	0	0	0	0	50,808
2033	0	0	0	0	0	0	50,455
2038	0	0	0	0	0	0	52,037
2043	0	0	0	0	0	0	53,618
2048	0	0	0	0	0	0	55,199

5.3.7.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-55 for the Effective PV Forecast, Table 5-56 for the Spatial Base Forecast and Table 5-57 for the PVWatts Forecast.

Table 5-55 Centralized BESS N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,868	192,865	57,793	0
2028	0	0	0.00	0.00	0	5,564	201,538	74,566	0
2033	0	0	0.00	0.00	0	8,643	210,603	94,113	0
2038	0	0	0.00	0.00	0	11,723	220,085	116,383	0
2043	0	0	0.00	0.00	0	14,802	228,568	137,579	0
2048	0	0	0.00	0.00	0	17,882	234,771	153,645	0

Table 5-56 Centralized BESS N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	0	0	0	0	0	4,263	194,613	60,963	0
2022	0	0	0	0	0	6,462	197,970	67,380	0
2028	0	0	0	0	0	19,657	211,637	96,459	0
2033	0	0	0	0	0	30,652	222,543	122,423	0
2038	0	0	0	0	0	41,647	233,279	149,725	0
2043	0	0	0.00	0.00	0	52,643	242,925	175,812	0
2048	31	7	0.73	0.07	4	63,638	251,122	198,913	10

Table 5-57 Centralized BESS N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,868	192,865	57,793	0
2028	0	0	0.00	0.00	0	5,564	201,538	74,566	0
2033	0	0	0.00	0.00	0	6,877	201,766	75,038	0
2038	0	0	0.00	0.00	0	9,153	209,643	91,958	0
2043	0	0	0.00	0.00	0	11,430	216,849	108,598	0
2048	0	0	0.00	0.00	0	13,706	221,946	120,939	0

In analyzing the Centralized BESS in Valley South Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-58 only thermal violations associated with each constraint are reported.

Table 5-58 List of Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Valley EFG-Tap 22 #1	N-1	Valley EFG-Newcomb	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2048	-	-
Moraga-Tap 150	N-1	Skylark-Tenaja	2048	-	-

5.3.7.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Centralized BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and the Centralized BESS in Valley South.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-59 below for all three forecasts.

Table 5-59 Cumulative Benefits – Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	52,822.43	50,795.77	67,205.68
N-1	EENS (MWh)	6,374.80	21,683.80	73,274.95
N-1	IP (MW)	466.50	780.05	1,375.05
N-1	SAIDI (hr)	585.07	1,379.19	10,728.97
N-1	SAIFI	10.48	18.89	65.15
N-1	PFD (hr)	1,320.00	1,999.00	3,455.50
N-1	Flex-1 (MWh)	302,807.75	510,722.46	460,154.62
N-1	Flex-2-1 (MWh)	-	-	-

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-1	Flex-2-2 (MWh)	21,738.28	55,025.37	135,096.52
N-0	EENS (MWh)	22,750.50	56,580.70	140,938.80
N-0	IP (MW)	2,713.40	4,056.40	6,290.90
N-0	SAIDI (hr)	445.38	3,267.62	14,809.66
N-0	SAIFI	16.61	60.22	150.00
N-0	PFD (hr)	410.50	815.00	1,617.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Centralized BESS in Valley South. The project provides significant relief addressing the N-0 and N-1 needs in the Valley South system. However, the solution does not offer any flexibility in terms of system tie-lines and capabilities to support planned, unplanned and emergency conditions in the system. The batteries alone cannot complement the system needs during high impact low probability events since they are not configured to operate as micro-grids or a viable alternative to system tie-lines for extended events of extended duration.

5.3.7.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South transformer is avoided in the near term and long-term horizon. Across all sensitivities, the benefits range between 22.7 to 140.9 GWh of avoided EENS.
2. Minimal N-1 overloads are observable in the long-term horizon for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 6.3 to 73.2 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Due to HILP events affecting Valley Substation, the project is unable to serve incremental load in the Valley South System. The BESS installed capacity cannot be effectively be translated to any benefits due to limited opportunities for charging that could reasonably be expected during HILP events.
5. Overall, Centralized BESS in Valley South did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. While the project addressed N-0 and N-1 needs across the horizon, the solution offers limited flexibility benefits with higher implementation costs.

5.3.8 Valley South to Valley North and Distributed BESS in Valley South project (Project I)

The objective of this project is to transfer Newcomb and Sun City Substations to Valley North (identical to Project F) along with the procurement of distribution-system connected BESS (Utility scale DER) in the Valley South System. In this analysis, a load transfer from the Valley South System to the Valley North System precedes the investment in a distributed BESS. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however transformer loading would be at risk of exceeding rated capacity. Due to this, only the EENS (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on Valley North system have not been considered in the metrics. The project has been evaluated under need year[29], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

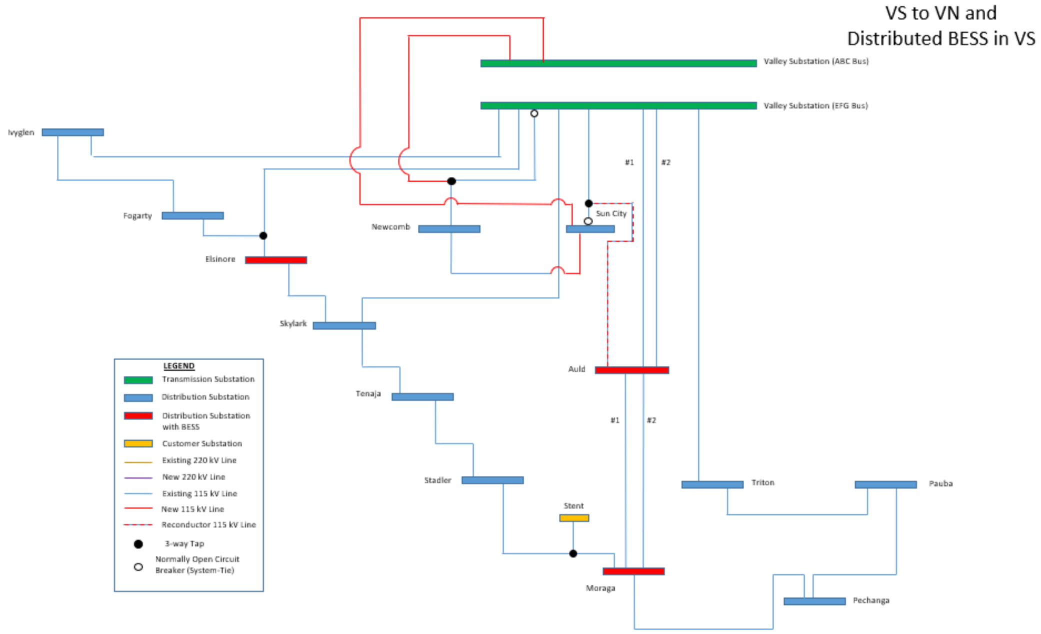
5.3.8.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through new 115 kV construction and reconfiguration.
2. Normally open circuit breakers at the Valley South System bus and at Sun City Substation are maintained as system tie-lines between the Valley North System and the Valley South System for transfer flexibility.
3. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceeds their rated capacity. The initial need year is identified as 2036 and 2043 in the Spatial Base and Effective PV forecasts, respectively. No procurements are required in the PVWatts forecast.
4. Storage investments totaling 50 MW are made at Auld, Elsinore, and Moraga Substations, which have been identified as having sufficient space to likely accommodate on-site BESS installations. The 50 MW total of BESS was modeled as 10 MW at Auld, 20 MW at Elsinore and 20 MW at Moraga Substation.

Figure 5-10 presents a high-level representation of the proposed configuration.

[29] 2022 and 2021, depending on need year from forecast under study



Schematic Representation. Not to scale.

Figure 5-10 Tie-lines between Valley South and Valley North and Distributed BESS in Valley South Project scope.

5.3.8.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-60 for the Effective PV Forecast, Table 5-61 for the Spatial Base Forecast and Table 5-62 for the PVWatts Forecast.

Table 5-60 Valley South to Valley North and Distributed BESS in Valley SouthN-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	51,777
2033	0	0	0	0	0	0	53,817
2038	136	14	2.891	0.160	4	18	55,858
2043	775	43	17.296	0.910	19	19	57,898
2048	2,567	156	139.417	2.099	57	66	59,923

Table 5-61 Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,723
2022	0	0	0	0	0	0	50,479
2028	0	0	0	0	0	0	53,801
2033	305	56	4.652	0.607	13	0	56,568
2038	2,389	143	140.282	2.807	51	0	59,310
2043	7,812	253	871.407	9.143	102	0	62,034
2048	16,176	371	2773.833	13.245	159	0	64,749

Table 5-62 Valley South to Valley North and Distributed BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	50,960
2033	0	0	0	0	0	0	51,342
2038	0	0	0.000	0.000	0	0	53,028
2043	94	49	0.706	0.118	6	0	54,713
2048	754	202	17.871	0.941	19	0	56,399

5.3.8.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-63 for the Effective PV Forecast, Table 5-64 for the Spatial Base Forecast and Table 5-65 for the PVWatts Forecast.

Table 5-63 Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	192	28	3.28	0.18	19	17,620	210,603	32,011	19
2038	605	38	21.12	0.56	39	23,898	220,085	43,191	37
2043	1,273	47	70.69	1.18	64	29,331	228,568	54,727	60
2048	2,087	87	167.36	1.94	92	31,383	234,771	64,235	86

Table 5-64 Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	12	6	0	0	4	4,239	194,613	17,164	4
2022	32	10	0	0	5	6,425	197,970	19,844	5
2028	216	28	4	0	23	19,544	211,637	33,148	23
2033	778	42	29	1	44	30,477	222,543	46,386	41
2038	1,816	80	136	2	85	38,032	233,279	60,818	81
2043	3,686	77	430.95	3.44	128	44,742	242,925	76,137	125
2048	6,012	135	949.35	5.61	176	51,452	251,122	89,857	169

Table 5-65 Valley South to Valley North and Distributed BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	61	15	0.45	0.06	8	11,732	201,766	23,155	8
2038	168	26	2.60	0.15	17	15,334	209,643	30,979	17
2043	430	36	11.51	0.40	30	18,936	216,849	39,179	29
2048	733	41	28.01	0.68	44	22,538	221,946	45,597	41

In analyzing the Valley South to Valley North and Distributed BESS in Valley South project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from 2022 and beyond).

In Table 5-66 only thermal violations associated with each constraint are reported.

Table 5-66 List of Valley South to Valley North and Distributed BESS in Valley South project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Valley South Transformer	N-0	N/A (base case)	2036	2043	-
Valley North Transformer	N-0	N/A (base case)	2030		-
Auld-Moraga #1	N-0	N/A (base case)	2038	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Auld-Moraga #1	N-1	Skylark-Tenaja	2038	-	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Valley EFG-Triton #1	N-1	Moraga-Pechanga	2043	2043	-
Auld-Moraga #1	N-1	Valley EFG - Triton	2043	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	-

5.3.8.4 Evaluation of Benefits

The established performance metrics were compared between baseline and Valley South to Valley North and Distributed BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-67 below for all three forecasts.

Table 5-67 Cumulative Benefits – Valley South to Valley North and Distributed BESS in Valley South

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	26,508.24	19,245.60	27,277.58
N-1	EENS (MWh)	600.25	4,734.15	22,620.65

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-1	IP (MW)	-118.05	-135.50	-199.15
N-1	SAIDI (hr)	426.51	399.28	4,874.71
N-1	SAIFI	5.16	3.17	18.11
N-1	PFD (hr)	863.50	1,058.50	1,506.50
N-1	Flex-1 (MWh)	146,671.17	251,553.61	554,249.41
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,420.75	2,347,495.11
N-0	EENS (MWh)	20,123.90	45,850.48	44,964.24
N-0	IP (MW)	1,909.80	3,415.74	2,967.05
N-0	SAIDI (hr)	388.94	2,871.72	2,993.34
N-0	SAIFI	13.32	49.36	47.47
N-0	PFD (hr)	327.50	561.09	329.74

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Distributed BESS in Valley South Project. The project by design includes permanent transfer of large load centers from the Valley South System during initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The presence of a distributed BESS solution in the Valley South System alleviates the capacity needs in the Valley South System in the PV effective forecast, but not under Spatial Base forecast sensitivity. Additionally, the transformer overload condition is propagated to the Valley North System transformers beginning in the year 2030 in the Spatial Base forecast. The solution does not offer relief to address N-1 violations in the Valley South System. This is primarily because the topological changes do not significantly alter the configuration of Valley Substation. With the Distributed BESS solution in service, incremental relief is provided under N-1 conditions.

5.3.8.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers are avoided in the near-term and long-term horizon until the year 2033. However, the transfer of loads result in overloads on the Valley North System transformers by year 2037. Under N-0, EENS of 2,600 MWh is recorded in the PV Effective Forecast for 2048, and 16,200 MWh is recorded under Spatial Base forecast sensitivity. Across all sensitivities, the benefits range between 20.1 to 44.9 GWh of avoided EENS.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 0.6 to 22.6 GWh through all forecasts.

