EXHIBIT G-2 (SECOND AMENDED)

Item G:

Cost/benefit analysis of several alternatives for:

- Enhancing reliability;
- Providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart grid solutions.

Response to Item G

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This second amended motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: January 29, 2021

Summary of Revisions:

This revision modifies the cost benefit analysis to correct various errors and to clarify specific elements of the analysis. These changes are summarized in Supplemental Data Response to Item C[1] and in the attached revised report by Quanta Technologies.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

The attached report, prepared by Quanta Technology as a contractor to Southern California Edison (SCE), provides a cost-benefit analysis comparing several alternatives, including the Alberhill System Project (ASP). The identification of alternatives and methodology for this cost-benefit analysis are described in the Quanta Technology report and summarized with additional context in the response to DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C (Planning Study).

This cost-benefit analysis is one factor among many which informs and supports SCE's recommended solution[2]. Other factors integrated into SCE's analysis and informing SCE's recommended solution include, but are not limited to, benefits achieved in both the near and long term, potential environmental impacts, input from the general public and other stakeholders, and other risk considerations.

[2] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

A Appendix: Quanta Cost Benefit Analysis

The Quanta Technology report, *Cost Benefit Analysis of Alternatives Version 2.1 (Second Amended Motion)*, which includes supporting cost benefit spreadsheets, is attached as Appendix A to this data submittal.

QUANTA
TECHNOLOGY

REPORT

Deliverable 3: Benefit Cost Analysis of Alternatives

PREPARED FOR

Southern California Edison (SCE)

DATE

June 15, 2021
Version 2.1(Errata)

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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
2.0	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • For monetization purposes, reliability benefits are translated into Expected Energy Not Served (EENS) by consideration of average load at risk over duration of event. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Treatment of probabilities associated with Flex-2-2 event. • Separating costs from two customer classes (commercial and residential) to three customer classes (Residential, Small & Medium Industries and Commercial)

		• Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Updated Present Value of Revenue Requirements (PVRR) and Total costs associated with alternatives. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only. • Project scope and associated costs have been added to several alternatives to address N-1 line capacity violations that occur within the first ten years of the project planning horizon. • The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. • Other minor editorial corrections and clarifications.
2.1(Second Amended Motion)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

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 the benefit-cost analysis [BCA]) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with the SCE study team 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 the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for the alternative projects is based on power flow studies in coordination with quantitative analysis to forecast the impacts of each alternative under evaluation, including the ASP. The projects' performance impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of the alternatives using benefit-cost and risk analysis frameworks to quantify the value of monetary benefits over the project horizon was conducted.

A total of 13 alternatives, including the ASP, were studied within this framework to evaluate their performance and contribution towards the project objectives. These alternatives were categorized as follows:

- Minimal investment
- Conventional
- Non-wires alternative (NWA)
- Hybrid (conventional plus NWA)

Highlights of the study are as follows:

- Consistent with industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region and the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties such as load-reducing technologies and the state of California's electrification goals.
  - Across the considered 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 area. This forecast demonstrates a range of loading from 1,083 to 1,377 MVA from the year 2019 to 2048.
- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System. Considering the aggregated benefits under normal and emergency[1] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy and $4.3 billion in cost savings to the end customers. The alternatives demonstrating the next-highest benefits (following the ASP) are SDG&E, SCE Orange County, and SDG&E with Centralized BESS (battery energy storage system) in Valley South.
- The BCA framework was implemented to evaluate and compare alternatives performance:
  - NWA solutions remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). Under the other forecasts, NWAs accrue significant costs over time due to the 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.
  - Menifee, ASP, SDG&E, and the Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than ASP.
- The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology warrants that the additional incremental cost is economically justifiable only if the benefit realized exceeds the incremental cost. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as type of project (reliability versus economic),environmental impact and risks.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of 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 NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-to-cost ratios.
  - The benefits attributed to operational flexibility from NWAs 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 as the most favorable among the considered alternatives over a 30-year period.

[1] N-0, N-1, and operational flexibility.

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. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

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List of Acronyms and Abbreviations

Term	Definition
AAEE	additional achievable energy efficiency
AAPV	additional achievable photovoltaic
AC	alternating current
ACSR	aluminum conductor steel-reinforced (cable)
AMI	advanced metering infrastructure
AS	ancillary service
ASP	Alberhill System Project
BCA	benefit-cost analysis
BES	bulk electric system
BESS	battery energy storage system
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CEC	California Energy Commission
CIGRE	International Council on Large Electric Systems
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DA	day-ahead
DER	distributed energy resource
EENS	expected energy not served
ENA	Electrical Needs Area
EV	electric vehicle
GWh	gigawatt-hours
HILP	high-impact low-probability (event)
IERP	Integrated Energy Policy Report (of the California Energy Commission)
IP	interrupted power
ISO	independent system operator
LAR	load at risk

Term	Definition
LMDR	load modifying demand response
LMP	locational marginal price
LTELL	long-term emergency loading limits
MBCA	marginal benefit-to-cost analysis
MEA	mutually exclusive alternatives
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
O&M	operations and maintenance
PATHWAYS	a long-horizon energy model developed by Energy and Environmental Economics, Inc.
PFD	period of flexibility deficit
PV	photovoltaic
PVRR	present value of revenue requirements
RA	Resource Adequacy
RegDown	Regulation down
RegUp	Regulation up
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOC	state of charge
STELL	short-term emergency loading limits
VO&M	variable operations and maintenance
VSSP	Valley South 115 kV Subtransmission Project
WACC	weighted aggregate cost of capital
WECC	Western Electricity Coordinating Council

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 [BCA]) 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 (BES) under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility,[2] and resilience 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, resilience, 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 as follows:

- Construction of a 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

[2] 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 resilience 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.

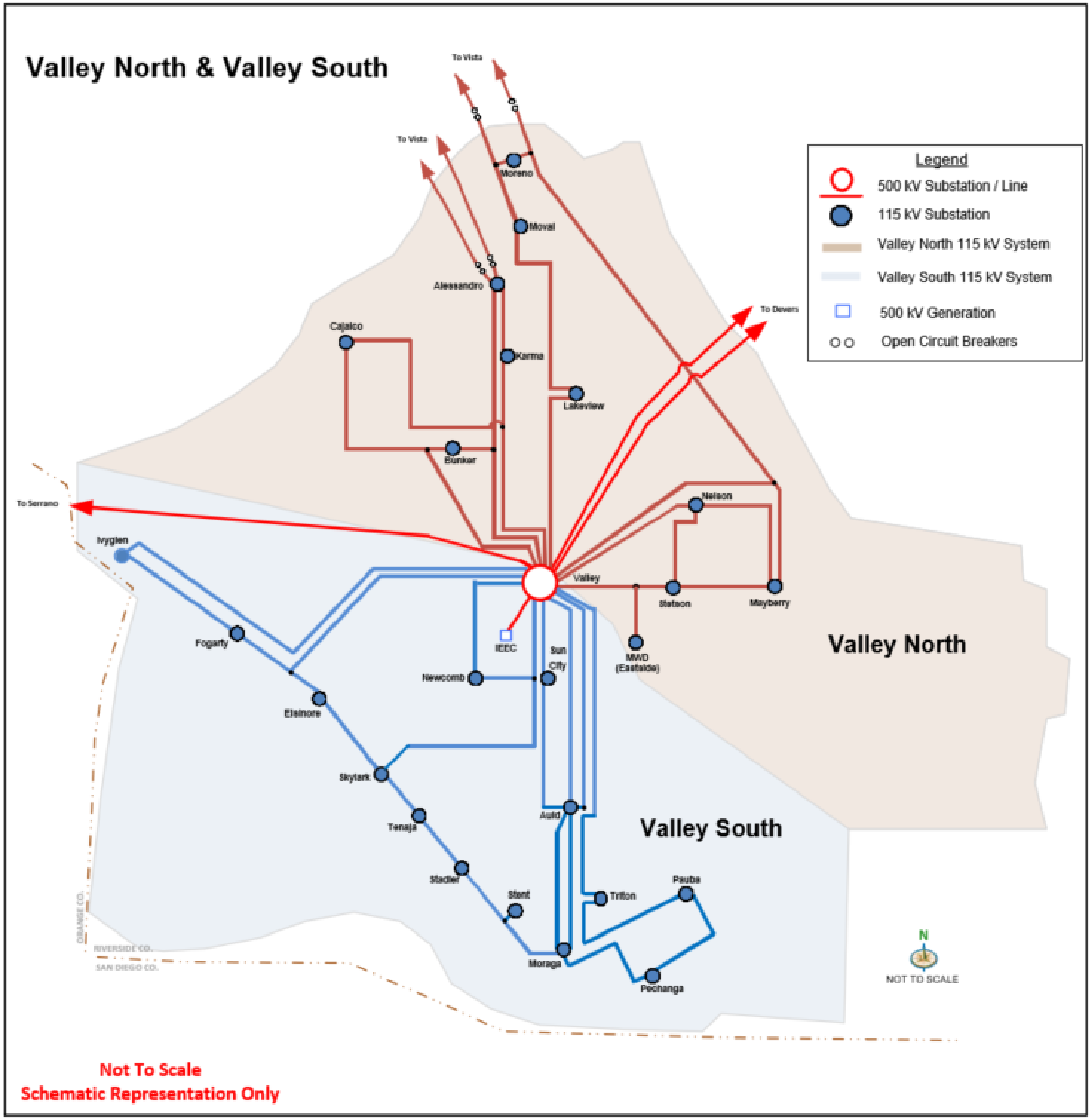


Figure 1-1. Valley Substation Service Areas[3]

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

[3] Valley-Ivyglen and VSSP projects included [12]

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; these included, but were not limited to, energy storage, demand response, and distributed energy resources (DERs).

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 the 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 BCA 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 independently of SCE's current forecasting methodology and practices; however, both SCE's and Quanta Technology's analysis incorporated the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) forecasts for the first 10 years through 2028.
2. Using power flow simulations and a quantitative review of project data, the forecasted impact of the proposed ASP 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 ASP or any other major projects requiring CPUC approval, along with the associated costs for such actions.
4. BCA 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 a data-driven quantitative assessment of project performance, coupled with BCA 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[4] as stipulated by the project proceedings:

[4] 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 ENA.
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 ENA (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
- A 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 a 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 was 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) being considered to address the reliability needs in the absence of the ASP. Through a screening process, the selected set of alternative projects 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 BCA of the ASP along with the list of system alternatives from Task 4. This analysis intended 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

This report has been organized consistent with the tasks outlined in Section 1.3. The report has been separated into several sections 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 Section 2 of this report, the long-term spatial load forecast is discussed. This section is complementary to Quanta Technology's load forecast report [1], which focused on the near-term load forecast and describes the technical details behind the spatial load forecasting methodology.

Section 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 in the analysis.

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

Section 6 presents the results from the BCA and deterministic risk assessment.

Section 7 presents the report conclusions and is followed by applicable references (Section 8) and an appendix (Section 9) that provides the N-2 probabilities associated with circuits that share a common tower structures.

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 a 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 the year 2028 were presented in a separate report [1]. This forecast was constructed from a baseload forecast and incorporated DER development according to CEC's 2018 IEPR [2] 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 section 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 the year 2028. This spatial forecast methodology is based on a 30-year horizon year,[5] 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
2025	1205	874

[5] 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]
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 (EVs), energy storage, and load modifying demand response (LMDR) categories.

2.2.1 AAPV Disaggregation

For AAPV, SCE provided two scenarios: 1) SCE Effective PV and 2) 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 the SCE 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 (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	AAPV SCE Effective PV	-4.9	-4.9	-4.9	-4.9	-4.9	-4.5	-4.0	-3.7	-3.7	-2.9
	AAPV PVWatts	-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	-5.7	-5.0	-4.2	-3.4	-3.0	-2.8	-2.7	-2.4	-2.1	-1.9
	AAPV PVWatts	-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 AAEE, EVs, energy storage, and 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 (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Electric Vehicle	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.2	0.3
	AAEE	-2.3	-2.1	-2.6	-2.8	-3.2	-2.9	-2.8	-2.7	-2.8	-2.9
	Energy Storage	-0.5	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
	LMDR	0.0	-0.5	0.0	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0
Valley South	Electric Vehicle	0.8	0.9	0.8	0.6	0.7	0.6	0.6	0.4	0.4	0.4
	AAEE	-3.4	-2.9	-3.6	-2.6	-3.0	-2.8	-2.7	-2.5	-2.6	-2.8
	Energy Storage	-1.0	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
	LMDR	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 the impacts of DERs, it is necessary to have DER forecasts that extend to the year 2048. The estimation of DER from the year 2029 until the year 2048 has been performed 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 model [3], on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the AAPV forecasts of Table 2-2, starting from the year 2029, to generate an estimation of the AAPV in the Valley South and Valley North Systems up to the year 2048. The estimated AAPV at the 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 the Solar Generation [MVA], and Estimated AAPV SCE Effective PV (in 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 the Solar Generation [MVA], and Estimated AAPV PVWatts (in 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 (CAGR) of 3% was used as a reasonable expectation for future AAPV after the 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 (in 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.

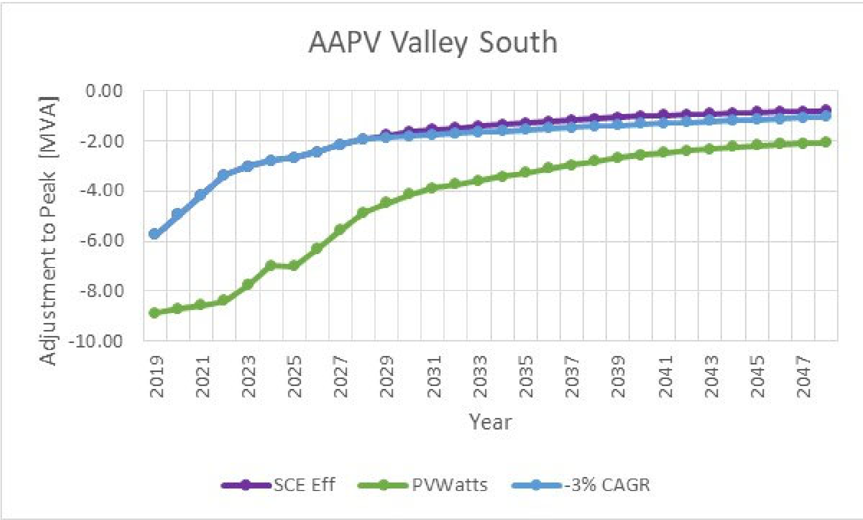


Figure 2-1. AAPV Forecasted Growth Scenarios for Valley South

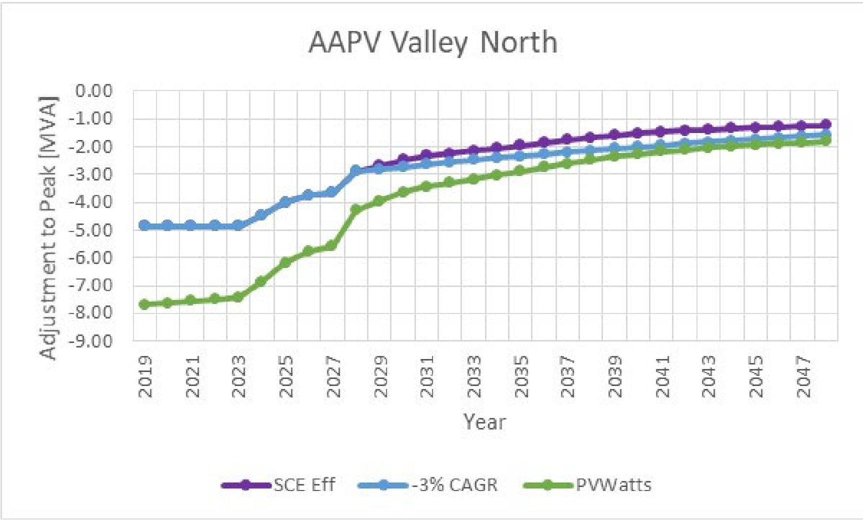


Figure 2-2. AAPV Forecasted Growth Scenarios for Valley North

2.3.2 EV Growth from 2029 to 2048

The EV disaggregated forecast of Table 2-3 was extended until the 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 EV forecast of Table 2-3, starting from the year 2028. The estimated EV load at the Valley South and the Valley North System are shown in Table 2-7.

Table 2-7. California PATHWAYS CEC 2050 Case for the Light EV Load (in 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.

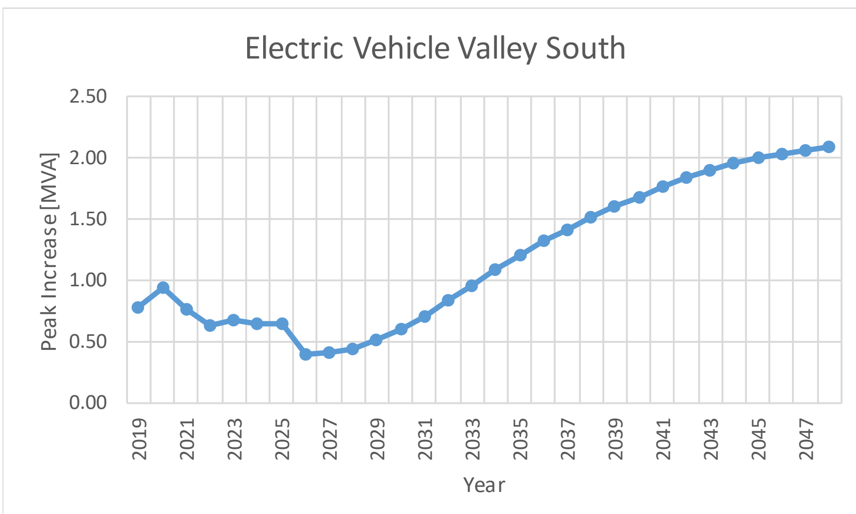


Figure 2-3. EV Forecasted Growth for Valley South

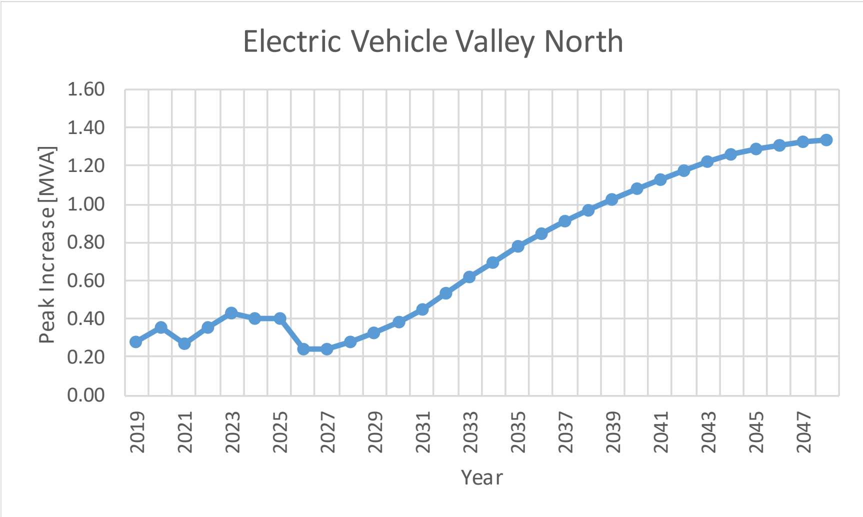


Figure 2-4. EV Forecasted Growth for Valley North

2.3.3 Energy Efficiency Growth from 2029 to 2048

The energy efficiency disaggregated forecast of Table 2-3 was extended until the 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 (in 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.

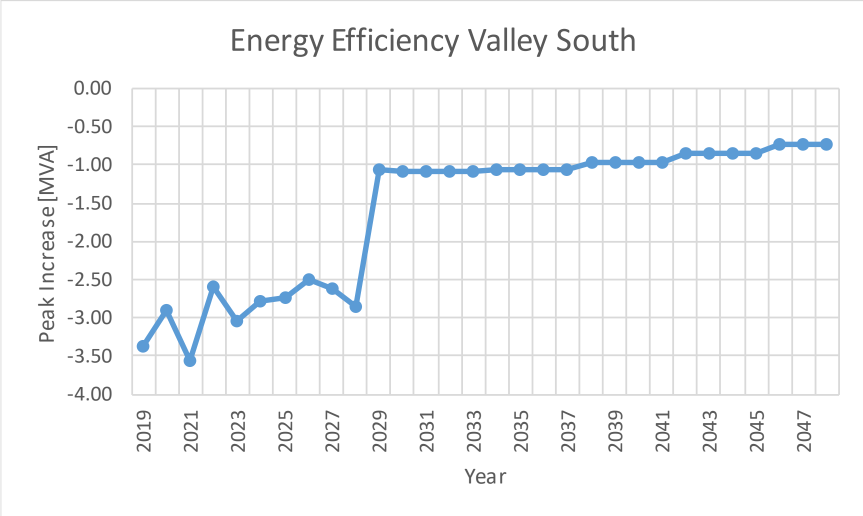


Figure 2-5. Energy Efficiency Forecasted Growth for Valley South

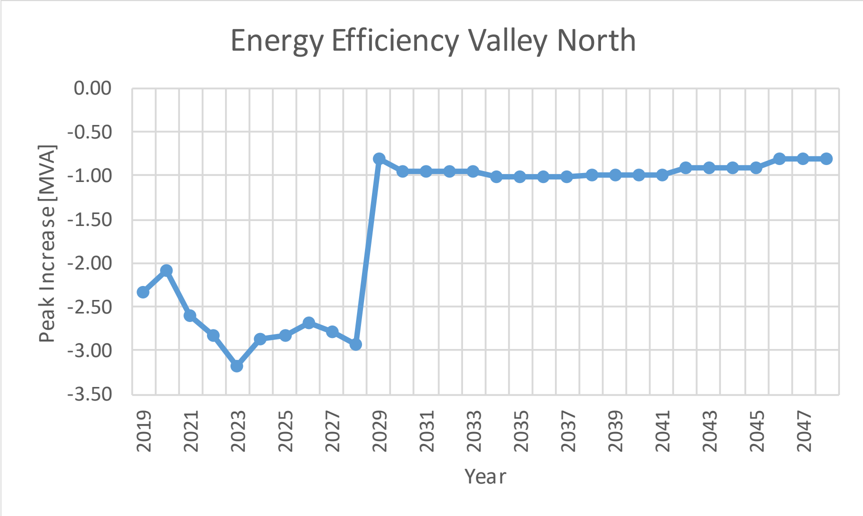


Figure 2-6. Energy Efficiency Forecasted Growth for Valley North

2.3.4 Energy Storage 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 the year 2048. By SCE criteria, it was estimated that 60% of this storage would be associated with 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 an 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 CAGR of energy storage was identified for each area (Valley North and Valley South) so that the year 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 (in 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.

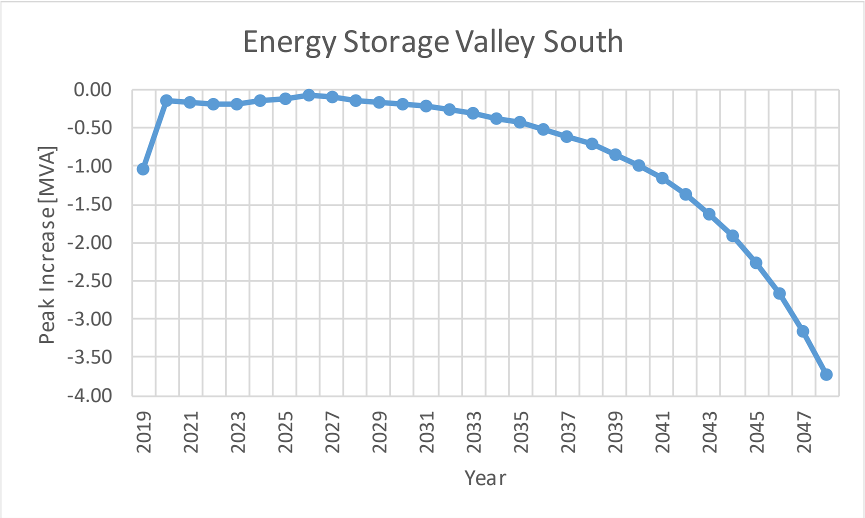


Figure 2-7. Energy Storage Forecasted Growth for Valley South

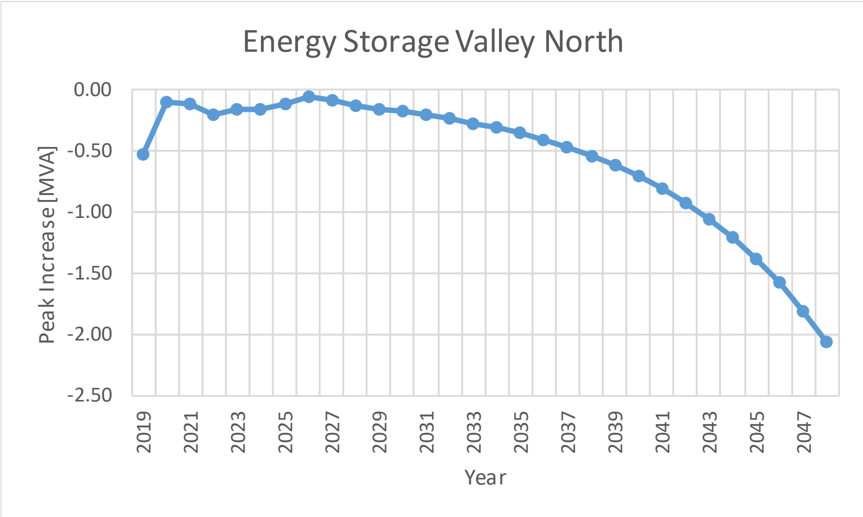


Figure 2-8. Energy Storage Forecasted Growth for Valley North

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 the 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 the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the 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

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]
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

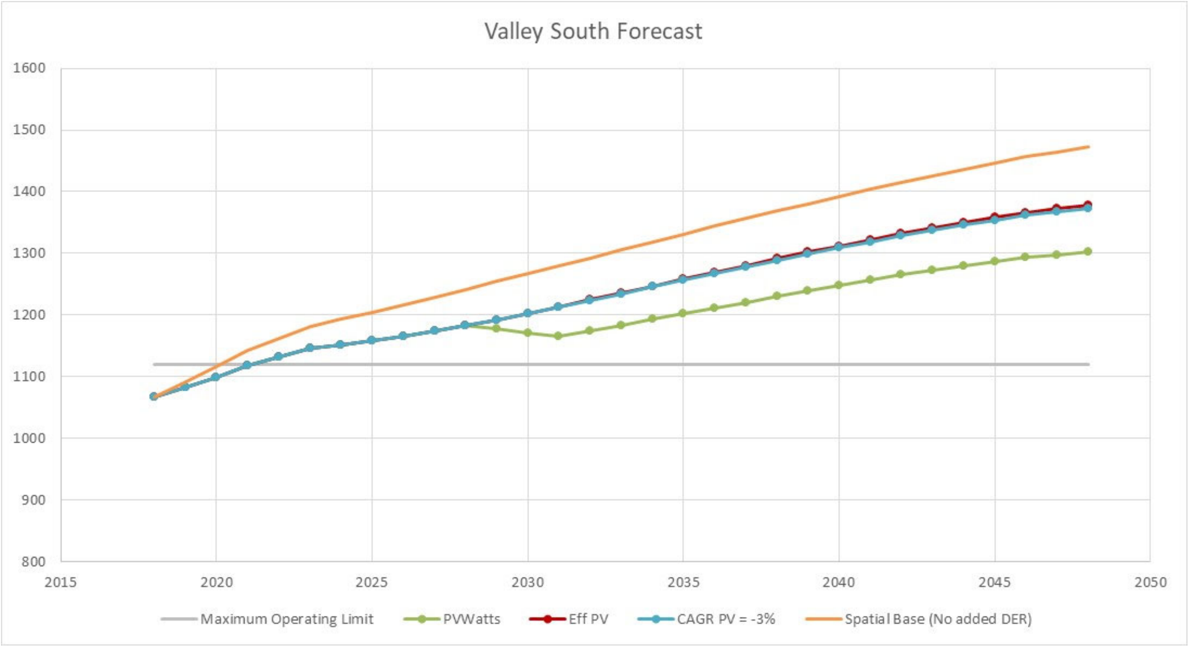


Figure 2-9. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Table 2-11. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the 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

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]
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

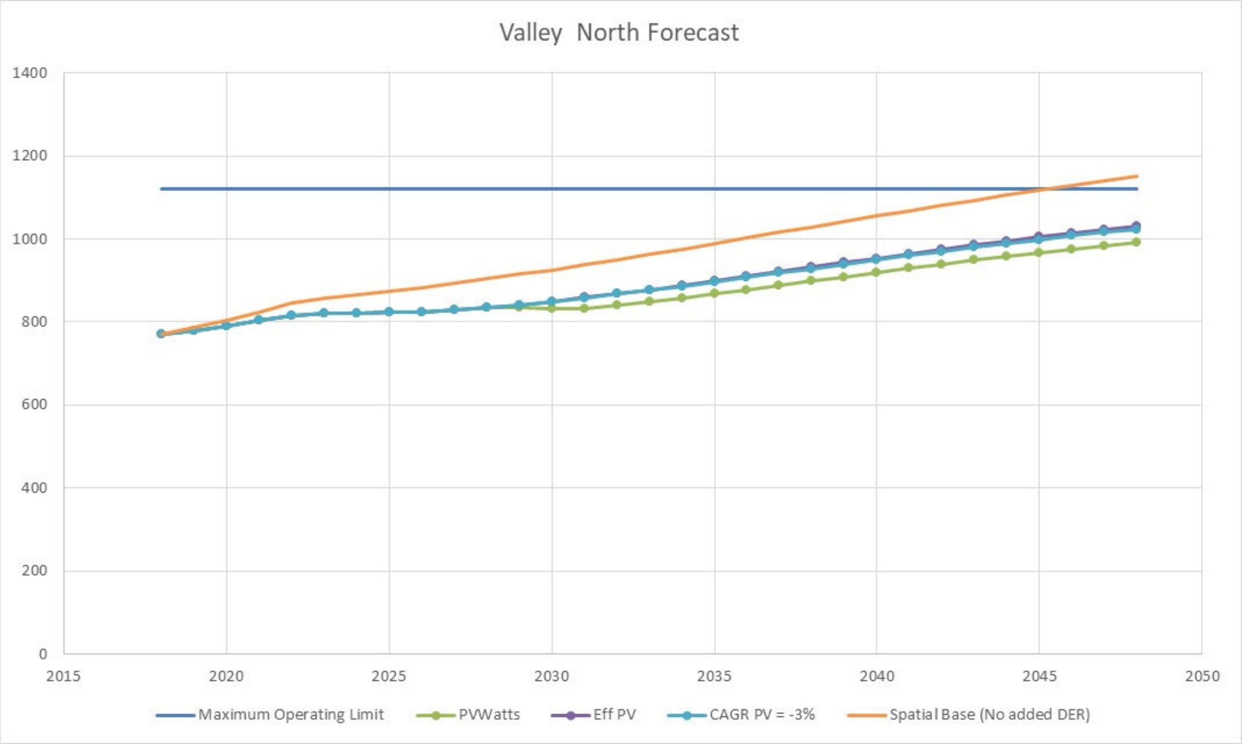


Figure 2-10. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

3 RELIABILITY ASSESSMENT AND 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 discussed further in Sections 4 and5. Within the framework of this analysis, reliability, capacity, operational flexibility, and resilience 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 the 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 the benefits or impacts of operational flexibility and resilience (high-impact low-probability events [HILP])
5. To compare and 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 as follows:

- **Capacity**
  - Serve current and long-term projected electrical demand requirements in the SCE ENA.
  - 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 Subtransmission Planning Criteria and Guidelines.
  - Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South System).

- **Operational Flexibility and Resilience**
  - 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 a platform to evaluate monetized and non-monetized project benefits
4. Utilize tools such as benefit-to-cost ratio, incremental BCA, and $/unit benefit to substantiate alternative selection and conclusions.

Each of the above areas is further detailed throughout this section.

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 Valley North Systems:
   a. 2018 system configuration (current system)
   b. 2021 system configuration (Valley–Ivyglen [4] and VSSP [5] 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 Valley 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 Section 2 of this report. The primary forecasts under consideration for reliability analysis are 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 South System. The developed forecasts take into consideration the variabilities in future developments of PV, EV, energy efficiency, energy storage, and LMDR.