3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Should a HILP event affect Valley Substation, this solution is unable to serve incremental load in Valley South System by leveraging the capabilities of system tie-lines. Additionally, the BESS capacity cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, Valley South to Valley North and Distributed BESS in Valley South Project did not demonstrate comparable levels of performance in addressing the needs identified in the Valley South System service territory. The project offers limited advantages in addressing the short-term and long-term needs of the system

5.3.9 SDG&E and Centralized BESS in Valley South (Project J)

This project proposes to construct a new 230/115 kV substation provided power by the San Diego Gas & Electric transmission system (identical to Project B). This solution is coupled with Centralized BESS in Valley South (identical to Project H) to provide further relief over the long-term horizon. The project has been evaluated under need year[30], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

5.3.9.1 Description of Project Solution

The proposed project would transfer Pechanga and Pauba substations to a new 230/115 kV transmission substation receiving 230 kV service from the SDG&E electric system. The proposed project would include the following components:

1. Point of interconnection would be a new 230/115 kV substation between the SCE-owned Pechanga Substation and SDG&E-owned Talega-Escondido 230 kV transmission line to the south. Two 230/115 kV transformers (one load-serving and one spare).
2. New double-circuit 230 kV transmission line looping the new substation into SDG&E's Talega-Escondido 230 kV transmission line.
3. New 115 kV line construction to allow transfer of Pechanga and Pauba Substations from Valley South to new 230/115 kV substation.
4. Create system tie-lines between the new 230/115 kV system and the Valley South System through normally open circuit breakers at SCE's Triton and Moraga Substations to provide operational flexibility and to accommodate potential future additional load transfers.
5. Rebuild of existing Pechanga Substation and/or expansion of existing property at Pechanga Substation to accommodate required new 115 kV switch rack positions.
6. BESS would be installed near Auld Substations following construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceeds their rated capacity. The following storage sizes have been established and detailed in Table 5-68 to Table 5-70 below, for all forecasts.
8. Sizing analysis has been performed for all forecasts on a 5-year outlook i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026.

[30] 2022 and 2021, depending on need year from forecast under study

9. At each site, a contingency reserve is maintained of 10 MW 50 MWh in accordance with SCE planning criteria and guidelines for N-1 conditions.

Table 5-68 Storage Sizing and Siting – Effective PV Forecast

Storage MW and MWh - Effective PV Forecast		
	Auld	
Year	Total Battery Size	
	MW	MWh
2039	65	189
2044	25	130
Total Battery Size (including contingency)	**90 MW/319 MWh**	

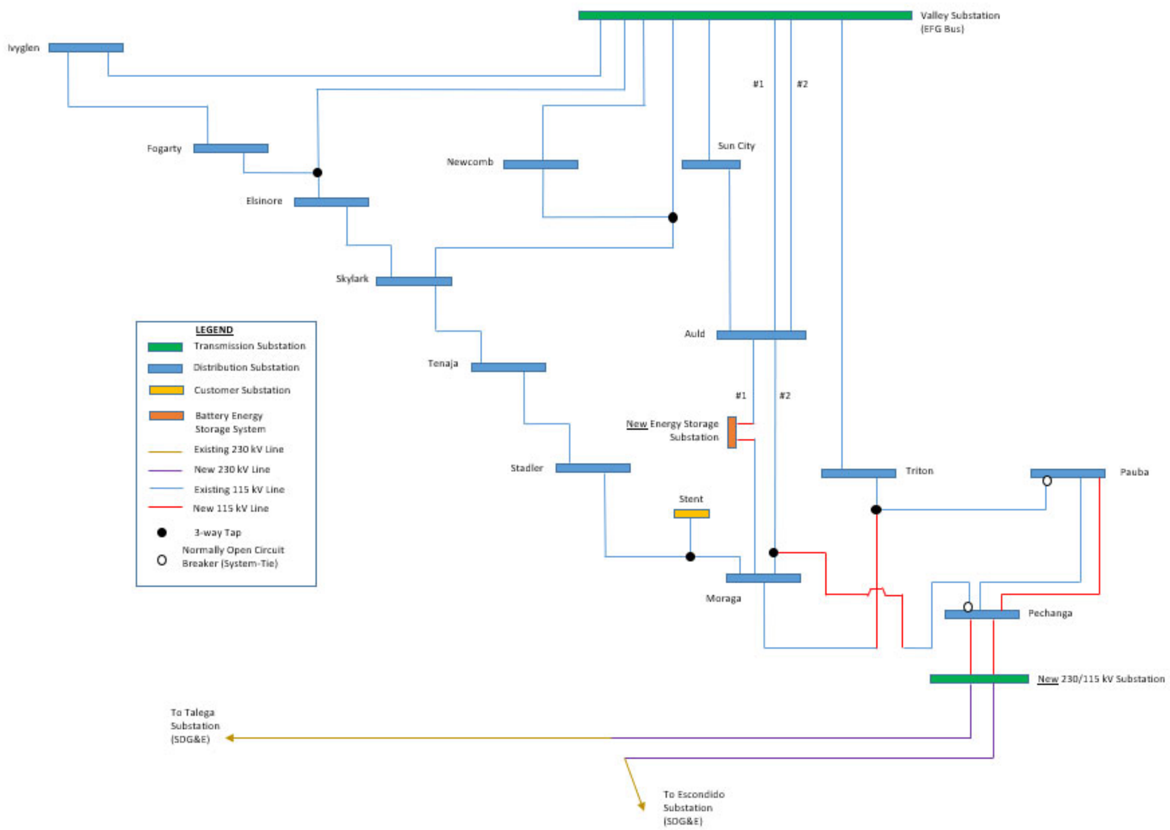
Table 5-69 Storage Sizing and Siting – Spatial Forecast

Storage MW and MWh - Spatial Base		
	Auld	
Year	Total Battery Size	
	MW	MWh
2033	82	262
2038	56	323
2043	49	323
Total Battery Size (including contingency)	**187 MW/908 MWh**	

Table 5-70 Storage Sizing and Siting – PVWatts Forecast

Storage MW and MWh - PVWatts		
	Auld	
Year	Total Battery Size	
	MW	MWh
2048	20	64
Total Battery Size (including contingency)	**20 MW/64 MWh**	

Figure 5-11 presents a high-level representation of the proposed configuration.



Schematic Representation. Not to scale.

Figure 5-11 SDG&E and Centralized BESS in Valley South Project Scope

5.3.9.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions in the system are presented in Table 5-71 for the Effective PV Forecast, Table 5-72 for the Spatial Base Forecast and Table 5-73 for the PVWatts Forecast.

Table 5-71 SDG&E and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	44,182
2028	0	0	0	0	0	0	46,553
2033	0	0	0	0	0	0	48,529
2038	0	0	0	0	0	0	50,505
2043	0	0	0	0	0	0	51,023
2048	0	0	0	0	0	0	51,176

Table 5-72 SDG&E and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	44,182
2022	0	0	0	0	0	0	44,715
2028	0	0	0	0	0	0	46,963
2033	0	0	0	0	0	0	48,837
2038	0	0	0	0	0	0	50,687
2043	0	0	0	0	0	0	52,537
2048	0	0	0	0	0	0	54,387

Table 5-73 SDG&E and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	44,182
2028	0	0	0	0	0	0	46,553
2033	0	0	0	0	0	0	45,310
2038	0	0	0	0	0	0	46,470
2043	0	0	0	0	0	0	47,630
2048	0	0	0	0	0	0	48,790

5.3.9.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions in the system are presented in Table 5-74 for the Effective PV Forecast, Table 5-75 for the Spatial Base Forecast and Table 5-76 for the PVWatts Forecast.

Table 5-74 SDG&E and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,523	57,104	12,006	0
2028	0	0	0.00	0.00	0	3,969	63,631	17,792	0
2033	0	0	0.00	0.00	0	6,007	70,782	25,448	0
2038	0	0	0.00	0.00	0	8,045	78,642	35,134	0
2043	0	0	0.00	0.00	0	16,628	85,866	45,192	0
2048	0	0	0.00	0.00	0	26,848	91,166	53,403	0

Table 5-75 SDG&E and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	0	0	0	0	0	2,697	58,391	13,056	0
2022	0	0	0	0	0	5,668	60,909	15,232	0
2028	0	0	0	0	0	16,922	71,622	26,413	0
2033	0	0	0	0	0	26,300	80,726	37,913	0
2038	0	0	0	0	0	35,679	89,892	51,367	0
2043	0	0	0.00	0.00	0	38,756	98,133	65,410	0
2048	0	0	0.00	0.00	0	40,257	105,137	78,883	0

Table 5-76 SDG&E and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	1,523	57,104	12,006	0
2028	0	0	0.00	0.00	0	3,969	63,631	17,792	0
2033	0	0	0.00	0.00	0	9,532	63,808	17,964	0
2038	0	0	0.00	0.00	0	13,100	70,007	24,567	0
2043	0	0	0.00	0.00	0	16,669	75,927	31,653	0
2048	0	0	0.00	0.00	0	19,840	80,218	37,223	0

In analyzing the SDG&E and Centralized BESS in Valley South project, no constraints were found to be binding under N-0 and N-1 conditions.

5.3.9.4 Evaluation of Benefits

The established performance metrics were compared between baseline and SDG&E and Centralized BESS in Valley South to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E and Centralized BESS for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-77 below for all three forecasts.

Table 5-77 Cumulative Benefits – SDG&E and Centralized BESS

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	195,515.19	214,367.05	249,946.93

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-1	EENS (MWh)	6,374.80	21,683.80	73,367.35
N-1	IP (MW)	466.50	780.05	1,396.95
N-1	SAIDI (hr)	585.07	1,379.19	10,731.16
N-1	SAIFI	10.48	18.89	65.37
N-1	PFD (hr)	1,320.00	1,999.00	3,467.50
N-1	Flex-1 (MWh)	236,636.48	519,519.47	667,574.50
N-1	Flex-2-1 (MWh)	3,750,849.98	3,785,438.88	3,975,283.83
N-1	Flex-2-2 (MWh)	1,747,226.49	2,043,804.58	2,582,574.34
N-0	EENS (MWh)	22,750.50	56,580.70	140,938.80
N-0	IP (MW)	2,713.40	4,056.40	6,290.90
N-0	SAIDI (hr)	445.38	3,267.62	14,809.66
N-0	SAIFI	16.61	60.22	150.00
N-0	PFD (hr)	410.50	815.00	1,617.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the SDG&E and Centralized BESS in Valley South Project. With the BESS investments, the range of benefits are substantial in the N-1 category and N-0 category. However, the flexibility benefits offered by the solution are limited in comparison to ASP.

5.3.9.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the near term and long-term horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range between 22.7 to 140.9 GWh of avoided EENS.
2. With SDG&E and Centralized BESS in Valley South Project in service, the N-1 EENS benefits in the system range from 6.3 to 73.3 GWh through all forecasts. With the incremental investment in BESS, no N-1 overloads were observed in the system.
3. The project provides considerable flexibility to address planned and unplanned or emergency outages in the system while also providing benefits to address needs under high impact, low probability events that occur in the Valley System. However, these benefits are not as significant in comparison to ASP.
4. Should a HILP event occur and impact Valley Substation, the SDG&E and Centralized BESS in Valley South Project is able to recover approximately 280 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be

effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.

5. Overall, SDG&E and Centralized BESS Project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. The project design offers several advantages that are mostly realized in combination with storage investments.

5.3.10 Mira Loma and Centralized BESS in Valley South project (Alternatives K)

The objective of this alternative is to take advantage of the Mira Loma system to provide a new source of supply into the Valley South service area. To address capacity needs across the 30-year horizon, this solution is coupled with Centralized BESS in Valley South. This is essentially a combination of Projects E and H. The project has been evaluated under need year[31], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3.

5.3.10.1 Description of Project Solution

1. Construct new 220/115 kV substation with two transformers (including a spare) and associated facilities. The substation would be located near SCE's existing Mira Loma Substation and would be provided power by looping in an existing 220 kV line. The proposed project would construct new double-circuit 115 kV subtransmission lines from new 220/115 kV substation to Ivyglen Substation in the Valley South System.
2. Transfer load at Ivyglen and Fogarty Substations from the Valley South System to the new 220/115 kV system created.
3. Creates two system tie-lines between Valley South and new system at Valley Substation and Fogarty Substation respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. BESS would be installed near Pechanga or Auld Substations following construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
6. The initial BESS would be constructed near Pechanga Substation with an ultimate design capacity of 200 MW. Once this maximum value is reached, a subsequent and similar installation would be constructed near Auld Substation.
7. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceeds their rated capacity. The following storage sizes have been established and detailed in Table 5-78 to Table 5-80 below, for all forecasts.
8. Sizing analysis has been performed for all forecasts on a 5-year outlook i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026.
9. Due to the radial design of the Valley South System under study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.

[31] 2022 and 2021, depending on need year from forecast under study

10. At each site, a contingency reserve is maintained of 10 MW 50 MWh in accordance with SCE planning criteria and guidelines for N-1 conditions.

Table 5-78 Storage Sizing and Siting – Spatial Base Forecast

Storage MW and MWh - Spatial Base				
	Pechanga		Auld	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2026	99	299		
2031	52	373		
2036	61	463		
2041			54	427
2046			18	157
Total Battery Size	**284 MW/ 1719 MWh**			

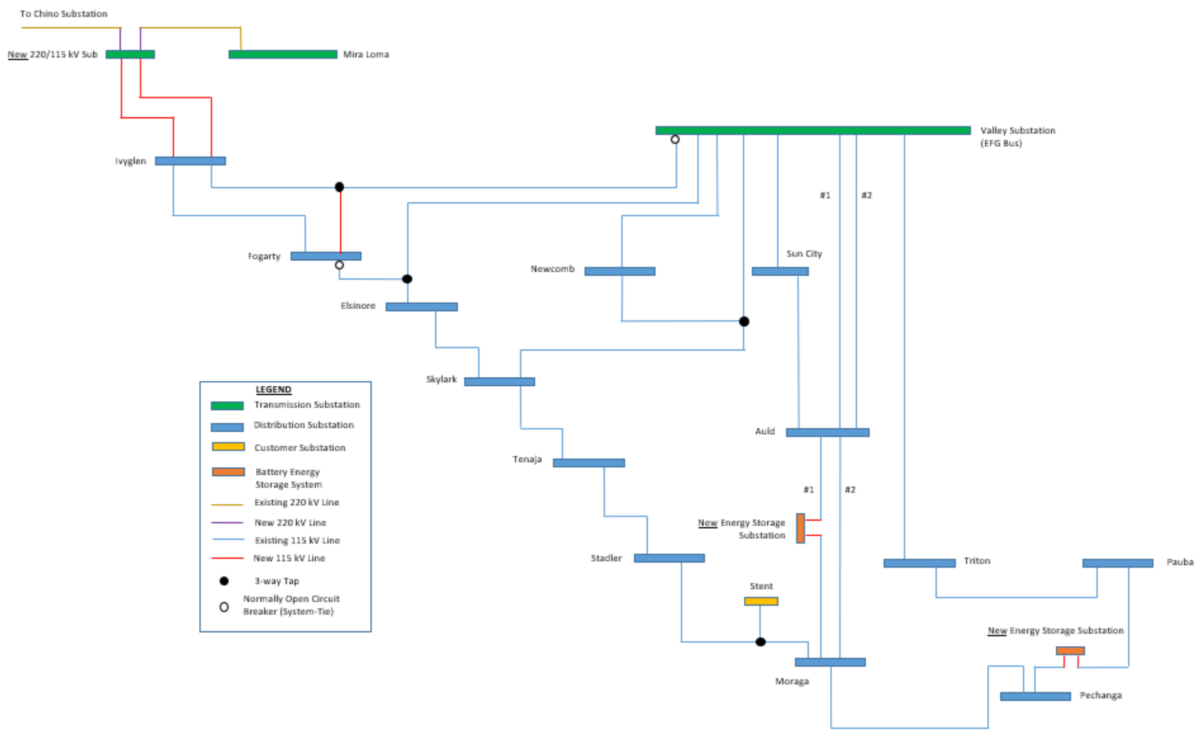
Table 5-79 Storage Sizing and Siting – Effective PV Forecast

Storage MW and MWh - SCE Effective PV		
	Pechanga	
Year	Total Battery Size	
	MW	MWh
2031	83	247
2036	48	303
2041	43	296
2046	12	106
Total Battery Size	186 MW/ 952 MWh	

Table 5-80 Storage Sizing and Siting – PVWatts Forecast

Storage MW and MWh - PVWatts		
	Pechanga	
Year	Total Battery Size	
	MW	MWh
2036	66	195
2041	34	194
2046	9	62
Total Battery Size	109 MW/ 451 MWh	

Figure 5-12 presents a high-level representation of the proposed configuration.



Schematic Representation. Not to scale.

Figure 5-12 Tie-line to Mira Loma and Centralized BESS in Valley South Project Scope

5.3.10.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-81 for the Effective PV Forecast, Table 5-82 for the Spatial Base Forecast and Table 5-83 for the PVWatts Forecast.

Table 5-81 Mira Loma and Centralized BESS in Valley South N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,456
2028	0	0	0	0	0	0	48,017
2033	0	0	0	0	0	0	50,408
2038	0	0	0	0	0	0	53,323
2043	0	0	0	0	0	0	56,238
2048	0	0	0	0	0	0	59,154

Table 5-82 Mira Loma and Centralized BESS in Valley South N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	48,849
2022	0	0	0	0	0	0	49,618
2028	106	38	0.423	0.106	4	4	42,629
2033	607	104	10.225	0.603	12	17	48,041
2038	1,449	172	41.743	1.439	29	29	53,453
2043	3,382	238	164.624	3.360	45	49	58,864
2048	4,994	294	441.584	4.962	69	89	64,276

Table 5-83 Mira Loma and Centralized BESS in Valley South N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	48,453
2028	0	0	0	0	0	0	50,945
2033	0	0	0	0	0	0	53,021
2038	58	24	0	0	4	4	55,097
2043	273	69	1.896	0.271	7	7	57,173
2048	526	184	56.774	1.892	30	30	59,250

5.3.10.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions in the system are presented in Table 5-84 for the Effective PV Forecast, Table 5-85 for the Spatial Base Forecast and Table 5-86 for the PVWatts Forecast.

Table 5-84 Mira Loma and Centralized BESS in Valley South N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	2,180	139,483	18,208	0
2028	24	10	0.13	0.03	5	6,493	147,439	25,978	5
2033	74	13	0.91	0.08	12	9,614	155,755	35,786	12
2038	143	15	4.27	0.15	29	12,522	164,453	47,823	29
2043	281	30	12.22	0.29	43	15,430	172,235	60,170	42
2048	244	27	13.98	0.25	59	17,302	177,925	70,326	55

Table 5-85 Mira Loma and Centralized BESS in Valley South N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	1	1	0	0	2	1,063	141,086	19,647	2
2022	11	4	0	0	4	2,091	144,166	22,589	4
2028	78	12	1	0	13	8,263	156,703	37,006	13
2033	193	25	6	0	32	13,405	166,708	51,240	32
2038	279	23	15	0	54	18,548	176,557	67,798	52
2043	447	36	32.08	0.46	75	23,691	185,405	84,795	69
2048	630	38	47.85	0.66	94	28,834	192,924	100,353	73

Table 5-86 Mira Loma and Centralized BESS in Valley South N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	0	0	0	0	0	2,180	139,483	18,207	0
2028	24	10	0.13	0.03	5	6,493	147,439	25,978	5
2033	27	11	0.14	0.03	5	5,964	147,648	26,202	5
2038	72	15	0.74	0.07	10	6,950	154,875	34,677	10
2043	106	14	2.63	0.11	24	7,644	161,485	43,499	24
2048	161	22	5.30	0.17	32	8,337	166,160	50,404	32

In analyzing the Mira Loma and Centralized BESS in Valley South project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-87 only thermal violations associated with each constraint are reported.

Table 5-87 List of Mira Loma and Centralized BESS in Valley South Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2023	2023
Valley EFG-Tap 39 #1	N-1	Valley EFG-Newcomb-Skylark	2048	-	-
Tap 39-Elsinore #1	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2038	2048	-
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Valley EFG-Tap 22#1	N-1	Valley EFG-Newcomb	2048	-	-

5.3.10.4 Evaluation of Benefits

The established performance metrics were compared between baseline and the Mira Loma and Centralized BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizons. The benefits are quantified as the difference between baseline and project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-88 below for all three forecasts.

Table 5-88 Cumulative Benefits – Mira Loma and Centralized BESS in Valley South

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	50,251.33	41,337.60	51,951.25
N-1	EENS (MWh)	4,795.52	18,393.70	66,422.10
N-1	IP (MW)	182.73	374.85	778.55
N-1	SAIDI (hr)	551.21	1,249.86	10,314.95
N-1	SAIFI	8.85	15.49	58.16
N-1	PFD (hr)	1,018.00	1,387.00	2,293.00
N-1	Flex-1 (MWh)	345,803.92	491,783.90	992,221.48
N-1	Flex-2-1 (MWh)	1,472,688.43	1,489,270.72	1,569,278.78
N-1	Flex-2-2 (MWh)	1,490,804.78	1,735,711.14	2,181,052.61
N-0	EENS (MWh)	22,750.50	56,580.70	140,938.80
N-0	IP (MW)	2,713.40	4,056.40	6,290.90
N-0	SAIDI (hr)	445.38	3,267.62	14,809.66
N-0	SAIFI	16.61	60.22	150.00
N-0	PFD (hr)	410.50	815.00	1,617.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Mira Loma and Centralized BESS in Valley South Project. The project completely addresses N-0 needs in the Valley South System. The project offers limited flexibility to support N-1 needs in the system accruing significant EENS in the short-term and long-term horizon. The capacity afforded by the system tie-lines does not fully support emergency and maintenance conditions in the system.

5.3.10.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided over the study horizon. This trend is observable across all considered forecasts. Across all sensitivities, the benefits range between 22.7 to 140.9 GWh of avoided EENS.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 4.7 to 66.4 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that may occur in the Valley System.
4. Should a HILP event occur and impact Valley Substation, the Mira Loma and Centralized BESS in Valley South Project is able to recover approximately 110 MW of load in the Valley South System by leveraging the capabilities of its system tie-lines. The BESS installed capacity alone cannot be effectively translated to any benefits due to the reasonably expected limited opportunities for charging during HILP events.
5. Overall, Mira Loma and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers limited advantage in addressing the N-1 and Flexibility needs of the system

5.3.11 Valley South to Valley North and Centralized BESS in Valley South and Valley North (Project L)

The objective of this project would be to transfer the loads at Newcomb and Sun City substations to Valley North (identical to Project #F). Additionally, BESS installation would be constructed within both the Valley South and North systems to provide relief over the long-term horizon. This is a combination of Projects F and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however transformer loading would be at risk of exceeding rated capacity. Due to this, only the EENS (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on Valley North system have not been considered in the metrics. The project has been evaluated under need year[32], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3

[32] 2022 and 2021, depending on need year from forecast under study

5.3.11.1 Description of Project Solution

The proposed project would include the following components:

1. The proposed project would transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through construction of new 115 kV lines.
2. Normally open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system tie-lines between Valley North and Valley South for transfer flexibility.
3. Reconductor existing Auld-Sun City 115 kV line which would become the Valley-Auld-Sun City 115 kV line.
4. BESS would be installed near Pechanga in Valley South and Allesandro Substation in Valley North following construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
5. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceeds their rated capacity. The following storage sizes have been established and detailed in Table 5-89 to Table 5-91 below, for all forecasts.
6. Sizing analysis has been performed for all forecasts on a 5-year outlook i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026.
7. At each site, a contingency reserve is maintained of 10 MW 50 MWh in accordance with SCE planning criteria and guidelines for N-1 conditions.