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 exceed maximum operating limits (1,120 MVA). Figure 3-2, presents the representative load forecast for Valley North where the loading on the Valley North transformers exceed 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 the need year to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

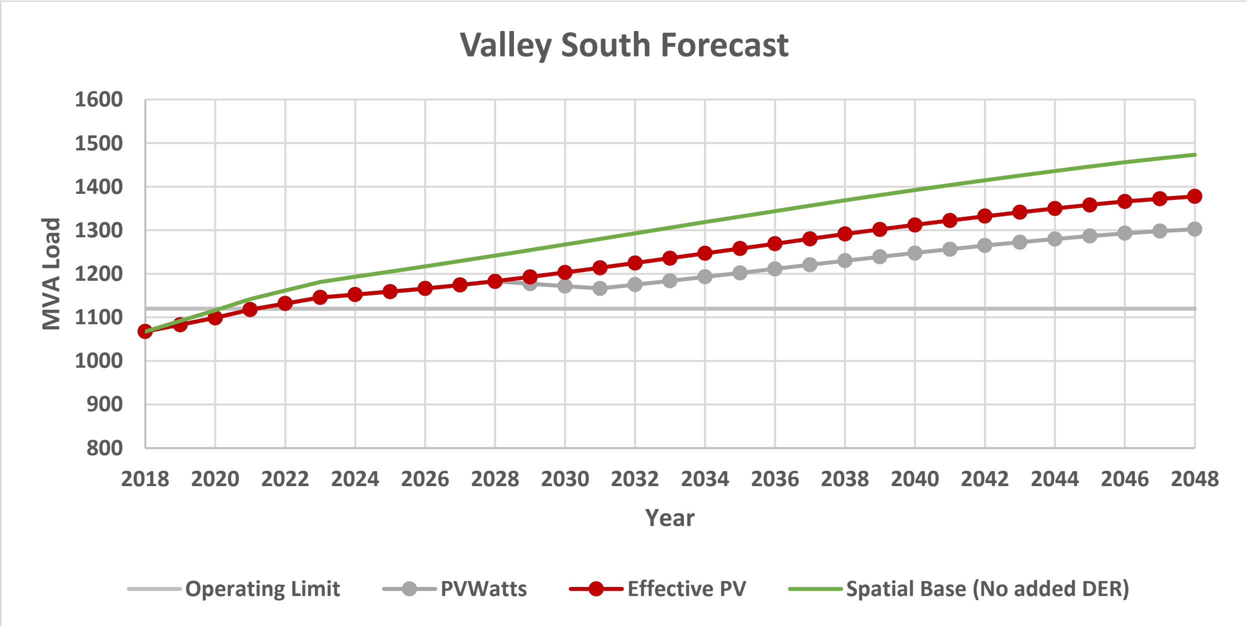


Figure 3-1. Valley South Load Forecast (Peak)

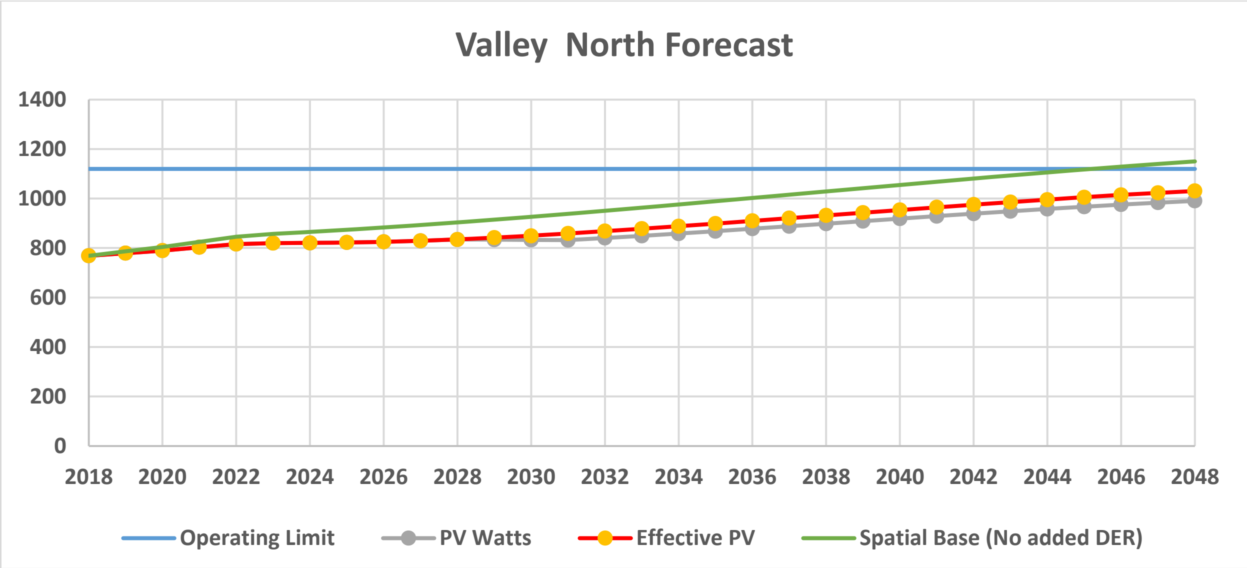


Figure 3-2. Valley North Load Forecast (Peak)

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

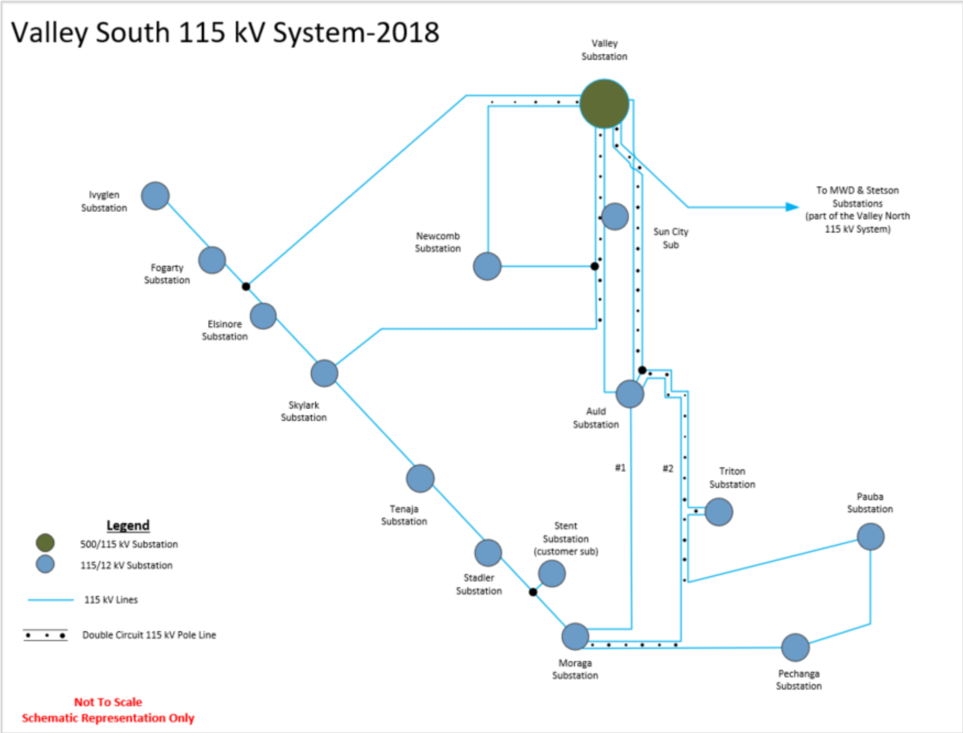


Figure 3-3. Valley South System Current Configuration (2018)

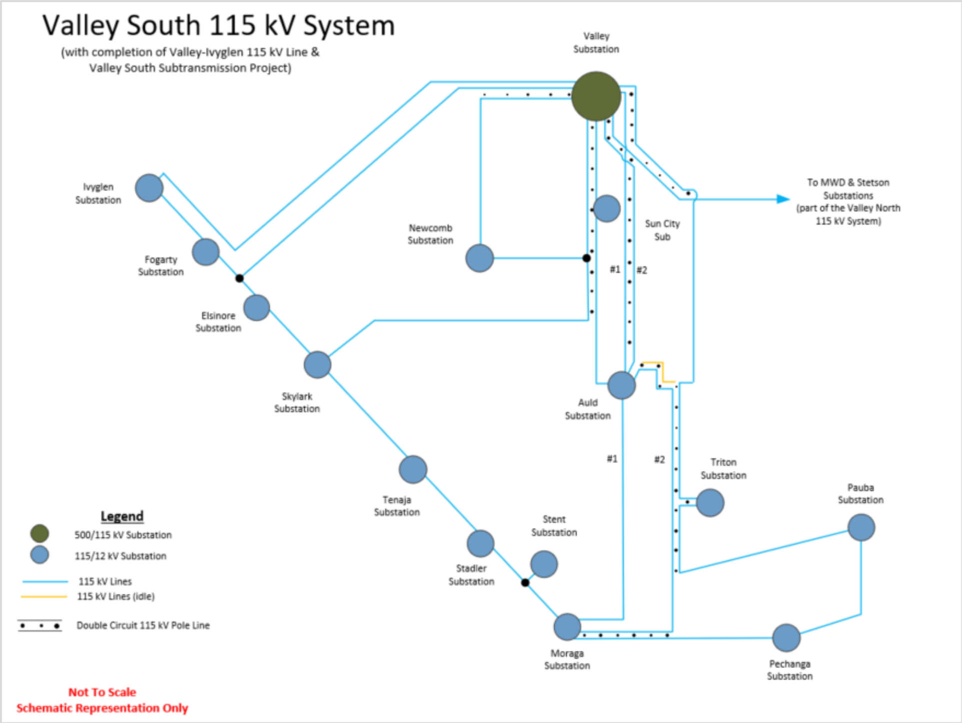


Figure 3-4. Valley South System Configuration (2021)

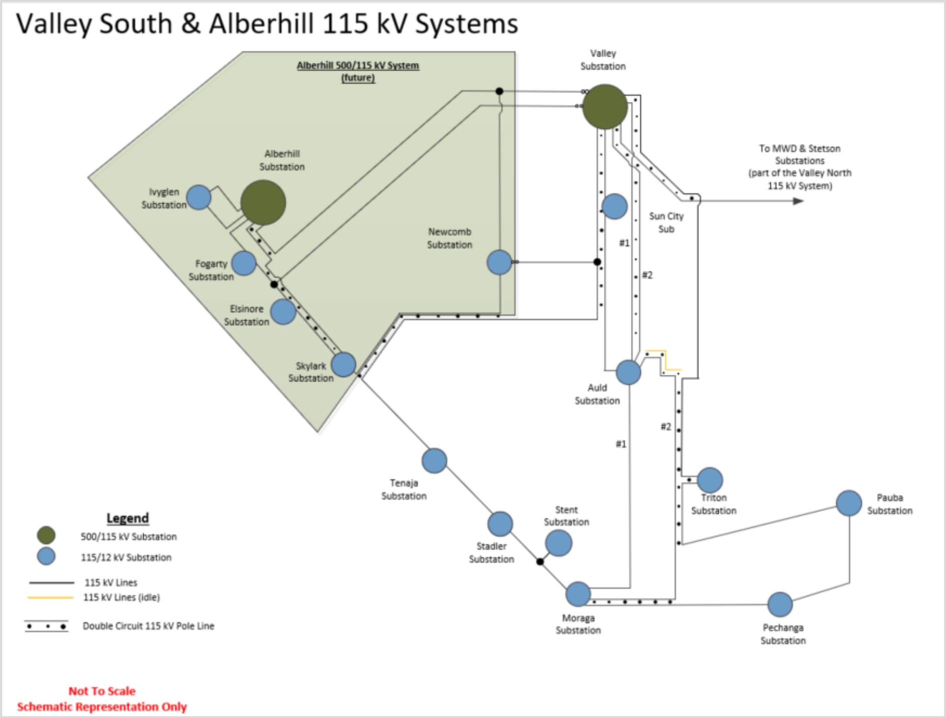


Figure 3-5. Valley South System Configuration (2022 with ASP in-service)

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.[6] This load shape is presented in Figure 3-6.

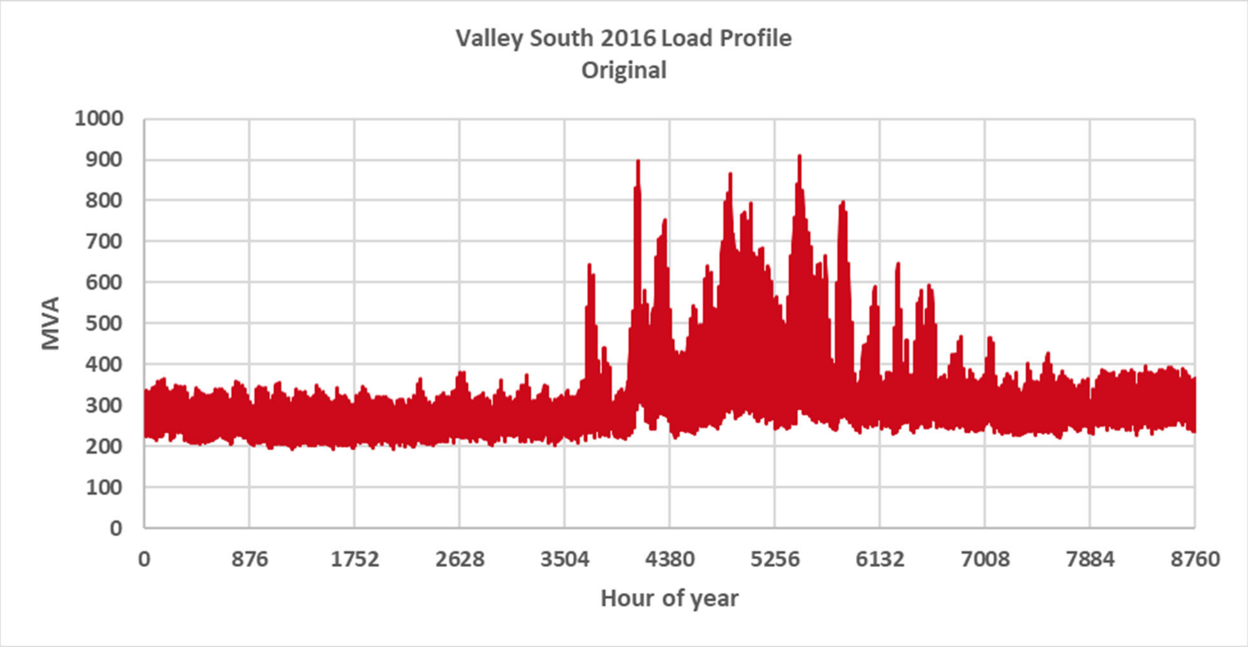


Figure 3-6. Load Shape of the Valley South System

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 Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards were referenced when considering any potential impacts on the 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

[6] 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 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 South 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.

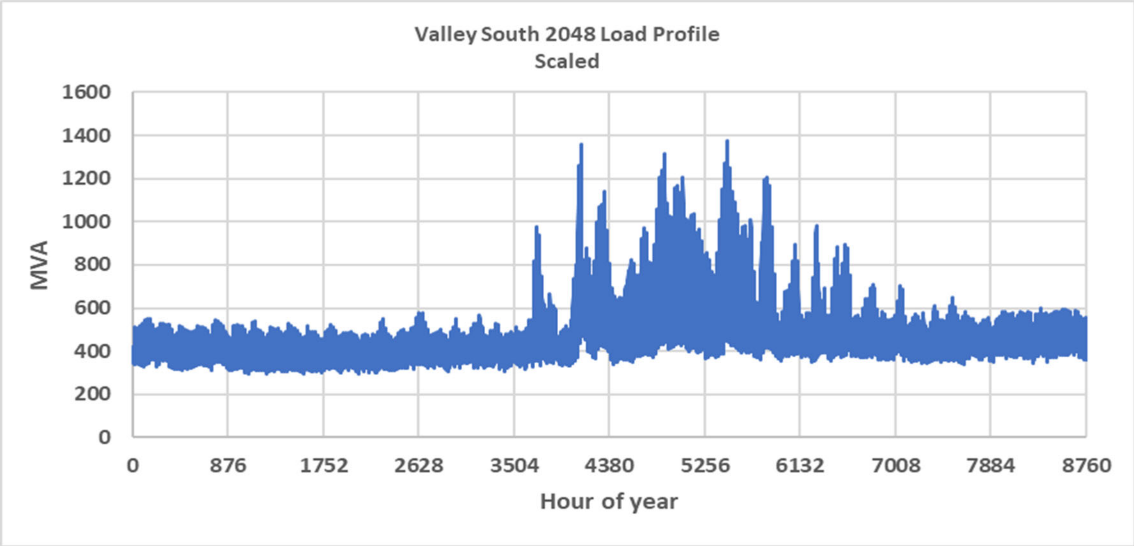


Figure 3-7. Scaled Valley South Load Shape Representative of Study Years

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 (AC) 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.

Unless otherwise specified, all calculations performed under reliability analysis compute the load at risk in MW or MWh, which is not a probability-weighted metric.

The N-1 contingency has been evaluated for every hour of the 8,760 simulations, and the outages were considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the 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, tie-lines were engaged to minimize system impacts. The losses are monitored every hour and aggregated across the existing and new transmission lines in the service area.

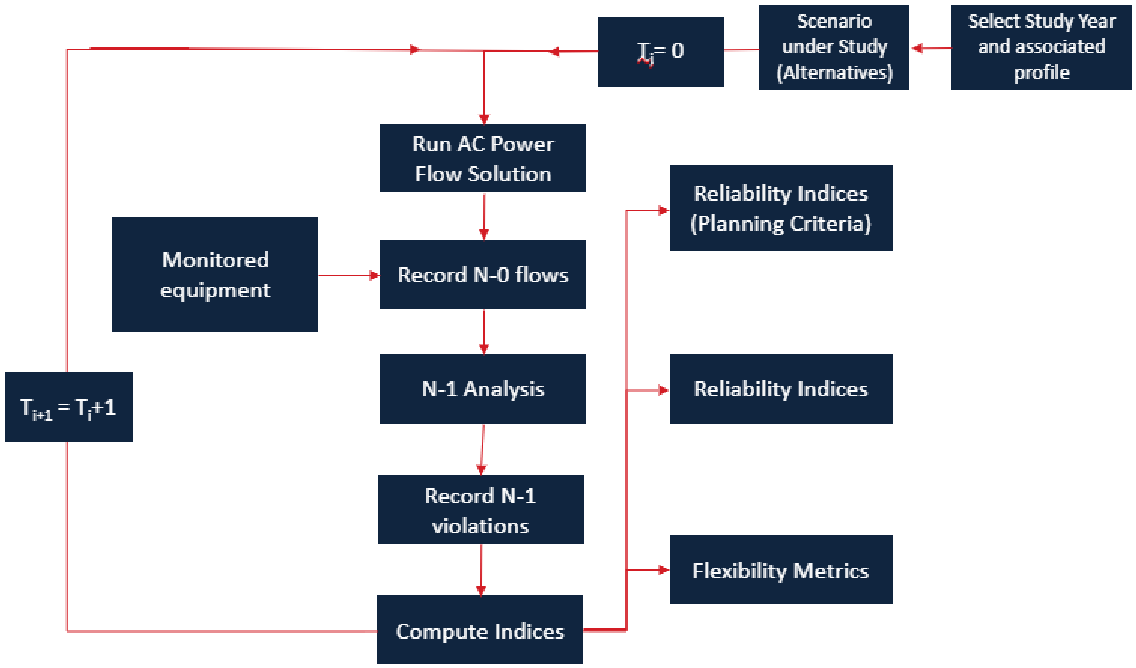


Figure 3-8. Flowchart of Reliability Assessment Process

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

Flexibility Metric 1 evaluates the system under N-2 (common pole double-circuit outages) addressing combinations of two transmission lines out of service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common tower or right-of-way. 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 (LAR) and to calculate the weighted amount using the associated contingency probabilities. The probability-weighted MWh is representative of the expected energy not served (EENS). The contingency probabilities were derived from a review of the historic outage data in the timeframe from 2005 to 2018 in the SCE 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 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 LAR to accumulate in the system. When the project under evaluation has tie-lines, they are used to minimize system impacts.

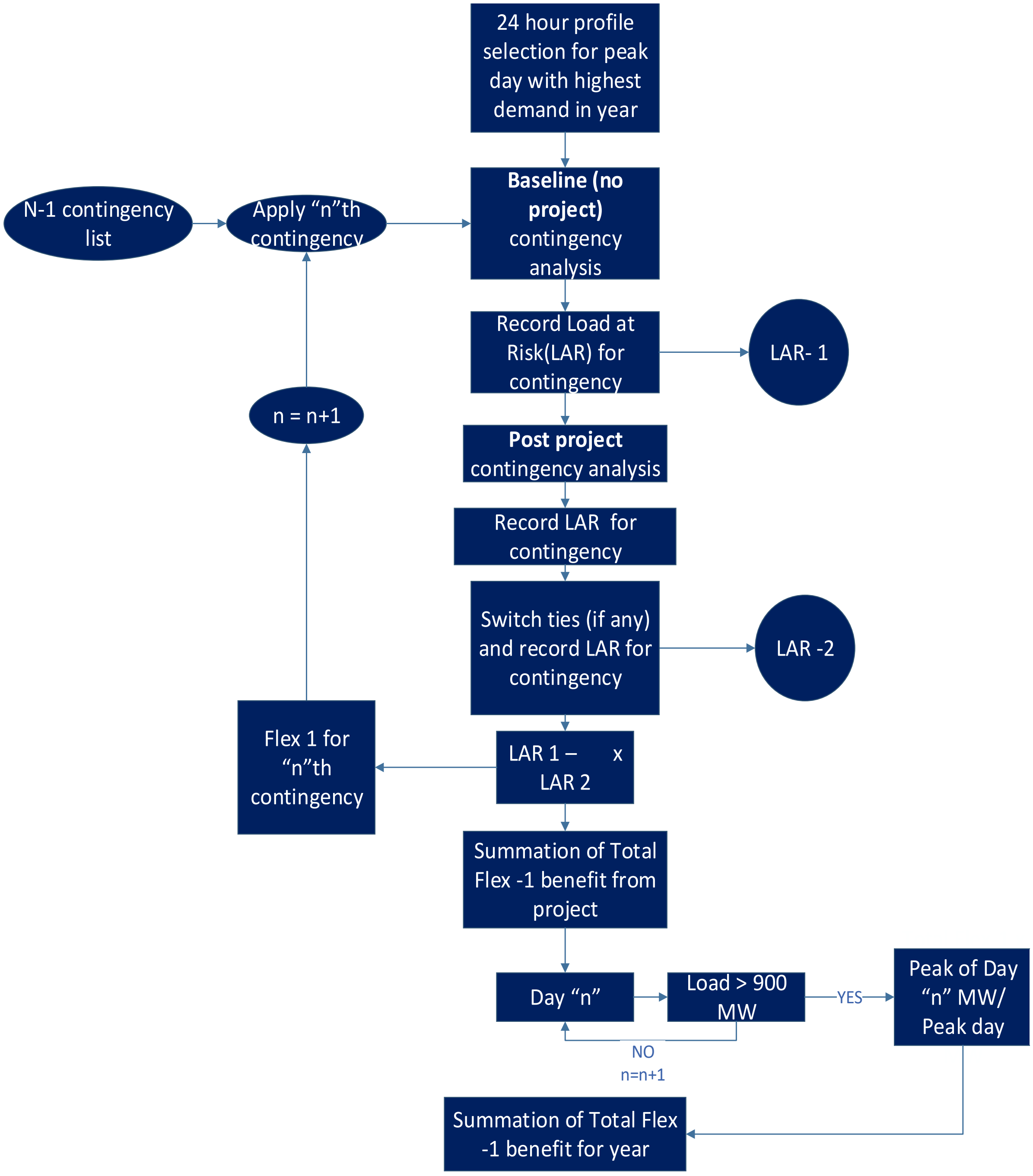


Figure 3-9. Flowchart of Flexibility Metric 1 (Flex-1) Calculation Process

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 Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of LAR.

- Flexibility Metric 2-1 evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of LAR is determined. Utilizing power-flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- Flexibility Metric 2-2 evaluates a condition wherein the Valley South ENA is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g. fire or explosion) of one of the two transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Utilizing the 8,760-load shape and the transformer short-term emergency loading limits (STELL) and long-term emergency loading limits (LTELL), the average amount of MWh over a 2-week duration LAR is estimated and aggregated ("mean time to repair" under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

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 the 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 electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions and under normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, or planned outage condition. Therefore, it is expected to operate the system radially and to accommodate flexibility by employing normally open system tie-lines.
- Resilience has been viewed as an extension of the flexibility benefits, wherein system tie-lines are leveraged to recover load under HILP events.

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

- **Load at Risk (LAR)**
  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. 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 the voltage sensitivity of the bus to bring the 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 a bus voltage from the 0.95 per unit limit, the amount of load drop to avoid the violation was determined.

b. LAR was computed for N-0 and N-1 events and aggregated or averaged over 1 year. The focus of the analysis is on the Valley South System. However, under N-0 condition, LAR 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 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 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, or 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. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served using the flexibility attributes of the project.
    b. Flexibility Metric 2: Recover load for the emergency condition: Single point of failure at the Valley substation and its transformer banks.
        i. Flex-2-1: Calculated as the energy unserved when the system is impacted by HILP events such as loss of the Valley Substation resulting in no source left to serve the load. 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 an average 2-week period (assumed minimum restoration duration for events of this magnitude) in the Valley South system.
        ii. Flex-2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (two transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley South System. Projects that establish system tie-lines to adjacent networks can support load recovery during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was 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 has 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 the 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.

The benefit is defined as the value of the impact of a project on 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 LAR, IP, and PFD (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.

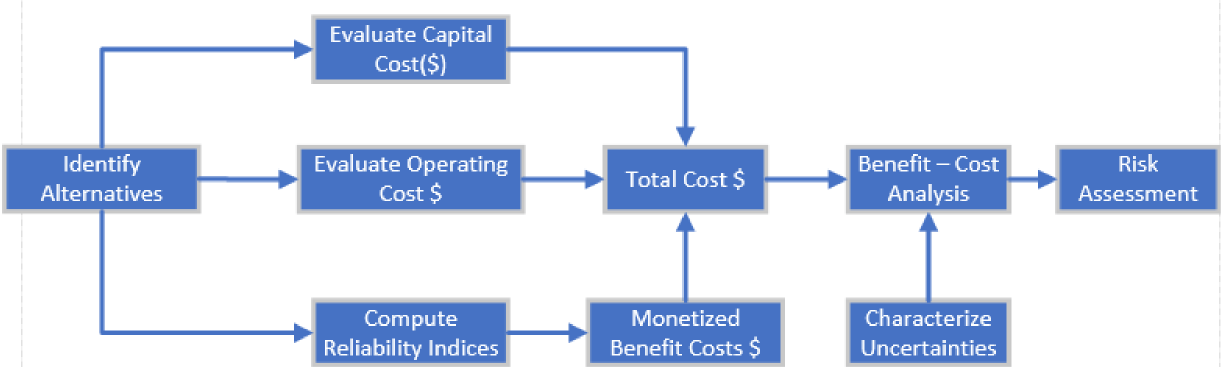


Figure 3-10. BCA Framework

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 and 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 used throughout the study horizon. The PVRR costs are offset for incremental revenues generated by the battery energy storage system (BESS) assets through market participation. Table 3-2 presents the financial assumptions considered in this analysis. Further details pertaining to each of the assumptions are presented in the upcoming sections of this report.

In the scope of this assessment, the benefits for considered metrics (Section 3.2.4) are derived by a comparison of system performance with and without the project in service. Depending on the benefit category, a distinction is made between monetized and non-monetized benefits. The monetized benefits are typically probability-weighted and represented as EENS. Unless otherwise specified, the non-monetized benefits are not probability weighted. The benefits in combination with PVRR costs have been used at different capacities to develop a comprehensive view of project performance. This evaluation framework includes a 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 [LMP])	40 $/MWh	CAISO[7]
Inflation rate (price escalation)	2.5%	Quanta
Load distribution: residential	33%	SCE
Load distribution: small & medium business	36%	SCE
Load distribution: commercial and industrial	31%	SCE
Annual outage rate for Flexibility-2-2 events	0.0015	CIGRE[8]
Annual outage rate for HILP event (Flexibility-2-1 events)	0.01	NERC[9]

The non-monetized benefits have been presented in two different formats. From the perspective of reliability analysis (Sections 4 and 5), they are described as the sum (or the cumulative effect) of the benefits of the project over the project study horizon. In the cost-benefit framework (Section 6), the non-monetized benefits are calculated as the present worth of benefits discounted at the weighted aggregate cost of capital (WACC) throughout the study horizon. An example of the latter, LAR (MWh) benefits of the ASP under normal system condition (N-0) and their present worth using the discount rate of WACC are presented in Figure 3-11.

[7] http://oasis.caiso.com/ (Node: VALLEYSC_5_B1)
[8] Reference [8]
[9] Reference [7]

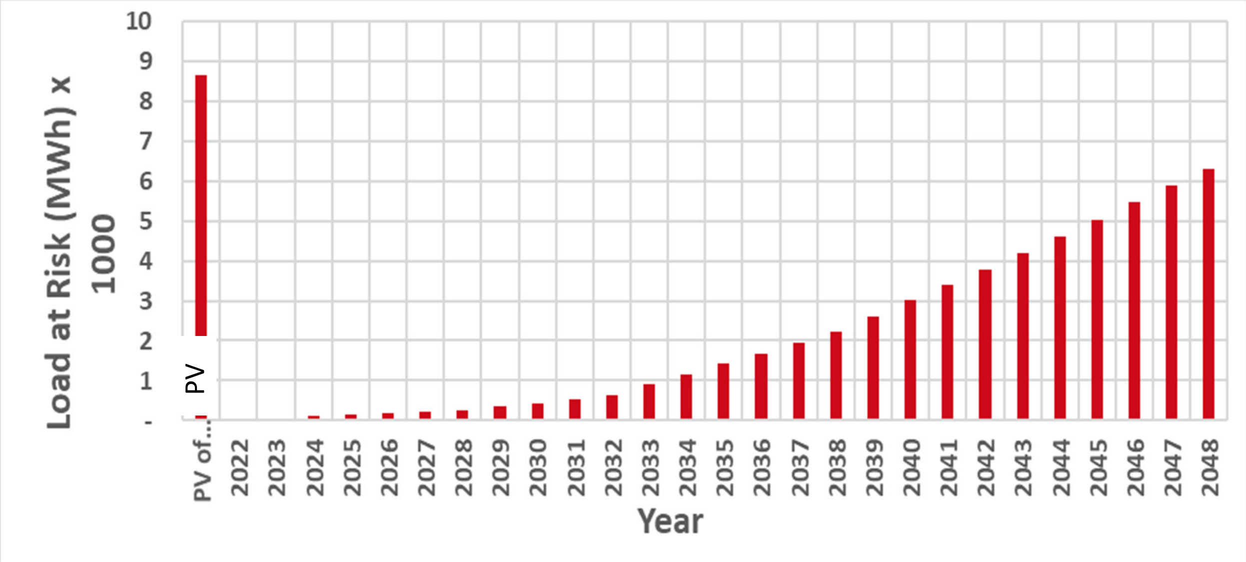


Figure 3-11. LAR (N-0) Benefits Accumulated for ASP over the Study Horizon

LAR (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 [6]. These costs are separated into residential, small & medium business, and commercial & industrial in $/kWh. Figure 3-12 presents the costs over a 24-hour duration as applied to this assessment.

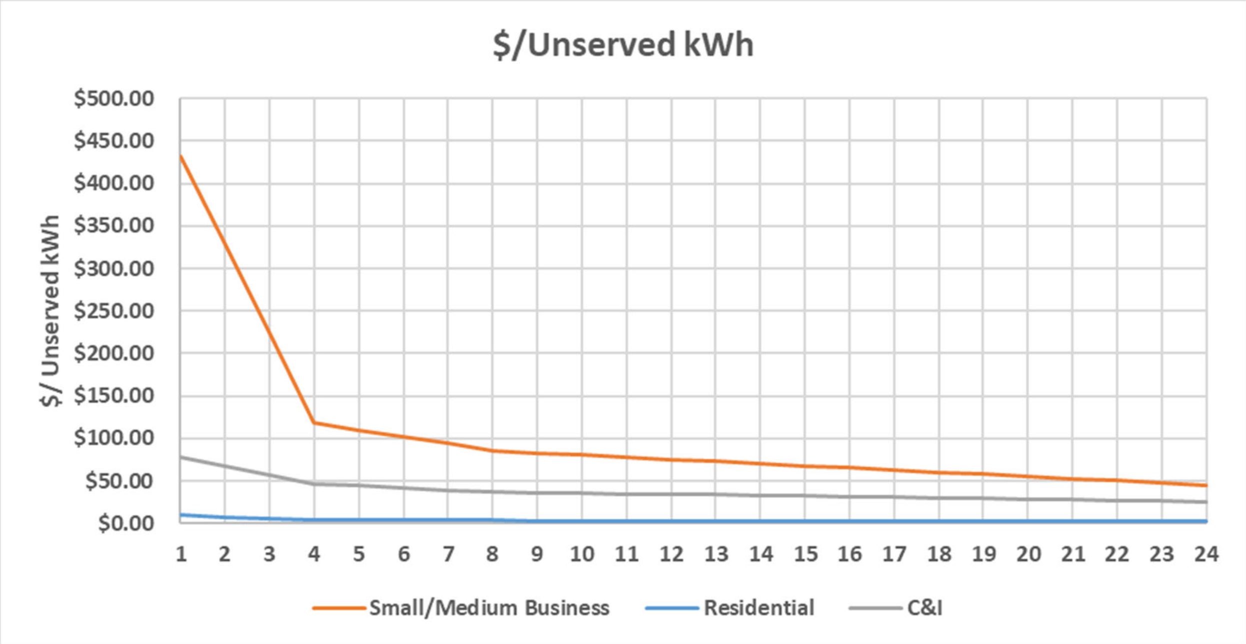


Figure 3-12. Value of Unserved kWh

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

- EENS under N-0 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.
  - Costs derived from Figure 3-12 for the 1-hour outage, consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
- EENS under N-1 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages have been derived from historic event data in the Valley South, with a failure rate of 3.4 outages per 100 mile years and a mean duration of 2.8 hours.[10] The outage probabilities associated with N-1 circuits are presented in Table 3-3. For new lines in the alternatives, probabilities have been calculated using the estimated length of the circuit and the associated failure rates using the 3.4 outages per 100 mile-years metric.

Table 3-3. N-1 Line Outage Probabilities in Valley South

Line Name	Line Outage Probability Index
Auld-Moraga #1	0.36074
Auld-Moraga #2	0.40664
Auld-Sun City	0.27846
Elsinore-Skylark	0.1632
Fogarty-Ivyglen	0.32164
Moraga-Pechanga	0.17578
Moraga-Stadler-Stent	0.23188
Pauba-Pechanga	0.26112
Pauba-Triton	0.26622
Skylark-Tenaja	0.14994
Stadler-Tenaja	0.17374
Valley-Elsinore-Fogarty	0.59092

[10] Provided by SCE.

Line Name	Line Outage Probability Index
Valley-Newcomb	0.21454
Valley-Newcomb-Skylark	0.67966
Valley-Sun City	0.12818
Valley-Ivyglen	0.918
Valley-Auld #1	0.40664
Valley-Auld #2	0.34884
Valley-Triton	0.53244

- Flexibility-1 Metric
  - LAR (MWh) for 1 year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) are used consistent with the principles of rolling outages between different customers at each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages were derived from historic event data in Valley South System, with a failure rate of 0.8 outages per 100 mile years and a mean duration of 3 hours.
  - Considering the large combination of N-2 circuit outages that potentially impact the Valley South System, Flexibility 1 metrics are limited only to circuits that share a double circuit pole. The outage probabilities associated with N-2 contingencies are provided in the Appendix (Section 9).
- Flexibility-2-1 Metric
  - LAR (MWh) over an average 2-week duration multiplied by the cost of lost load ($/MWh) associated with assumed a 2-week outage duration multiplied by the outage probability.
  - The outage duration for this event is considered to be 2 weeks, reflective of the minimum restoration duration for an event of this magnitude. The cost has been derived as the average cost of lost load using hour 1 and hour 24 from Figure 3-12. Considering the uncertainties and shortage of publically available data sources to support the quantification of customer interruption costs due to events of this magnitude, the average of hour 1 and hour 24 cost data would prevent bias towards to a higher or lower monetary impact.
  - The cost associated with this event for residential is 5.68$/kWh, small/medium business is 238.4$/kWh, and commercial/industrial is 52.11$/kWh.
  - 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 [7].
- Flexibility-2-2 Metric
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.

  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities associated with this event have been adopted from the CIGRE Transformer Reliability Survey [8] data for major transformer events (fire or explosion) reported to be 0.00075 failures per transformer year.
- Losses
  - Losses (MWh) for the year multiplied by the average locational marginal price (LMP) at the Valley 500-kV substation.
  - The average LMPs are obtained from production simulation of the CAISO model for the year 2021 and 2022 and escalated each year.
  - 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 the in-service year 2021/2022 (depending on the need year from forecast used for the study) to 2048, which covers 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 the present worth of costs and benefits, three different types of analysis have been considered to select the most suitable project among the pool of alternatives. The proposed methodologies utilize the benefits in their non-monetized and monetized representation.

3.3.1.1 Benefit-Cost Analysis (BCA)

The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. 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 from the cost of the project to aggregate benefits introduced by the project.

The relevant benefit categories are monetized per the discussion in Section 3.3.1. The benefits are derived as differences in monetized costs with and without the 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 conditions (N-0), which translates into a $6.6M cost to customers. However, with a project such as ASP in service, the 50 MW of EENS is eliminated, and the $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 the project and the 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 the 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 $474M, and the present worth of N-0 EENS benefit from the ASP (in comparison to baseline) is 8,657 MWh. The ratio of $474M/8,657 MWh suggests that this project would require an investment of $54,753 to achieve 1 MWh of N-0 EENS benefit.