Table 5-89 Storage Sizing and Siting – Spatial Base Forecast

Storage MW and MWh - Spatial Base				
	Pechanga (VS)		Alessandro (VN)	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2030			97	375
2035(VS-2036)	81	242	77	635
2042 (VS-2041)	49	291	72	704
2045(VS-2046)	18	114	39	418
Total Battery Size	433 MW/ 2779 MWh			

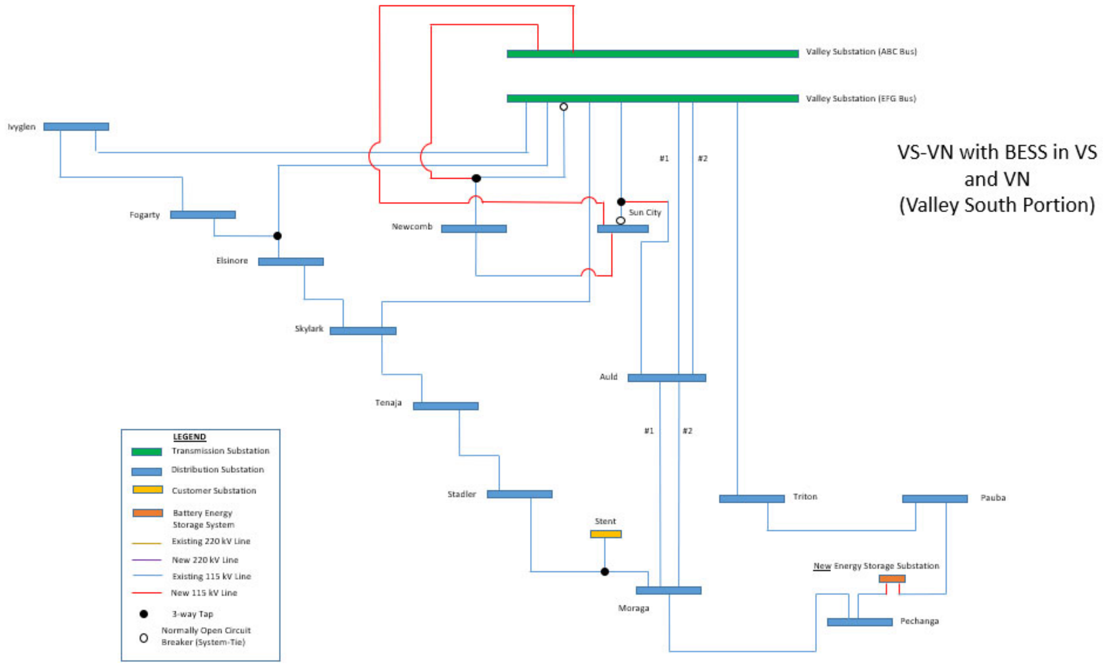
Table 5-90 Storage Sizing and Siting – Effective PV Forecast

Storage MW and MWh - Effective PV Forecast				
	Pechanga (VS)		Alessandro (VN)	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2037			83	290
2042 (VS-2043)	39	108	46	335
2046	10	42	18	165

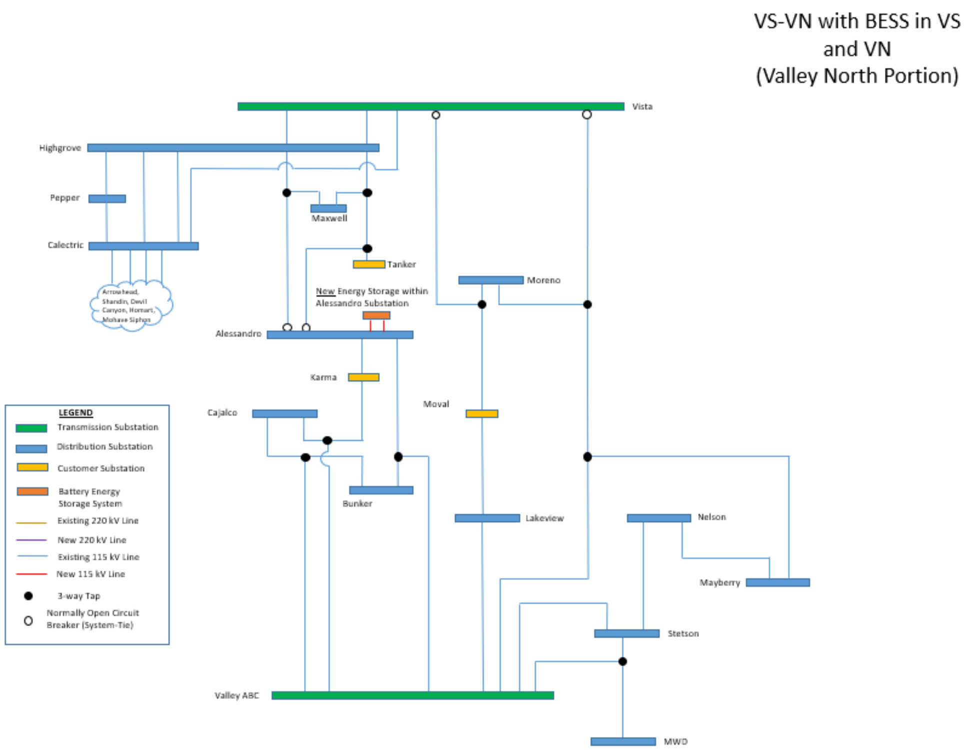
Total Battery Size (including Contingency)	196 MW/ 940 MWh

Table 5-91 Storage Sizing and Siting – PVWatts Forecast

Storage MW and MWh - PVWatts				
	Pechanga (VS)		Alessandro (VN)	
Year	Total Battery Size		Total Battery Size	
	MW	MWh	MW	MWh
2040	0	0	67	204
2045	0	0	27	140
Total Battery Size	94 MW/ 369 MWh			



Schematic Representation. Not to scale.



Schematic Representation. Not to scale.

Figure 5-13 Valley South to Valley North and Centralized BESS in Valley South and Valley North

5.3.11.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions are presented in Table 5-92 for the Effective PV Forecast, Table 5-93 for the Spatial Base Forecast and Table 5-94 for the PVWatts Forecast.

Table 5-92 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	51,777
2033	0	0	0	0	0	0	53,817
2038	0	0	0	0	0	0	55,858
2043	0	0	0	0	0	0	57,893
2048	0	0	0	0	0	0	59,910

Table 5-93 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,723
2022	0	0	0	0	0	0	50,479
2028	0	0	0	0	0	0	53,801
2033	0	0	0	0	0	0	56,568
2038	0	0	0	0	0	0	59,306
2043	0	0	0	0	0	0	62,024
2048	0	0	0	0	0	0	64,742

Table 5-94 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	50,960
2033	0	0	0	0	0	0	51,342
2038	0	0	0	0	0	0	53,028
2043	0	0	0	0	0	0	54,713
2048	0	0	0	0	0	0	56,399

5.3.11.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions are presented in Table 5-95 for the Effective PV Forecast, Table 5-96 for the Spatial Base Forecast and Table 5-97 for the PVWatts Forecast.

Table 5-95 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	5	3	0	0	3	3,808	192,865	15,864	3
2028	59	14	0.43	0.05	8	11,342	201,538	22,946	8
2033	191	28	3.26	0.17	19	17,620	210,603	32,011	19
2038	605	38	20.43	0.56	38	23,898	220,085	43,191	37
2043	1,295	47	70.29	1.20	63	28,049	228,568	54,725	58
2048	5	3	0	0	3	3,808	192,865	15,864	3

Table 5-96 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	12	6	0	0	4	4,239	194,613	17,164	4
2022	35	11	0	0	5	6,425	197,970	19,844	5
2028	219	28	5	0	23	19,544	211,637	33,148	23
2033	779	42	30	1	44	30,477	222,543	46,386	41
2038	1,725	80	124	2	81	37,158	233,279	61,842	77
2043	3,084	77	325.23	2.89	114	41,004	242,925	78,185	112
2048	4,662	145	647.64	4.39	151	44,851	251,122	93,441	148

Table 5-97 Valley South to Valley North and Centralized BESS in Valley South and Valley North N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	61	15	0.45	0.06	8	11,732	201,766	23,155	8
2038	168	26	2.60	0.15	17	15,334	209,643	30,979	17
2043	430	36	11.51	0.40	30	18,936	216,849	39,179	29
2048	733	41	28.01	0.68	44	22,538	221,946	45,597	41

In analyzing the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-98 only thermal violations associated with each constraint are reported.

Table 5-98. List of Valley South to Valley North and Centralized BESS in Valley South and Valley North Project System Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Auld-Moraga #1	N-1	Valley EFG - Triton	2038	2048	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.11.4 Evaluation of Benefits

The established performance metrics were compared between baseline and Valley South to Valley North and Centralized BESS in Valley South and Valley North Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-99 below for all three forecasts.

Table 5-99 Cumulative Benefits – Valley South to Valley North and Centralized BESS in Valley South and Valley North

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV Forecast	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	26,508.24	19,321.59	27,375.15
N-1	EENS (MWh)	600.25	5,318.95	30,258.23
N-1	IP (MW)	-118.05	-112.12	-224.05
N-1	SAIDI (hr)	426.51	485.59	6,392.56
N-1	SAIFI	5.16	3.70	25.03
N-1	PFD (hr)	863.50	1,097.50	1,677.50
N-1	Flex-1 (MWh)	146,671.17	278,473.49	594,548.74
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,679.52	2,322,663.11
N-0	EENS (MWh)	22,750.50	56,580.70	140,938.80
N-0	IP (MW)	2,713.40	4,056.40	6,290.90
N-0	SAIDI (hr)	445.38	3,267.62	14,809.66
N-0	SAIFI	16.61	60.22	150.00
N-0	PFD (hr)	410.50	815.00	1,617.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project. The project by design includes permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The solution completely addresses the N-0 system needs in the Valley South and Valley North Systems. Due to the investment in BESS resources scheduled over the long-term horizon, majority of the N-1 benefits are realized only in future years.

5.3.11.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloading on the Valley South System transformers is avoided in the near-term and long-term horizon. Additionally, the installation of batteries avoids the N-0 needs in the Valley North System following the transfer of load from the Valley South System. Across all sensitivities, the benefits range between 22.7 to 140.9 GWh of avoided EENS.

2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, N-1 EENS benefits in the system range from 0.6 to 30.25 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System through leveraging the capabilities of its system tie-lines.
5. Overall, Valley South to Valley North and Centralized BESS in Valley South and Valley North Project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers limited advantage in addressing the N-1 and Flexibility needs of the system

5.3.12 Valley South to Valley North to Vista and Centralized BESS in Valley South project (Project M)

The objective of this project would be to transfer the loads at Newcomb and Sun City substations to Valley North. The load at Moreno in the Valley North system would be transferred to the Vista system (identical to Project #G). The premise of this methodology is to relieve loading on the Valley North system to accommodate a load transfer from Valley South. Additionally, BESS is installed in Valley South to provide relief over the long-term horizon. This is essentially a combination of Projects G and H. Initial screening studies demonstrated that the load transfer would result in minimal line overloads (N-0 and N-1) in the Valley North system, however transformer loading would be at risk of exceeding rated capacity. Due to this, only the EENS (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on Valley North system have not been considered in the metrics. The project has been evaluated under need year[33], 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established by Section 3.2.4 have been calculated using the study methodology outlined by Section 3.2.3

5.3.12.1 Description of Project Solution

The proposed project would include the following components:

1. Moreno Substation is transferred to Vista 220/115 kV system through existing system tie-lines between Valley North and Vista Systems.
2. New 115 kV line construction to restore subtransmission network connectivity following transfer of Moreno Substation.
3. Normally open circuit breaker at Moreno Substation to provide a system tie-line between the Vista System and the Valley North System.
4. The proposed project would also transfer the loads at Newcomb and Sun City Substations from the Valley South System to the Valley North System through construction of new 115 kV lines (see Project F).
5. Normally open circuit breakers at the Valley South bus and at Sun City Substation are maintained as system ties between the Valley North System and the Valley South System for transfer flexibility.
6. Reconductor existing Auld-Sun City 115 kV line which would become the Valley-Auld-Sun City 115 kV line

[33] 2022 and 2021, depending on need year from forecast under study

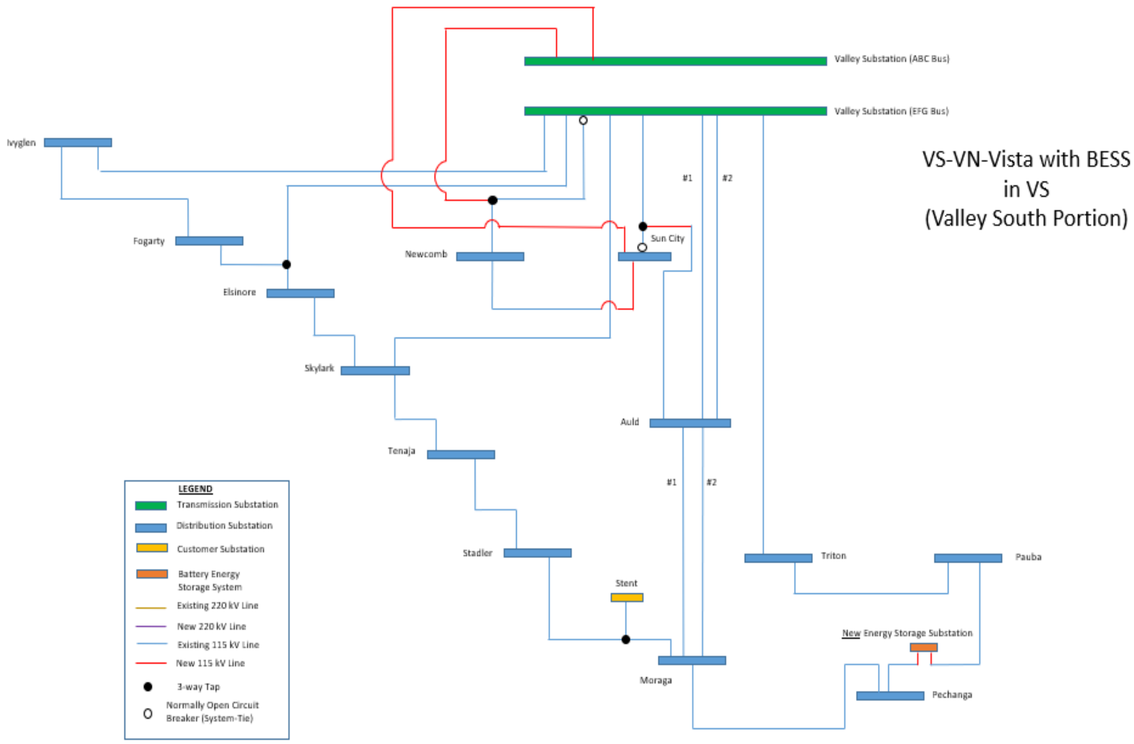
7. BESS would be installed near Pechanga Substation following construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
8. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceeds their rated capacity. The following storage sizes have been established and detailed in Table 5-100 to Table 5-101 below, for all forecasts. No batteries were required at Valley South in the PVWatts forecast.
9. Sizing analysis has been performed for all forecasts on a 5-year outlook i.e., in the year 2021, investments are made to cover the 5-year horizon till 2026.
10. At each site, a contingency reserve is maintained of 10 MW 50 MWh in accordance with SCE planning criteria and guidelines for N-1 conditions.

Table 5-100 Storage Sizing and Siting – Spatial Base Forecast

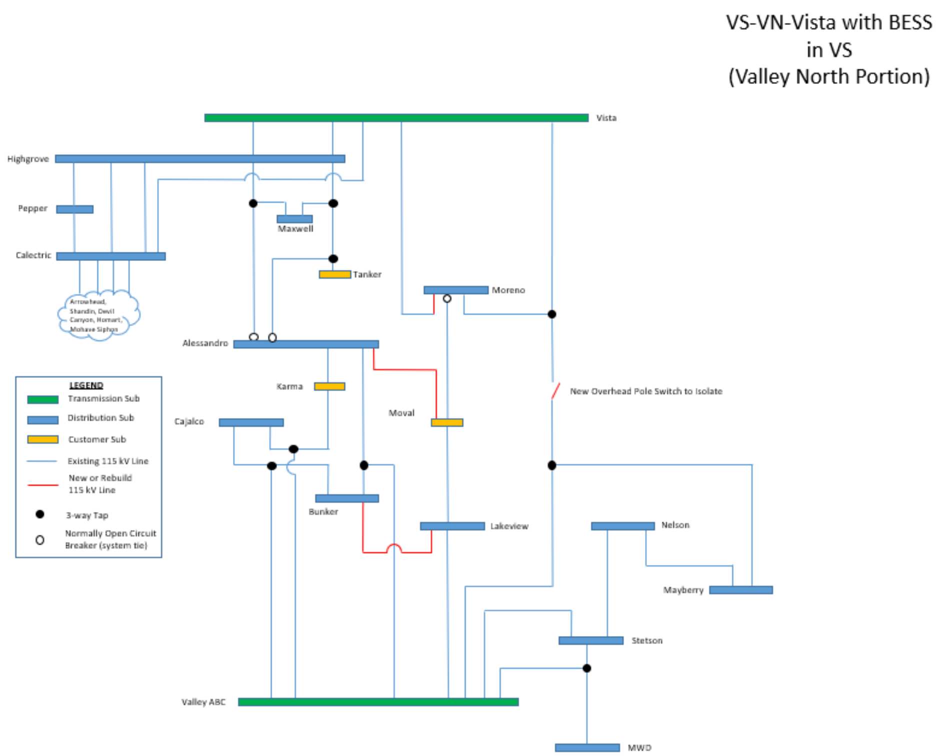
Storage MW and MWh - Spatial Base		
	Pechanga	
Year	Total Battery Size	
	MW	MWh
2036	81	242
2041	49	291
2046	18	114
Total Battery Size (including contingency)	148 MW/647 MWh	

Table 5-101 Storage Sizing and Siting – Effective PV Forecast

Storage MW and MWh - Effective PV Forecast		
	Pechanga	
Year	Total Battery Size	
	MW	MWh
2043	39	108
2046	10	42
Total Battery Size (including contingency)	49 MW/150 MWh	



Schematic Representation. Not to scale.



Schematic Representation. Not to scale.

Figure 5-14. Valley South to Valley North to Vista and Centralized BESS in Valley South

5.3.12.2 System Performance under Normal conditions (N-0)

Findings from system analysis under N-0 conditions in the system are presented in Table 5-102 for the Effective PV Forecast, Table 5-103 for the Spatial Base Forecast and Table 5-104 for the PVWatts Forecast.

Table 5-102 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	51,777
2033	0	0	0	0	0	0	53,817
2038	0	0	0	0	0	0	55,858
2043	78.2	30	0.108	0.018	5	6	57,893
2048	735.2	83.2	0.230	0.021	18	11	59,910

Table 5-103 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2021	0	0	0	0	0	0	49,723
2022	0	0	0	0	0	0	50,479
2028	0	0	0	0	0	0	53,801
2033	0	0	0	0	0	0	56,568
2038	676	81.2	9.989	0.588	17	17	59,306
2043	3415.6	161.6	172.187	2.969	58	58	62,024
2048	8000	232.2	761.032	7.389	103	103	64,742

Table 5-104 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-0 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	CAIDI (hr)	Losses (MWh)
2022	0	0	0	0	0	0	49,328
2028	0	0	0	0	0	0	50,960
2033	0	0	0	0	0	0	51,342
2038	0	0	0	0	0	0	53,028
2043	0	0	0	0	0	0	54,713
2048	67.8	36.6	0.295	0.059	5	5	56,399

5.3.12.3 System Performance under Normal Conditions (N-1)

Findings from system analysis under N-1 conditions in the system are presented in Table 5-105Table 4-11 for the Effective PV Forecast, Table 5-106 for the Spatial Base Forecast and Table 5-107 for the PVWatts Forecast.

Table 5-105 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Effective PV Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	5	3	0	0	3	3,808	192,865	15,864	3
2028	59	14	0.43	0.05	8	11,342	201,538	22,946	8
2033	191	28	3.26	0.17	19	17,620	210,603	32,011	19
2038	605	38	20.43	0.56	38	23,898	220,085	43,191	37
2043	1,295	47	70.29	1.20	63	28,049	228,568	54,725	58
2048	1,893	79	142.25	1.76	84	23,691	234,771	64,145	81

Table 5-106 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (Spatial Base Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2021	12	6	0	0	4	4,239	194,613	17,164	4
2022	35	11	0	0	5	6,425	197,970	19,844	5
2028	219	28	5	0	23	19,544	211,637	33,148	23
2033	779	42	30	1	44	30,477	222,543	46,386	41
2038	1,725	80	124	2	81	37,158	233,279	61,842	77
2043	3,084	77	325.23	2.89	114	41,004	242,925	78,185	112
2048	4,662	145	647.64	4.39	151	44,851	251,122	93,441	148

Table 5-107 Valley South to Valley North to Vista and Centralized BESS in Valley South Project N-1 System Performance (PVWatts Forecast)

Year	EENS (MWh)	IP (MW)	SAIDI (hr)	SAIFI	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)	CAIDI
2022	6	3	0	0	3	3,808	192,865	15,864	3
2028	58	15	0.42	0.05	8	11,342	201,538	22,946	8
2033	61	15	0.45	0.06	8	11,732	201,766	23,155	8
2038	168	26	2.60	0.15	17	15,334	209,643	30,979	17
2043	430	36	11.51	0.40	30	18,936	216,849	39,179	29
2048	733	41	28.01	0.68	44	22,538	221,946	45,597	41

In analyzing the Valley South to Valley North to Vista and Centralized BESS in Valley South project, the following constraints were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the EENS among other reliability metrics under study (reported from need year and beyond).

In Table 5-108 only thermal violations associated with each constraint are reported.

Table 5-108 List of Valley South to Valley North to Vista and Centralized BESS in Valley South Project Thermal Constraints

Overloaded Element	Outage Category	Outage Definition	Spatial Base	Effective PV	PVWatts
			Year of Overload		
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Auld-Moraga #1	N-1	Auld-Moraga #2	2021	2022	2022
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2038	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
Moraga-Tap 150 #1	N-1	Skylark-Tenaja	2048	-	-
Skylark-Tap 22 #1	N-1	Valley EFG-Elsinore-Fogarty	2033	2038	2043
Auld-Moraga #1	N-1	Valley EFG - Triton	2038	2048	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.12.4 Evaluation of Benefits

The established performance metrics were compared between baseline and Valley South to Valley North to Vista and Centralized BESS in Valley South Project to quantify the overall benefits accrued over 30-year study horizon. The benefits are quantified as the difference between baseline and project for each of the metrics.

The cumulative value of benefits accumulated over the 30-year horizon are presented in Table 5-109 below for all three forecasts.

Table 5-109 Cumulative Benefits – Valley South to Valley North to Vista and Centralized BESS in Valley South Project

Category	Component	Cumulative Benefits over 30-year horizon (until 2048) PVWatts Forecast	Cumulative Benefits over 30-year horizon (until 2048) Effective PV Forecast	Cumulative Benefits over 30-year horizon (until 2048) Spatial Base Forecast
N-0	Losses (MWh)	26,508.24	19,321.59	27,375.15
N-1	EENS (MWh)	600.25	5,318.95	30,258.23
N-1	IP (MW)	-118.05	-112.12	-224.05
N-1	SAIDI (hr)	426.51	485.59	6,392.56
N-1	SAIFI	5.16	3.70	25.03
N-1	PFD (hr)	863.50	1,097.50	1,677.50
N-1	Flex-1 (MWh)	146,671.17	278,473.49	594,548.74
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	1,585,237.85	1,848,679.52	2,322,663.11
N-0	EENS (MWh)	22,612.50	54,062.30	96,777.80
N-0	IP (MW)	2,637.80	3,686.80	4,379.90
N-0	SAIDI (hr)	444.79	3,266.49	11,620.65
N-0	SAIFI	16.49	60.08	110.31
N-0	PFD (hr)	398.50	741.00	939.00

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North to Vista and Centralized BESS in Valley South Project. The project by design includes permanent transfer of relatively large load centers in the Valley South System during the initial years. This provides significant N-0 system relief in the Valley South System, but at the expense of limited operational flexibility. The addition of batteries complements the needs in the Valley South System reducing EENS to zero effectively over the long-term horizon. The transfer of loads from the Valley North System to the Vista System avoid transformer overloads in Valley North until 2041. The solution does not offer relief to address N-1 violations in the system. With the investment in storage resources scheduled over the long-term horizon, the majority of the N-1 benefits are realized only in the future years.

5.3.12.5 Key Highlights of System Performance

The key highlights of system performance are as follows:

1. With the project in service, overloads on the Valley South System transformers is avoided in the near-term and long-term horizon. Additionally, transfer of loads from the Valley North System to the Vista System defers the N-0 condition needs in Valley North until 2041. Across all sensitivities, the benefits range between 22.6 to 96.7 GWh of avoided EENS.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, the N-1 EENS benefits in the system range from 0.6 to 30.2 GWh through all forecasts.
3. The project provides only limited flexibility to address planned, unplanned or emergency outages in the system and high impact, low probability events that occur in the Valley System.
4. Should a HILP event occur and impact Valley Substation, the project is unable to serve incremental load in the Valley South System by leveraging capabilities of its tie-lines.
5. Overall, Valley South to Valley North to Vista and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to ASP in addressing the needs identified in the Valley South System service territory. While the project addresses N-0 capacity shortages in the system, it offers limited advantage in addressing the N-1 and Flexibility needs of the system

5.4 Summary of Findings

Through the analysis of alternatives and applicable reliability metrics, EENS, and Flexibility (Flex-1 and Flex-2) provide valuable insight into the reliability, capacity, resiliency, and flexibility objectives of project performance. Table 5-110 to Table 5-112 present a summary of these findings across all forecasts.

Table 5-110 Cumulative Benefits: Effective PV Forecast

		Project ID							
Project name		Alberhill System project	San Diego Gas & Electric project	Valley South to Valley North to Vista	Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	Menifee	Mira Loma
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**
N-1	**EENS**	20.65	21.68	2.75	21.68	18.39	4.73	2.96	7.20
N-1	**Available Flex-1**	777.35	312.02	233.80	510.72	491.78	251.55	233.61	466.20
N-1	**Available Flex-2-1**	5426.24	3,785.44	0.00	0.00	1489.27	0.00	3368.62	1489.27
N-1	**Available Flex-2-2**	2872.78	2,043.80	1848.42	55.03	1735.71	1848.42	1848.42	1735.03
N-0	**EENS**	56.57	55.56	53.6999	56.58	56.58	45.85	56.23	42.09

Table 5-111 Cumulative Benefits: Spatial Base Forecast

		Project ID							
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**
N-1	**EENS**	66.74	72.69	11.82	73.27	66.42	22.62	12.98	18.32
N-1	**Available Flex-1**	1,410.77	579.27	465.58	460.15	992.22	554.25	461.61	676.79
N-1	**Available Flex-2-1**	5,837.74	3,975.28	0.00	0.00	1569.28	0.00	3542.65	1569.28
N-1	**Available Flex-2-2**	3,799.08	2,581.14	2322.66	135.10	2181.05	2347.50	2322.66	2174.92
N-0	**EENS**	140.57	132.23	91.35	140.94	140.94	44.96	135.61	85.89

Table 5-112 Cumulative Benefits: PVWatts Forecast

		Project ID							
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**
N-1	**EENS**	6.28	6.37	0.60	6.37	4.80	0.60	0.60	2.57

The following insights are established upon review of the project performance, system benefits, and overall needs in the Valley South system.