3.3.1.3 Incremental BCA

Incremental BCA is 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 summarized below [9]:

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

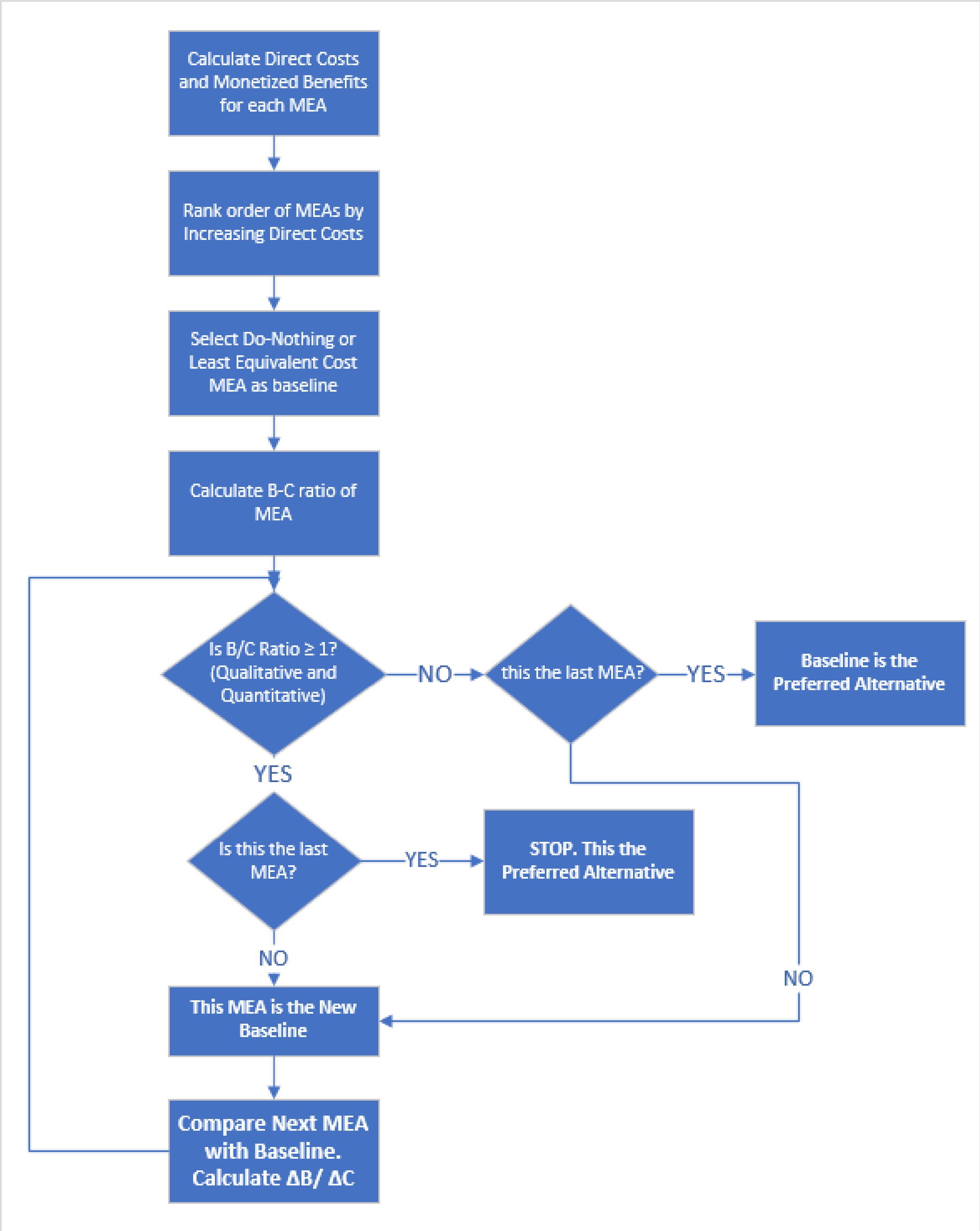


Figure 3-13. Incremental BCA Flowchart

Incremental BCA, also known as marginal benefit-to-cost analysis (MBCA), is considered a superior approach relative to a conventional BCA, for utilities to compare the cost effectiveness of alternative projects. The methodology assures “that dollars will be spent one at a time, with each dollar funding the project that will result in the most reliability benefit, resulting in an optimal budget allocation that identifies the projects that should be funded and the level of funding for each. This process allows service quality to remain as high as possible for a given level of funding—allowing electric utilities to be competitive, profitable, and successful in the new environment of deregulation” [10].

3.3.2 BESS Revenue Stacking

Revenue stacking describes a situation where a BESS is used for more than one domain of applications. When wholesale market applications and transmission and 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).

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 (NWAs 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 are offered into the 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 AS markets. Each day, the optimization would co-optimize the energy and AS participation across the day 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 the 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 Variable O&M Cost ($/kWh)	Parameter (QTech)	0.005 $/kWh
Battery Min/Max Allowable State of Charge (SOC)	Parameter (QTech)	Min/Max: 5/100%
Start/End of Day SOC	Parameter (QTech)	50%
BESS Charging Efficiency	Parameter (QTech)	92%
Wholesale Day-Ahead LMP Data ($/kWh)	Time-series (ISO)	Data extracted for 01/01/2018 – 01/01/2019
BESS Discharging Efficiency	Parameter (QTech)	98%
Regulation Up and Down Clearing Market Prices ($/kW)	Time-series (ISO)	Data extracted for 01/01/18 – 01/01/2019
LMP Price Escalation/yr	Time-series (QTech)	2.5%
LA Basin Local RA Weighted Average Value ($/kW-Month)	Parameter (CPUC [11])	3.64/kW – Month for year 2018

This evaluation was carried out using a proprietary optimization tool developed by Quanta Technology. The tool uses a mixed-integer programming methodology. The co-optimization of storage resource participation in energy and AS 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 AS markets was evaluated. Each day, the optimization would co-optimize the energy and AS participation across the day 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, RegUp, and RegDown capacity less the variable O&M. Note: the variable O&M of $0.00579/kWh is considered for both charging and discharging of the battery. A low-order variable O&M 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 a 24-hour duration.

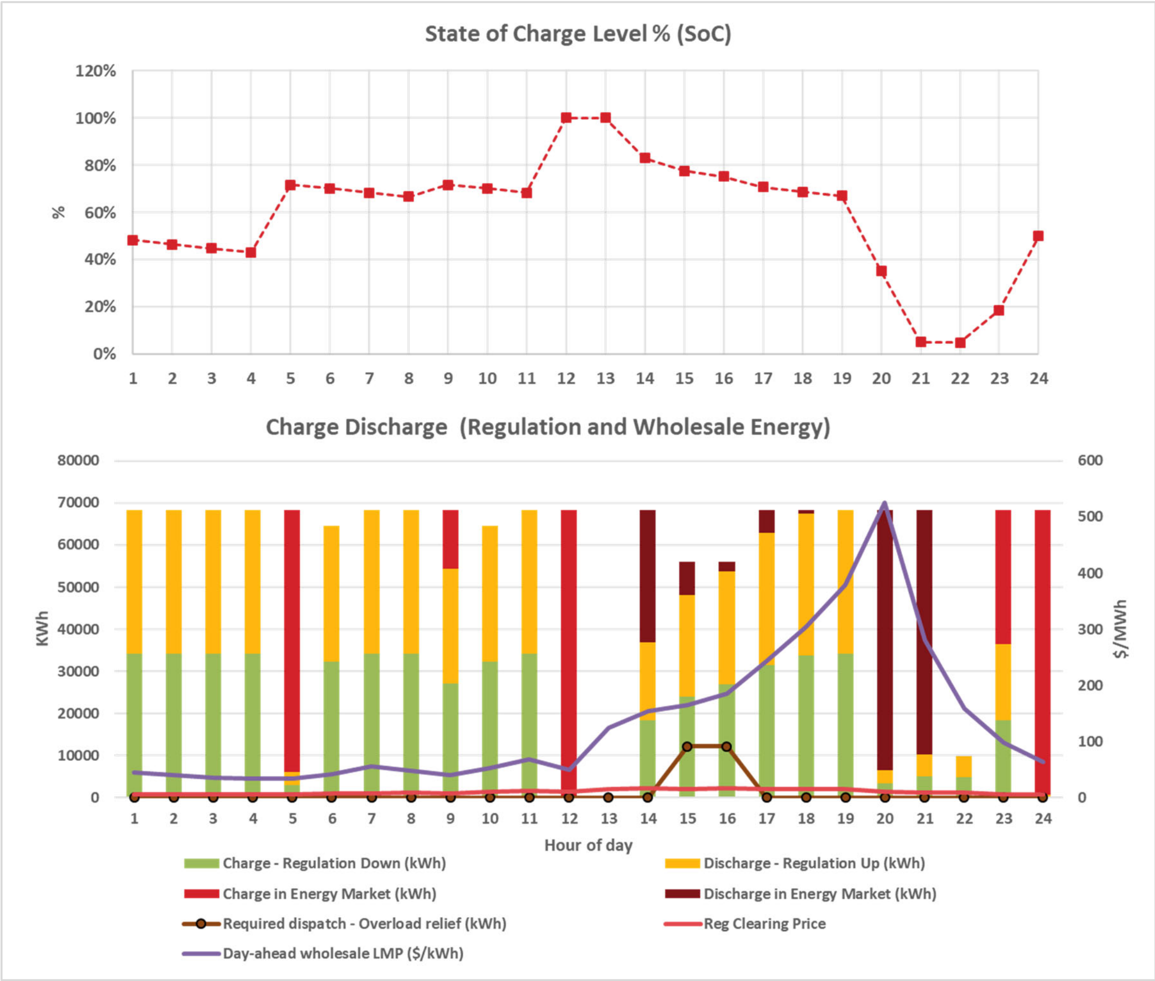


Figure 3-14. Daily Scheduling Example

In addition to participation in wholesale energy and AS markets, potential revenue available from the Resource Adequacy (RA capacity markets) have been estimated. The revenues are derived using local RA prices for the Los Angeles basin area obtained from the CPUC 2018 Resource Adequacy Report [11].

The model assumes 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 RA market outside the summer operating period). The RA prices representative of the weighted average values has been used and escalated at a rate of 2.5% for future years. The analysis takes into consideration the minimum 4-hour duration requirement for BESS participation while accounting for capacity fading at a rate of 3% per year.

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.

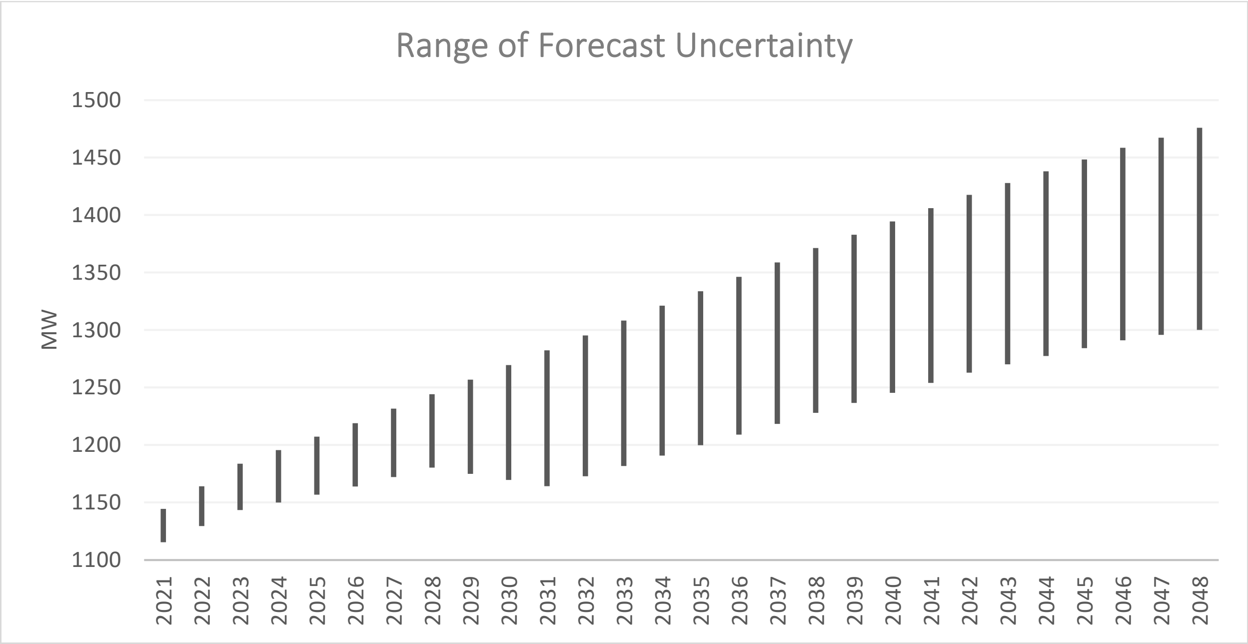


Figure 3-15. Load Forecast Range

Table 3-5. Statistics Associated with Load Forecast

Year	Low (MW)	High (MW)
2023	1146	1181
2028	1183	1242
2038	1230	1369
2048	1302	1474

Considering the spectrum of 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 alternatives 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 section is to apply the reliability assessment framework to 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 the 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 the benefits or impacts of flexibility and resilience (HILP events)
5. To guide for comparing projects against alternatives

Within the framework of this analysis, the reliability, capacity, flexibility, and resilience 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 the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.2.1 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	905	120	18	54,472
2038	2,212	190	37	56,656
2043	4,184	246	53	58,840
2048	6,310	288	77	61,024

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	50	22	4	50,082
2022	129	42	5	50,888
2028	908	131	19	54,467
2033	2,844	205	42	57,450
2038	5,741	280	69	60,432
2043	9,888	348	102	63,415
2048	14,522	411	142	66,397

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

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

4.2.2 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	163,415	133,688	2,774
2033	249	21	54	254,140	139,702	3,514
2038	679	35	88	344,864	145,991	4,421
2043	1,596	45	120	435,589	151,619	5,294
2048	2,823	68	153	526,314	155,733	5,975

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	18	4	18	54,545	129,095	2,255
2022	40	6	28	87,602	131,322	2,491
2028	231	23	60	285,950	140,388	3,612
2033	989	40	98	451,239	147,622	4,670
2038	2,435	62	147	616,529	154,744	5,811
2043	5,599	71	204	781,818	161,142	6,952
2048	10,024	128	261	947,107	166,580	8,000

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	122,681	133,688	2,774
2033	75	11	33	531,497	133,840	2,791
2038	182	20	51	872,176	139,065	3,432
2043	454	29	79	1,212,856	143,845	4,110
2048	805	35	94	1,553,536	147,226	4,615

In the baseline system analysis, the following constraints (Table 4-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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		
Valley South Transformer	N-0	Base case	2021	2022	2022
Auld to Moraga #1	N-0	Base case	2038	2047	
Valley EFG to Tap 39	N-0	Base case	2043		
Valley EFG to Sun City	N-0	Base case	2043		
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 the baseline system are as follows:

1. Without any project in service, the Valley South System transformers are 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 the year 2028, 250 MWh of LAR is observed 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 LAR ranges from 2,600 MWh to 14,500 MWh in a 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 the 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 the year 2048.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain system N-1 security.
5. In the Effective PV forecast by the year 2028, 67 MWh of LAR 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 LAR ranges from 805 MWh to 10,000 MWh in a 30-year horizon.

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

The ASP has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.3.1 Description of Project Solution

The ASP 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 currently served by the Valley South 115 kV system. Two transformers were 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) currently 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.

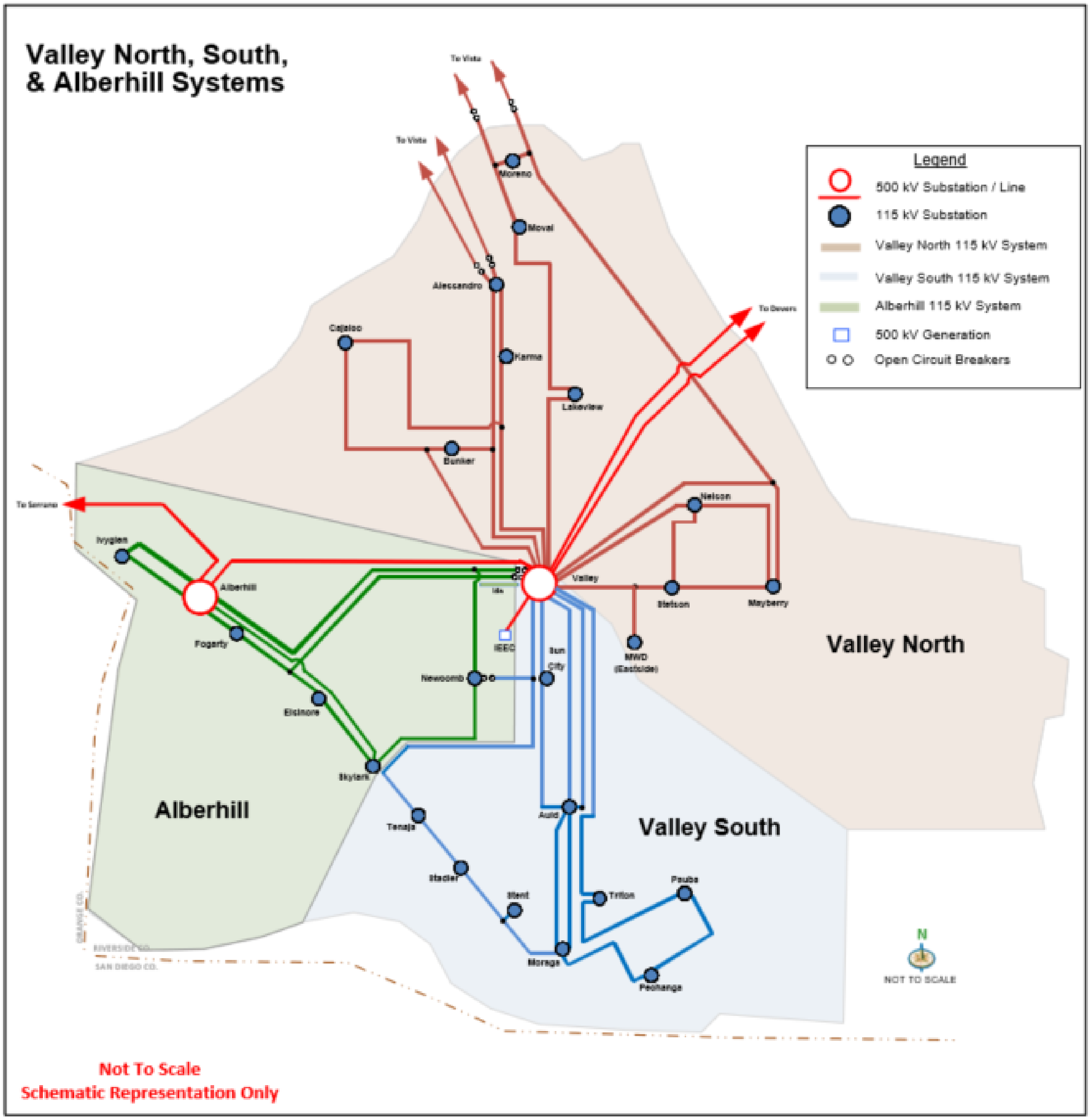


Figure 4-1. Alberhill System Project and Resulting Valley North and South Systems

4.3.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	44,380
2038	0	0	0	46,089
2043	0	0	0	47,797
2048	3	2	2	49,506

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	40,954
2022	0	0	0	41,590
2028	0	0	0	43,417
2033	0	0	0	44,939
2038	1	1	1	46,462
2043	28	8	6	47,984
2048	93	14	10	49,506

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

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

4.3.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	0	1163	0
2028	0	0	0	30,438	1516	0
2033	0	0	0	56,720	1947	0
2038	21	8	4	83,001	2452	0
2043	84	17	8	109,283	2954	1
2048	202	24	14	136,664	3345	4

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	0	1,229	-
2022	0	0	0	11,530	1,363	-
2028	0	0	0	80,713	1,999	-
2033	33	11	5	138,365	2,593	-
2038	163	22	12	196,017	3,249	3
2043	530	34	6	253,669	3,896	11
2048	1,080	43	43	311,321	4,494	27

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	0	1,163	0
2028	0	0	0	11,254	1,516	0
2033	0	0	0	20,632	1,526	0
2038	0	0	0	30,011	1,899	0
2043	7	4	2	39,389	2,272	0
2048	30	10	5	48,395	2,559	0

In analyzing the ASP, the following constraints (Table 4-14) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Auld – Moraga #1	N-0	N/A (base case)	2048		
Valley EFG – Sun City	N-0	N/A (base case)	2048		
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 the baseline and the ASP to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 4-15 for the 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	277,608	362,676
N-1	LAR (MWh)	6,282	20,327	69,479
N-1	IP (MW)	428	601	954
N-1	PFD (hr)	1,300	1,907	3,277
N-1	Flex-1 LAR (MWh)	3,901,429	6,024,126	9,664,642
N-1	Flex-2-1 LAR (MWh)	3,657,700	3,779,849	4,101,527
N-1	Flex-2-2 LAR (MWh)	87,801	106,937	141,992

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	LAR (MWh)	22,751	56,575	140,566
N-0	IP (MW)	2,713	4,053	6,213
N-0	PFD (hr)	411	811	1,559

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons 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 resilience 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. 3 MWh of LAR is recorded under N-0 condition (Effective PV Forecast) in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line. Across all sensitivities, the benefits range between 22.7 and 140.5 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With the ASP in service, the N-1 benefits in the system range from 6.2 to 66.7 GWh through all forecasts. In the Effective PV Forecast by the 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, or emergency outages throughout the system while also providing significant benefits to address needs under 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 can 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 the load forecast. The available flexibility through system tie-lines provides 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 identify and screen potential alternatives that meet the project objectives detailed in Section 1.2. Each of these alternatives is 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. NWAs include energy storage, demand response, energy efficiency programs, DERs, and other smart grid investments like smart meters. Hybrid solutions are a combination of Conventional and NWAs.

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

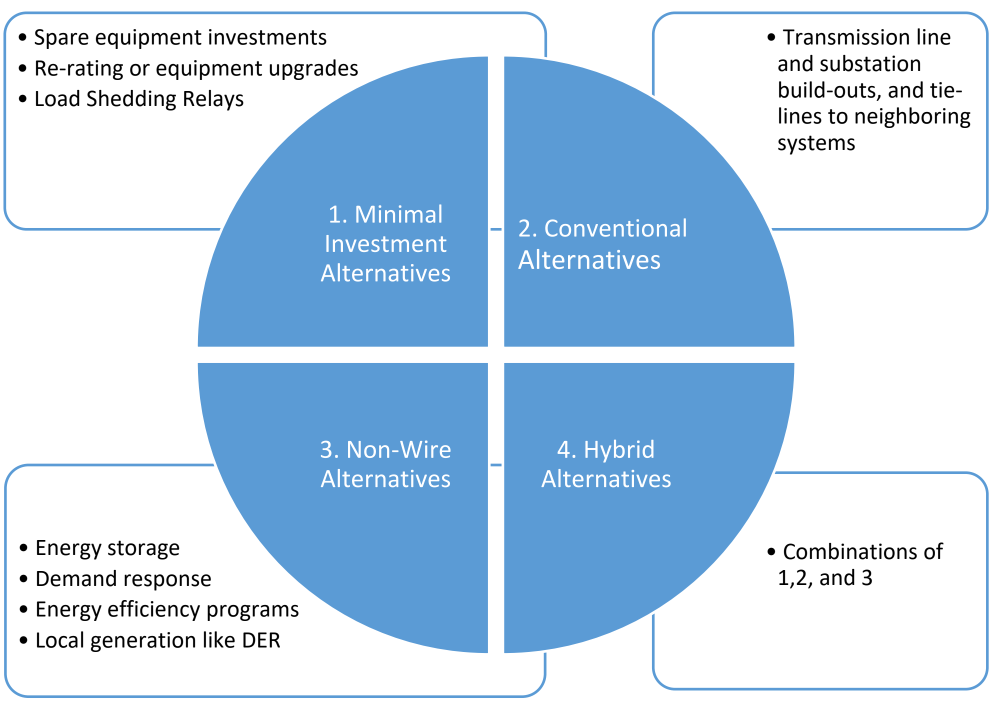


Figure 5-1. Categorization of Considered Alternatives

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

- Use reliability analysis results with no project in service and available reports detailing the 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 was evaluated under the most constraining conditions identified from the "no project" scenario results. Figure 5-2 describes the Valley South System relative to neighboring electrical systems.
- Seek guidance from the LAR metrics to provide the viability of alternatives. For example, the identified MWh need is large and predominantly occurs during off-peak hours of the day when PV-DER type solutions might not be available.

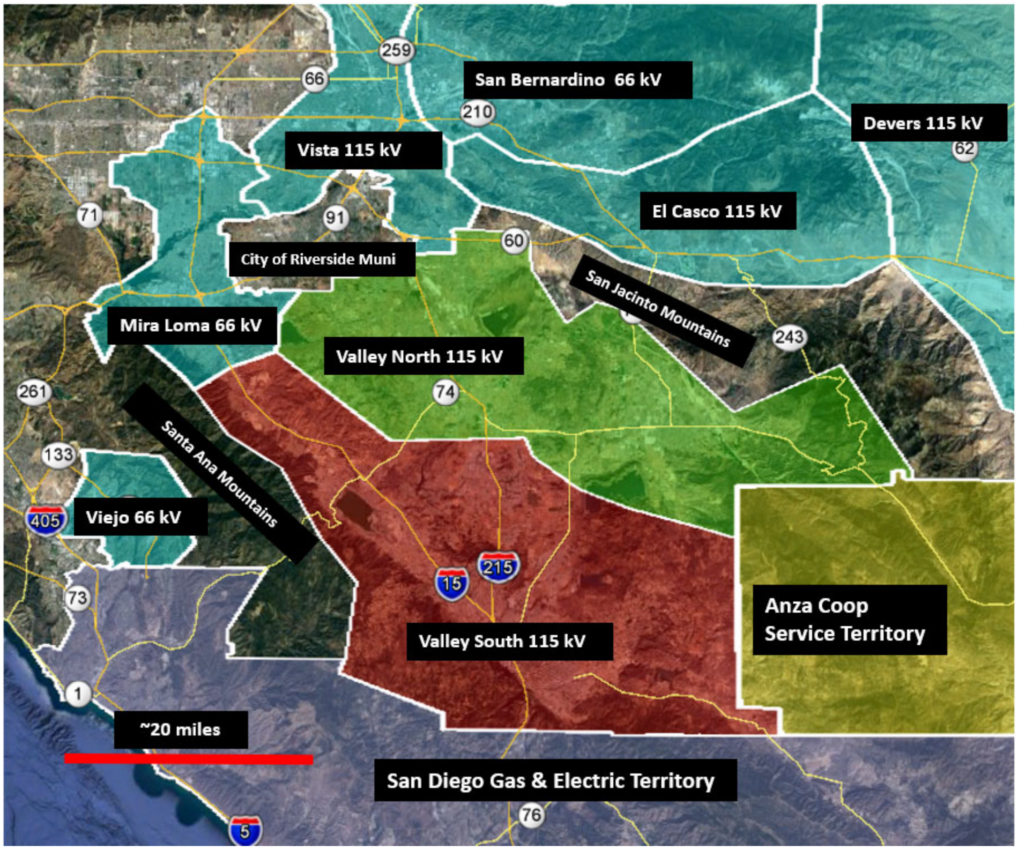


Figure 5-2. Valley System and Neighboring Electrical Systems

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 pertaining to the scope, design, and project performance are described in the upcoming sections. Note that the ASP and project alternatives are identified using an alphabetic character, A through M, which is used throughout this report to refer to 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 the 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 via the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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. The 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 the 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.

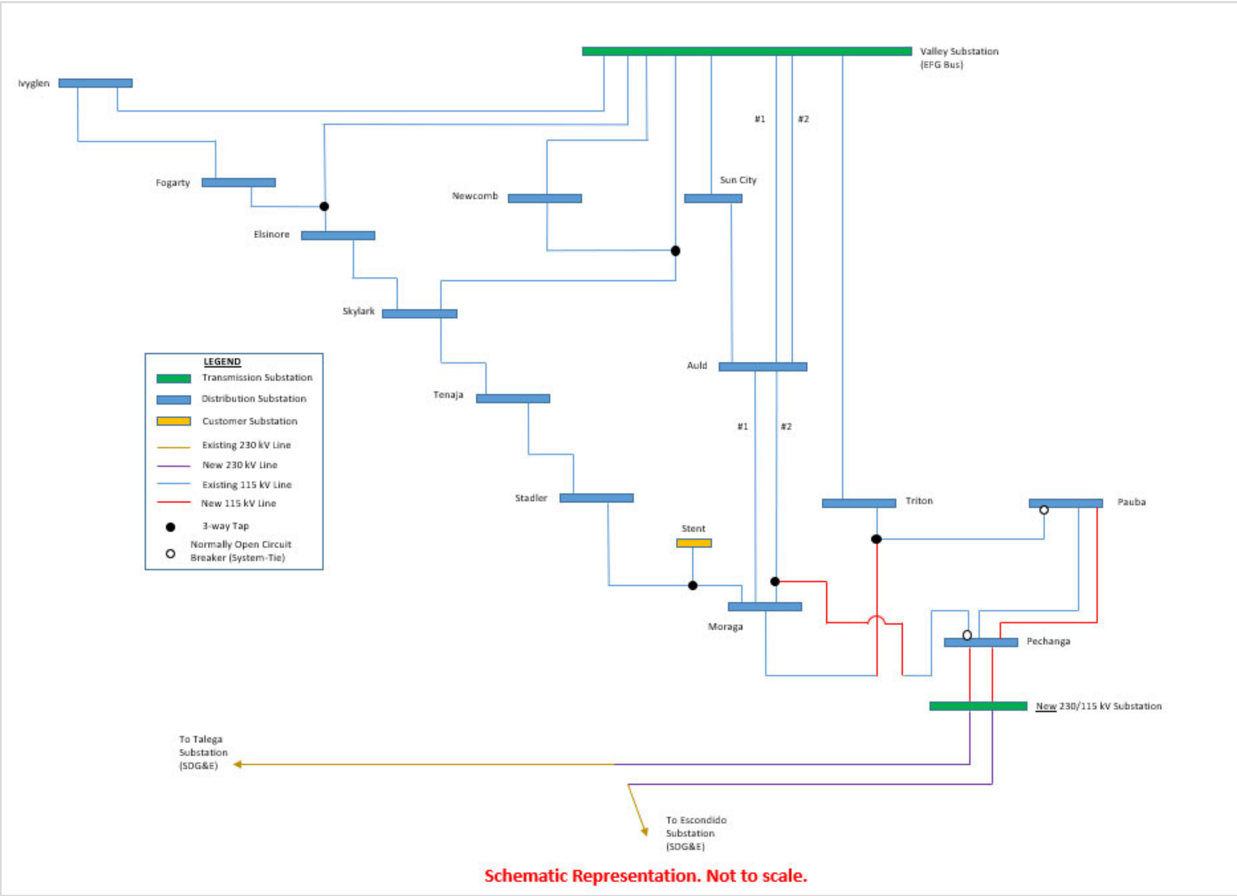


Figure 5-3. SDG&E Project Scope

5.3.1.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	82	31	4	52,481
2048	244	63	7	54,457

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	199	56	6	50,710
2043	655	112	12	52,584
2048	1,499	152	28	54,457

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

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

5.3.1.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	52,762	17,895	636
2033	0	0	0	79,372	21,123	926
2038	0	0	0	105,982	24,949	1,274
2043	0	0	0	132,591	28,757	1,662
2048	0	0	0	159,201	31,740	1,978

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	20,830	15,677	468
2022	0	0	0	30,189	16,727	545
2028	0	0	0	86,343	21,517	958
2033	0	0	0	133,137	26,018	1,380
2038	0	0	0	179,931	31,008	1,889
2043	30	7	4	226,725	35,874	2,413
2048	196	18	8	273,520	40,207	2,937

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	36,859	17,895	636
2033	0	0	0	50,217	17,971	641
2038	0	0	0	63,575	20,763	896
2043	0	0	0	76,933	23,589	1,146
2048	0	0	0	90,291	25,756	1,352

In analyzing the SDG&E project, the following constraints (Table 5-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 (base case)	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 the baseline and the SDG&E Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-8 for the 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 Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	200,879	214,200	249,117
N-1	LAR (MWh)	6,375	21,684	75,545
N-1	IP (MW)	467	780	1,321
N-1	PFD (hr)	1,320	1,999	3,432
N-1	Flex-1 (MWh)	3,362,638	5,414,801	9,902,236
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689	97,230
N-0	LAR (MWh)	22,748	55,563	132,227
N-0	IP (MW)	2,710	3,726	4,978
N-0	PFD (hr)	410	775	1,444

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 is 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 a longer distance from the 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- and mid-term horizon. This trend is observable across all forecast sensitivities. Under N-0, 240 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,500 MWh under the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 132.2 GWh of avoided LAR.
2. With the SDG&E Project in service, the N-1 benefits in the system range from 6.3 to 72.6 GWh through all forecasts. The design of the 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 the Valley South System. In the Spatial Base Forecast, by the 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 the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Following a HILP event, the SDG&E Project can 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 the lower range of forecast sensitivities.

5.3.2 SCE Orange County (Project C)

The SCE Orange County Project was evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 to the new 220/115 kV substation. This configuration would include the construction of the new 230 kV double-circuit transmission line.
3. The proposed solution would transfer SCE's Tenaja and Stadler 115/12 kV Substations to the new 220/115 kV system through the 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.