1. Valley South system is vulnerable to risk of unserved energy starting year 2022 under the Effective PV and PVWatts forecasts and year 2021 under the Spatial Base forecast. The Spatial Base forecast assumes current levels of DER adoption persist through the long-term horizon, whereas the other two forecasts adopt DER consistent with IEPR 2018 forecasts.
2. The unserved energy in the Valley South system continues to grow beyond the 10-year planning horizon. This drives the need for solutions that are capable of supporting long-term load growth trends in the Valley system.
3. The load forecast includes the expected levels of peak reduction from DER technologies over the long-term horizon. The amount of relief offered by the expected levels were determined to be insufficient to meet the needs in Valley South service territory.
4. Dependency on non-wire solutions, like centralized storage, drives large investments and requires periodic upgrades to keep pace with the load growth trend in the system. Although these solutions provide N-0 and N-1 relief, they offer limited flexibility to support planned, unplanned, and emergency operations in the system (including N-2 outages and HILP events).
5. Dependency on neighboring systems (Valley North and Mira Loma) provides limited relief in terms of N-0 and N-1 benefits. While some solutions address the needs in Valley South system, they aggravate the condition in their own service territory. For example, with transfer of loads to Valley North, the risk of transformer overload significantly increases in the Valley North service territory. Additional transfers from Valley North to its neighbors, provide limited relief over long-term horizon. These solutions are also restricted by the capabilities of the neighboring system during peak loading conditions.
6. A combination of storage and tie-lines to neighboring systems provide improved benefits in comparison to stand-alone non-wire alternatives. These benefits are realized because tie-lines can be leveraged in combination with local storage capacity. However, these solutions were found to require large investments, while only contributing towards N-0 objectives in the system. Although they offer improved flexibility and N-1 benefits, they are not sufficient to adequately meet all the needs in Valley South.
7. Wire-based alternatives offer the highest relief to meet the needs in the Valley South system. These solutions were found adequately meet the range of forecast sensitivities while meeting the overall project objectives. With the exception of the projects that did not meet the needs over the study horizon and those with significant implementation difficulty, wire-based alternatives offer the highest benefits.
8. In all considered forecasts, ASP provided the highest aggregated benefits. Aggregated benefits are derived from the cumulative value of EENS and Flex metrics that translate into capacity, reliability, resiliency and flexibility needs in the Valley South service area. ASP consistently provides the highest aggregated benefits across all considered forecasts.
9. From a capacity perspective, ASP, San Diego Gas and Electric and Hybrid solution (San Diego Gas and Electric and Centralized BESS in Valley South) provide the most relief. Taking into consideration the combination of Flexibility and Resiliency needs, ASP and San Diego Gas & Electric are the most preferable alternatives.

6 BENEFIT-COST ANALYSIS

6.1 Introduction

The objective of this task is to perform a detailed benefit-cost and risk analysis of the ASP and alternative projects introduced in chapter 5. This framework provides an additional basis for comparison of project performance while justifying the business case of each alternative in meeting the load growth and reliability needs of the Valley South system.

Benefit-Cost analysis is a commonly used tool in public policy discussion and decisions. Benefit is defined as a value of the impact of a project to a firm, a household, or society in general. This value can be either monetized or treated on a unit basis while dealing with reliability metrics like EENS, SAIDI, and SAIFI among other considerations. Net benefits are the total reductions in costs and damages as compared to the baseline, accruing to firms, customers, and society at large, excluding transfer payments between these beneficiary groups. All future benefits and costs are reduced to a present worth (NPV) using a discount rate, and an inflation rate, over the project lifetime.

Following the quantification of present worth of costs and benefits (Chapters 4 and 5), three different types of analysis have been considered to provide a comprehensive view of the value attributed to each project. These are traditional benefit-cost analysis, $/Unit Benefit analysis, and Incremental benefit-cost analysis. These analyses use non-monetized and monetized benefits consistent with the methodology described in Section 3.3 over the 30-year study horizon.

6.2 Benefit-Cost Calculation Spreadsheet

All the findings within this chapter are maintained in a spreadsheet outlining the calculations and associated costs. Hence, three spreadsheets[34] are provided that cover three study forecasts (Spatial Base, Effective PV, and PVWatts).

The key elements within the spreadsheet are addressed in individual tabs are briefly introduced.

- Summary
    - Summarizes the study results and findings.

- Incremental Benefit Cost Analysis
    - Results and rankings from incremental benefit cost analysis.

- Cost Assumptions
    - Outlines the key study inputs and assumptions.

- Baseline System Analysis
    - Raw reliability Indices.
    - Monetized value of the baseline reliability metrics.

[34] The three Excel spreadsheets are attached to this report.

Each spreadsheet address the following information as an individual tab for each alternative project.

- Benefit-cost Quantification to Baseline System
  - Raw reliability indices.
  - Monetized value of project reliability metrics.
  - Comparison of each project against baseline system performance.

6.3 Results from Benefit-Cost analysis

The benefit-cost analysis is performed for all three forecasts under consideration, consistent with the methodology described in Section 3.3, and the study results for the following 13 alternative projects are present.

A. Alberhill System
B. San Diego Gas & Electric
C. SCE Orange County
D. Menifee
E. Mira Loma
F. Valley South to Valley North
G. Valley South to Valley North to Vista
H. Centralized BESS in Valley South
I. Valley South to Valley North and Distributed BESS in Valley South
J. SDG&E and Centralized BESS in Valley South
K. Mira Loma and Centralized BESS in Valley South
L. Valley South to Valley North and Centralized BESS in Valley South and Valley North
M. Valley South to Valley North to Vista and Centralized BESS in Valley South

6.3.1 Project Costs

The cost for each project is provided by SCE, in the PVRR and Aggregated (Total Capital Expenditure) representation. The PVRR costs include the investment costs and project expenses and calculated using applicable discount rate. The cost of components associated with the design of projects are aggregated to develop the Total capital expenditure. For projects that includes BESS, the PVRR costs are offset by revenues generated from market participation. Information regarding the scope of project have been summarized in Chapter 4 and 5.

Table 6-1 provides the present worth and aggregated costs associated with each project. For BESS-based solutions, the cost varies as a function of the forecast under study. Table 6-2 provides the present worth of market participation revenues for BESS-based solution.

Table 6-1 Project cost (PVRR and Capex)

#	Project	Effective PV Forecast		Spatial Base		PVWatts	
		Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)	Present Worth ($M)	Aggregated ($M)
A	Alberhill System Project	$545	$545	$545	$545	$545	$545
B	SDG&E	$469	$540	$469	$540	$469	$540
C	SCE Orange County	$806	$951	$806	$951	$806	$951
D	Menifee	$315	$358	$315	$358	$315	$358
E	Mira Loma	$290	$328	$290	$328	$290	$328
F	Valley South to Valley North	$185	$190	$185	$190	$185	$190
G	Valley South to Valley North to Vista	$270	$285	$270	$285	$270	$285
H	Centralized BESS in Valley South	$575	$1,474	$923	$2,363	$417	$1,004
I	Valley South to Valley North and Distributed BESS in Valley South	$201	$295	$213	$324	$185	$190
J	SDG&E and Centralized BESS in Valley South	$559	$923	$701	$1,473	$504	$685
K	Mira Loma and Centralized BESS in Valley South	$571	$1,358	$829	$2,156	$429	$881
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$358	$1,139	$726	$2,582	$239	$538
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$291	$470	$400	$951	$270	$285

Table 6-2 Present Worth of Market Participation Revenues

#	Project	Effective PV Forecast	Spatial Base	PVWatts
		Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)	Present Worth of Market Participation Revenue ($M)
H	Centralized BESS in Valley South	$70	$109	$47
I	Valley South to Valley North and Distributed BESS in Valley South	$2	$5	-
J	SDG&E and Centralized BESS in Valley South	$5	$19	-
K	Mira Loma and Centralized BESS in Valley South	$25	$57	$8
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$12	$57	$4
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2	$11	-

6.3.2 Baseline system Analysis

From the baseline system, the raw reliability indices computed in 4.2 are reflective of overall impact to customers in the Valley South service territory. The monetization of EENS and Flexibility benefits demonstrate the aggregated cost impact to customers in the region. All benefits have been monetized consistent with the methodology outlined in in Section 3.3 and derived as present worth. Table 6-3 below presents the costs associated with each monetized category.

Table 6-3 Baseline system Monetization

		Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Residential (N-1)	Monetized EENS ($)	1,363,590	4,652,003	355,031
Commercial(N-1)	Monetized EENS ($)	5,658,198	19,303,420	1,473,194
Aggregate	Monetized EENS ($)	7,021,788	23,955,422	1,828,225
Residential (N-0)	Monetized EENS ($)	55,025,531	122,402,385	24,322,737
Commercial(N-0)	Monetized EENS ($)	242,736,972	524,690,134	111,616,614
Aggregate	Monetized EENS ($)	297,762,503	647,092,520	135,939,351
Residential (N-0)	Monetized Value for Flex-1 ($)	988,376,054	1,642,693,710	712,935,284
Commercial(N-0)	Monetized Value for Flex-1 ($)	4,071,746,130	6,767,294,420	2,937,031,377

		Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Aggregate	Monetized Value for Flex-1 ($)	5,060,122,184	8,409,988,130	3,649,966,661
Residential	Monetized Value for Flex-2 ($)	134,980,721	148,280,873	126,326,350
Commercial	Monetized Value for Flex-3 ($)	583,334,131	637,917,498	547,594,065
Aggregate	Monetized Value for Flex-4 ($)	718,314,852	786,198,371	673,920,415
Aggregate ($M)		6,083	9,867	4,462

The results demonstrate that the aggregated range of cost impacts accrued by the customer range from 4.4$B to 9.8$B over the horizon of forecast uncertainties captured by this analysis. Projects that effectively reduce the customer costs in all benefit categories are most suitable to address the growing needs in Valley South system.

6.3.3 Benefit-Cost Analysis

The ratio of benefit-cost has been derived across the long-term study horizon. The costs are adopted from Table 6-1 and the monetized benefits are derived using the methodology in Section 3.3. Only relevant benefit categories have been monetized where the energy unserved component is calculated, including EENS, Flex-1, Losses, and Flex-2.

Table 6-4 to Table 6-6 exhibit the benefit to cost ratio for the 13 alternatives under three forecasts, wherein alternatives can be ranked against the benefit to cost ratio.

Table 6-4 SCE Effective PV Forecast – BC Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
H	Mira Loma	$3,548	12.23
A	Alberhill System Project	$6,063	11.12
M	Valley South to Valley North	$1,948	10.53
F	Valley South to Valley North and Distributed BESS in Valley South	$2,012	10.01
L	SDG&E and Centralized BESS in Valley South	$4,373	7.82
C	Valley South to Valley North to Vista	$1,988	7.36
K	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,140	7.35
G	Menifee	$2,262	7.18
E	Mira Loma and Centralized BESS in Valley South	$3,740	6.55
D	Centralized BESS in Valley South	$3,633	6.32
I	SCE Orange County	$5,095	6.32
B	SDG&E	$2,939	6.27
J	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,149	6.00

Table 6-5 SCE Spatial Base Forecast – BC Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
A	Alberhill System Project	$9,839	18.05
F	Valley South to Valley North	$3,270	17.68
I	Valley South to Valley North and Distributed BESS in Vall	$3,628	17.03
E	Mira Loma	$4,774	16.46
G	Valley South to Valley North to Vista	$3,466	12.84
D	Menifee	$3,844	12.20
C	SCE Orange County	$8,265	10.25
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$3,975	9.94
B	SDG&E	$4,597	9.80
K	Mira Loma and Centralized BESS in Valley South	$6,932	8.36
J	SDG&E and Centralized BESS in Valley South	$4,992	7.12
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$4,114	5.67
H	Centralized BESS in Valley South	$3,422	3.71

Table 6-6 PVWatts Forecast – BC Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
H	Mira Loma	$2,673	9.22
A	Alberhill System Project	$4,444	8.16
F	Valley South to Valley North and Distributed BESS in Valley South	$1,346	7.27
M	Valley South to Valley North	$1,346	7.27
E	Mira Loma and Centralized BESS in Valley South	$2,766	6.45
J	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,357	5.68
D	Centralized BESS in Valley South	$2,356	5.65
G	Menifee	$1,619	5.14
L	SDG&E and Centralized BESS in Valley South	$2,568	5.09
C	Valley South to Valley North to Vista	$1,356	5.02
K	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,356	5.02
B	SDG&E	$2,209	4.71
I	SCE Orange County	$3,720	4.62

As Table 6-4 demonstrates, for effective PV forecast the Mira Loma project renders the largest benefit to cost ratio of 12.2. Although the Mira Loma project has the largest benefit to cost ratio, its cost of $290M is 56% higher than the least expensive project; i.e. Valley South to Valley North with a cost of $185M (Table 6-1), while benefit-to-cost ratio is 16% higher. In other words, the Mira Loma additional benefits as compared against the Valley South to Valley North is less than the additional cost. Hence, by using the benefit to cost ratio, the actual cost and benefit amounts are not individually considered, and projects are sufficiently not compared.