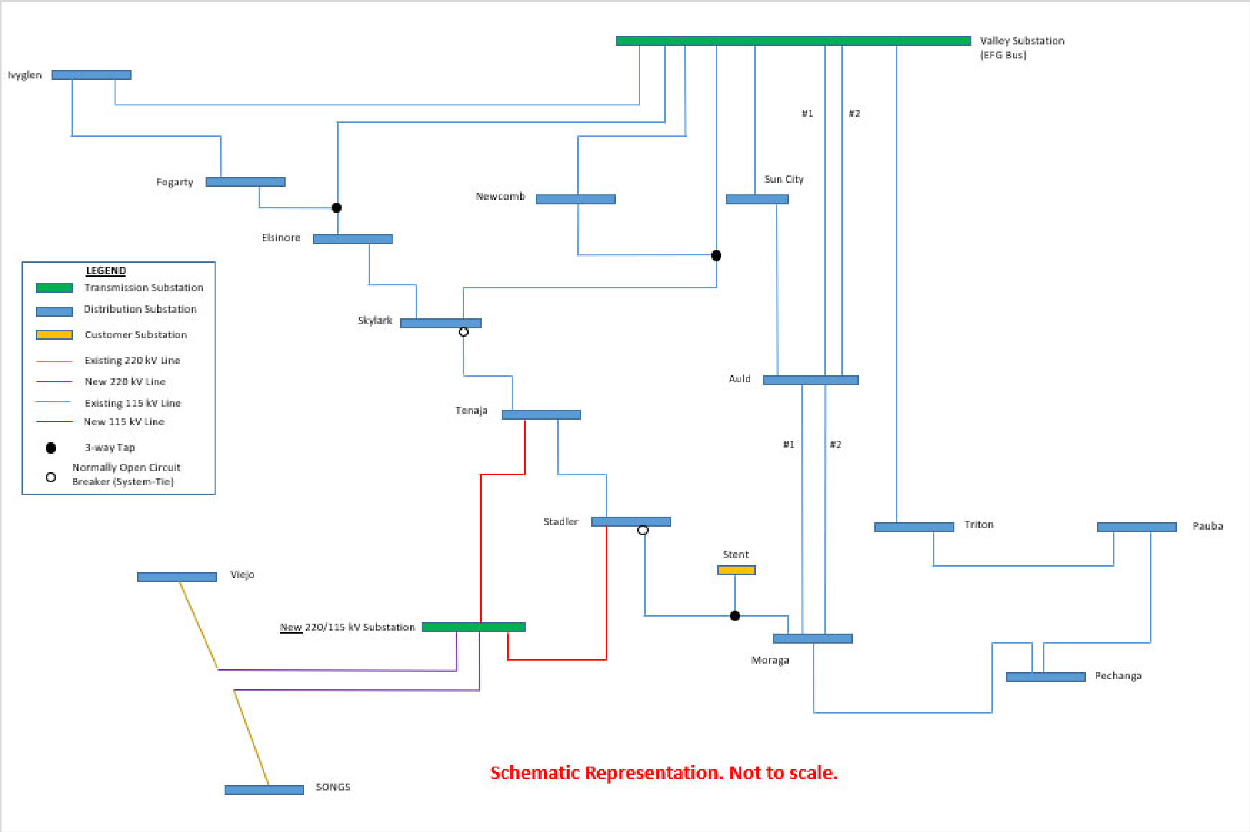


Figure 5-4. SCE Orange County Project Scope

5.3.2.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	**2022**	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	47,596
	2038	0	0	0	49,599
	2043	72	31	4	51,602
	2048	232	65	7	53,605

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	**2021**	0	0	0	43,574
	2022	0	0	0	44,330
	2028	0	0	0	41,444
	2033	0	0	0	45,672
	2038	183	55	5	49,899
	2043	536	111	11	54,126
	2048	1,426	159	27	58,353

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

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

5.3.2.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886	14,219	344
	2028	13	3	5	142,815	16,791	519
	2033	35	3	2	215,046	19,823	769
	2038	130	14	7	288,277	23,407	1,078
	2043	313	26	14	359,507	27,650	1,413
	2048	578	36	28	417,292	29,833	1,703

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2021**	5	3	2	55,886	14,711	375
	2022	10	3	2	77,708.23	15,692	438
	2028	38	5	4	208,643.16	20,192	798
	2033	176	17	8	317,755.59	24,412	1,169
	2038	497	32	24	426,868.03	29,138	1,633
	2043	1,179	46	37	535,980.47	33,790	2,108
	2048	2,275	74	56	645,092.91	37,969	2,570

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886	14,219	344
	2028	13	3	5	103,236	16,791	519
	2033	15	3	6	142,695	16,863	523
	2038	32	3	10	182,154	19,485	735
	2043	95	10	21	221,613	22,133	968
	2048	159	16	23	261,072	24,165	1,146

In analyzing the SCE Orange County Project, the following constraints (Table 5-15) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 a 30-year study. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The cumulative value of the benefits over the 30-year horizon is presented in Table 5-16 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	193,424	187,601	203,637
N-1	LAR (MWh)	5,159	17,520	59,898
N-1	IP (MW)	337	447	661
N-1	PFD (hr)	1,055	1,785	2,923
N-1	Flex-1 (MWh)	583,840	1,278,674	4,209,439
N-1	Flex-2-1 (MWh)	3,200,515	3,255,754	3,449,007
N-1	Flex-2-2 (MWh)	69,270	81,467	103,655
N-0	LAR (MWh)	22,751	55,560	133,064
N-0	IP (MW)	2,713	3,724	4,986
N-0	PFD (hr)	411	776	1,456

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 is substantial in the N-1 category and loss reduction. The project's contribution to loss reduction is primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to point of delivery. Additionally, this project displaces loading on subtransmission lines with a 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 the 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- and mid-term horizon. Under N-0, 230 MWh of LAR 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 from 22.7 to 133 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With SCE Orange County Project in service, the N-1 LAR 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 the HILP events that occur in the Valley South 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- or mid-term horizon and under the 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. The 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 the 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.
6. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

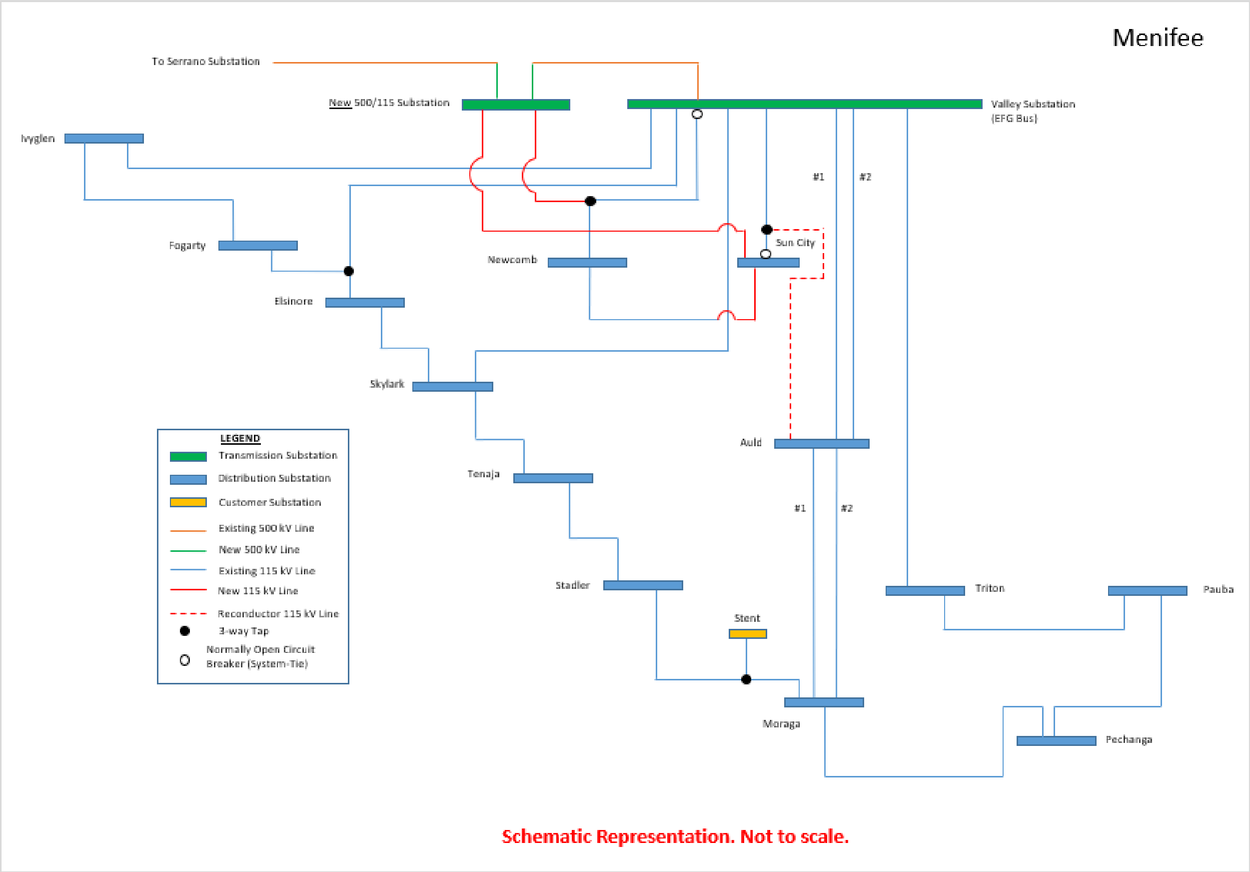


Figure 5-5. Menifee Project Scope

5.3.3.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	53,316
2038	0	0	0	55,324
2043	3	3	1	57,332
2048	114	39	4	59,341

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,287
2022	0	0	0	50,035
2028	0	0	0	53,305
2033	0	0	0	56,030
2038	73	29	4	58,754
2043	385	83	8	61,479
2048	902	130	14	64,204

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

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

5.3.3.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	54,051	28,475	842
2033	4	2	2	81,311	33,145	1,161
2038	103	14	19	108,570	38,226	1,586
2043	472	22	67	135,830	42,887	2,025
2048	1040	38	155	163,090	46,332	2,369

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	25,088	616
2022	0	0	0	31,297	26,706	715
2028	4	2	2	91,039	33,690	1,202
2033	156	18	22	140,824	39,569	1,710
2038	722	37	70	190,610	45,496	2,286
2043	1,968	56	163	240,395	50,845	2,902
2048	3,737	68	272	290,181	55,391	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	46,835	28,475	843
2033	0	0	0	68,082	28,590	850
2038	0.4	0.4	1	89,330	32,641	1,122
2043	47	10	11	110,577	36,471	1,426
2048	138	17	22	131,824	39,242	1,679

In analyzing the Menifee project, the following constraints (Table 5-23) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.3.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-24 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	41,268	33,102	41,920
N-1	LAR (MWh)	5,724	15,368	51,103
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,370
N-1	Flex-1 (MWh)	2,795,076	5,356,744	9,661,860
N-1	Flex-2-1 (MWh)	2,860,352	2,885,882	3,029,498
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	22,751	56,229	136,040
N-0	IP (MW)	2,713	3,930	5,371
N-0	PFD (hr)	411	800	1,519

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Menifee Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the 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.

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, 114 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 985 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 135.6 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 5.7 to 48 GWh through all forecast sensitivities.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, the Menifee Project can serve a total of approximately 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.4.1 Description of Project Solution

1. Construct a 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 the 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 the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

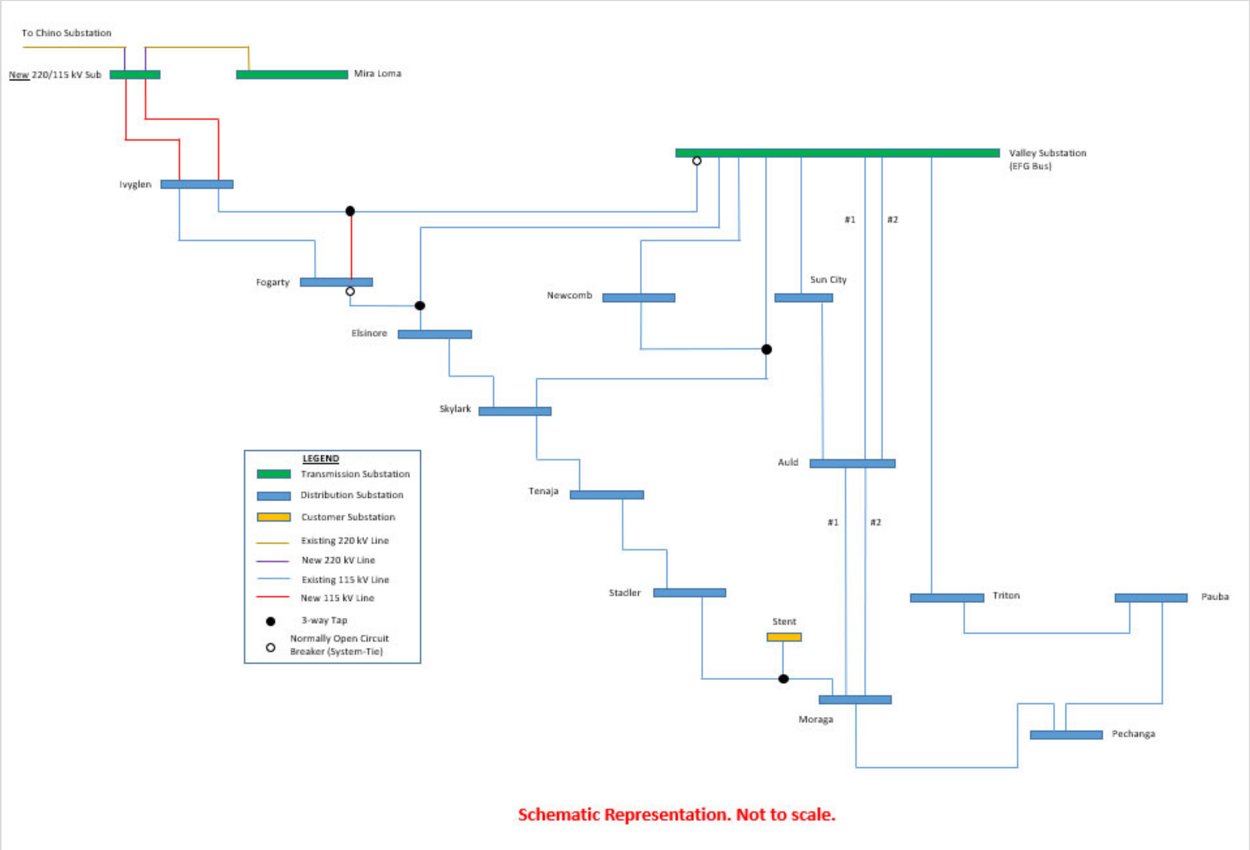


Figure 5-6. Tie-line to Mira Loma Project Scope

5.3.4.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	82	31	4	53,021
2038	314	84	9	55,097
2043	807	138	22	57,173
2048	1,905	184	30	59,250

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	106	38	4	42,629
2033	607	104	12	48,041
2038	1,449	172	29	53,453
2043	3,365	238	45	58,864
2048	4,958	294	81	64,276

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

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

5.3.4.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	99,638	87,598	944
2033	18	4	7	149,889	93,115	1,299
2038	94	15	27	200,140	98,884	1,766
2043	493	30	66	250,391	104,047	2,219
2048	1,151	40	127	300,643	107,821	2,609

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	39,336	83,384	708
2022	0	0	0	56,324	85,427	828
2028	12	4	7	158,254	93,744	1,345
2033	253	19	39	243,197	100,380	1,885
2038	822	36	114	328,139	106,913	2,513
2043	2427	57	246	413,081	112,783	3,150
2048	4599	77	442	498,023	117,771	3,772

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	93,650	87,598	944
2033	0	0	0	138,912	87,737	951
2038	4	2	4	184,174	92,531	1,259
2043	64	9	16	229,436	96,915	1,601
2048	197	20	29	274,697	100,017	1,852

In analyzing the Mira Loma Project, the following constraints (Table 5-31) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-	-
Tap 39-Elsinore #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
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	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	2038

5.3.4.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-32 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	48,851	40,333	47,004
N-1	LAR (MWh)	5,454	15,237	45,012
N-1	IP (MW)	355	421	603
N-1	PFD (hr)	1,041	1,125	214
N-1	Flex-1 (MWh)	623,316	3,255,037	6,500,106
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	65,168	82,069
N-0	LAR (MWh)	19,577	44,963	98,703
N-0	IP (MW)	1,720	2,270	2,721
N-0	PFD (hr)	362	554	935

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 LAR 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 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, 1,905 MWh of LAR is recorded under the Effective PV Forecast for 2048. Similarly, the LAR of 5,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 18.9 to 110 GWh of avoided LAR.
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 benefits in the system range from 2.5 to 42.6 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, Mira Loma can 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 the 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics.

The project was considered to leverage the capabilities of tie-lines to move loads between the Valley South System and the Valley North System. However, this transfer would not satisfy the short-term and long-term objectives of the projects. No incremental benefits are provided to the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and 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. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

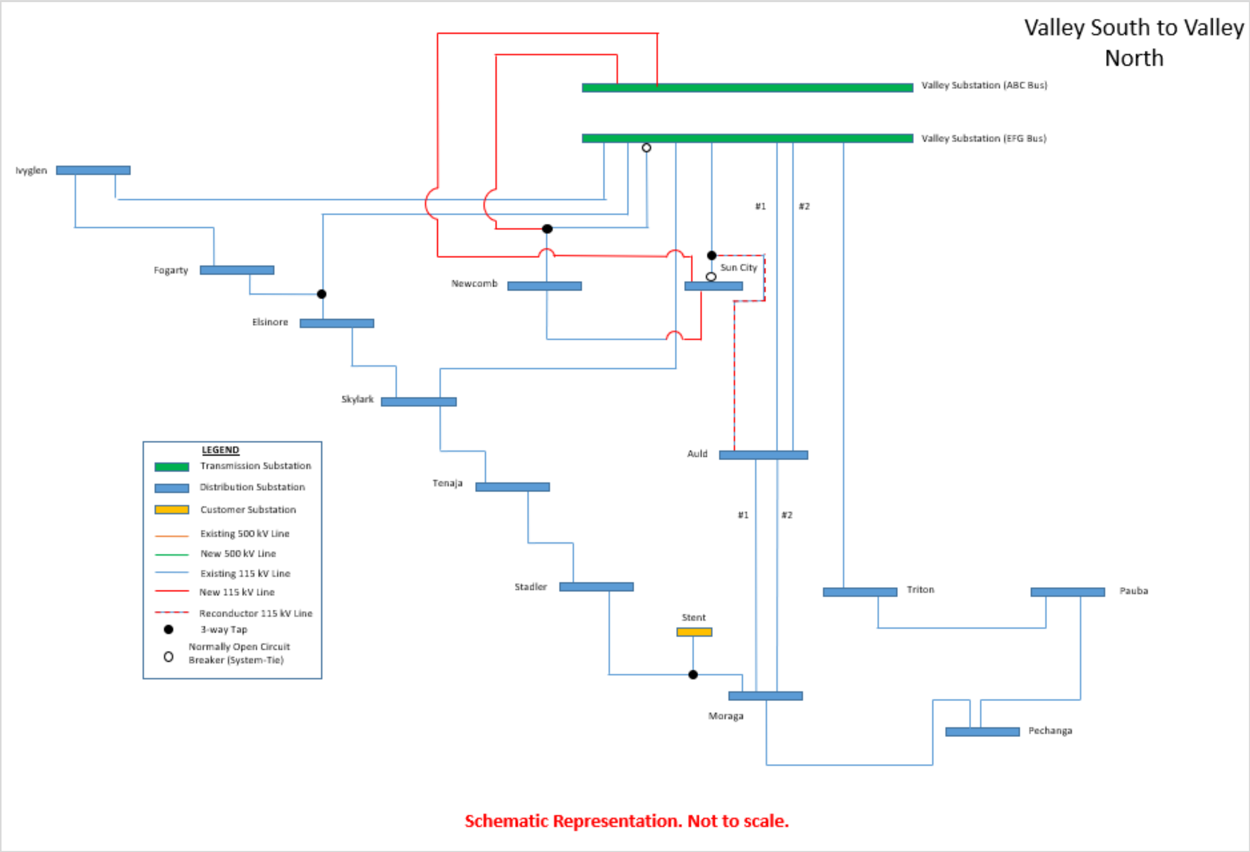


Figure 5-7. Tie-lines between Valley South and Valley North Project Scope

5.3.5.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	779	44	20	57,898
2048	2,680	192	55	59,939

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,468	173	56	59,336
2043	8,146	310	104	62,104
2048	16,818	433	165	64,872

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.5.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	54,051	133,688	843
2033	4	2	2	81,311	139,702	1,161
2038	103	14	19	108,570	145,991	1,586
2043	472	27	67	135,830	151,619	2,025
2048	1040	38	155	163,090	155,733	2,369

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	31,297	140,388	1,202
2028	4	2	2	91,039	140,388	1,202
2033	156	18	22	140,824	147,622	1,710
2038	722	37	70	190,610	154,744	2,286
2043	1968	56	163	240,395	161,142	2,902
2048	3737	68	272	290,181	166,580	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South Project, the following constraints (Table 5-39) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.5.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-40 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	50,734
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,356,743	9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	20,124	45,492	40,848
N-0	IP (MW)	1,910	3,211	2,380
N-0	PFD (hr)	328	537	288

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North Project. By design, the project includes a 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 the year 2030 in the Spatial Base Forecast and 2036 in the Effective PV Forecast.

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 the year 2043. However, the transfer of loads results in overloads on the Valley North transformer by the year 2037. 2,600 MWh of LAR is recorded under N-0 condition in the Effective PV Forecast and 16,800 MWh in the Spatial Base Forecast in the year 2048. Across all sensitivities, the benefits range from 20.1 to 45.4 GWh of avoided LAR.
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 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. During potential HILP events impacting Valley Substation, the project is unable to serve incremental load in the Valley South system.

5. Overall, the Valley South to Valley North Project did not demonstrate comparable levels of performance to the 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)

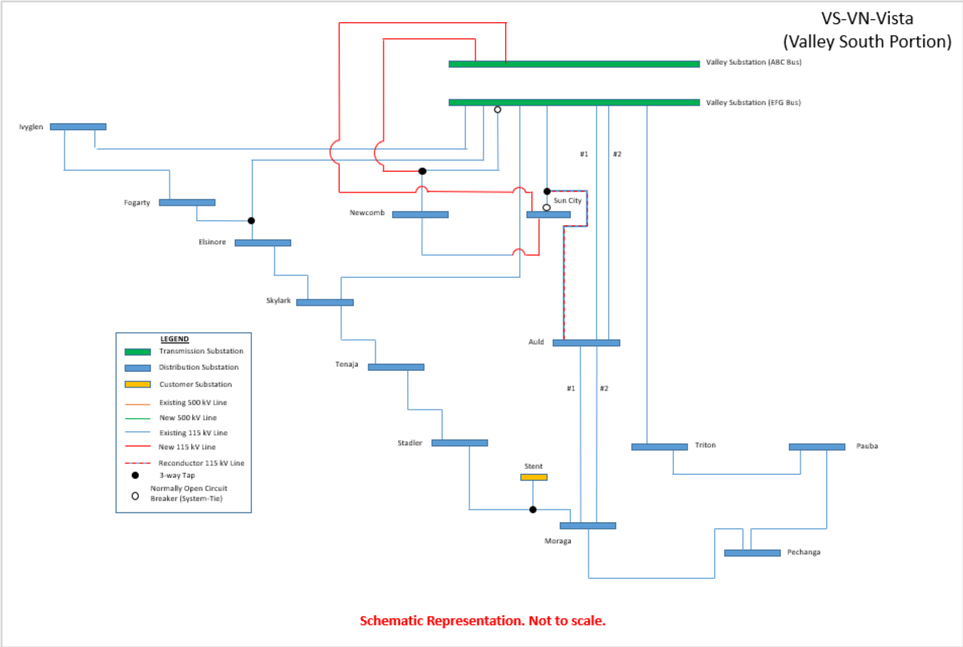
The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to the Valley North System (identical to Project F). Additionally, the load at Moreno Substation in the Valley North System would be transferred to the Vista 220/115 kV system. The premise of this methodology 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 at 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 the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the 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.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-8 presents a high-level representation of the proposed configuration.



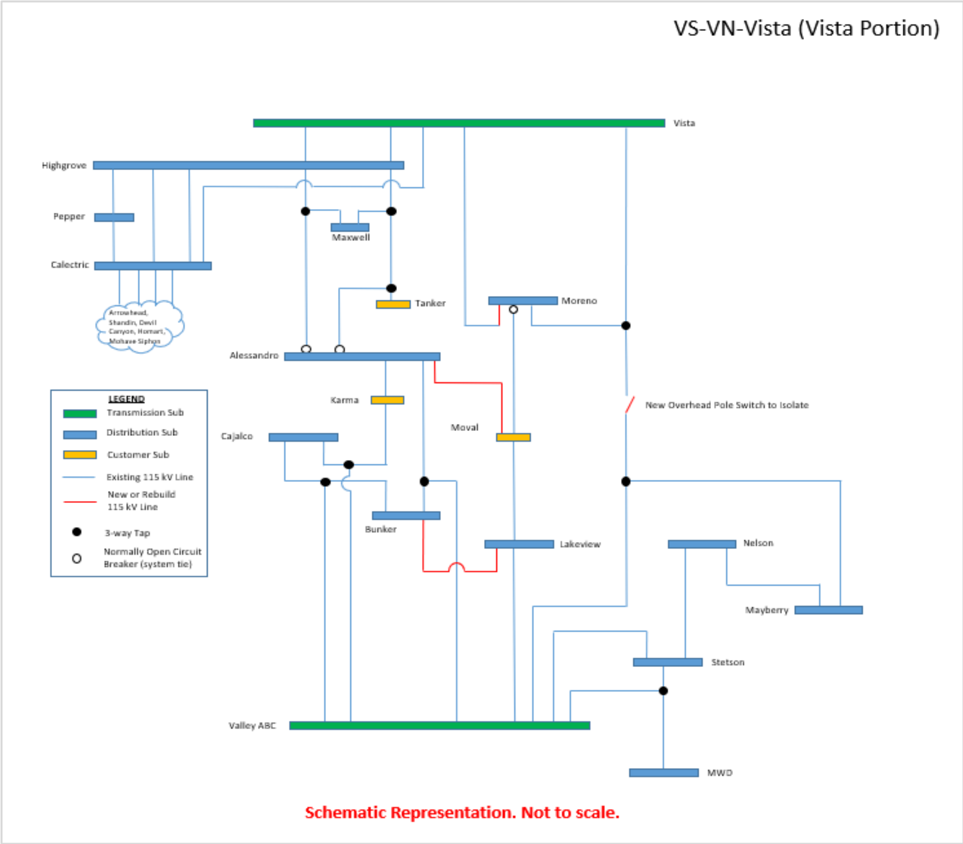


Figure 5-8. Tie-lines between Valley South to Valley North to Vista

5.3.6.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	54,225
2038	0	0	0	55,858
2043	83	31	6	57,898
2048	852	121	22	59,939

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	756	112	23	59,336
2043	3,843	246	66	62,104
2048	9,003	365	119	64,872

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

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

5.3.6.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	54,051	133,688	843
2033	4	2	2	81,311	139,702	1,161
2038	103	14	19	108,570	145,991	1,586
2043	472	27	67	135,830	151,619	2,025
2048	1040	38	155	163,090	155,733	2,370

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	31,297	140,388	1,202
2028	4	2	2	91,039	140,388	1,202
2033	156	18	22	140,824	147,622	1,710
2038	722	37	70	190,610	154,744	2,286
2043	1968	56	163	240,395	161,142	2,902
2048	3737	68	272	290,181	166,580	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South to Vista Project, the following constraints (Table 5-47) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.6.4 Evaluation of Benefits

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

The accumulative value of benefits over the 30-year horizon is presented in Table 5-48 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	50,735
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,356,743	9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,398	87,588
N-0	LAR (MWh)	22,613	53,700	91,349
N-0	IP (MW)	2,638	3,569	3,422
N-0	PFD (hr)	399	725	824

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. By design, the project includes a 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 the year 2041 in the Effective PV Forecast. The project also includes a transfer of load from the Valley North System to the Vista System. This temporarily remedies the system overload but does not provide relief over the long-term horizon.

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 results in overloads on the Valley North System transformers in the year 2041, with a transfer of loads to the Vista System. Under N-0, 852 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 9,000 MWh in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.6 to 91.3 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South 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 the 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

5.3.7 Centralized BESS in Valley South Project (Project H)

The premise of this solution is to utilize 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.7.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be near Pechanga and/or Auld Substations following the 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 through Table 5-51.
4. Due to the radial design of the Valley South System under the 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 of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-49. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	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)

Year	Total Battery Size			
	Pechanga		Auld	
	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/ 1666 MWh**				

Table 5-51. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	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.

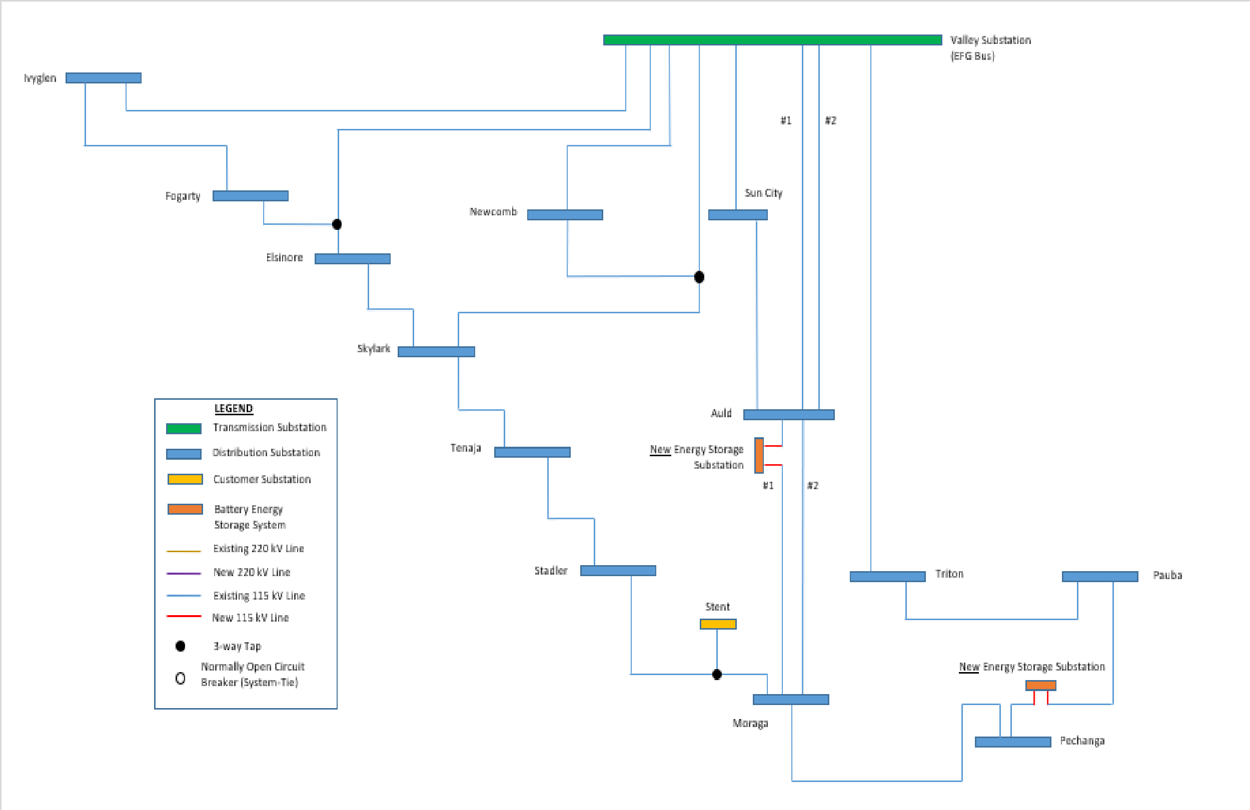


Figure 5-9. Energy Storage at Pechanga and/or Auld Substation as part of the Centralized BESS in the Valley South Project Scope

5.3.7.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	52,705
2038	0	0	0	54,602
2043	0	0	0	56,499
2048	0	0	0	58,396

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

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

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

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

5.3.7.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,492	127,935	2,138
2028	0	0	0	81,951	133,688	2,765
2033	0	0	0	123,478	139,702	3,483
2038	0	0	0	165,004	145,991	4,337
2043	0	0	0	206,531	151,619	5,136
2048	0	0	0	248,058	155,733	5,738

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	26,492	129,095	2,253
2022	0	0	0	32,545	131,322	2,486
2028	0	0	0	68,868	140,388	3,577
2033	0	0	0	99,136	147,622	4,567
2038	0	0	0	129,405	154,744	5,595
2043	0	0	0	159,674	161,142	6,584
2048	31	7	4	189,942	166,580	7,466

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,491	127,935	2,138
2028	0	0	0	47,161	133,688	2,765
2033	0	0	0	64,385	133,840	2,780
2038	0	0	0	81,609	139,065	3,404
2043	0	0	0	98,833	143,845	4,047
2048	0	0	0	116,058	147,226	4,516

In analyzing the Centralized BESS in Valley South Project, the following constraints (Table 5-58) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 the baseline and the Centralized BESS in Valley South Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Centralized BESS in Valley South.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-59 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	52,822	50,796	67,206
N-1	LAR (MWh)	6,375	21,684	75,132
N-1	IP (MW)	467	780	1,375
N-1	PFD (hr)	1,320	1,999	3,456
N-1	Flex-1 (MWh)	2,938,356	4,067,234	10,993,065
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	834	2,111	5,182
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Centralized BESS in Valley South Project. 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, or emergency conditions in the system. The batteries alone cannot complement the system needs during HILP events since they are not configured to operate as microgrids, nor are they 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 from 22.7 to 140.9 GWh of avoided LAR.
2. Minimal N-1 overloads are observable in the long-term horizon for all forecasts. With the project in service, the N-1 LAR 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 HILP events that occur in the Valley South 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, the Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast under study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 exceed 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.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

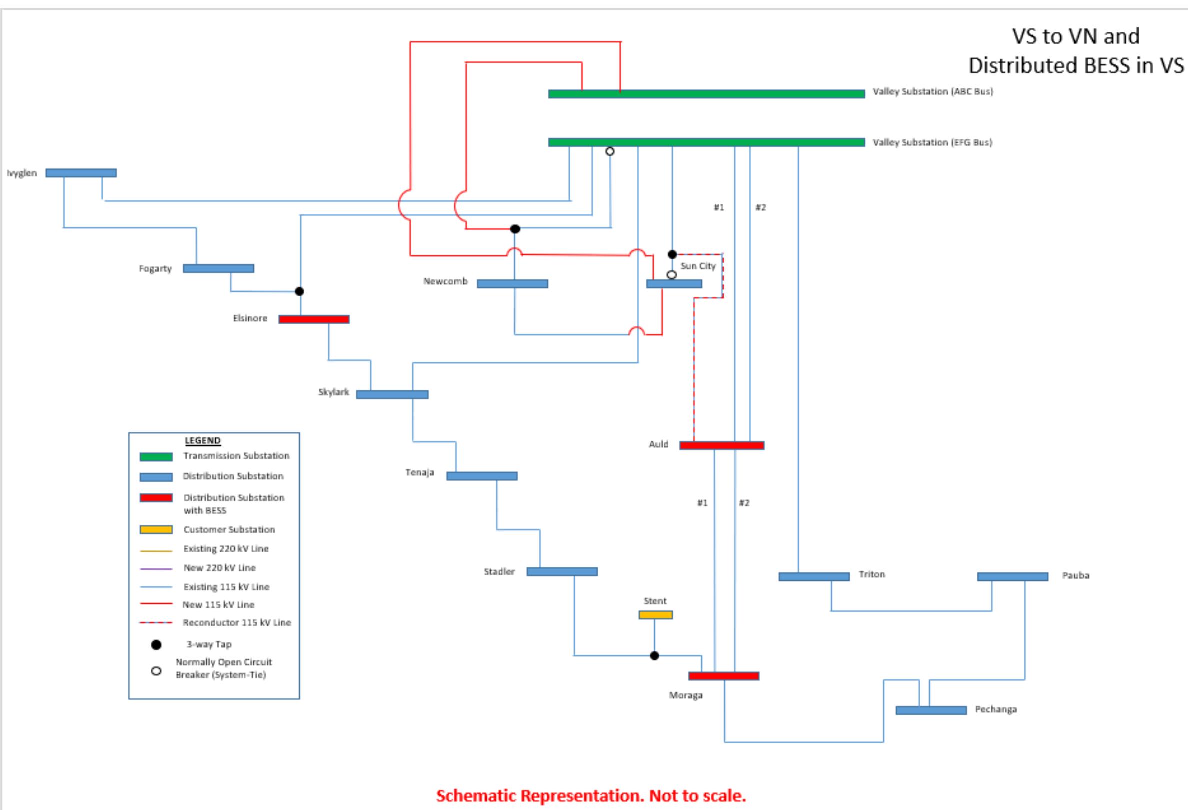


Figure 5-10. Tie-lines between Valley South and Valley North and Distributed BESS in Valley South Project Scope

5.3.8.2 System Performance under Normal Conditions (N-0)

Findings from the 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 South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	775	43	19	57,898
2048	2,567	156	57	59,923

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,388	143	51	59,310
2043	7,789	253	102	62,034
2048	16,127	371	159	64,749

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.8.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330	127,935	571
2028	0	0	0	44,298	133,688	843
2033	4	2	2	68,743	139,702	1,161
2038	103	14	19	92,170	145,991	1,586
2043	324	18	45	113,095	151,619	2,025
2048	614	23	80	134,586	155,733	2,370

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,331	129,095	616
2022	0	0	0	27,808	131,322	715
2028	4	2	2	66,672	140,388	1,202
2033	156	18	22	99,058	147,622	1,710
2038	488	23	69	131,445	154,744	2,247
2043	1357	33	155	163,831	161,142	2,823
2048	2506	65	243	196,218	166,580	3,320

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,293	139,065	1,122
2043	47	10	11	110,530	143,845	1,426
2048	138	17	22	131,768	147,226	1,679

In analyzing the Valley South to Valley North and Distributed BESS in Valley South Project, the following constraints (Table 5-66) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
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	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	-

5.3.8.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-67 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,245.60	27,277.58
N-1	LAR (MWh)	5,724	17,090.60	57,832
N-1	IP (MW)	366	526.95	790.25

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-1	PFD (hr)	1,196	1,389	1,459
N-1	Flex-1 (MWh)	2,275,927	5,741,522	10,977,462
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,405	88,541
N-0	LAR (MWh)	20,124	45,854	45,131
N-0	IP (MW)	1,910	3,416	2,967
N-0	PFD (hr)	328	561	330

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. By design, the project includes a permanent transfer of large load centers from 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 presence of a distributed BESS solution in the Valley South System alleviates the capacity needs in the Valley South System in the Effective PV Forecast, but not under the 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.

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 results in overloads on the Valley North System transformers by the year 2037. Under N-0, 2,600 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 16,200 MWh is recorded under the Spatial Base Forecast sensitivity. Across all sensitivities, the benefits range from 20.1 to 45.1 GWh of avoided LAR.
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 benefits in the system range from 5.7 GWh to 55 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event affect Valley Substation, this solution is unable to serve incremental load in the 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, the 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 SDG&E 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 the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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. The 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 the 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 the 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 exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-68 through Table 5-70, 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. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-68. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	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 Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	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)

Year	Total Battery Size	
	Auld	
	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.

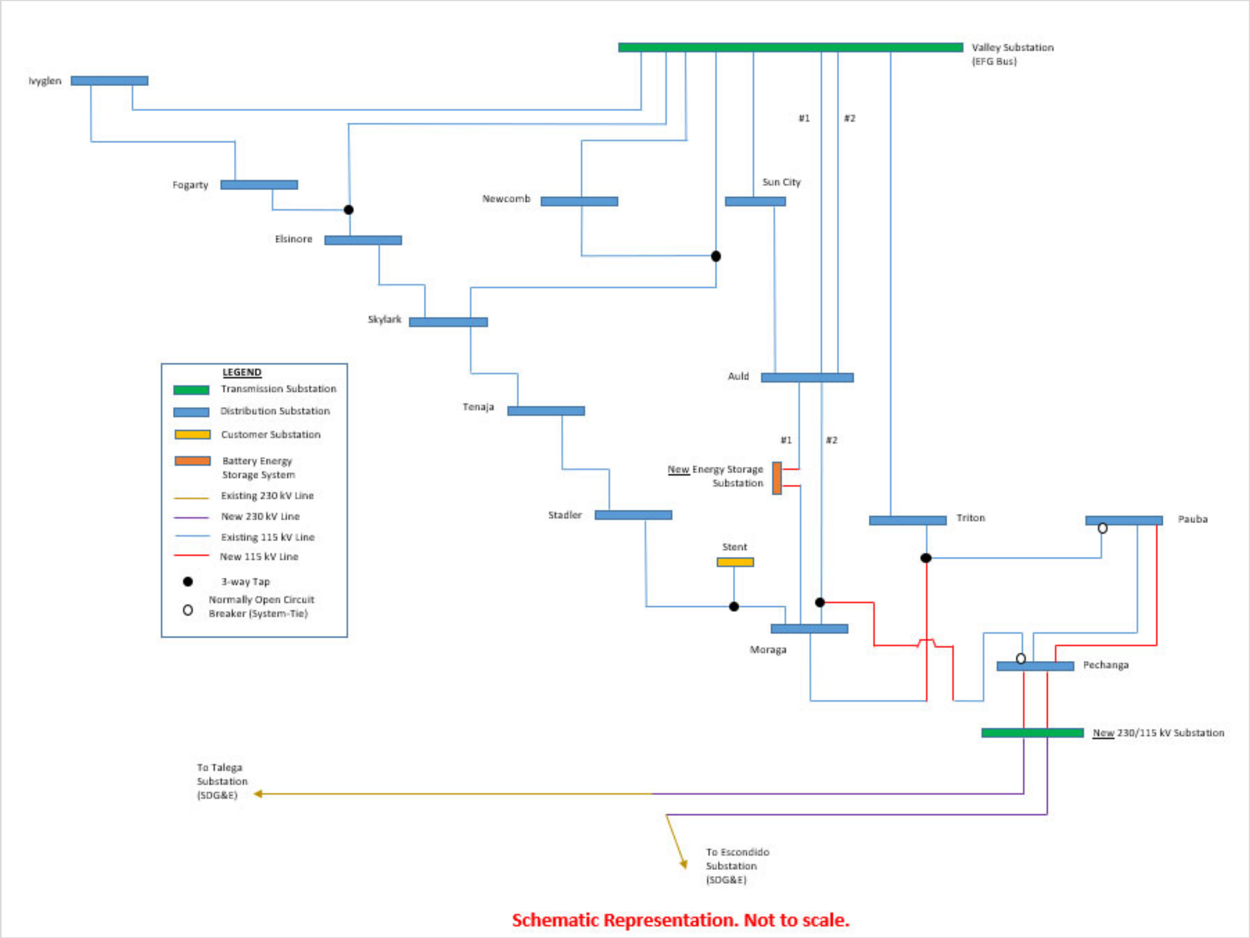


Figure 5-11. SDG&E and Centralized BESS in Valley South Project Scope

5.3.9.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	0	0	0	51,023
2048	0	0	0	51,176

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

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

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

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

5.3.9.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	42,455	17,895	636
2033	0	0	0	63,537	21,123	926
2038	0	0	0	84,920	24,949	1,274
2043	0	0	0	106,303	28,757	1,662
2048	0	0	0	128,102	31,740	1,977

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	16,761	15,677	468
2022	0	0	0	22,124	16,727	545
2028	0	0	0	54,299	21,517	958
2033	0	0	0	81,112	26,018	1,380
2038	0	0	0	107,924	31,008	1,889
2043	0	0	0	134,737	35,874	2,409
2048	0	0	0	161,550	40,207	2,924

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	33,355	17,895	636
2033	0	0	0	47,182	17,971	641
2038	0	0	0	61,010	20,763	896
2043	0	0	0	74,838	23,589	1,146
2048	0	0	0	88,666	25,756	1,352

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-77 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	195,515	214,367	249,947
N-1	LAR (MWh)	6,375	21,684	76,225
N-1	IP (MW)	467	780	1,397
N-1	PFD (hr)	1,320	1,999	3,468
N-1	Flex-1 (MWh)	3,439,502	5,894,261	11,526,786
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689	97,285
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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 is substantial in the N-1 category and N-0 category. However, the flexibility benefits offered by the solution are limited in comparison to the 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 from 22.7 to 140.9 GWh of avoided LAR.

2. With SDG&E and Centralized BESS in Valley South Project in service, the N-1 LAR 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 the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Should a HILP event occur and impact Valley Substation, the SDG&E and Centralized BESS in Valley South Project can 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, the SDG&E and Centralized BESS Project did not demonstrate comparable levels of performance to the 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 the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.10.1 Description of Project Solution

1. Construct a 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 the 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 the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
6. BESS would be installed near Pechanga or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. 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.

8. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-78 through Table 5-80, for all forecasts.
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. Due to the radial design of the Valley South system under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-78. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	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)

Year	Total Battery Size	
	Pechanga	
	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)

Year	Total Battery Size	
	Pechanga	
	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.

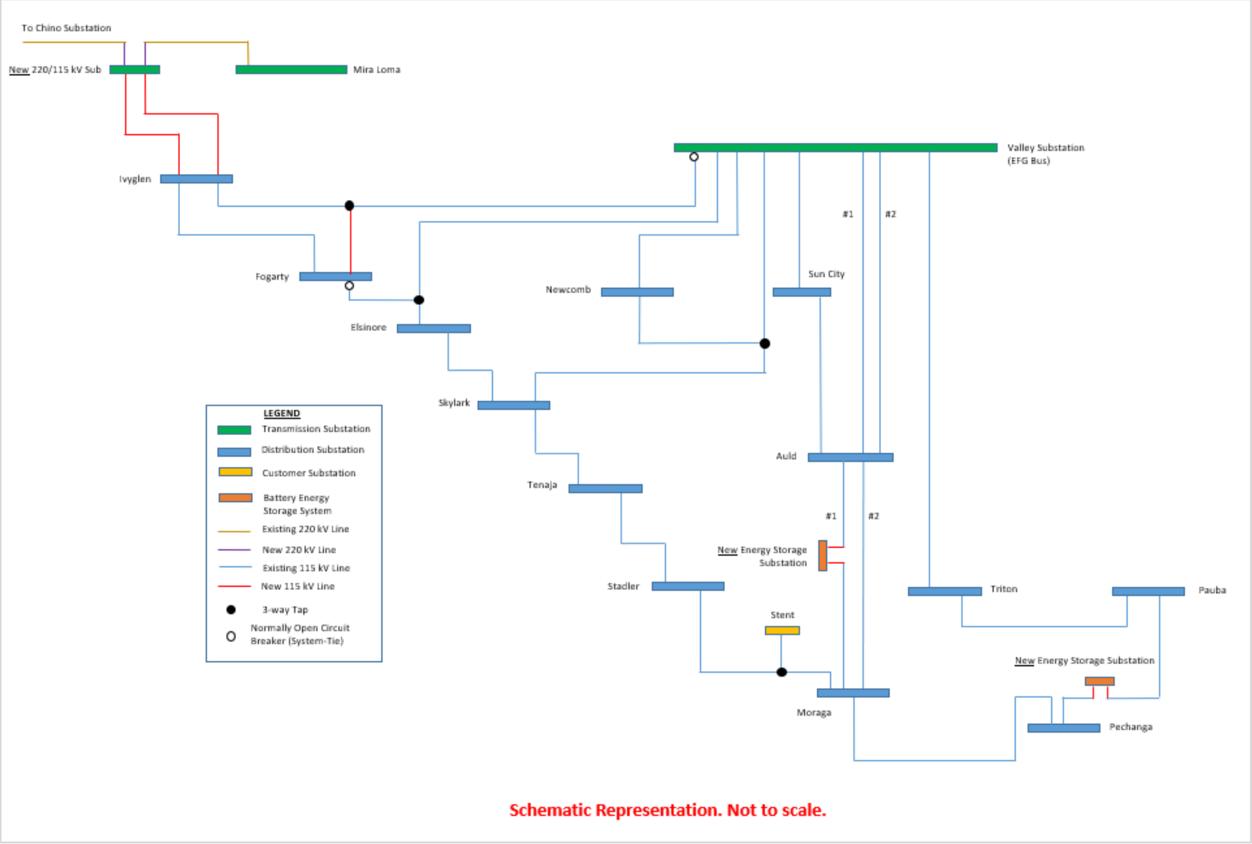


Figure 5-12. Tie-line to Mira Loma and Centralized BESS in Valley South Project Scope

5.3.10.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,456
2028	0	0	0	48,017
2033	0	0	0	50,408
2038	0	0	0	53,323
2043	0	0	0	56,238
2048	0	0	0	59,154

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	0	0	0	42,629
2033	0	0	0	48,041
2038	0	0	0	53,453
2043	0	0	0	58,864
2048	0	0	0	64,276

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	0	0	0	55,097
2043	0	0	0	57,173
2048	0	0	0	59,250

5.3.10.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120	82,321	650
2028	0	0	0	87,130	87,598	944
2033	0	0	0	130,912	91,967	1,299
2038	0	0	0	174,909	98,884	1,766
2043	5	2.5	2	218,906	104,047	2,217
2048	15.2	2.5	9	262,902	107,821	2,602

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	34,121	83,384	708
2022	0	0	0	43,257	85,427	828
2028	0	0	0	98,075	93,744	1,345
2033	0	0	0	143,757	100,380	1,885
2038	11	3	6	189,439	106,913	2,508
2043	35	4	20	253,121	112,783	3,132
2048	182	11	61	280,803	117,771	3,729

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120	82,321	650
2028	0	0	0	86,2221	87,598	944
2033	0	0	0	129,639	87,737	951
2038	0	0	0	173,057	92,531	1,259
2043	0	0	0	216,474	96,915	1,601
2048	0	0	0	259,892	100,017	1,852

In analyzing the Mira Loma and Centralized BESS in Valley South project, the following constraints (Table 5-87) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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		
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 the 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 the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-88 for the 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 Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	50,251	41,338	51,951
N-1	LAR (MWh)	6,375	21,303	72,541
N-1	IP (MW)	467	760	1,333
N-1	PFD (hr)	1,320	1,962	3,152
N-1	Flex-1 (MWh)	893,598	3,831,571	9,614,215
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	65,194	82,304
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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 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 from 22.7 to 140.9 GWh of avoided LAR.
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 benefits in the system range from 6.3 to 72.5 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that may occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the Mira Loma and Centralized BESS in Valley South Project can 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, the Mira Loma and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 a 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 Valley 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

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 the 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. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
5. BESS would be installed near Pechanga in Valley South and Allesandro Substation in Valley North following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
6. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-89 through Table 5-91, for all forecasts.
7. 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).
8. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-89. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	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**				

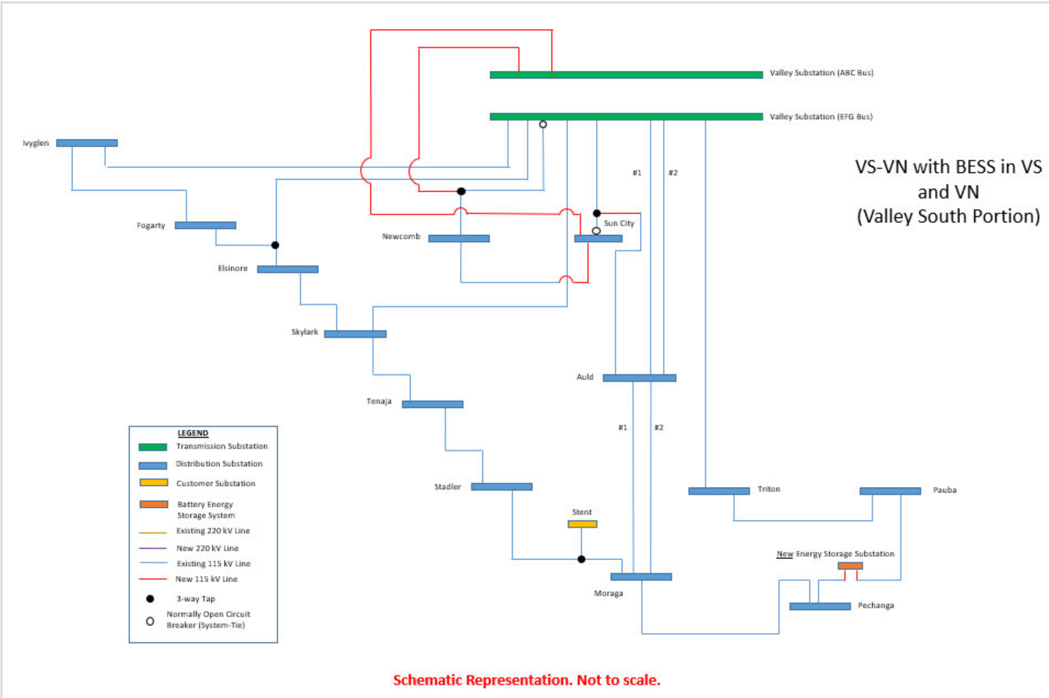
Table 5-90. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	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)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2040	0	0	67	204
2045	0	0	27	140
Total Battery Size: **94 MW/ 344 MWh**				

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



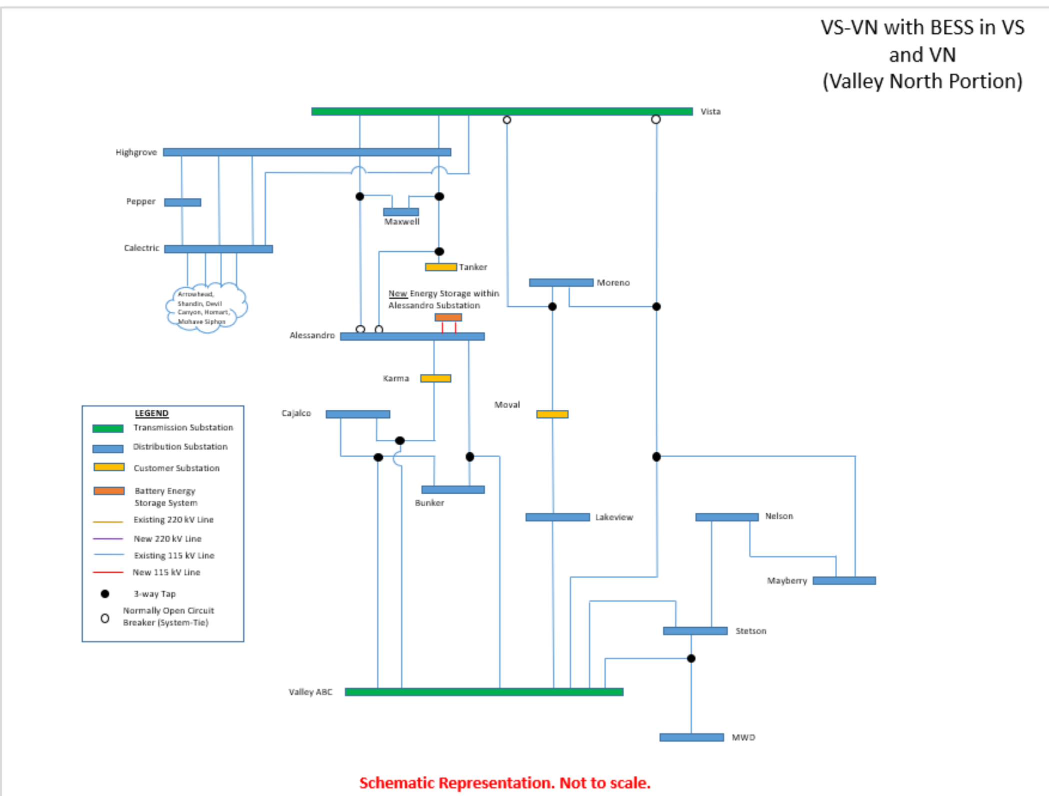


Figure 5-13. Valley South to Valley North and Centralized BESS in Valley South and Valley North

5.3.11.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	0	0	0	57,893
2048	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	0	0	0	59,306
2043	0	0	0	62,024
2048	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	0	0	0	56,399

5.3.11.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	64,547	133,688	843
2033	4	2	2	84,028	139,702	1,161
2038	103	14	19	116,572	145,991	1,586
2043	351	24	45	146,858	151,619	2,025
2048	506	27	73	194,760	155,733	2,366

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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,083	129,095	616
2022	0	0	0	25,681	131,322	715
2028	4	3	2	53,273	140,388	1,202
2033	156	19	22	72,267	147,622	1,710
2038	445	23	66	99,260	154,744	2,284
2043	1,063	29	135	122,253	161,142	2,889
2048	1,845	76	205	145,246	166,580	3,429

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,293	139,065	1,122
2043	47	10	11	110,531	143,845	1,426
2048	138	17	22	131,769	147,226	1,679

In analyzing the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project, the following constraints (Table 5-98) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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
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
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.11.4 Evaluation of Benefits

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

The accumulative values of benefits over the 30-year horizon are presented in Table 5-99 for the three forecasts.

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

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	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740

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-1	Flex-1 (MWh)	2,795,927	5,140,766.57	11,694,529
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408	87,739
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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. By design, the project includes a 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.

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 from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, N-1 benefits in the system range from 5.7 to 59.54 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South 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, the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project did not demonstrate comparable levels of performance to the 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 a 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 a transfer of Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista and Valley North Systems.
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 the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system ties between the Valley North and Valley South Systems for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
8. BESS would be installed near Pechanga Substation following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
9. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-100 and Table 5-101, for all forecasts. No batteries were required at Valley South in the PVWatts Forecast.
10. 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).
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-100. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	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)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2043	39	108
2046	10	42
Total Battery Size (including contingency): **49 MW / 150 MWh**		

Figure 5-14 presents a high-level representation of the proposed configuration.

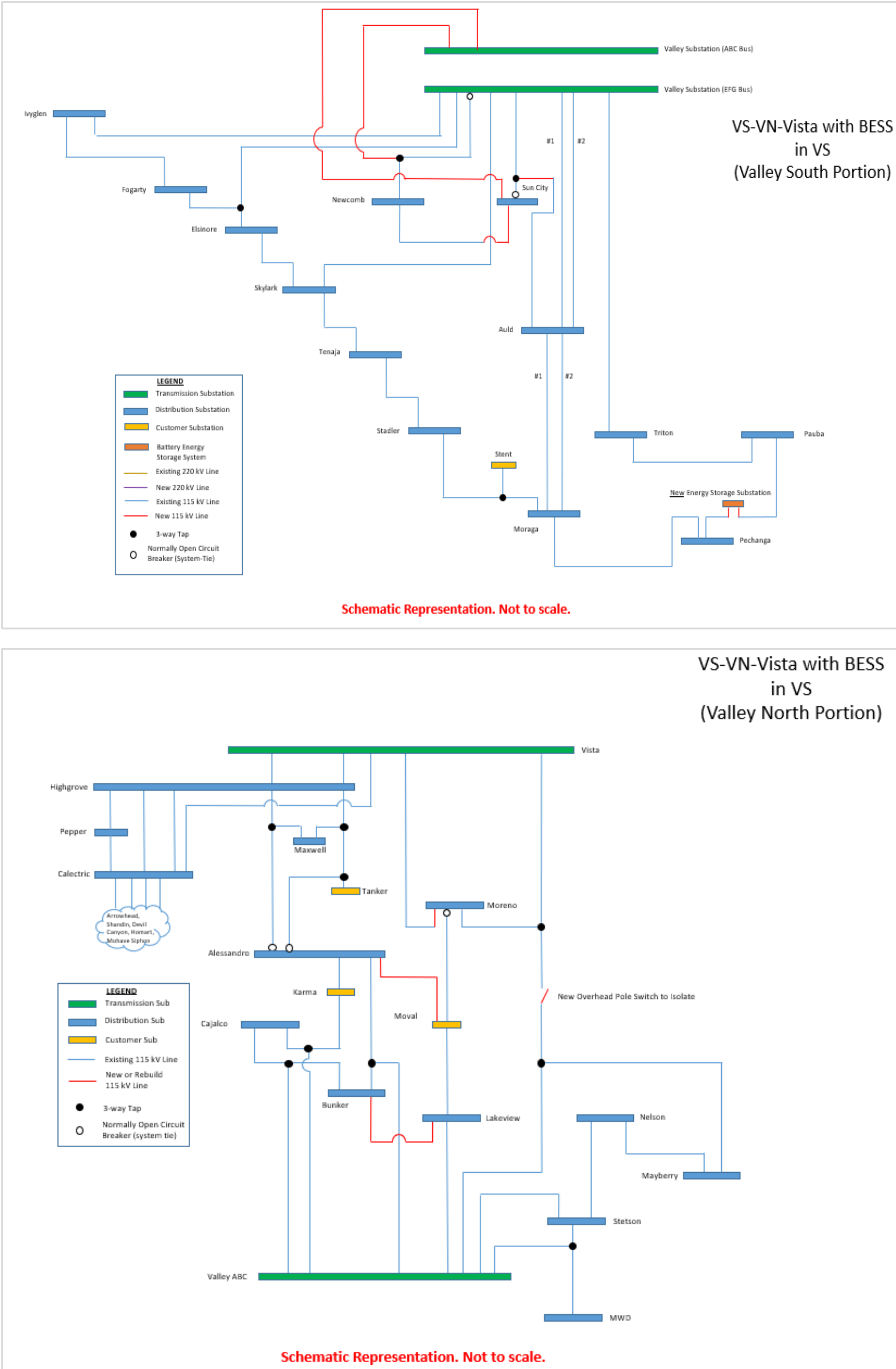


Figure 5-14. Valley South to Valley North to Vista and Centralized BESS in Valley South

5.3.12.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	78	30	5	57,893
2048	735	83	18	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	676	81	17	59,306
2043	3416	162	58	62,024
2048	8000	232	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.12.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-105 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331	127,935	571
2028	0	0	0	64,547	133,688	843
2033	4	2	2	84,028	139,702	1,160
2038	103	14	19	116,572	145,991	1,586
2043	351	24	45	146,858	151,619	2,025
2048	506	27	73	194,760	155,733	2,366

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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,083	129,095	616
2022	0	0	0	25,681	131,322	715
2028	4	3	2	53,273	140,388	1,202
2033	156	19	22	76,267	147,622	1,710
2038	445	23	66	99,260	154,744	2,284
2043	1,063	29	135	122,253	161,142	2,889
2048	1,845	76	205	145,247	166,580	3,429

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330	127,935	571
2028	0	0	0	46,816	133,688	843
2033	0	0	0	68,054	133,840	850
2038	0.4	0.4	1	89,292	139,065	1,122
2043	47	10	11	110,530	143,845	1,426
2048	138	17	22	131,768	147,226	1,679

In analyzing the Valley South to Valley North to Vista and Centralized BESS in Valley South Project, the following constraints (Table 5-108) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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
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
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.12.4 Evaluation of Benefits

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

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-109 for the three forecasts.

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

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	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927	5,140,766.57	11,694,529
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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-1	Flex-2-2 (MWh)	59,402	69,408	87,739
N-0	LAR (MWh)	22,613	54,062	96,778
N-0	IP (MW)	2,638	3,687	4,380
N-0	PFD (hr)	399	741	939

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. By design, the project includes a 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 effectively reducing LAR to zero 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.

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 are avoided in the near-term and long-term horizon. Additionally, the 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 LAR.
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 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 HILP events that occur in the Valley South 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, the Valley South to Valley North to Vista and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 a 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, LAR, and flexibility (Flex-1 and Flex-2) provide valuable insight into the reliability, capacity, resilience, and flexibility objectives of project performance. Table 5-110 through 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 Project	Centralized BESS in Valley South Project	Mira Loma and Centralized BESS in Valley South Project	Valley South to Valley North and Distributed BESS in Valley South Project	Menifee Project	Mira Loma Project	SCE Orange County Project	Valley South to Valley North and Centralized BESS in Valley South and Valley North Project	Valley South to Valley North to Vista and Centralized BESS in Valley South Project	SDG&E and Centralized BESS in Valley South Project	Valley South to Valley North Project
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	20	21	15	21	21	17	15	15	17	18	18	21	15
N-2	**Available Flex-1**	6,024	5,415	5,357	4,067	3,831	5,742	5,357	3,2554	1,279	5,141	5,141	5,894	5,357
N-2	**Available Flex-2-1**	3,780	3,218	-	-	1,263	-	2,368	1,263	3,256	-	-	3,218	-
N-2	**Available Flex-2-2**	107	77	69	1	65	69	69	65	81	69	69	77	69
N-0	**LAR**	57	56	54	57	57	46	56	50	56	57	54	57	45

Table 5-111. Cumulative Benefits: Spatial Base Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	69	76	51	76	76	58	51	45	60	62	62	76	51
N-2	**Available Flex-1**	9,665	9,902	9,662	10,993	9,614	10,977	9,662	6,500	4,209	11,694	11,694	11,526	9,662
N-2	**Available Flex-2-1**	4,102	3,403	-	-	1,327	-	3,030	1,327	3,449	-	-	3,403	-
N-2	**Available Flex-2-2**	142	97	88	5	82	-	88	82	104	88	88	97	88
N-0	**LAR**	141	132	91	141	141	89	136	110	133	141	97	141	41

Table 5-112. Cumulative Benefits: PVWatts Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	6	6	6	6	6	6	6	5	5	6	6	6	6
N-2	**Available Flex-1**	4,205	3,363	2,795	2,939	894	2796	2,795	623	584	2,796	2,796	3,440	2,795
N-2	**Available Flex-2-1**	3,658	3,167	-	-	1,252	-	2,860	1,252	3,201	-	-	3,167	-
N-2	**Available Flex-2-2**	88	65	59	1	56	59	59	56	69	59	59	65	59
N-0	**LAR**	23	23	23	23	23	20	23	19	23	23	23	23	20

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

1. The Valley South System is vulnerable to the 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 South 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 the Valley South System service territory.
4. Dependency on NWA solutions (e.g., 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 or 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 the Valley South System, they aggravate the condition in the adjacent subtransmission system. For example, with a 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 a 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 NWAs. 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 to 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 to adequately meet the range of forecast sensitivities while meeting the overall project objectives. Except for the projects that did not meet the objectives over the study horizon and those with significant implementation difficulty, wire-based alternatives offer the highest benefits.
8. In all considered forecasts, the ASP provided the highest aggregated benefits. Aggregated benefits are derived from the cumulative value of LAR and Flex Metrics that translate into capacity, reliability, resilience, and flexibility needs in the Valley South service area. The ASP consistently provides the highest aggregated benefits across all considered forecasts.
9. From a capacity perspective, the ASP, SDG&E, and Hybrid solutions (SDG&E and Centralized BESS in Valley South) provide the most relief. Taking into consideration the combination of flexibility and resilience needs, the ASP, Orange County Project, and SDG&E Project are the most preferable alternatives.

6 BENEFIT-COST ANALYSIS (BCA)

6.1 Introduction

The objective of this task was to perform a detailed benefit-cost and risk analysis of the ASP and alternative projects introduced in Section 5. This framework provides an additional basis for the 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.

The benefit is defined as the value of the impact of a project on 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 LAR, Interrupted Power, and Period of Flexibility Deficit 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 the present worth of costs and benefits (Sections 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 BCA, $/unit benefit analysis, and incremental BCA. 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 section are maintained in a spreadsheet outlining the calculations and associated costs. Hence, three spreadsheets[11] are provided that cover three study forecasts (Spatial Base, Effective PV, and PVWatts). These spreadsheets are provided with this submission.

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 the incremental benefit-cost analysis.
- Cost Assumptions
  - Outlines the key study inputs and assumptions.
- Baseline System Analysis
  - Raw reliability Indices.
  - The monetized value of the baseline reliability metrics.

[11] 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.
  - The 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 Projects' Cost

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 the applicable discount rate. The cost of components associated with the design of projects is aggregated to develop the Total capital expenditure. For projects that include BESS, the PVRR costs are offset by revenues generated from market participation. Information regarding the scope of the projects has been summarized in Sections 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 the 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	$474	$545	$474	$545	$474	$545
B	SDG&E	$453	$540	$453	$540	$453	$540
C	SCE Orange County	$748	$951	$748	$951	$748	$951
D	Menifee	$331	$396	$331	$396	$331	$396
E	Mira Loma	$309	$369	$309	$365	$309	$365
F	Valley South to Valley North	$207	$221	$207	$221	$207	$221
G	Valley South to Valley North to Vista	$290	$317	$290	$317	$309	$365
H	Centralized BESS in Valley South	$525	$1,474	$848	$2,363	$381	$1,004
I	Valley South to Valley North and Distributed BESS in Valley South	$232	$326	$228	$354	$200	$218
J	SDG&E and Centralized BESS in Valley South	$531	$923	$658	$1,473	$479	$685
K	Mira Loma and Centralized BESS in Valley South	$560	$1,396	$601	$2,194	$448	$920
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$1,172	$700	$2,616	$255	$572
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$505	$404	$986	$269	$307

Table 6-2. Present Worth of Market Participation Revenues

Wholesale Energy and Ancillary Service markets				
#	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	-

Capacity and Resource Adequacy Markets				
#	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	$48,515	$74,932	$34,058
I	Valley South to Valley North and Distributed BESS in Valley South	$863	$2,105	-
J	SDG&E and Centralized BESS in Valley South	$3,579	$13,712	-
K	Mira Loma and Centralized BESS in Valley South	$18,124	$36,287	$6,395
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$10,185	$37,148	$2,798
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,000	$7,841	-

6.3.2 Baseline System Analysis

From the baseline system, the raw reliability indices computed in Section 4.2 are reflective of the overall impact on 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 Section 3.3 and derived as present worth. Table 6-3 presents the aggregated costs, taking into consideration the combination of Residential, Small & Medium Business and Commercial & Industrial customers.

Table 6-3. Baseline System Monetization

Category	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Monetized Value for EENS - N-1	126,010	428,178	35,200
Monetized Value for EENS - – N-0	2,530,518,587	5,999,276,476	1,029,268,277
Monetized Value for Flex-1	6,191,361	9,670,328	4,309,495
Monetized Value for Flex-2 ($)	1,765,322,893	1,816,115,205	1,722,124,246
Aggregate ($M)	**4,302**	**7,825**	**2,756**

The results demonstrate that the aggregated range of cost impacts accrued by the customer range from 2.7$B to 7.8$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 the 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 – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,882	11.73
F	Valley South to Valley North	$2,156	10.41
I	Valley South to Valley North and Distributed BESS in Valley South	$2,165	9.33
A	Alberhill System Project	$4,282	9.03
B	SDG&E	$4,001	8.84
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,479	8.58
G	Valley South to Valley North to Vista	$2,470	8.52
E	Mira Loma	$2,601	8.42
J	SDG&E and Centralized BESS in Valley South	$4,041	7.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542	6.93
K	Mira Loma and Centralized BESS in Valley South	$3,132	5.59
C	SCE Orange County	$4,021	5.38
H	Centralized BESS in Valley South	$2,535	4.83

Table 6-5. SCE Spatial Base Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$7,201	21.76
A	Alberhill System Project	$7,788	16.43
B	SDG&E	$7,218	15.93
G	Valley South to Valley North to Vista	$4,617	15.92
E	Mira Loma	$4,766	15.42
F	Valley South to Valley North	$2,618	12.65
I	Valley South to Valley North and Distributed BESS in Valley South	$2,736	12.00
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$4,771	11.81
J	SDG&E and Centralized BESS in Valley South	$7,523	11.43
K	Mira Loma and Centralized BESS in Valley South	$6,604	10.99
C	SCE Orange County	$7,258	9.70
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$6,016	8.59
H	Centralized BESS in Valley South	$6,008	7.08

Table 6-6. PVWatts Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$2,381	7.19
A	Alberhill System Project	$2,740	5.78
B	SDG&E	$2,520	5.56
J	SDG&E and Centralized BESS in Valley South	$2,520	5.26
E	Mira Loma	$1,512	4.89
I	Valley South to Valley North and Distributed BESS in Valley South	$955	4.77
F	Valley South to Valley North	$955	4.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,039	4.07
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,036	3.85
K	Mira Loma and Centralized BESS in Valley South	$1,625	3.63
G	Valley South to Valley North to Vista	$1,036	3.57
C	SCE Orange County	$2,533	3.39
H	Centralized BESS in Valley South	$1,032	2.71

As Table 6-4 demonstrates, for the effective PV forecast the Menifee project renders the largest benefit to cost ratio of 11.02. Although the Menifee project has the largest benefit to cost ratio, its cost of $331M is 60% higher than the least expensive project, i.e. Valley South to Valley North with a cost of $207M (Table 6-1). However, the benefit-to-cost ratio of the Valley South to Valley North is 10.41, which is 6% higher. In other words, the additional 40% cost of the Menifee project as compared to the Valley South to Valley North project renders 6% of additional benefit. The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. While it provides an indication of each project's performance, it does not adequately provide a measure to compare alternatives.

The best project among a set of alternative projects is not necessarily the one that maximizes the benefit-to-cost ratio. The benefit-to-cost analysis is a measure consider in the determination to reject or approve a project. But when it comes to the selection among alternatives and the process of reliability improvement projects, an incremental benefit-cost analysis should be conducted. The incremental benefit-to-cost analysis methodology is based on the principle of spending each dollar funding the project that will result in the most benefit, resulting in an optimal budget allocation that identifies the projects that should be funded [10].

To conduct a correct selection among alternative projects with widely disparate benefits an incremental analysis approach to evaluating benefits and costs is necessary [9]. 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 ascending order of the present worth of costs. The do-nothing with zero cost is then selected as the baseline, i.e. alternative "0". The next expensive project is then considered, and the incremental benefit-to-cost analysis is then conducted to determine if such a selection should be made or not. 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. Alternative "F" versus baseline incremental benefit-cost ratio was evaluated using the present worth of monetized benefits versus PVRR costs.

In general, a project is selected if the incremental benefits exceed its incremental cost. This approach can be conducted for non-monetized and monetized benefits. The non-monetized selection is qualitative and subjective as the selection is based on individual indices performance. The monetized analysis is solely based on a single incremental benefit-to-cost ratio. Both non-monetized and monetized incremental cost-benefit analyses are depicted in the following tables. As the selection under non-monetized analysis is subjective, the results are presented for demonstration only.

For monetized incremental cost-benefit analysis, if the incremental ratio is larger than unity the next expensive project "F" is selected. Once a selection is made, the selected alternative replaces the baseline. This selection is demonstrated as "0→F" in Table 6-8. The process continues through the list of alternative projects, which are ranked in ascending cost order until the list is exhausted.

At the next step, the second least expensive project, i.e. "I" is compared to the baseline project "F". Project "I" was not selected as the incremental benefit-to-cost ratio is less than unity, and hence "F" remains as the baseline project. The incremental benefit-cost analysis will continue by iterating between the baseline and the next expensive alternative. The selection will stop once the incremental benefit-cost ratio becomes unfavorable or the list is exhausted. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks.