The best project among a set of alternative projects is not necessarily the one that maximizes the benefit to cost ratio. To conduct a correct selection among alternative projects with widely disparate benefits an incremental analysis approach to evaluating benefits and costs is necessary [2]. This approach is presented in Section 6.3.4.

6.3.4 Incremental Benefit-Cost Analysis

As described earlier, the incremental analysis starts with ranking alternatives in the order of increasing present worth of costs with do-nothing as the baseline; i.e. alternative “0.” Then the incremental benefit to cost ratio between the baseline and the next expensive alternative is evaluated, which in this case is alternative F; i.e. Valley South to Valley North in. Alternative F versus baseline incremental benefit-cost ratio was evaluated using present worth of monetized benefits versus PVRR costs. Since the incremental benefits exceeds the cost outlay, the ratio is larger than unity, and the next expensive project “F” is selected. The selected alternative replaces the baseline. This selection is demonstrated as “0→F.”

At the next step, the second least expensive project; i.e. "I" is compared to baseline project "F." Project "I" was selected as the new baseline, as it demonstrated incremental benefits over project "F." The incremental benefit-cost analysis will continue by iterating between the baseline and next expensive alternative. The selection will stop once the incremental benefit cost ratio becomes unfavorable or the list is exhausted.

In general, a project is selected if its incremental benefits exceed its incremental cost. The selection can be qualitative for non-monetized benefits. As explained above, for monetized benefits, the next expensive project is selected over baseline if the incremental benefit to cost ratio is greater than 1.0. The process continues through the list of alternative projects, which are ranked in ascending cost order, until the list is exhausted.

For monetized benefits, the criteria to move forward to the next expensive project is considered as positive (total) aggregated value greater than unity. As one moves along the trajectory of least cost solutions, the more positive numbers are indicative of improved monetized benefits in each of the categories. If the next expensive alternative presents more favorable returns, and a decision to stop at the previous solution is made, it is representative of benefits that are available but not realized.

The incremental benefit cost analysis of the monetized benefits are presented in Table 6-8, Table 6-10 and Table 6-12 for the Effective PV, Spatial Base, and PVWatts forecasts respectively.

The incremental benefit cost analysis of non-monetized benefits are presented in Table 6-7, Table 6-9 and Table 6-11 for the Effective PV, Spatial Base, and PVWatts forecasts respectively. The selections were conducted qualitatively and are presented for reference only.

Table 6-7 Non-Monetized Benefits – Incremental Benefit Cost Analysis – Effective PV Forecast

Category		Alternative selection								
		0 → F	F → I	I → G	I → E	E → M	E → D	E → L	E → B	E → A
N-1	EENS	-2.16	-12.68	2.94	-6.18	479.49	29.74	7.05	-10.62	-7.02
N-1	IP	0.19	-0.08	0.02	-0.72	60.63	2.71	0.89	-0.69	-0.4
N-1	SAIDI	-0.08	-1.82	0.42	-0.51	36.57	3.03	0.54	-0.39	-0.26
N-1	SAIFI	0	-0.01	0	0	0.32	0.04	0	-0.01	-0.01
N-1	PFD	-1.44	0.13	-0.03	-0.69	55.02	2.33	0.81	-0.59	-0.37
N-1	Available Flex-1	-291.45	-100.22	23.24	-583.93	49538	2135.1	728.5	165.77	-281.29
N-1	Available Flex-2-1	0	0	0	-5649.03	502763.6	-25453.47	7393.58	-4340.61	-5075.61
N-1	Available Flex-2-2	-2855.24	0	0	353.28	-31464.4	-1257.68	-462.71	-475.34	-1137.07
N-0	EENS	-40.78	0.00	-12.81	3.32	-1103.77	-55.10	-20.71	-7.31	-5.52
N-0	IP	-4.14	-1.16	-0.32	2.11	-220.59	-9.80	-3.77	-1.24	-1.00
N-0	SAIDI	-1.92	-0.72	-0.54	-0.10	-29.13	-1.16	-0.43	-0.16	-0.11
N-0	SAIFI	-0.04	0.00	-0.02	0.00	-1.39	-0.05	-0.02	-0.01	-0.01
N-0	PFD	-0.64	-0.16	-0.26	0.10	-28.66	-1.37	-0.52	-0.18	-0.14
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	N	Y

Table 6-8 Monetized Benefits – Incremental Benefit Cost Analysis – Effective PV Forecast

Category		Alternative selection								
		0 → F	F → I	I → G	I → E	E → M	E →D	E → L	E → B	E →A
N-0	EENS	1.35	0.16	0.54	-0.23	57.02	2.57	0.98	0.33	0.26
N-0	Losses	0	0	0	0	-0.37	-0.01	-0.01	0.01	0.02
N-1	EENS	0.01	0.05	-0.01	0	0.19	-0.01	0	0.03	0.02
N-1	Flexibility-1	8.23	3.77	-0.87	16.31	-1359.91	-60.33	-20	-4.95	7.95
N-1	Flexibility-2-1	0	0	0	1.31	-116.49	5.89	-1.71	1.01	1.18
N-1	Flexibility-2-2	0.95	0	0	-0.12	11.05	0.44	0.16	0.17	0.44
Total	Aggregate	10.53	3.97	-0.34	17.26	-1408.14	-51.43	-20.57	-3.42	9.85
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	N	Y

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Table 6-9 Non-Monetized Benefits – Incremental Benefit Cost Analysis – Spatial Base Forecast

Category		Alternative selection							
		0 → F	F→ I	I → G	I →E	E → D	E → M	E → B	E → A
N-1	EENS	-7.95	-41.79	20.53	-0.03	30.12	-7.04	-38.85	-24.68
N-1	IP	0.18	0.71	-0.35	-1.04	2.96	0.75	-1.29	-0.71
N-1	SAIDI	-2.02	-4	1.96	-1.79	0.68	-0.1	-2.87	-1.77
N-1	SAIFI	0	-0.04	0.02	0	-0.01	-0.01	-0.04	-0.02
N-1	PFD	-1.97	-0.1	0.05	-1	2.24	0.52	-1.43	-0.92
N-1	Available Flex-1	-533.81	-350.76	172.3	-454.27	1825.78	282.42	118.77	-610.53
N-1	Available Flex-2-1	0	0	0	-6656.19	-25879.9	4659.33	-4415.29	-5295.44
N-1	Available Flex-2-2	-3380.97	-95.03	46.68	532.76	-1534.47	-348.74	-584.92	-1507.84
N-0	EENS	-58.95	0	-95.54	-62.55	-197.61	-9.71	-25.49	-21.28
N-0	IP	-4.54	-2.28	-1.88	1.96	-19.43	-3.29	-2.39	-2.26
N-0	SAIDI	-3.25	-0.33	-14.88	-11.65	-9.43	0.35	-1.32	-0.97
N-0	SAIFI	-0.06	-0.01	-0.13	-0.08	-0.19	-0.01	-0.03	-0.02
N-0	PFD	-0.66	-0.17	-1.28	-0.85	-3.27	-0.19	-0.41	-0.34
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	Y

Table 6-10 Monetized Benefits – Incremental Benefit Cost Analysis – Spatial Base Forecast

Category		Alternative selection							
		0 → F	F→ I	I → G	I →E	E → D	E → M	E → B	E → A
N-0	EENS	1.56	0.49	3.19	1.67	7.65	0.72	0.99	0.84
N-0	Losses	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
N-1	EENS	0.03	0.16	-0.08	-0.07	0.06	0.06	0.11	0.07
N-1	Flexibility-1	15.00	12.09	-5.94	11.96	-51.31	-7.09	-3.31	17.16
N-1	Flexibility-2-1	0.00	0.00	0.00	1.51	5.88	-1.06	1.00	1.21
N-1	Flexibility-2-2	1.09	0.04	-0.02	-0.18	0.52	0.12	0.20	0.56
Total	Aggregate	17.68	12.78	-2.85	14.88	-37.21	-7.26	-1.01	19.84
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	Y

Table 6-11 Non-Monetized Benefits – Incremental Benefit Cost Analysis – PVWatts Forecast

Category		Alternative selection							
		0 → I	I → F	I → L	L → G	L→ M	L → E	E→ D	E → H
N-1	EENS	-0.62	0.00	0.00	0.00	0.00	-7.83	15.98	-3.90
N-1	IP	0.16	0.00	0.00	0.00	0.00	-0.71	1.44	-0.74
N-1	SAIDI	-0.29	0.00	0.00	0.00	0.00	-0.24	0.50	-0.05
N-1	SAIFI	0.00	0.00	0.00	0.00	0.00	-0.01	0.01	0.00
N-1	PFD	-1.22	0.00	0.00	0.00	0.00	-0.97	1.98	-0.32
N-1	Available Flex-1	-211.58	0.00	0.00	0.00	0.00	-868.06	1770.83	10.14
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	0.00	-9795.98	-25328.97	3933.82
N-1	Available Flex-2-2	-2590.18	0.00	0.00	0.00	0.00	549.31	-1120.59	3525.26
N-0	EENS	-18.50	0.00	-4.45	0.36	0.44	6.90	-14.08	-2.77
N-0	IP	-2.85	0.00	-1.41	0.20	0.20	2.15	-4.38	-0.86
N-0	SAIDI	-0.27	0.00	-0.09	0.00	0.00	0.32	-0.65	-0.13
N-0	SAIFI	-0.01	0.00	-0.01	0.00	0.00	0.01	-0.03	-0.01
N-0	PFD	-0.40	0.00	-0.15	0.03	0.03	0.30	-0.61	-0.12
Decision to move forward (Y/N)		Y	N	Y	N	N	Y	N	N

Table 6-12 Monetized Benefits – Incremental Benefit Cost Analysis – PVWatts Forecast

Category		Alternative selection							
		0 → I	I → F	I → L	L → G	L→ M	L → E	E→ D	E → H
N-0	EENS	0.67	0	0.21	-0.02	-0.02	-0.35	0.72	0.14
N-0	Losses	0	0	0	0	0	0.01	-0.01	0
N-1	EENS	0	0	0	0	0	0.01	-0.02	0.01
N-1	Flexibility-1	5.74	0	0	0	0	24.08	-49.13	-0.58
N-1	Flexibility-2-1	0	0	0	0	0	2.27	5.86	-0.91
N-1	Flexibility-2-2	0.86	0	0	0	0	-0.19	0.39	-1.16
Total	Aggregate	7.27	0	0.21	-0.02	-0.02	25.81	-42.18	-2.5
Decision to move forward (Y/N)		Y	N	Y	N	N	Y	N	N

6.3.5 Levelized Cost Analysis ($/Unit Benefit)

Table 6-13 to Table 6-15 presents the $/Unit Benefit obtained for each alternative under evaluation. The levelized cost/benefit ratio for each reliability index (EENS through PFD) is calculated for each alternative. For example, in Table 6-13, 0.19 as listed under column A and row N-1 EENS is the ratio of Alberhill project $545 M (Table 6-1) net present cost to present worth of N-1 EENS over study horizon of 2,943 MWh.

A smaller N-1 EENS value implies a more cost-effective solution. Along each row the ratios are heat-map ranked, with green and red marking the favorable and unfavorable sides of the spectrum. The rightmost three columns, Alternative Rankings, identifies the first three project per reliability index. The table bottom row, Count of Rank #1, provides the frequency that an alternative ranked first.