For monetized benefits, the criteria to move forward to the next expensive project is considered as a positive (total) aggregated value greater than unity. As one moves along the trajectory of the 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 is 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 is 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→ M	I → G	I → E	I →D	I → L	I → B	B → A	A → H	A → J	A → K	A → C
N-1	LAR	-11.27	-6.50	-0.94	2.80	2.73	1.64	-0.42	-2.32	5.23	-2.20	-1.97	-1.22	1.61
N-1	IP	-0.54	-0.28	0.04	0.12	0.17	0.07	0.02	-0.16	0.97	-0.41	-0.36	-0.22	0.10
N-1	PFD	-1.58	-1.07	-0.16	0.46	0.44	0.27	-0.07	-0.35	0.49	-0.21	-0.19	-0.08	0.08
N-1	Available Flex-1	-5,893.06	-3,339.83	2,223.74	1,439.58	7,537.63	843.39	938.91	317.75	-9,549.32	10,147.65	1,604.86	6,728.74	4,329.79
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	-5,555.36	-9,860.00	0.00	-4,889.92	-7,682.16	24,377.09	2,889.84	9,482.20	560.54
N-1	Available Flex-2-2	-95.59	-0.02	0.00	0.01	15.28	0.01	0.00	-9.02	-346.00	566.20	130.16	123.05	22.44
N-0	LAR	-36.29	-1.28	-15.50	-14.69	3.84	-10.93	-8.24	-4.59	-4.67	-0.01	-0.01	-0.01	0.36
N-0	IP	-3.70	-0.74	-0.57	-0.38	2.44	-0.58	-0.51	-0.16	-1.55	-0.01	-0.01	0.00	0.12
N-0	PFD	-0.57	-0.10	-0.35	-0.31	0.12	-0.26	-0.20	-0.10	-0.18	-0.01	-0.01	0.00	0.01
Decision to move forward (Y/N)		Y	Y	N	N	N	N	N	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F → I	F → M	M → G	M → E	E →D	D → L	D → B	B → A	A → H	A → J	A → K	A → C
N-0	EENS	10.356	0.373	3.948	-9.313	-23.358	23.629	0.290	-0.235	1.812	0.003	0.003	0.002	-0.123
N-0	Losses	0.001	0.000	0.000	-0.001	0.018	-0.007	-0.006	0.023	0.055	-0.073	-0.021	-0.045	-0.005
N-1	EENS	0.000	0.000	0.000	-0.009	-0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N-1	Flexibility-1	0.020	0.009	0.000	0.026	-0.107	0.098	-0.001	-0.008	0.105	-0.044	-0.030	-0.036	-0.016
N-1	Flexibility-2-1	0.000	0.000	0.000	0.000	29.576	34.485	-37.505	1.191	10.992	-33.935	-4.135	-13.246	-0.802
N-1	Flexibility-2-2	0.036	0.000	0.000	0.000	-0.022	0.020	0.000	0.006	0.136	-0.217	-0.051	-0.048	-0.009
Total	Sum of ΔB/ΔC (aggregate)	10.413	0.382	3.947	-9.297	6.087	58.233	-37.216	0.954	13.044	-34.192	-4.213	-13.329	-0.949
Decision to move forward (Y/N)		Y	N	Y	Y	Y	Y	N	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F→ I	I → G	I →E	I → D	I → M	M → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-1	LAR	-33.49	-37.60	12.74	17.76	6.87	-2.55	-33.16	31.64	-5.17	-3.91	4.25	4.87	-1.91
N-1	IP	-0.75	-0.86	0.29	0.28	0.18	-0.03	-1.66	2.46	-0.41	-0.32	0.13	0.23	-0.15
N-1	PFD	-2.16	-0.13	0.04	1.72	0.03	-0.20	-4.41	1.04	0.04	-0.14	0.86	0.22	-0.06
N-1	Available Flex-1	-9,712.04	-12,207.92	4,134.94	11,626.02	2,488.99	-799.25	7,106.92	-1,615.54	1,112.01	-1,621.04	-1,390.76	4,664.64	-419.28
N-1	Available Flex-2-1	0.00	0.00	0.00	-5,369.71	-9,643.82	0.00	-22,563.56	-9,103.32	6,786.12	1,038.97	5,737.98	650.75	3,467.34
N-1	Available Flex-2-2	-113.44	-4.86	1.65	18.85	0.99	0.50	-50.26	-485.96	110.90	55.44	56.05	31.36	94.63
N-0	LAR	-50.38	-18.14	-88.77	-60.88	-96.09	-33.99	-71.33	-41.13	-0.27	-0.19	-0.15	2.84	-0.09
N-0	IP	-4.06	-3.03	-1.72	1.87	-3.25	-1.20	-1.36	-7.01	-0.06	-0.04	-0.03	0.52	-0.02
N-0	PFD	-0.59	-0.22	-1.18	-0.77	-1.43	-0.49	-1.08	-0.62	-0.05	-0.03	-0.03	0.04	-0.02
Decision to move forward (Y/N)		Y	Y	Y	N	N	N	Y	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F→ I	I → G	G→E	E → D	D → M	D → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-0	EENS	12.57	5.62	30.35	-23.03	76.11	-14.85	-1.16	13.86	0.10	0.07	0.05	-0.97	0.03
N-0	Losses	0.00	0.00	0.00	0.02	-0.01	0.00	0.03	0.08	-0.04	-0.01	-0.02	-0.01	-0.01
N-1	EENS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	Flexibility-1	0.03	0.03	-0.01	-0.17	0.14	0.01	-0.01	0.12	-0.02	-0.01	0.00	-0.02	0.00
N-1	Flexibility-2-1	0.00	0.00	0.00	31.04	34.42	-18.45	1.28	12.89	-9.32	-1.47	-7.85	-0.92	-4.74
N-1	Flexibility-2-2	0.04	0.00	0.00	-0.03	0.02	0.00	0.01	0.19	-0.04	-0.02	-0.02	-0.01	-0.04
Total	Sum of ΔB/ΔC (aggregate)	12.64	5.65	30.34	7.81	110.69	-33.29	0.11	27.07	-9.28	-1.43	-7.82	-1.93	-4.75
Decision to move forward (Y/N)		Y	Y	Y	Y	Y	Y	Y	Y	N	Y	Y	N	N

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

Category		Alternative selection												
		0 → I	I → F	I → L	L → M	L → G	L → E	L → D	L → H	L → K	L → B	B → A	A → J	A → C
N-1	**LAR**	-4.72	0.00	0.00	0.00	0.00	0.51	0.00	-0.52	-0.34	-0.33	0.40	-1.69	0.59
N-1	**IP**	-0.45	0.00	0.00	0.00	0.00	0.03	0.00	-0.09	-0.06	-0.05	0.17	-0.71	0.06
N-1	**PFD**	-1.51	0.00	0.00	0.00	0.00	0.12	0.00	-0.10	-0.07	-0.07	0.09	-0.37	0.15
N-1	**Available Flex-1**	-3,475.85	29.81	0.00	0.00	5.89	9,466.51	2.75	-78.96	2,261.87	-594.68	-11,884.27	43,746.18	3,460.14
N-1	**Available Flex-2-1**	0.00	0.00	0.00	0.00	0.00	-7,882.61	-12,775.72	0.00	-2,205.50	-5,394.24	-7,225.14	30,345.58	516.40
N-1	**Available Flex-2-2**	-89.61	0.00	0.00	0.00	0.00	19.50	0.00	141.18	5.46	-8.89	-287.42	1,207.16	18.02
N-0	**LAR**	-17.11	0.00	-4.37	0.81	0.32	6.52	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	**IP**	-2.64	0.00	-1.38	0.44	0.17	2.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	**PFD**	-0.37	0.00	-0.15	0.07	0.03	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Decision to move forward (Y/N)		**Y**	**Y**	**N**	**Y**	**N**	**N**	**N**	**N**	**N**	**N**	**Y**	**Y**	**N**

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

Category		Alternative selection												
		0 → I	I → F	I → L	L → M	L → G	L → E	E → D	D → H	D → K	D → B	B → A	A → J	A → C
N-0	**EENS**	4.73	0.00	1.53	-0.19	-0.08	-2.09	5.14	0.00	0.00	0.00	0.00	0.00	0.00
N-0	**Losses**	0.00	0.00	0.00	0.00	0.00	0.01	-0.01	0.00	0.00	0.02	0.06	-0.28	0.00
N-1	**EENS**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	**Flexibility-1**	0.01	0.00	0.00	0.00	0.00	-0.04	0.10	-0.02	-0.02	0.00	0.09	-0.35	-0.01
N-1	**Flexibility-2-1**	0.00	0.00	0.00	0.00	0.00	10.89	34.26	-26.84	-6.44	1.12	10.19	-42.82	-0.73
N-1	**Flexibility-2-2**	0.03	0.00	0.00	0.00	0.00	-0.01	0.02	-0.13	0.00	0.01	0.11	-0.46	-0.01
Total	**Sum of ΔB/ΔC (aggregate)**	4.77	0.00	1.53	-0.19	-0.08	8.74	39.52	-26.98	-6.46	1.12	10.39	-43.63	-0.75
Decision to move forward (Y/N)		**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**	**Y**	**N**	**N**	**Y**	**Y**	**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 (LAR through PFD) is calculated for each alternative. For example, in Table 6-13, 0.16 as listed under column A and row N-1 LAR is the ratio of Alberhill project $474 M (Table 6-1) net present cost to present worth of N-1 LAR over study horizon of 2,896 MWh.

A smaller N-1 LAR value implies a more cost-effective solution. Along each row, the ratios are ranked using heat-mapping, with green and red marking the most favorable and the most unfavorable ends of the spectrum. The rightmost three columns, Alternative Rankings, identifies the first three projects 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 Alternative

Effective PV Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.16	0.15	0.12	0.17	0.19	0.09	0.14	0.14	0.30	0.14	0.11	0.18	0.09	F	I	M
N-1	IP ↓	3.57	2.94	2.62	3.42	3.70	1.97	2.99	2.95	7.12	3.17	2.50	3.45	1.87	F	I	M
N-1	PFD ↓	1.13	1.05	0.88	1.22	1.31	0.65	1.01	0.96	1.88	1.01	0.79	1.23	0.63	F	I	M
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	F	I	G
N-1	Flex-2-1↓	3.81E-04	4.20E-04			1.31E-03		4.09E-04	7.22E-04	6.86E-04			4.92E-04		A	D	B
N-1	Flex-2-2↓	1.62E-02	2.08E-02	1.47E-02	1.65E+00	3.02E-02	1.17E-02	1.68E-02	1.67E-02	3.25E-02	1.86E-02	1.46E-02	2.44E-02	1.05E-02	F	I	M
N-0	LAR ↓	0.05	0.05	0.03	0.06	0.06	0.03	0.04	0.04	0.09	0.04	0.03	0.06	0.03	F	I	M
N-0	IP ↓	0.56	0.55	0.36	0.62	0.66	0.30	0.39	0.52	0.91	0.43	0.35	0.62	0.27	F	I	M
N-0	PFD ↓	3.24	3.17	2.10	3.58	3.81	1.93	2.28	2.78	5.24	2.50	2.07	3.62	1.76	F	I	M
Count of Rank #1		1	0	0	0	0	0	0	0	0	0	0	0	8			

Table 6-14. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Spatial Base Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.05	0.05	0.04	0.09	0.06	0.03	0.05	0.05	0.10	0.09	0.05	0.07	0.03	I	F	G
N-1	IP ↓	2.28	1.75	1.86	3.21	2.32	1.31	2.13	1.99	5.16	3.93	2.27	2.47	1.33	I	F	B
N-1	PFD ↓	0.70	0.65	0.65	1.21	0.89	0.51	0.74	0.69	1.21	1.44	0.83	0.94	0.46	F	I	B
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	F	G	A
N-1	Flex-2-1↓	3.66E-04	4.10E-04			1.38E-03		3.33E-04	3.11E-04	6.69E-04			5.95E-04		E	D	A
N-1	Flex-2-2↓	1.31E-02	1.74E-02	1.23E-02	1.10E+00	2.72E-02	9.67E-03	1.41E-02	1.32E-02	2.71E-02	2.98E-02	1.72E-02	2.53E-02	8.81E-03	F	I	G
N-0	LAR ↓	0.02	0.02	0.02	0.04	0.03	0.02	0.02	0.01	0.04	0.03	0.02	0.03	0.02	E	D	G
N-0	IP ↓	0.36	0.38	0.29	0.63	0.45	0.25	0.27	0.25	0.63	0.52	0.36	0.49	0.25	F	E	I
N-0	PFD ↓	1.70	1.71	1.45	2.98	2.11	1.80	1.21	1.13	2.80	2.46	1.90	2.31	1.70	E	D	G
Count of Rank #1		0	0	0	0	0	2	0	3	0	0	0	0	4			

Table 6-15. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

PVWatts Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.47	0.45	0.31	0.38	0.44	0.21	0.35	0.34	0.89	0.27	0.29	0.47	0.22	I	F	L
N-1	IP ↓	4.91	4.52	3.25	3.80	4.47	2.24	3.70	3.51	9.37	2.85	3.01	4.78	2.31	I	F	L
N-1	PFD ↓	1.51	1.43	0.96	1.21	1.42	0.66	1.09	1.04	2.75	0.84	0.89	1.52	0.68	I	F	L
N-1	Flex-1↓	0.0005	0.0006	0.0004	0.0006	0.0014	0.0003	0.0005	0.0017	0.0065	0.0004	0.0004	0.0006	0.0003	I	F	L
N-1	Flex-2-1↓	3.89E-04	4.24E-04			1.05E-03		3.41E-04	7.26E-04	6.94E-04			4.48E-04		D	A	B
N-1	Flex-2-2↓	1.84E-02	2.30E-02	1.72E-02	2.87E+00	2.66E-02	1.12E-02	1.85E-02	1.83E-02	3.60E-02	1.42E-02	1.50E-02	2.43E-02	1.16E-02	I	F	L
N-0	LAR ↓	0.13	0.12	0.08	0.10	0.12	0.06	0.09	0.10	0.20	0.07	0.07	0.13	0.06	I	F	L
N-0	IP ↓	0.79	0.75	0.49	0.63	0.74	0.38	0.55	0.55	1.24	0.42	0.45	0.79	0.39	I	F	L
N-0	PFD ↓	5.78	5.53	3.59	4.65	5.46	2.71	4.04	4.04	9.12	3.11	3.32	5.84	2.80	I	F	L
Count of Rank #1		0	0	0	0	0	8	1	0	0	0	0	0	0			

6.4 Risk Analysis

The risk analysis performed within this assessment is deterministic. 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	9.03	16.43	5.78
SDG&E	8.84	15.93	5.56
Valley South to Valley North to Vista	8.52	15.92	3.57
Centralized BESS in Valley South	4.83	7.08	2.71
Mira Loma and Centralized BESS in Valley South	5.59	10.99	3.63
Valley South to Valley North and Distributed BESS in Valley South	9.33	12.00	4.77
Menifee	11. 73	21.76	7.19
Mira Loma	8.42	15.42	4.89
SCE Orange County	5.38	9.70	3.39
Valley South to Valley North and Centralized BESS in Valley South and Valley North	6.93	8.59	4.07
Valley South to Valley North to Vista and Centralized BESS in Valley South	8. 58	11.81	3.85
SDG&E and Centralized BESS in Valley South	7.61	11.43	5.26
Valley South to Valley North	10.41	12.65	4.61

6.5 Summary of Findings

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

1. Without a project in service to address the needs in the Valley South System, the aggregate cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis.
2. The benefit-cost analysis demonstrates Menifee as the project with the highest B-C ratio in Effective PV, Spatial Base, and PVWatts forecast. This is followed by the Alberhill System project and San Diego Gas & Electric. In the case of Valley South to Valley North alternatives, the project's low cost overrides the performance benefits and drive the ratios higher. The Menifee alternative has an advantage of lower cost while providing superior performance to Valley South to Valley North alternatives in select (Flex-2) categories. However, the benefits are realized only in the short

term horizon, with limited long-term benefits. A quick review of the overall benefits in Section 6.3.3 and raw reliability performance in Section 5.3.3, 5.3.5 and 5.3.6 further justifies this claim. The benefits accrued by ASP were found to be substantial over the horizon maintaining its rank across all three forecasts.

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 6.3.5.
4. Wire-based solutions demonstrate higher $/Unit benefit performance under the Effective PV and Spatial Base forecasts of load growth.
5. The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected. 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. An overall assessment of the top-ranking alternatives with consideration of risks, demonstrate the superiority of ASP to meet all the short term and long-term project objectives in the Valley South System.

7 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for SCE's 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 BCA) 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 the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives used 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 used 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 the industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and CEC's IEPR projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and California's electrification goals.
  - Across the three 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 used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System.

Considering the aggregated benefits under normal and emergency[12] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $4.3 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following the ASP are SDG&E, SCE Orange County, and SDG&E with Centralized BESS in Valley South.

- The BCA framework was implemented to evaluate and compare individual alternatives' performance.
  - NWAs remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). In the other forecasts, NWAs accrue significant additional costs over time due to the 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.
  - Menifee, ASP, SDG&E, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than the ASP.
- The benefit-to-cost ratio is one measure to consider in determining if any project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology determines whether additional incremental cost is economically justifiable on the basis that the additional benefits realized exceeds the incremental cost.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrate that:
  - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from NWAs 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-year horizon.

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. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

[12] N-0, N-1 and operational flexibility.

8 REFERENCES

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

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[4] "Valley-Ivyglen project CPUC Decision 18-08-026," issued August 31, 2018.

[5] "VSSP (Valley South 115 kV Subtransmission Project) CPUC Decision 16-12-001," issued December 1, 2016.

[6] "SCE Value of Service Study," 2018.

[7] NERC, "Order No. 830, GMD Research Work Plan, Addressing Geomagnetic Disturbance Events and Impacts on Reliability," https://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD_Research_Work_Plan_Apr_17_2018.pdf, April 2018.

[8] CIGRE Working Group A2.37, "Transformer Reliability Survey (Section 6.8)," December 2015.

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

[10] R. E. Brown, Electric Power Distribution Reliability, 2009.

[11] CPUC Energy Division, "2018 Resource Adequacy Report," https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report.pdf , August 2019.

[12] 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.

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

9 APPENDIX: N-2 PROBABILITIES

The N-2 probabilities associated with circuits that share a common tower structures are presented in this table.

	Auld-Moraga #2	Auld-Sun City	Fogarty-Ivyglen	Moraga-Pechanga	Pauba-Triton	Valley-Auld #1	Valley-Auld #2	Valley-Elsinore-Fogarty	Valley-Newcomb	Valley-Newcomb-Skylark	Valley-Sun City	Valley-Auld-Triton	Valley-Ivyglen
Auld-Moraga #2				0.0088	0.0194							0.02696	
Auld-Sun City										0.0304			
Fogarty-Ivyglen													0.0032
Moraga-Pechanga	0.0088												
Pauba-Pechanga													
Pauba-Triton	0.01944											0.002	
Valley-Auld #1							0.0698						
Valley-Auld #2						0.0698						0.016	
Valley-Elsinore-Fogarty									0.024				
Valley-Newcomb								0.024					
Valley-Newcomb-Skylark		0.0304									0.0309		
Valley-Sun City										0.03096			
Valley-Auld-Triton	0.02696				0.002		0.016						
Valley-Ivyglen			0.0032										

EXHIBIT G-2 (SECOND AMENDED) REDLINE

Item G:

Cost/benefit analysis of several alternatives for:

- Enhancing reliability;
- Providing additional capacity including evaluation of energy storage, distributed energy resources, demand response or smart grid solutions.

Response to Item G

Revision 1.1 (Second Amended Motion)

Revision Date: June 16, 2021

Summary of Revisions:

This Second Amended Motion corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the report are unaffected.

Revision 1

Revision Date: January 29, 2021

Summary of Revisions:

This revision modifies the cost benefit analysis to correct various errors and to clarify specific elements of the analysis. These changes are summarized in Supplemental Data Response to Item C[1] and in the attached revised report by Quanta Technologies.

[1] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C.

The attached report, prepared by Quanta Technology as a contractor to Southern California Edison (SCE), provides a cost-benefit analysis comparing several alternatives, including the Alberhill System Project (ASP). The identification of alternatives and methodology for this cost-benefit analysis are described in the Quanta Technology report and summarized with additional context in the response to DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item C (Planning Study).

This cost-benefit analysis is one factor among many which informs and supports SCE's recommended solution[2]. Other factors integrated into SCE's analysis and informing SCE's recommended solution include, but are not limited to, benefits achieved in both the near and long term, potential environmental impacts, input from the general public and other stakeholders, and other risk considerations.

[2] See DATA REQUEST SET ED-Alberhill-SCE-JWS-4 Item I.

A Appendix: Quanta Cost Benefit Analysis

The Quanta Technology report, *Cost Benefit Analysis of Alternatives Version 2.1 (Second Amended Motion)*, which includes supporting cost benefit spreadsheets, is attached as Appendix A to this data submittal.

QUANTA TECHNOLOGY

REPORT

Deliverable 3: Benefit Cost Analysis of Alternatives

PREPARED FOR

Southern California Edison (SCE)

DATE

~~January 27~~June 15, 2021
~~(~~Version 2.~~0~~1(Errata))

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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
2.0	1/27/2021	This revision corrects errors identified in the cost-benefit analysis results. Specifically: • Modifying the treatment of reliability benefits into Load at Risk (LAR) without probability weighting. This includes N-1, Flex -1 and Flex – 2 benefit categories. • For monetization purposes, reliability benefits are translated into Expected Energy Not Served (EENS) by consideration of average load at risk over duration of event. • Treatment of N-1 and N-2 probabilities associated with events in the Valley South System. • Treatment of probabilities associated with Flex-2-2 event. • Separating costs from two customer classes (commercial and residential) to three customer classes (Residential, Small & Medium Industries and Commercial)

		• Modifying the definition of Flex-2-1 and Flex-2-2 events to no longer constrain the events that drives the impact to occur at peak summer load conditions. The events now account for varying conditions throughout the years. • Updated Present Value of Revenue Requirements (PVRR) and Total costs associated with alternatives. • Removing consideration for SAIDI, SAIFI and CAIDI from the reliability metrics, which were previously provided for information purposes only. • Project scope and associated costs have been added to several alternatives to address N-1 line capacity violations that occur within the first ten years of the project planning horizon. • The market participation revenues for alternatives that include Battery Energy Storage Systems (BESS) were modified to include Resource Adequacy payments for the eight months of the year where the BESS would not be dedicated to the system reliability need. • Other minor editorial corrections and clarifications.
2.1(Errata)	6/15/2021	This revision corrects a number of results table discrepancies resulting from improper transfer of data among analysis spreadsheets and results tables. The discussion and conclusions in the reports are unaffected.

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 the benefit-cost analysis [BCA]) and alternative study using rigorous and data-driven methods.

A comprehensive framework was developed in coordination with the SCE study team 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 the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for the alternative projects is based on power flow studies in coordination with quantitative analysis to forecast the impacts of each alternative under evaluation, including the ASP. The projects' performance impacts are translated into key reliability metrics, representative of project performance over a 30-year horizon. Detailed analysis of the alternatives using benefit-cost and risk analysis frameworks to quantify the value of monetary benefits over the project horizon was conducted.

A total of 13 alternatives, including the ASP, were studied within this framework to evaluate their performance and contribution towards the project objectives. These alternatives were categorized as follows:

- Minimal investment
- Conventional
- Non-wires alternative (NWA)
- Hybrid (conventional plus NWA)

Highlights of the study are as follows:

- Consistent with industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region and the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties such as load-reducing technologies and the state of California's electrification goals.
  - Across the considered 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 area. This forecast demonstrates a range of loading from 1,083 to 1,377 MVA from the year 2019 to 2048.

- Several reliability metrics were used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System. Considering the aggregated benefits under normal and emergency[1] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy and $4.3 billion in cost savings to the end customers. The alternatives demonstrating the next-highest benefits (following the ASP) are SDG&E, SCE Orange County, and SDG&E with Centralized BESS (battery energy storage system) in Valley South.
- The BCA framework was implemented to evaluate and compare alternatives performance:
  - NWA solutions remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). Under the other forecasts, NWAs accrue significant costs over time due to the 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.
  - Menifee, ASP, SDG&E, and the Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than ASP.
- The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology warrants that the additional incremental cost is economically justifiable only if the benefit realized exceeds the incremental cost. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as type of project (reliability versus economic),environmental impact and risks.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of 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 NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-to-cost ratios.
  - The benefits attributed to operational flexibility from NWAs 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 as the most favorable among the considered alternatives over a 30-year period.

[1] N-0, N-1, and operational flexibility.

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. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

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List of Acronyms and Abbreviations

Term	Definition
AAEE	additional achievable energy efficiency
AAPV	additional achievable photovoltaic
AC	alternating current
ACSR	aluminum conductor steel-reinforced (cable)
AMI	advanced metering infrastructure
AS	ancillary service
ASP	Alberhill System Project
BCA	benefit-cost analysis
BES	bulk electric system
BESS	battery energy storage system
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CEC	California Energy Commission
CIGRE	International Council on Large Electric Systems
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DA	day-ahead
DER	distributed energy resource
EENS	expected energy not served
ENA	Electrical Needs Area
EV	electric vehicle
GWh	gigawatt-hours
HILP	high-impact low-probability (event)
IERP	Integrated Energy Policy Report (of the California Energy Commission)
IP	interrupted power
ISO	independent system operator
LAR	load at risk

Term	Definition
LMDR	load modifying demand response
LMP	locational marginal price
LTELL	long-term emergency loading limits
MBCA	marginal benefit-to-cost analysis
MEA	mutually exclusive alternatives
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
O&M	operations and maintenance
PATHWAYS	a long-horizon energy model developed by Energy and Environmental Economics, Inc.
PFD	period of flexibility deficit
PV	photovoltaic
PVRR	present value of revenue requirements
RA	Resource Adequacy
RegDown	Regulation down
RegUp	Regulation up
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOC	state of charge
STELL	short-term emergency loading limits
VO&M	variable operations and maintenance
VSSP	Valley South 115 kV Subtransmission Project
WACC	weighted aggregate cost of capital
WECC	Western Electricity Coordinating Council

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 [BCA]) 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 (BES) under the jurisdiction of the California Independent System Operator (CAISO). This imposes unique challenges to the reliability, capacity, operational flexibility,[2] and resilience 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, resilience, 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 as follows:

- Construction of a 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

[2] 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 resilience 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.

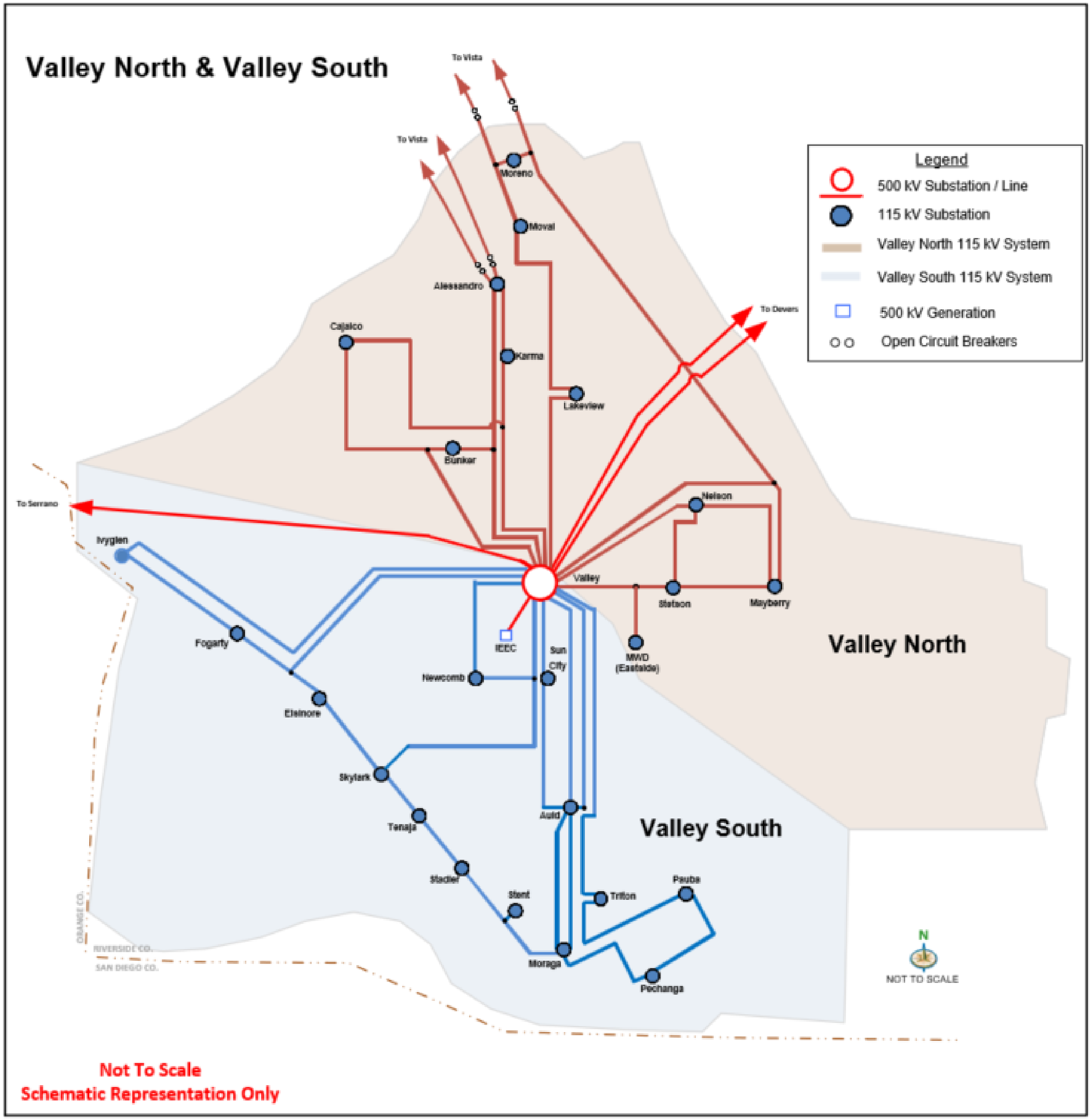


Figure 1-1. Valley Substation Service Areas[3]

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

[3] Valley-Ivyglen and VSSP projects included [12]

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; these included, but were not limited to, energy storage, demand response, and distributed energy resources (DERs).

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 the 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 BCA 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 independently of SCE's current forecasting methodology and practices; however, both SCE's and Quanta Technology's analysis incorporated the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) forecasts for the first 10 years through 2028.
2. Using power flow simulations and a quantitative review of project data, the forecasted impact of the proposed ASP 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 ASP or any other major projects requiring CPUC approval, along with the associated costs for such actions.
4. BCA 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 a data-driven quantitative assessment of project performance, coupled with BCA 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[4] as stipulated by the project proceedings:

[4] 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 ENA.
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 ENA (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
- A 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 a 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 was 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) being considered to address the reliability needs in the absence of the ASP. Through a screening process, the selected set of alternative projects 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 BCA of the ASP along with the list of system alternatives from Task 4. This analysis intended 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

This report has been organized consistent with the tasks outlined in Section 1.3. The report has been separated into several sections 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 Section 2 of this report, the long-term spatial load forecast is discussed. This section is complementary to Quanta Technology's load forecast report [1], which focused on the near-term load forecast and describes the technical details behind the spatial load forecasting methodology.

Section 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 in the analysis.

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

Section 6 presents the results from the BCA and deterministic risk assessment.

Section 7 presents the report conclusions and is followed by applicable references (Section 8) and an appendix (Section 9) that provides the N-2 probabilities associated with circuits that share a common tower structures.

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 a 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 the year 2028 were presented in a separate report [1]. This forecast was constructed from a baseload forecast and incorporated DER development according to CEC's 2018 IEPR [2] 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 section 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 the year 2028. This spatial forecast methodology is based on a 30-year horizon year,[5] 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
2025	1205	874

[5] 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]
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 (EVs), energy storage, and load modifying demand response (LMDR) categories.

2.2.1 AAPV Disaggregation

For AAPV, SCE provided two scenarios: 1) SCE Effective PV and 2) 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 the SCE 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 (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	AAPV SCE Effective PV	-4.9	-4.9	-4.9	-4.9	-4.9	-4.5	-4.0	-3.7	-3.7	-2.9
	AAPV PVWatts	-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	-5.7	-5.0	-4.2	-3.4	-3.0	-2.8	-2.7	-2.4	-2.1	-1.9
	AAPV PVWatts	-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 AAEE, EVs, energy storage, and 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 (units in MVA)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Valley North	Electric Vehicle	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.2	0.2	0.3
	AAEE	-2.3	-2.1	-2.6	-2.8	-3.2	-2.9	-2.8	-2.7	-2.8	-2.9
	Energy Storage	-0.5	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1
	LMDR	0.0	-0.5	0.0	-0.1	-0.2	-0.1	-0.1	0.0	0.0	0.0
Valley South	Electric Vehicle	0.8	0.9	0.8	0.6	0.7	0.6	0.6	0.4	0.4	0.4
	AAEE	-3.4	-2.9	-3.6	-2.6	-3.0	-2.8	-2.7	-2.5	-2.6	-2.8
	Energy Storage	-1.0	-0.1	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
	LMDR	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 the impacts of DERs, it is necessary to have DER forecasts that extend to the year 2048. The estimation of DER from the year 2029 until the year 2048 has been performed 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 model [3], on its CEC 2050 scenario. The same yearly growth rates for the state of California have been applied to the AAPV forecasts of Table 2-2, starting from the year 2029, to generate an estimation of the AAPV in the Valley South and Valley North Systems up to the year 2048. The estimated AAPV at the 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 the Solar Generation [MVA], and Estimated AAPV SCE Effective PV (in 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 the Solar Generation [MVA], and Estimated AAPV PVWatts (in 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 (CAGR) of 3% was used as a reasonable expectation for future AAPV after the 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 (in 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.

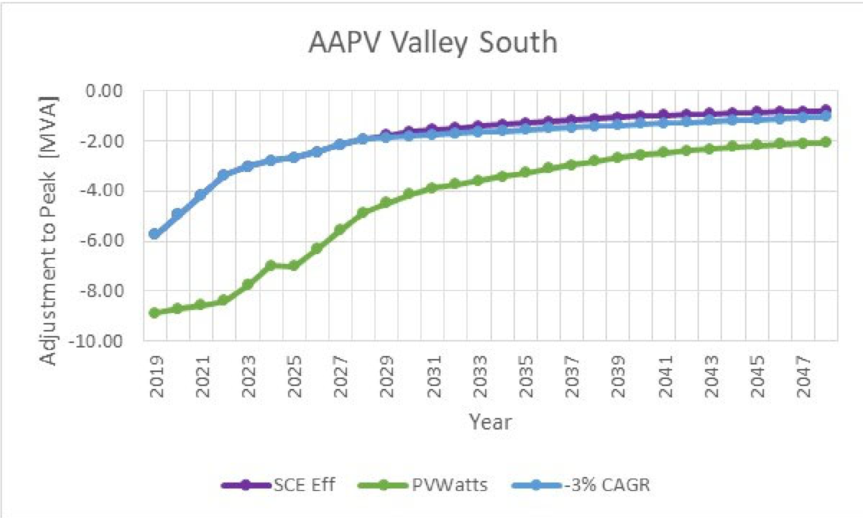


Figure 2-1. AAPV Forecasted Growth Scenarios for Valley South

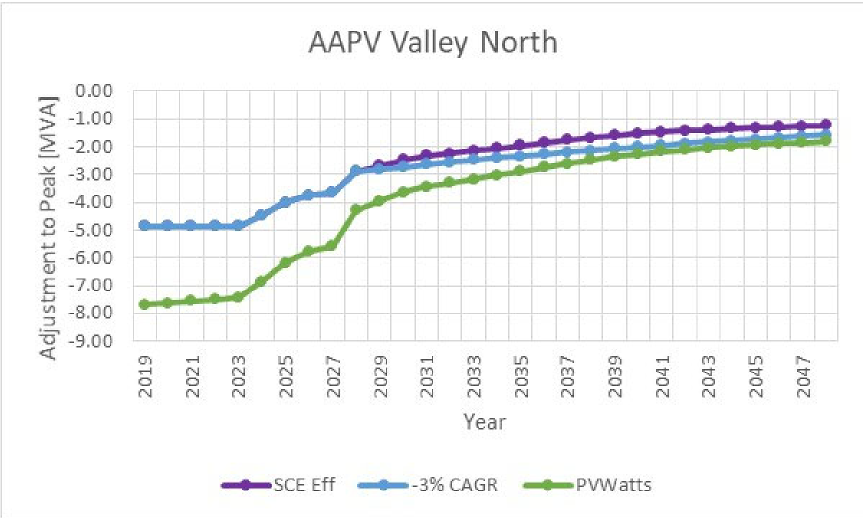


Figure 2-2. AAPV Forecasted Growth Scenarios for Valley North

2.3.2 EV Growth from 2029 to 2048

The EV disaggregated forecast of Table 2-3 was extended until the 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 EV forecast of Table 2-3, starting from the year 2028. The estimated EV load at the Valley South and the Valley North System are shown in Table 2-7.

Table 2-7. California PATHWAYS CEC 2050 Case for the Light EV Load (in 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.

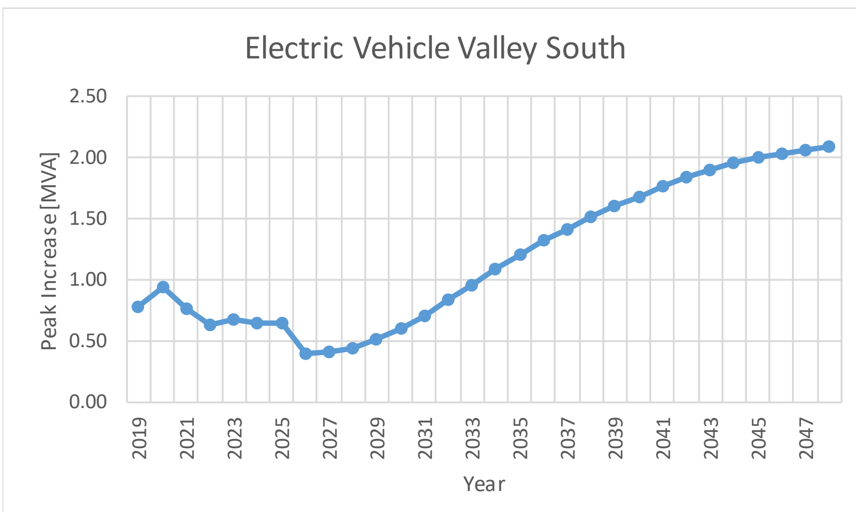


Figure 2-3. EV Forecasted Growth for Valley South

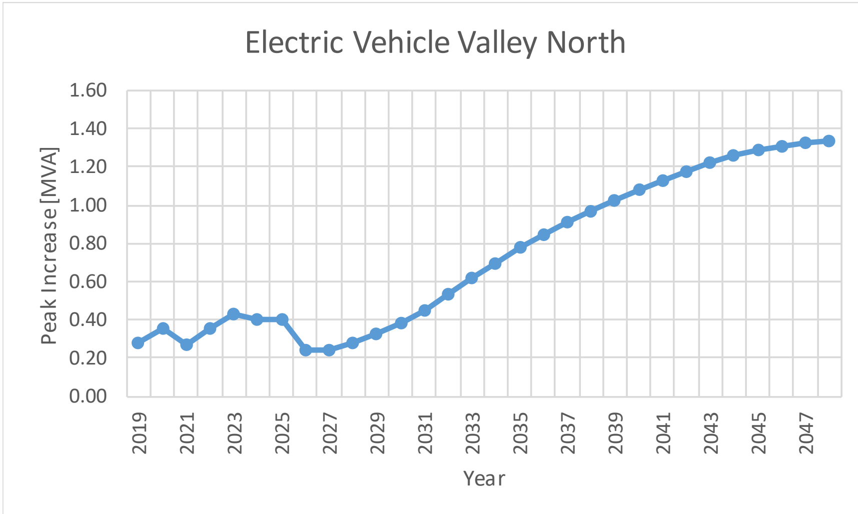


Figure 2-4. EV Forecasted Growth for Valley North

2.3.3 Energy Efficiency Growth from 2029 to 2048

The energy efficiency disaggregated forecast of Table 2-3 was extended until the 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 (in 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.

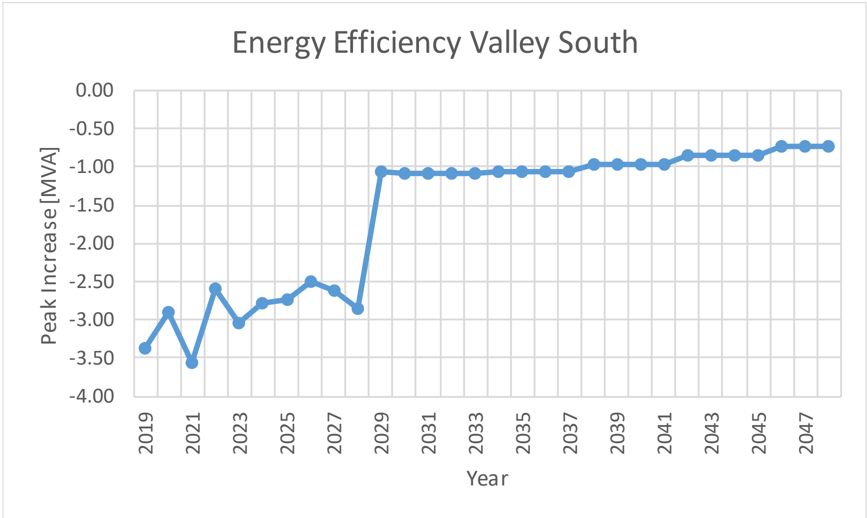


Figure 2-5. Energy Efficiency Forecasted Growth for Valley South

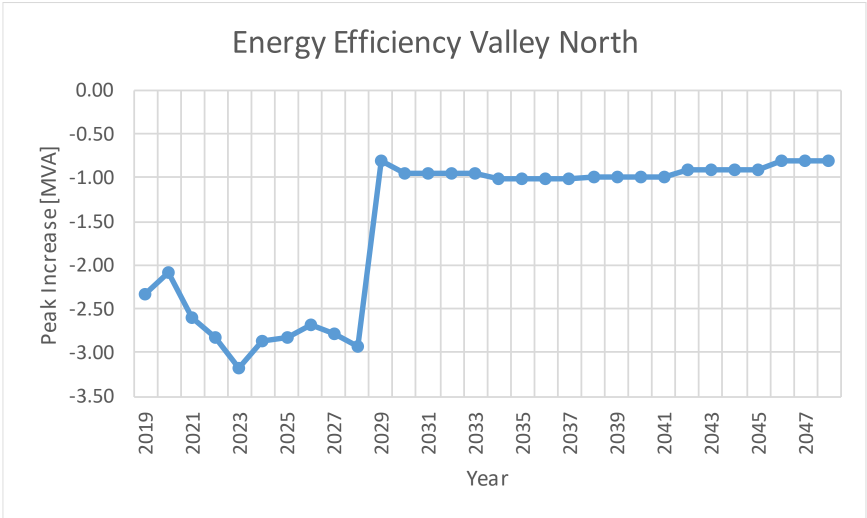


Figure 2-6. Energy Efficiency Forecasted Growth for Valley North

2.3.4 Energy Storage 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 the year 2048. By SCE criteria, it was estimated that 60% of this storage would be associated with 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 an 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 CAGR of energy storage was identified for each area (Valley North and Valley South) so that the year 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 (in 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.

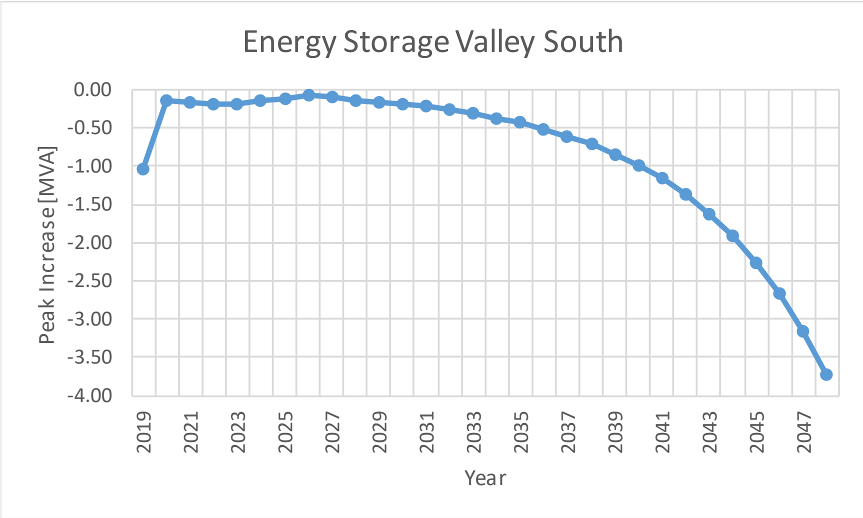


Figure 2-7. Energy Storage Forecasted Growth for Valley South

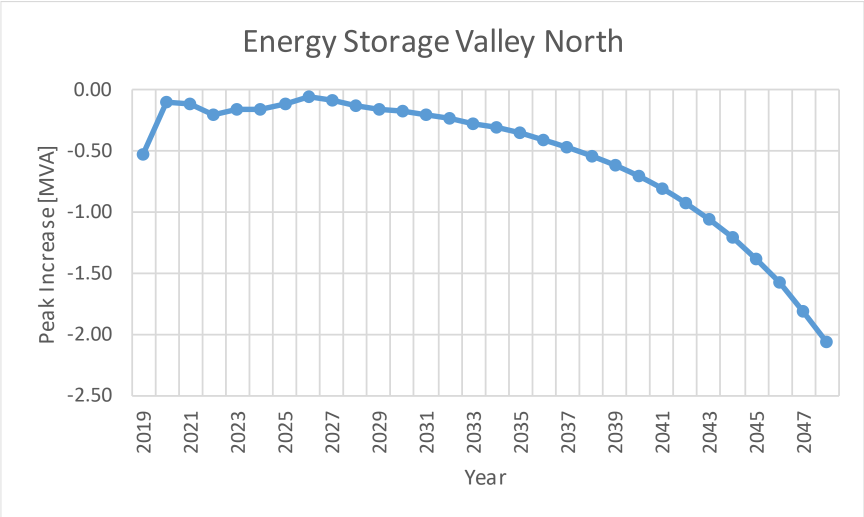


Figure 2-8. Energy Storage Forecasted Growth for Valley North

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 the 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 the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the 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

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]
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

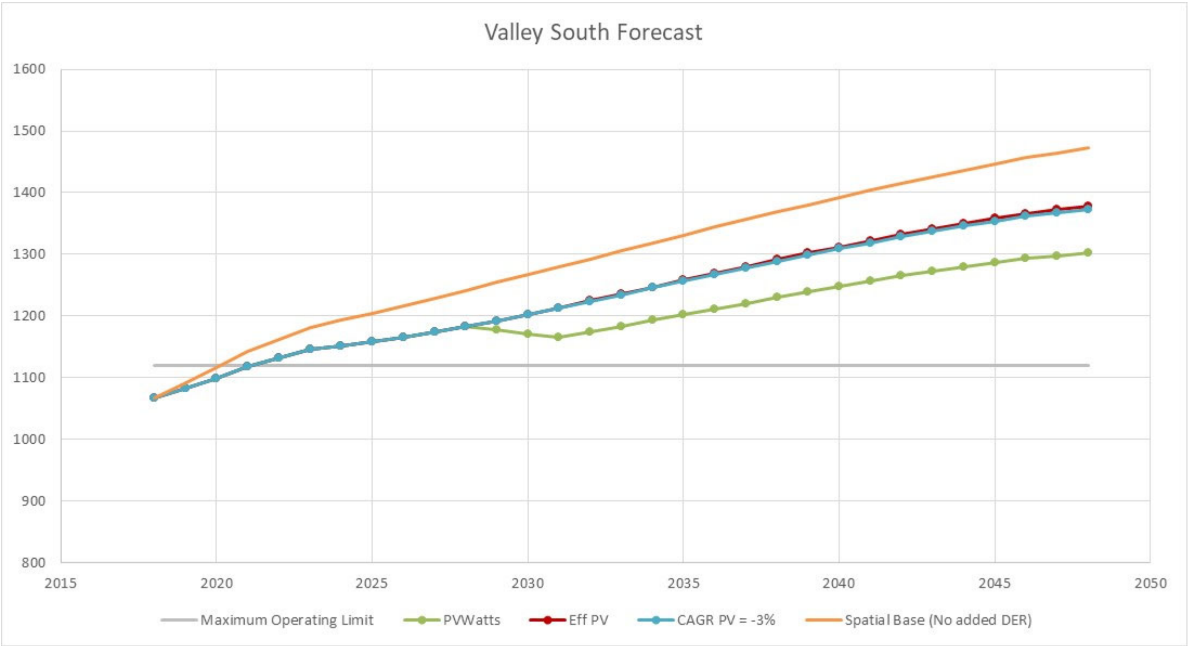


Figure 2-9. Final Results of the Spatial Forecast for Valley South, Considering Three AAPV Growth Alternatives after the Year 2028

Table 2-11. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the 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

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]
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

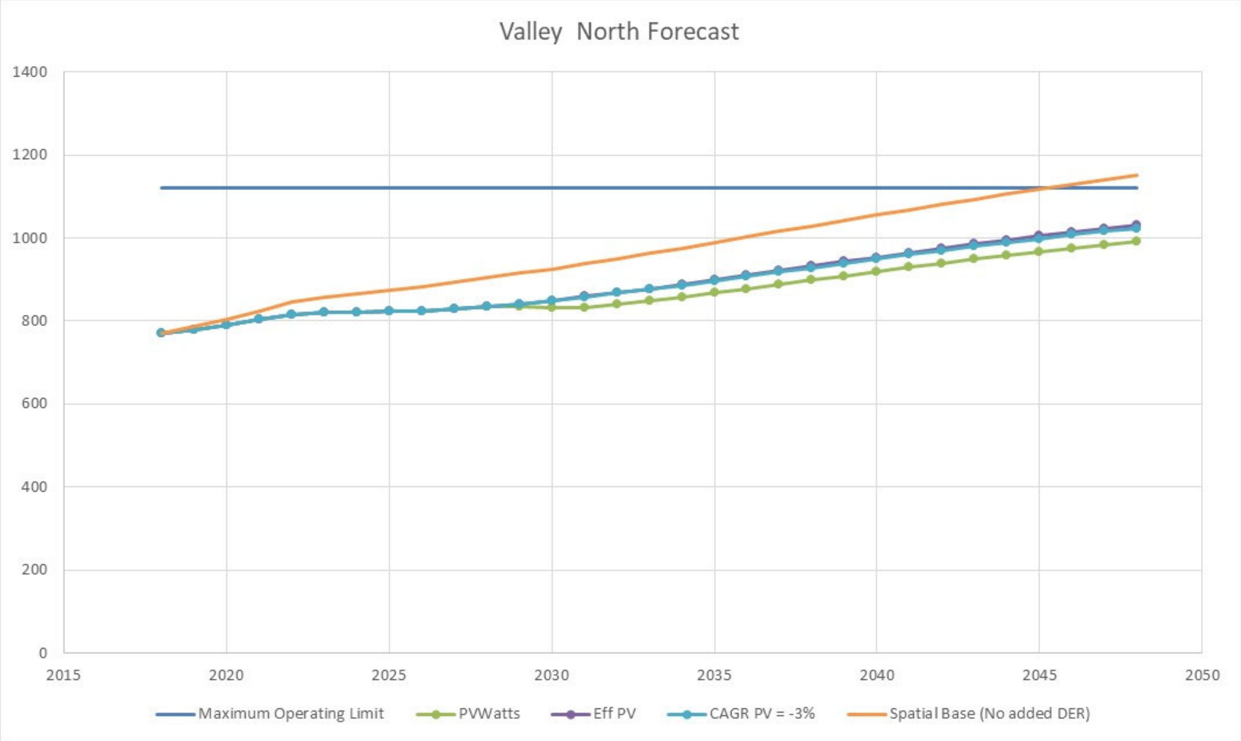


Figure 2-10. Final Results of the Spatial Forecast for Valley North, Considering Three AAPV Growth Alternatives after the Year 2028

3 RELIABILITY ASSESSMENT AND 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 discussed further in Sections 4 and5. Within the framework of this analysis, reliability, capacity, operational flexibility, and resilience 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 the 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 the benefits or impacts of operational flexibility and resilience (high-impact low-probability events [HILP])
5. To compare and 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 as follows:

- **Capacity**
  - Serve current and long-term projected electrical demand requirements in the SCE ENA.
  - 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 Subtransmission Planning Criteria and Guidelines.
  - Increase electrical system reliability by constructing a project in a location suitable to serve the ENA (i.e., the area served by the existing Valley South System).

- **Operational Flexibility and Resilience**
  - 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 a platform to evaluate monetized and non-monetized project benefits
4. Utilize tools such as benefit-to-cost ratio, incremental BCA, and $/unit benefit to substantiate alternative selection and conclusions.

Each of the above areas is further detailed throughout this section.

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 Valley North Systems:
   a. 2018 system configuration (current system)
   b. 2021 system configuration (Valley–Ivyglen [4] and VSSP [5] 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 Valley 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 Section 2 of this report. The primary forecasts under consideration for reliability analysis are 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 South System. The developed forecasts take into consideration the variabilities in future developments of PV, EV, energy efficiency, energy storage, and LMDR.

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 exceed maximum operating limits (1,120 MVA). Figure 3-2, presents the representative load forecast for Valley North where the loading on the Valley North transformers exceed 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 the need year to the end of the 10-year horizon (2028) and the 30-year horizon (2048).

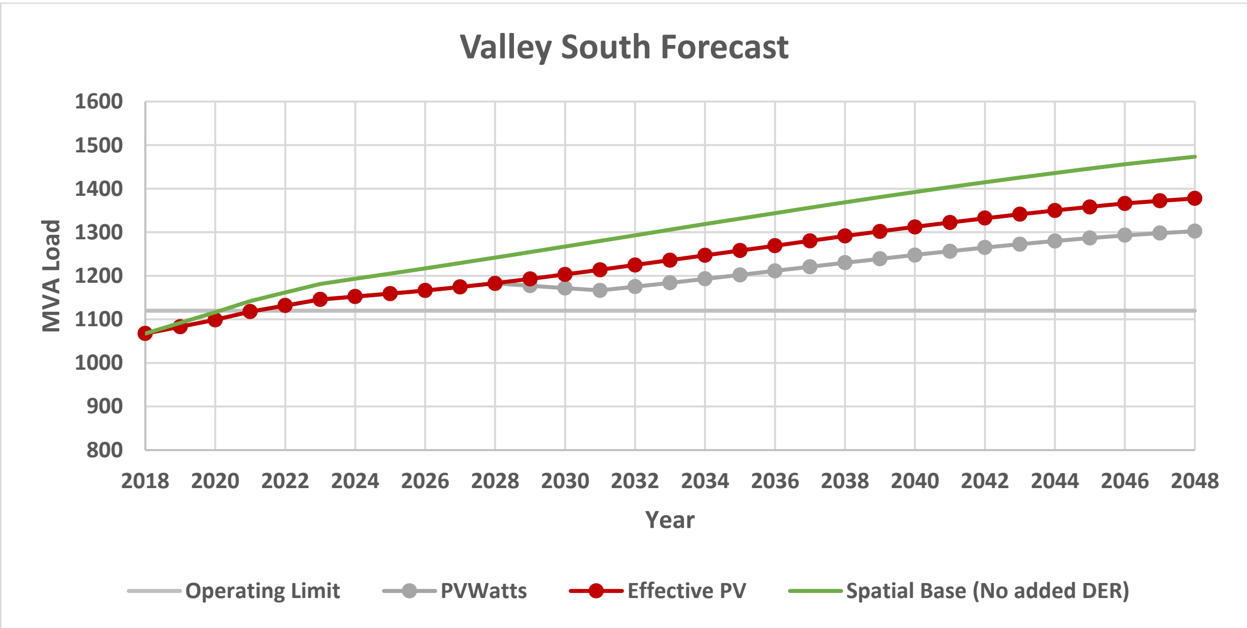


Figure 3-1. Valley South Load Forecast (Peak)

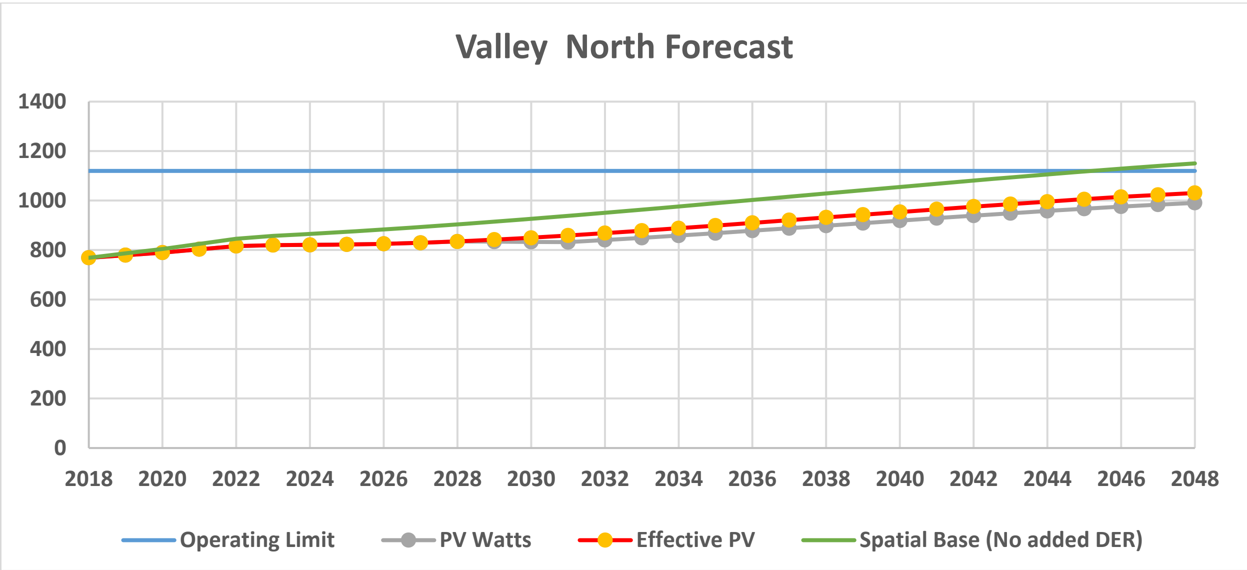


Figure 3-2. Valley North Load Forecast (Peak)

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

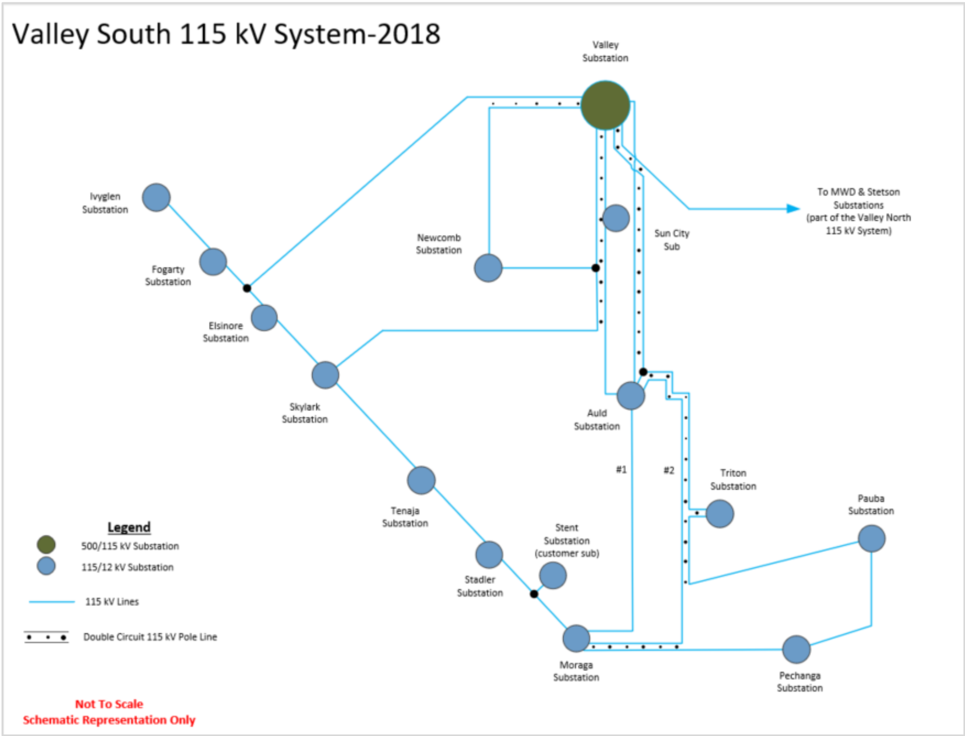


Figure 3-3. Valley South System Current Configuration (2018)

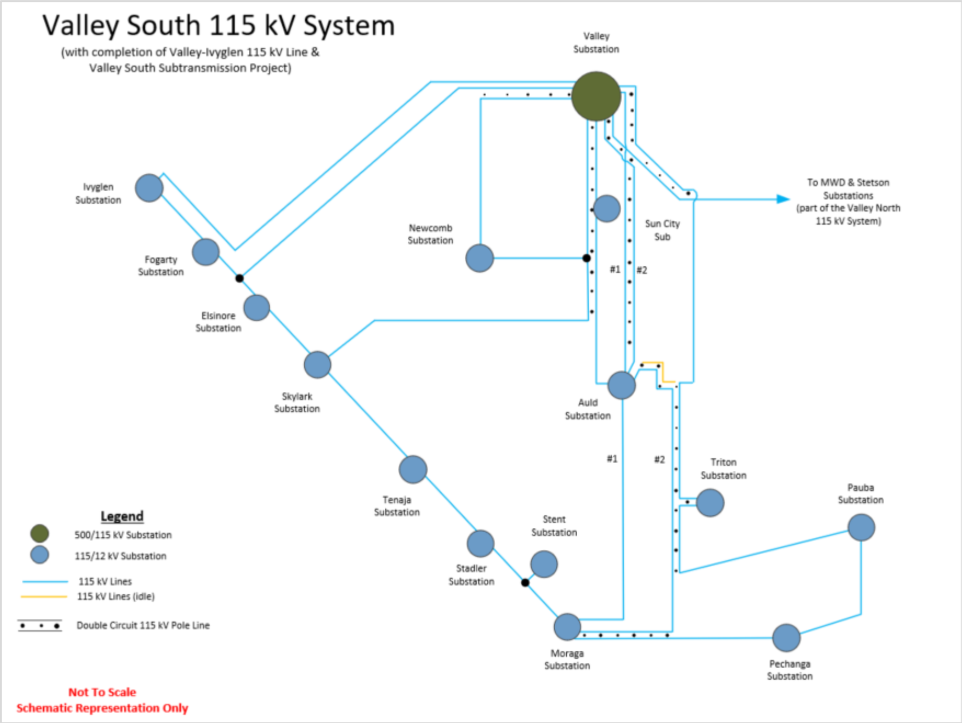


Figure 3-4. Valley South System Configuration (2021)

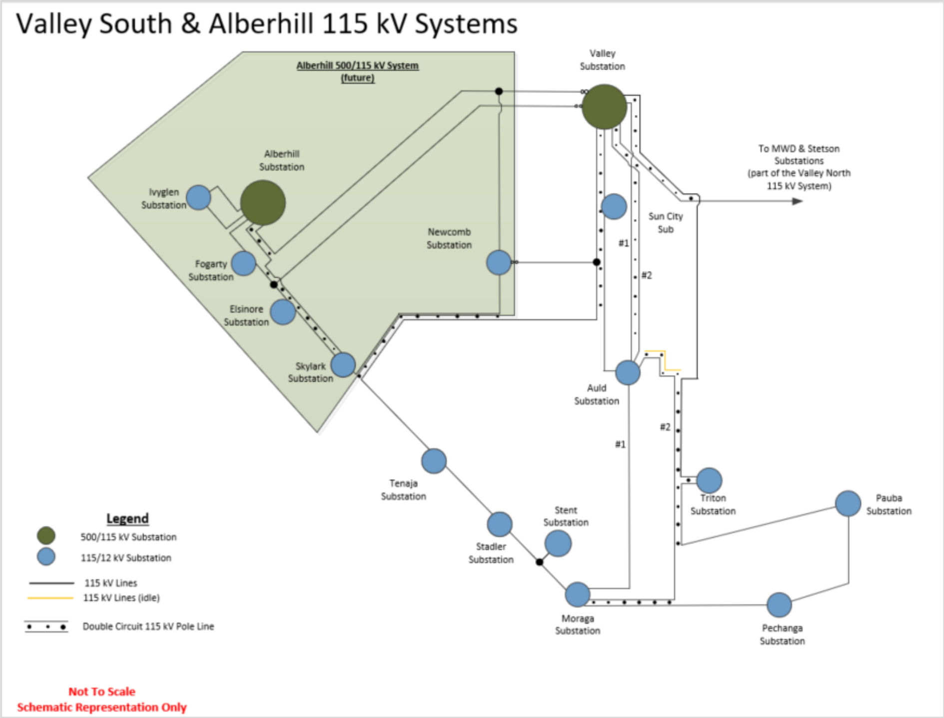


Figure 3-5. Valley South System Configuration (2022 with ASP in-service)

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.[6] This load shape is presented in Figure 3-6.

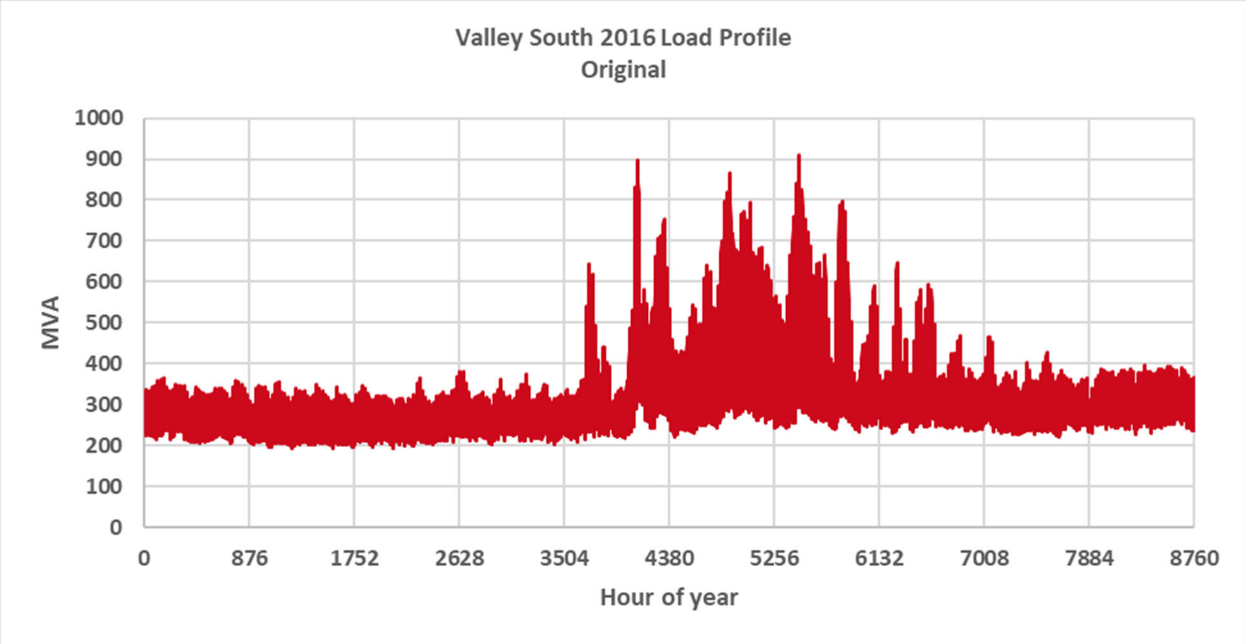


Figure 3-6. Load Shape of the Valley South System

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 Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards were referenced when considering any potential impacts on the 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

[6] 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 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 South 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.

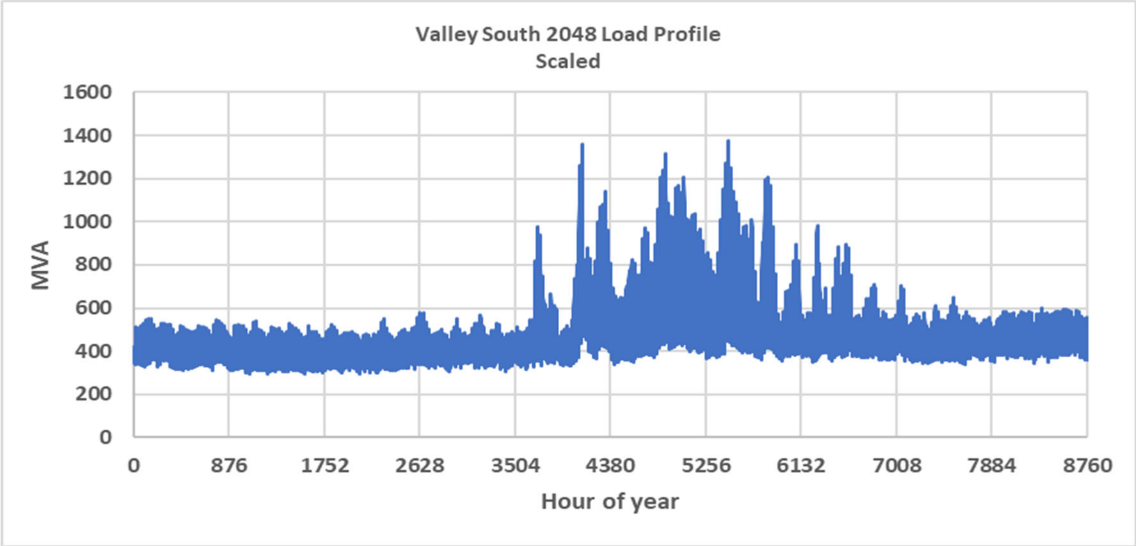


Figure 3-7. Scaled Valley South Load Shape Representative of Study Years

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 (AC) 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.

Unless otherwise specified, all calculations performed under reliability analysis compute the load at risk in MW or MWh, which is not a probability-weighted metric.

The N-1 contingency has been evaluated for every hour of the 8,760 simulations, and the outages were considered to occur with an equal probability. The contingencies were generated using the SCE contingency processor tool for the 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, tie-lines were engaged to minimize system impacts. The losses are monitored every hour and aggregated across the existing and new transmission lines in the service area.