Table 6-13 Levelized cost analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternat

Effective PV Forecast

		Alberhill System Project	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	SDG&E and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South
Reliability Metrics		A	B	C	D	E	F	G	H	I	J	K
N-1	**EENS ↓**	0.19	0.15	0.32	0.77	0.25	0.46	0.68	0.19	0.33	0.18	0.23
N-1	**IP ↓**	4.1	3.05	7.67	8.37	9.63	5.27	7.7	3.74	5.96	3.64	7.4
N-1	**SAIDI ↓**	3.5	2.94	5.4	23.38	3.25	12.93	18.88	3.61	4.62	3.51	4.02
N-1	**SAIFI ↓**	232.58	178.65	406.88	1893.17	390.87	1056.6	1542.06	219.03	565.52	212.93	275.56
N-1	**PFD ↓**	1.3	1.09	2.03	1.18	0.89	0.69	1.01	1.33	0.76	1.3	1.71
N-1	**Flex-1↓**	0.003	0.006	0.0053	0.0058	0.0027	0.0034	0.005	0.0049	0.0036	0.0044	0.0051
N-1	**Flex-2-1↓**	0.0003	0.0004	0.0006	0.0003	0.0006					0.0004	0.0011
N-1	**Flex-2-2↓**	0.0007	0.0008	0.0013	0.0006	0.0006	0.0004	0.0005	0.0692	0.0004	0.001	0.0011
N-0	**EENS ↓**	0.06	0.05	0.09	0.04	0.04	0.02	0.03	0.07	0.03	0.06	0.07
N-0	**IP ↓**	0.64	0.57	0.98	0.37	0.49	0.24	0.33	0.67	0.26	0.66	0.67
N-0	**SAIDI ↓**	1.35	1.16	2	0.78	0.77	0.52	0.67	1.42	0.55	1.38	1.41
N-0	**SAIFI ↓**	59.16	51.39	88.54	34.31	37.11	23.18	29.39	62.41	24.96	60.67	61.97
N-0	**PFD ↓**	3.72	3.29	5.64	2.17	2.61	1.57	1.95	3.92	1.68	3.81	3.89
Count of Rank #1		0	4	0	1	1	7	0	0	0	0	0

Table 6-14 Levelized cost analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternat

Spatial Base Forecast

		Alberhill System Project	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	SDG&E and Centralized BESS in Valley South	Mira Loma and Centralized BESS in Valley South
Reliability Metrics		A	B	C	D	E	F	G	H	I	J	K
N-1	**EENS ↓**	0.06	0.05	0.11	0.17	0.11	0.13	0.18	0.1	0.08	0.07	0.1
N-1	**IP ↓**	2.62	1.81	5.56	6.82	10.41	5.65	8.25	3.49	4.06	2.64	6.2
N-1	**SAIDI ↓**	0.51	0.41	0.76	0.52	0.47	0.49	0.72	0.81	0.44	0.62	0.77
N-1	**SAIFI ↓**	81.43	55.5	131.75	147.46	148.47	217.97	318.12	108.71	106.78	82.39	113.78
N-1	**PFD ↓**	0.8	0.67	1.31	0.81	0.65	0.51	0.74	1.31	0.58	1	1.67
N-1	**Flex-1↓**	0.0018	0.0038	0.0032	0.0032	0.002	0.0019	0.0027	0.0095	0.002	0.0053	0.0039
N-1	**Flex-2-1↓**	0.0003	0.0004	0.0006	0.0003	0.0006					0.0005	0.0016
N-1	**Flex-2-2↓**	0.0006	0.0007	0.0011	0.0005	0.0005	0.0003	0.0004	0.0458	0.0003	0.001	0.0014
N-0	**EENS ↓**	0.03	0.02	0.04	0.02	0.02	0.02	0.02	0.04	0.02	0.03	0.04
N-0	**IP ↓**	0.41	0.4	0.68	0.25	0.4	0.22	0.27	0.69	0.24	0.52	0.62
N-0	**SAIDI ↓**	0.31	0.27	0.46	0.18	0.19	0.31	0.19	0.53	0.35	0.4	0.47
N-0	**SAIFI ↓**	24.3	21.55	37.23	14.34	17.13	17.55	14.88	40.94	19.56	31.09	36.77
N-0	**PFD ↓**	1.96	1.77	3.02	1.15	1.78	1.52	1.35	3.25	1.68	2.47	2.92
Count of Rank #1		1	4	0	5	0	3	0	0	0	0	0

Table 6-15 Levelized cost analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternat

PVWatts Forecast

		Alberhill System Project	SDG&E	SCE Orange County	Menifee	Mira Loma	Valley South to Valley North	Valley South to Valley North to Vista	Centralized BESS in Valley South	Valley South to Valley North and Distributed BESS in Valley South	SDG&E and Centralized BESS in Valley South	Mira Loma and Centralize BESS in Valley Sout
Reliability Metrics		A	B	C	D	E	F	G	H	I	J	K
N-1	**EENS ↓**	0.54	0.46	0.96	2.75	0.56	1.62	2.36	0.41	1.62	0.5	0.57
N-1	**IP ↓**	5.64	4.68	10.1	10.36	51.56	6.08	8.88	4.16	6.08	5.03	9.82
N-1	**SAIDI ↓**	7.44	6.4	11.27	5.79	4.34	3.4	4.96	5.69	3.4	6.87	6.2
N-1	**SAIFI ↓**	375.64	318.58	624.96	483.84	296.96	284.16	414.72	283.26	284.16	342.35	354.79
N-1	**PFD ↓**	1.74	1.48	2.97	1.4	1.05	0.82	1.2	1.32	0.82	1.6	1.59
N-1	**Flex-1↓**	0.0041	0.0078	0.0071	0.008	0.0035	0.0047	0.0069	0.0051	0.0047	0.0067	0.005
N-1	**Flex-2-1↓**	0.0003	0.0004	0.0006	0.0003	0.0006					0.0004	0.0009
N-1	**Flex-2-2↓**	0.0008	0.0009	0.0014	0.0007	0.0006	0.0004	0.0006	0.1205	0.0004	0.001	0.001
N-0	**EENS ↓**	0.15	0.13	0.22	0.09	0.09	0.05	0.07	0.11	0.05	0.14	0.12
N-0	**IP ↓**	0.9	0.78	1.34	0.52	0.59	0.35	0.45	0.69	0.35	0.84	0.71
N-0	**SAIDI ↓**	10.08	8.67	14.9	5.82	7.66	3.77	5	7.71	3.77	9.32	7.93
N-0	**SAIFI ↓**	187.42	161.3	277.18	108.33	131.84	70.97	93.17	143.4	70.97	173.32	147.53
N-0	**PFD ↓**	6.65	5.73	9.83	3.84	4.35	2.5	3.33	5.09	2.5	6.15	5.23
Count of Rank #1		0	0	0	1	1	1	0	2	8	0	0

6.4 Risk Analysis

The risk analysis performed within this assessment was deterministic in nature. As stated earlier, three forecast sensitivities were considered: Effective PV, Spatial Base and PVWatts forecasts. The Effective PV forecast closely matches the expected load growth in the Valley South region. The Spatial Base and PVWatts forecasts are located above and below the Effective PV and thus were used as upper and lower bounds of uncertainty that characterize variability in the adoption of DER, impacts of electrification, and overall impacts of load reducing technologies.

Table 6-16 presents a comparison of the benefit cost ratios as they vary with different forecasts.

Table 6-16 Deterministic Risk Assessment

Project	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Alberhill System Project	11.12	18.05	8.16
SDG&E	6.27	9.80	4.71
Valley South to Valley North to Vista	7.36	12.84	5.02
Centralized BESS in Valley South	6.32	3.71	5.65
Mira Loma and Centralized BESS in Valley South	6.55	8.36	6.45
Valley South to Valley North and Distributed BESS in Valley South	10.01	17.03	7.27
Menifee	7.18	12.20	5.14
Mira Loma	12.23	16.46	9.22
SCE Orange County	6.32	10.25	4.62
Valley South to Valley North and Centralized BESS in Valley South and Valley North	6.00	5.67	5.68
Valley South to Valley North to Vista and Centralized BESS in Valley South	7.35	9.94	5.02
SDG&E and Centralized BESS in Valley South	7.82	7.12	5.09
Valley South to Valley North	10.53	17.68	7.27

An evaluation of the primary risk component; i.e. load forecast, through all futures provides insight into the solution that stands out and provides maximum relief under uncertainties.

6.5 Summary of Findings

The evaluation of findings from the variety of benefit cost analysis are presented below:

1. Without a project in service to address the needs in Valley South system, the aggregate cost impacts accrued by the customer range from 4.4$B to 9.8$B over the horizon of forecast uncertainties captured by this analysis.
2. The benefit cost analysis demonstrates Mira Loma as the project with highest B-C ratio in Effective PV and PVWatts forecast. This is followed by Alberhill System project and Valley South to Valley North. In the Spatial base forecast, the Alberhill System project and Valley South to Valley North alternatives are ranked highest, followed the Valley South to Valley North and Distributed BESS in

Valley South. The benefits accrued by ASP was found to be substantial over the three horizons maintaining its rank across all three forecasts. In the case of Mira Loma and Valley South to Valley North, the projects low cost overrides the performance benefits and drive the ratios higher. A quick review of the overall benefits in Section 6.3.3 and raw reliability performance in Section 5.3.4 and 5.3.5 further justifies this claim.

3. An evaluation of the $/Unit Benefit demonstrates that non-wire alternatives are favorable only under lower levels of forecasted growth. This is observable from the ranking of projects presented in Section 6.3.4.
4. Wire-based and hybrid solutions demonstrate higher $/Unit benefit performance under the Effective PV and Spatial Base forecasts of load growth. Alberhill System project consistently ranks in the top 3 through all considered forecasts.
5. The incremental benefit cost analysis of non-monetized metrics demonstrates that although low cost solutions provide benefits in comparison to the baseline, several benefit categories are left under-utilized till we get further down the list of alternatives. Using the Effective PV forecast as an example, if a decision is made to stop at Menifee due to superior performance in comparison to Valley South to Valley North to Vista and Baseline system, several projects are found to provide additional benefits to the system. This trend continues till a decision is made to stop at Alberhill System Project.
6. The incremental benefit cost analysis of monetized benefits demonstrates that beyond the Alberhill System Project all benefits are exhausted.
7. An overall assessment of the top-ranking alternatives with consideration of risks, demonstrate the superiority of ASP to meet all the project objectives in Valley South system.

7 CONCLUSIONS

Southern California Edison (SCE) retained Quanta Technology to supplement the existing record in the California Public Utilities Commission (CPUC) proceedings for SCE's Alberhill System Project (ASP) with additional analyses and alternative studies to meet the capacity and reliability needs of the Valley South 500/115 kV system. The overall objective of this analysis is to amend the ASP business case (including benefit-cost analysis) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with SCE to evaluate and rank the performance of alternatives. This evaluation is complemented by the development of load forecasts for the Valley South System planning area. Industry-accepted forecast methodologies to project load growth and to incorporate load-reduction programs (energy efficiency, demand response, and behind-the-meter generation) were implemented. The developed load forecast covers the horizon of 30 years (until year the 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives utilized power flow studies in coordination with quantitative analysis to forecast the impacts of alternatives under evaluation, including the ASP. The forecasted impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of alternatives utilized the benefit-cost and risk analysis framework to quantify the value of monetary benefits observed over the project horizon.

A total of 13 alternatives, including the ASP, were evaluated within this framework to validate performance and contribution towards satisfying project objectives. These alternatives were categorized into Minimal Investment, Conventional, Non-Wire, and Hybrid (Conventional plus Non-Wire) solutions.

The key findings of this study are summarized as follows:

- Consistent with Industry accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely Conventional and Spatial forecasts[35].
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and California's electrification goals.
  - Across all forecasts the reliability need year was identified as 2022, except for one sensitivity that identified 2021 as the need year.
  - The Effective PV Spatial load forecast is found to be the most consistent with trends in the Valley South needs area. This forecast demonstrates a range of load from 1,083 MVA to 1,377 MVA over 2019-2048.
- Several reliability metrics were utilized to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that ASP provides the

[35] The load forecasting methodologies and findings are documented in detail within Chapter 2 of this report.

highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resiliency and operational flexibility needs in the Valley South System. Considering the aggregated benefits under normal and emergency[36] conditions, the ASP results in 854 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $6 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following ASP are SCE Orange County, and SDG&E and Centralized BESS in Valley South.

- The benefit-cost analysis framework was implemented to evaluate and compare individual alternatives' performance.
  - Non-wire solutions remained cost-effective only under reduced load forecast levels (e.g., Reduced Trend and Low sensitivities of the Conventional forecasts). In the other forecasts, non-wire alternatives accrue significant additional costs over time due to incremental storage sizing necessary to address the load growth in the Valley South System.
  - Conventional and Hybrid alternatives can better satisfy project objectives and long-term reliability challenges in the system.
  - Mira Loma, ASP, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Mira Loma and Valley South to Valley North have lower costs relative to ASP; while providing sizably lower benefits than ASP.
- The incremental benefit-cost framework was implemented to select among alternatives, and the results demonstrated that ASP is the preferred alternative. The analysis is indicative of significant unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrates that:
  - The costs associated with the incremental size of the non-wire alternatives (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from non-wire alternatives are negligible.
- The results of the reliability, benefit-cost, and risk analyses indicated that the ASP meets the project objectives over the 10-year horizon and ranks the most favorable among the considered alternatives over the 30 years period.

Findings and results reported in this document are based on publicly available information along with the information furnished by the client at the time of the study. Quanta Technology reserves the right to amend results and conclusions should additional information be provided or become available.

[36] N-0, N-1 and Operational flexibility.

8 REFERENCES

[1] Quanta Technology, *Alberhill System Project Load Forecast,* 2019.

[2] W. Sullivan, Engineering Economy, 2012.

[3] CPUC, *3. Decision Granting Petition to Modify Permit to Construct the Valley-Ivyglen 115 kV Sub-transmission Line Project and Holding Proceeding Open for Certificate of Public Convenience and Necessity for The Alberhill System Project,* 2018.

APPENDIX A: GLOSSARY

ASP: Alberhill System Project
CAIDI: Customer Average Interruption Duration Index
CAISO: California Independent System Operator
CPUC: California Public Utility Commission
DER: Distributed Energy Resources
EENS: Expected Energy Not Served
NERC: North American Electric Reliability Corporation
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
SCE: Southern California Edison
SDG&E: San Diego Gas & Electric
WECC: Western Electricity Coordinating Council