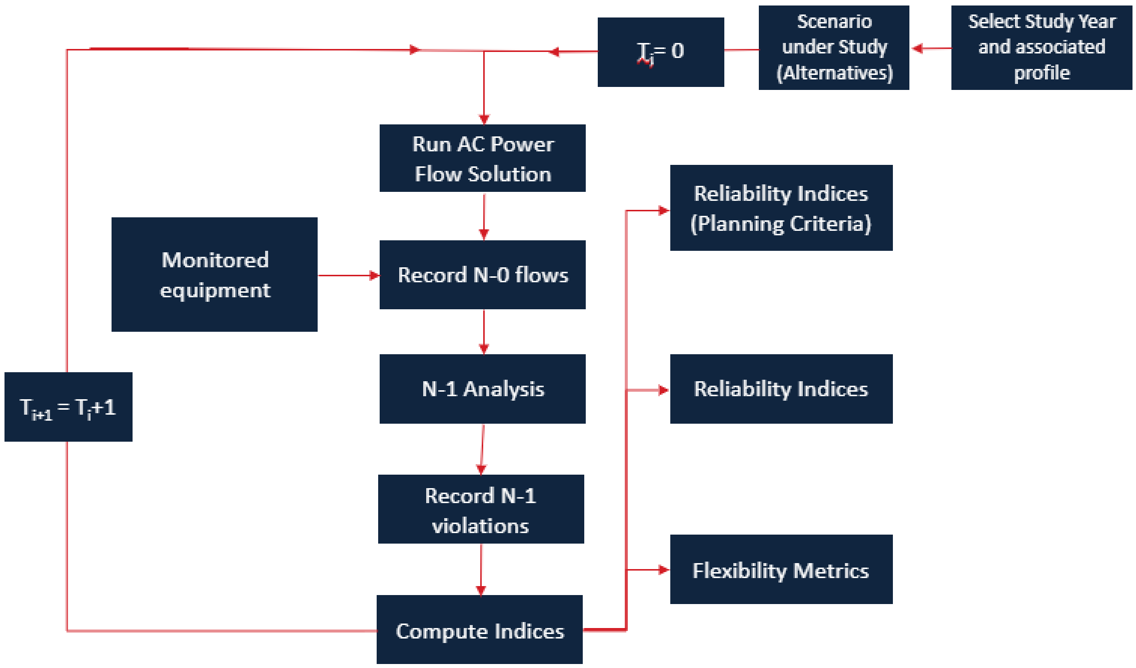


Figure 3-8. Flowchart of Reliability Assessment Process

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

Flexibility Metric 1 evaluates the system under N-2 (common pole double-circuit outages) addressing combinations of two transmission lines out of service. The contingencies were generated using the SCE contingency processor tool for the Valley South System. This tool generates double-circuit outages for all sub-transmission lines that share a common tower or right-of-way. 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 (LAR) and to calculate the weighted amount using the associated contingency probabilities. The probability-weighted MWh is representative of the expected energy not served (EENS). The contingency probabilities were derived from a review of the historic outage data in the timeframe from 2005 to 2018 in the SCE 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 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 LAR to accumulate in the system. When the project under evaluation has tie-lines, they are used to minimize system impacts.

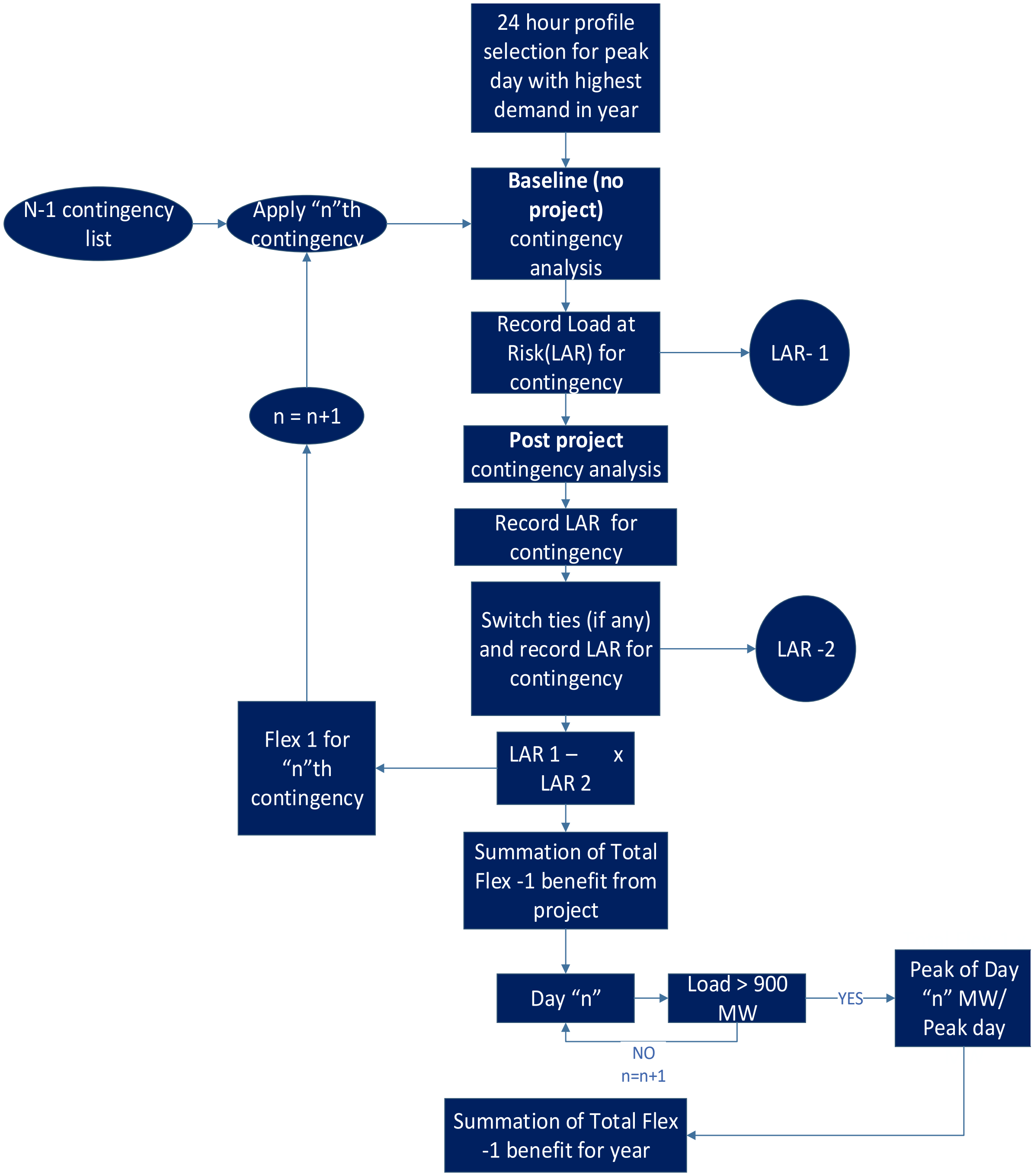


Figure 3-9. Flowchart of Flexibility Metric 1 (Flex-1) Calculation Process

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 Valley South ENA. Both components utilize a combination of power flow and load profile analysis to determine the amount of LAR.

- Flexibility Metric 2-1 evaluates the impact of the entire Valley Substation out of service, wherein all the load served by Valley Substation is at risk. Considering a 2-week event (assumed substation outage duration to fully recover from an event of this magnitude), the average amount of LAR is determined. Utilizing power-flow simulations to evaluate the maximum load that can be transferred by projects using system ties, the amount of load that can be recovered is estimated.
- Flexibility Metric 2-2 evaluates a condition wherein the Valley South ENA is served by a single transformer (i.e., two load-serving transformers at Valley Substation are out of service). This scenario is a result of a catastrophic failure (e.g. fire or explosion) of one of the two transformers, and causing collateral damage to the adjacent transformer, rendering both transformers unavailable. Under these conditions, the spare transformer is used to serve a portion of the load. Utilizing the 8,760-load shape and the transformer short-term emergency loading limits (STELL) and long-term emergency loading limits (LTELL), the average amount of MWh over a 2-week duration LAR is estimated and aggregated ("mean time to repair" under major failures). The analysis accounts for the incremental relief offered by solutions with permanent and temporary load transfer using system ties.

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 the 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 electricity demand can be met without service outages. Capacity is evaluated under normal and emergency system conditions and under normal and heat storm weather conditions (included in load forecast).
- Operational flexibility is considered as adequate electrical connections to adjacent electrical systems to address an emergency, maintenance, or planned outage condition. Therefore, it is expected to operate the system radially and to accommodate flexibility by employing normally open system tie-lines.
- Resilience has been viewed as an extension of the flexibility benefits, wherein system tie-lines are leveraged to recover load under HILP events.

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

- **Load at Risk (LAR)**
  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. 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 the voltage sensitivity of the bus to bring the 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 a bus voltage from the 0.95 per unit limit, the amount of load drop to avoid the violation was determined.

b. LAR was computed for N-0 and N-1 events and aggregated or averaged over 1 year. The focus of the analysis is on the Valley South System. However, under N-0 condition, LAR 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 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 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, or 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. The measure of the capability of the project to provide flexibility to avoid certain overloads and violations observable under the traditional no-project scenario. This flexibility is measured in terms of the incremental MWh that can be served using the flexibility attributes of the project.
  b. Flexibility Metric 2: Recover load for the emergency condition: Single point of failure at the Valley substation and its transformer banks.
     i. Flex-2-1: Calculated as the energy unserved when the system is impacted by HILP events such as loss of the Valley Substation resulting in no source left to serve the load. 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 an average 2-week period (assumed minimum restoration duration for events of this magnitude) in the Valley South system.
     ii. Flex-2-2: Calculated as the amount of MWh load at risk when the system is operating with a single (spare) transformer at Valley Substation (two transformers are out of service due to major failures). This event is calculated over an average 2-week period in the Valley South System. Projects that establish system tie-lines to adjacent networks can support load recovery during these events.

- **Period of Flexibility Deficit (PFD)**: The PFD is a measure of the total number of periods (hours) when the available flexible capacity (from system tie-lines) was 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 has 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 the 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.

The benefit is defined as the value of the impact of a project on 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 LAR, IP, and PFD (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.

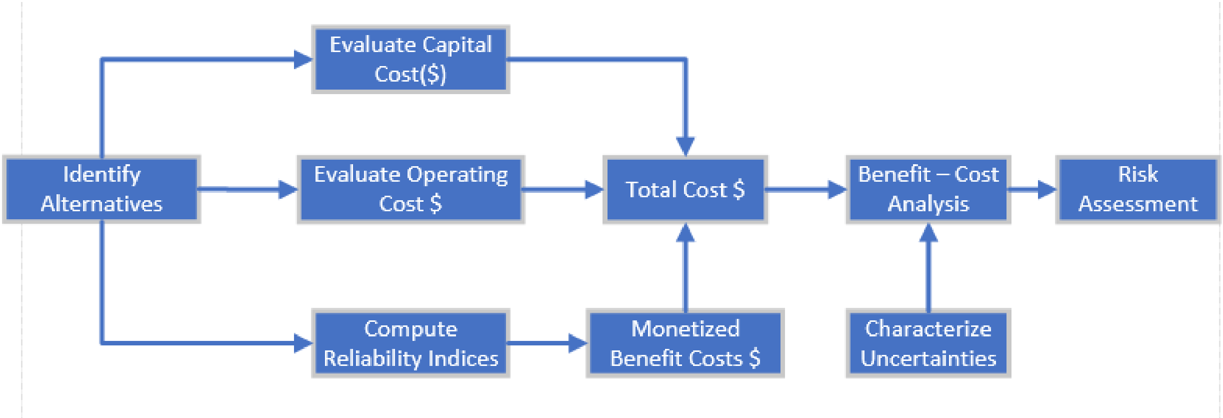


Figure 3-10. BCA Framework

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 and 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 used throughout the study horizon. The PVRR costs are offset for incremental revenues generated by the battery energy storage system (BESS) assets through market participation. Table 3-2 presents the financial assumptions considered in this analysis. Further details pertaining to each of the assumptions are presented in the upcoming sections of this report.

In the scope of this assessment, the benefits for considered metrics (Section 3.2.4) are derived by a comparison of system performance with and without the project in service. Depending on the benefit category, a distinction is made between monetized and non-monetized benefits. The monetized benefits are typically probability-weighted and represented as EENS. Unless otherwise specified, the non-monetized benefits are not probability weighted. The benefits in combination with PVRR costs have been used at different capacities to develop a comprehensive view of project performance. This evaluation framework includes a 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 [LMP])	40 $/MWh	CAISO[7]
Inflation rate (price escalation)	2.5%	Quanta
Load distribution: residential	33%	SCE
Load distribution: small & medium business	36%	SCE
Load distribution: commercial and industrial	31%	SCE
Annual outage rate for Flexibility-2-2 events	0.0015	CIGRE[8]
Annual outage rate for HILP event (Flexibility-2-1 events)	0.01	NERC[9]

The non-monetized benefits have been presented in two different formats. From the perspective of reliability analysis (Sections 4 and 5), they are described as the sum (or the cumulative effect) of the benefits of the project over the project study horizon. In the cost-benefit framework (Section 6), the non-monetized benefits are calculated as the present worth of benefits discounted at the weighted aggregate cost of capital (WACC) throughout the study horizon. An example of the latter, LAR (MWh) benefits of the ASP under normal system condition (N-0) and their present worth using the discount rate of WACC are presented in Figure 3-11.

[7] http://oasis.caiso.com/ (Node: VALLEYSC_5_B1)
[8] Reference [8]
[9] Reference [7]

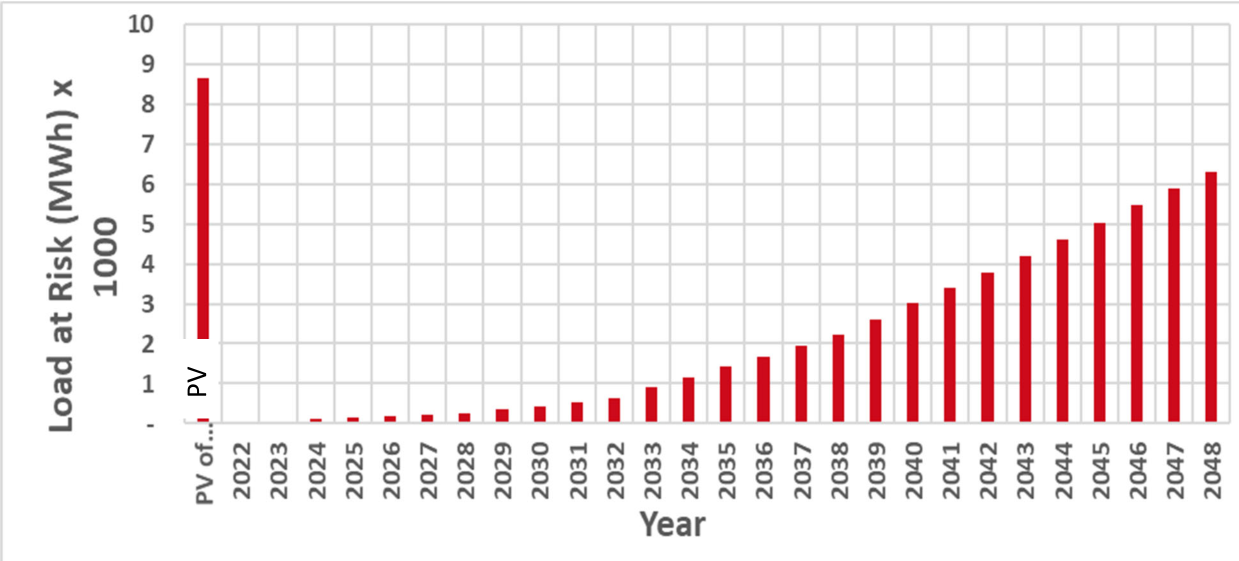


Figure 3-11. LAR (N-0) Benefits Accumulated for ASP over the Study Horizon

LAR (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 [6]. These costs are separated into residential, small & medium business, and commercial & industrial in $/kWh. Figure 3-12 presents the costs over a 24-hour duration as applied to this assessment.

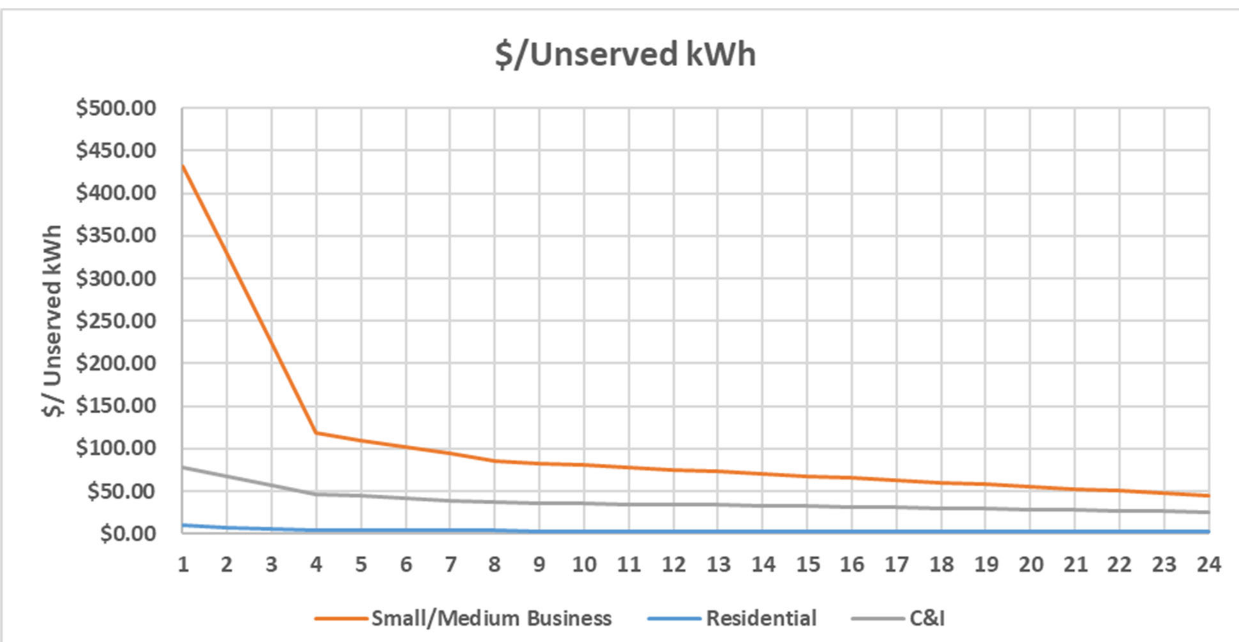


Figure 3-12. Value of Unserved kWh

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

- EENS under N-0 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour outage duration.
  - Costs derived from Figure 3-12 for the 1-hour outage, consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
- EENS under N-1 conditions:
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages have been derived from historic event data in the Valley South, with a failure rate of 3.4 outages per 100 mile years and a mean duration of 2.8 hours.[10] The outage probabilities associated with N-1 circuits are presented in Table 3-3. For new lines in the alternatives, probabilities have been calculated using the estimated length of the circuit and the associated failure rates using the 3.4 outages per 100 mile-years metric.

Table 3-3. N-1 Line Outage Probabilities in Valley South

Line Name	Line Outage Probability Index
Auld-Moraga #1	0.36074
Auld-Moraga #2	0.40664
Auld-Sun City	0.27846
Elsinore-Skylark	0.1632
Fogarty-Ivyglen	0.32164
Moraga-Pechanga	0.17578
Moraga-Stadler-Stent	0.23188
Pauba-Pechanga	0.26112
Pauba-Triton	0.26622
Skylark-Tenaja	0.14994
Stadler-Tenaja	0.17374
Valley-Elsinore-Fogarty	0.59092

[10] Provided by SCE.

Line Name	Line Outage Probability Index
Valley-Newcomb	0.21454
Valley-Newcomb-Skylark	0.67966
Valley-Sun City	0.12818
Valley-Ivyglen	0.918
Valley-Auld #1	0.40664
Valley-Auld #2	0.34884
Valley-Triton	0.53244

- Flexibility-1 Metric
  - LAR (MWh) for 1 year multiplied by the cost of lost load ($/MWh) associated with a 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) are used consistent with the principles of rolling outages between different customers at each hour.
  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities of circuit outages were derived from historic event data in Valley South System, with a failure rate of 0.8 outages per 100 mile years and a mean duration of 3 hours.
  - Considering the large combination of N-2 circuit outages that potentially impact the Valley South System, Flexibility 1 metrics are limited only to circuits that share a double circuit pole. The outage probabilities associated with N-2 contingencies are provided in the Appendix (Section 9).
- Flexibility-2-1 Metric
  - LAR (MWh) over an average 2-week duration multiplied by the cost of lost load ($/MWh) associated with assumed a 2-week outage duration multiplied by the outage probability.
  - The outage duration for this event is considered to be 2 weeks, reflective of the minimum restoration duration for an event of this magnitude. The cost has been derived as the average cost of lost load using hour 1 and hour 24 from Figure 3-12. Considering the uncertainties and shortage of publically available data sources to support the quantification of customer interruption costs due to events of this magnitude, the average of hour 1 and hour 24 cost data would prevent bias towards to a higher or lower monetary impact.
  - The cost associated with this event for residential is 5.68$/kWh, small/medium business is 238.4$/kWh, and commercial/industrial is 52.11$/kWh.
  - 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 [7].
- Flexibility-2-2 Metric
  - LAR (MWh) for the year multiplied by the cost of lost load ($/MWh) associated with 1-hour duration multiplied by the outage probability.
  - Costs associated with a 1-hour duration (Figure 3-12) were used consistent with the principles of rolling outages between different customers each hour.

  - The cost associated with a 1-hour duration for residential is 9.47$/kWh, small/medium business is 431.60$/kWh, and commercial/industrial is 78.28$/kWh.
  - Probabilities associated with this event have been adopted from the CIGRE Transformer Reliability Survey [8] data for major transformer events (fire or explosion) reported to be 0.00075 failures per transformer year.

- Losses
  - Losses (MWh) for the year multiplied by the average locational marginal price (LMP) at the Valley 500-kV substation.
  - The average LMPs are obtained from production simulation of the CAISO model for the year 2021 and 2022 and escalated each year.
  - 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 the in-service year 2021/2022 (depending on the need year from forecast used for the study) to 2048, which covers 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 the present worth of costs and benefits, three different types of analysis have been considered to select the most suitable project among the pool of alternatives. The proposed methodologies utilize the benefits in their non-monetized and monetized representation.

3.3.1.1 Benefit-Cost Analysis (BCA)

The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. 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 from the cost of the project to aggregate benefits introduced by the project.

The relevant benefit categories are monetized per the discussion in Section 3.3.1. The benefits are derived as differences in monetized costs with and without the 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 conditions (N-0), which translates into a $6.6M cost to customers. However, with a project such as ASP in service, the 50 MW of EENS is eliminated, and the $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 the project and the 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 the 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 $474M, and the present worth of N-0 EENS benefit from the ASP (in comparison to baseline) is 8,657 MWh. The ratio of $474M/8,657 MWh suggests that this project would require an investment of $54,753 to achieve 1 MWh of N-0 EENS benefit.

3.3.1.3 Incremental BCA

Incremental BCA is 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 summarized below [9]:

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

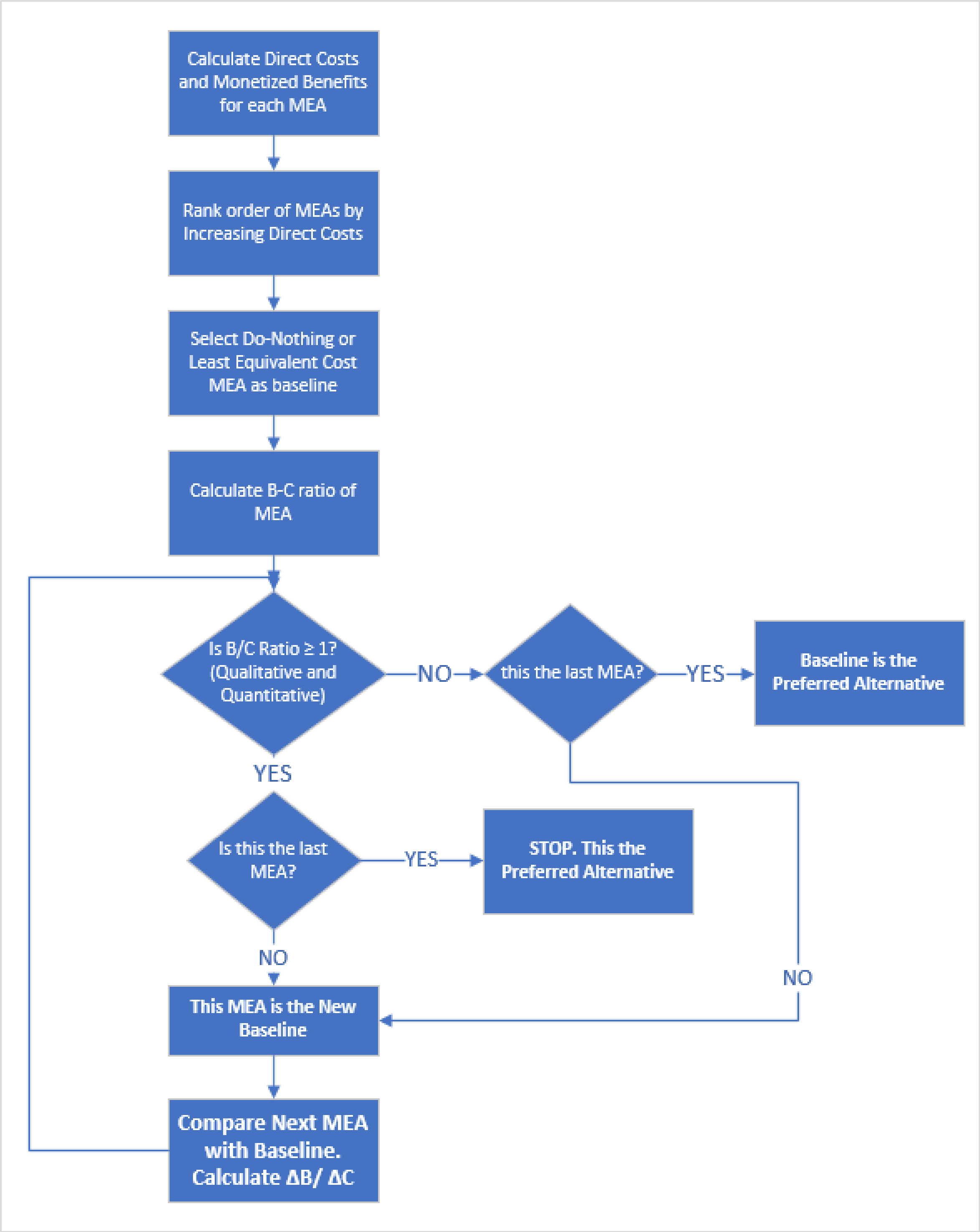


Figure 3-13. Incremental BCA Flowchart

Incremental BCA, also known as marginal benefit-to-cost analysis (MBCA), is considered a superior approach relative to a conventional BCA, for utilities to compare the cost effectiveness of alternative projects. The methodology assures "that dollars will be spent one at a time, with each dollar funding the project that will result in the most reliability benefit, resulting in an optimal budget allocation that identifies the projects that should be funded and the level of funding for each. This process allows service quality to remain as high as possible for a given level of funding—allowing electric utilities to be competitive, profitable, and successful in the new environment of deregulation" [10].

3.3.2 BESS Revenue Stacking

Revenue stacking describes a situation where a BESS is used for more than one domain of applications. When wholesale market applications and transmission and 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).

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 (NWAs 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 are offered into the 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 AS markets. Each day, the optimization would co-optimize the energy and AS participation across the day 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 the 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 Variable O&M Cost ($/kWh)	Parameter (QTech)	0.005 $/kWh
Battery Min/Max Allowable State of Charge (SOC)	Parameter (QTech)	Min/Max: 5/100%
Start/End of Day SOC	Parameter (QTech)	50%
BESS Charging Efficiency	Parameter (QTech)	92%
Wholesale Day-Ahead LMP Data ($/kWh)	Time-series (ISO)	Data extracted for 01/01/2018 – 01/01/2019
BESS Discharging Efficiency	Parameter (QTech)	98%
Regulation Up and Down Clearing Market Prices ($/kW)	Time-series (ISO)	Data extracted for 01/01/18 – 01/01/2019
LMP Price Escalation/yr	Time-series (QTech)	2.5%
LA Basin Local RA Weighted Average Value ($/kW-Month)	Parameter (CPUC [11])	3.64/kW – Month for year 2018

This evaluation was carried out using a proprietary optimization tool developed by Quanta Technology. The tool uses a mixed-integer programming methodology. The co-optimization of storage resource participation in energy and AS 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 AS markets was evaluated. Each day, the optimization would co-optimize the energy and AS participation across the day 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, RegUp, and RegDown capacity less the variable O&M. Note: the variable O&M of $0.00579/kWh is considered for both charging and discharging of the battery. A low-order variable O&M 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 a 24-hour duration.

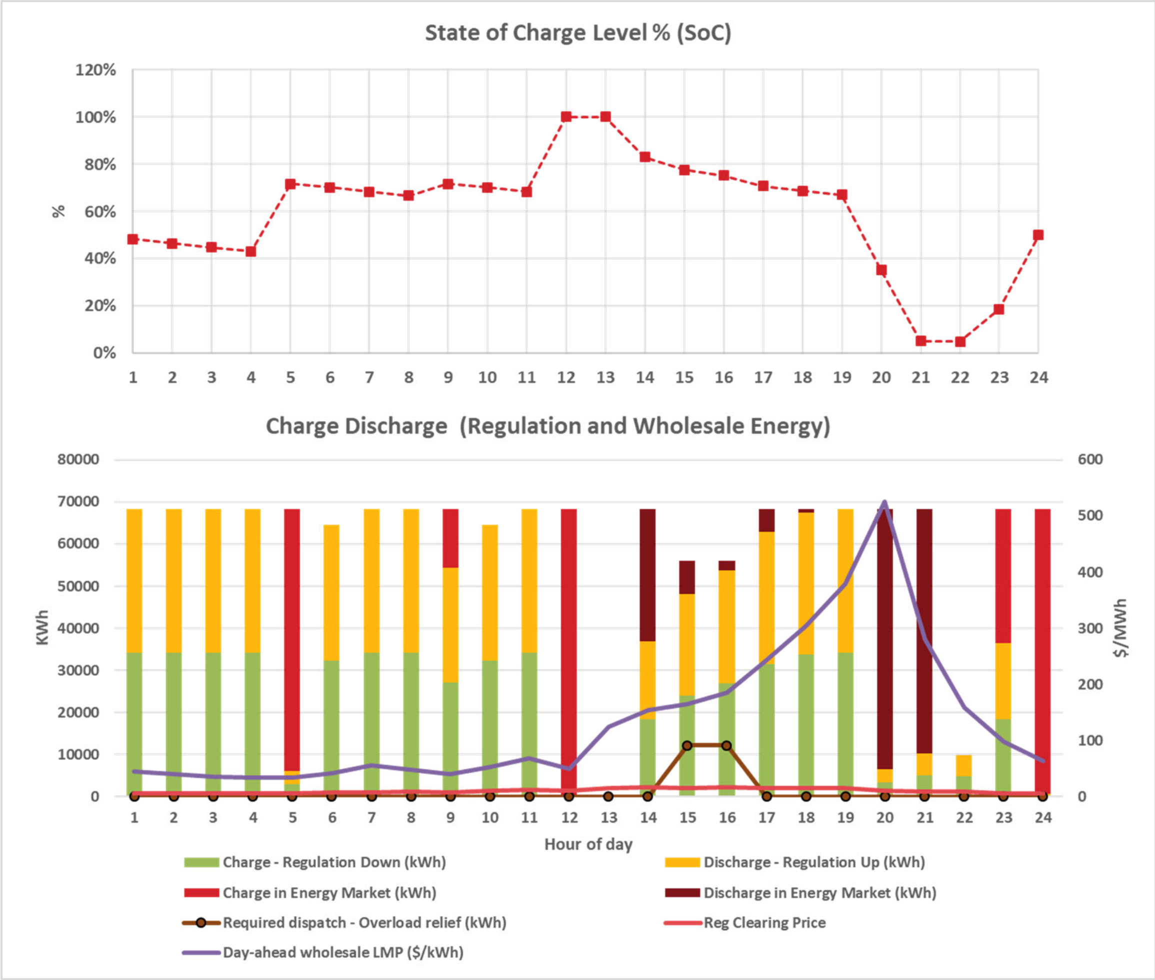


Figure 3-14. Daily Scheduling Example

In addition to participation in wholesale energy and AS markets, potential revenue available from the Resource Adequacy (RA capacity markets) have been estimated. The revenues are derived using local RA prices for the Los Angeles basin area obtained from the CPUC 2018 Resource Adequacy Report [11].

The model assumes 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 RA market outside the summer operating period). The RA prices representative of the weighted average values has been used and escalated at a rate of 2.5% for future years. The analysis takes into consideration the minimum 4-hour duration requirement for BESS participation while accounting for capacity fading at a rate of 3% per year.

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.

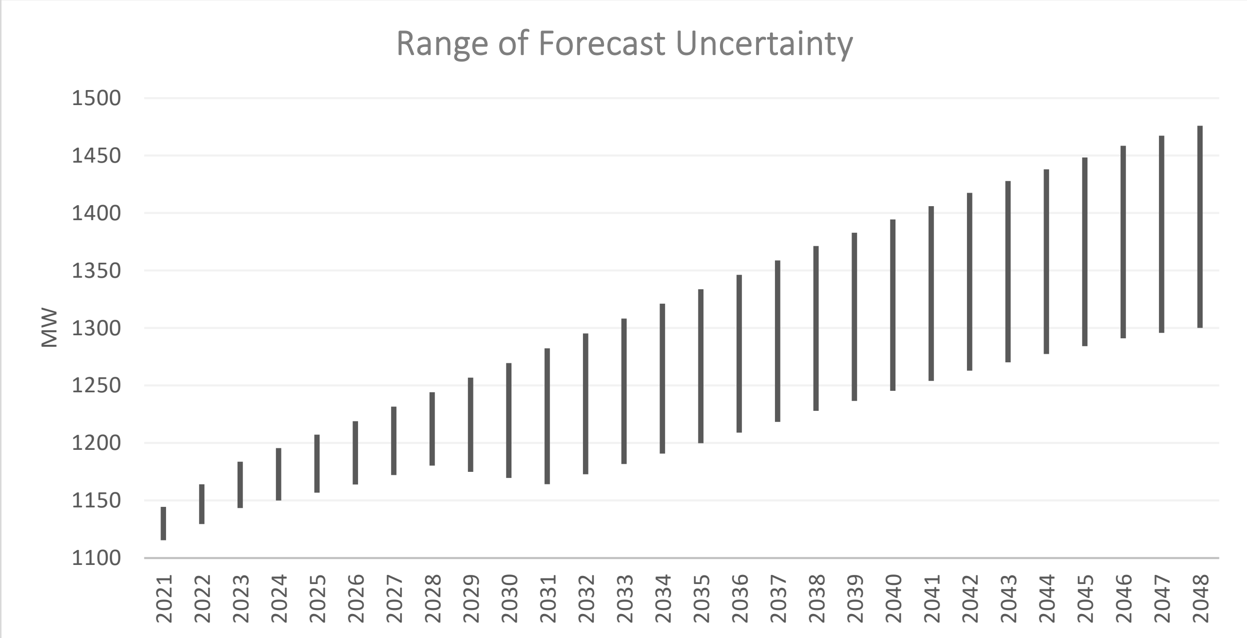


Figure 3-15. Load Forecast Range

Table 3-5. Statistics Associated with Load Forecast

Year	Low (MW)	High (MW)
2023	1146	1181
2028	1183	1242
2038	1230	1369
2048	1302	1474

Considering the spectrum of 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 alternatives 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 section is to apply the reliability assessment framework to 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 the 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 the benefits or impacts of flexibility and resilience (HILP events)
5. To guide for comparing projects against alternatives

Within the framework of this analysis, the reliability, capacity, flexibility, and resilience 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 the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.2.1 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	22	13	2	49,667
2028	250	65	7	52,288
2033	905	120	18	54,472
2038	2,212	190	37	56,656
2043	4,184	246	53	58,840
2048	6,310	288	77	61,024

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	50	22	4	50,082
2022	129	42	5	50,888
2028	908	131	19	54,467
2033	2,844	205	42	57,450
2038	5,741	280	69	60,432
2043	9,888	348	102	63,415
2048	14,522	411	142	66,397

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

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

4.2.2 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	163,415	133,688	2,774
2033	249	21	54	254,140	139,702	3,514
2038	679	35	88	344,864	145,991	4,421
2043	1,596	45	120	435,589	151,619	5,294
2048	2,823	68	153	526,314	155,733	5,975

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	18	4	18	54,545	129,095	2,255
2022	40	6	28	~~122,681~~87,602	131,322	2,491
2028	231	23	60	~~531,497~~285,950	140,388	3,612
2033	989	40	98	~~872,176~~451,239	147,622	4,670
2038	2,435	62	147	~~1,212,856~~616,529	154,744	5,811
2043	5,~~263~~599	71	204	781,818~~1,553,536~~	161,142	6,952
2048	~~9,236~~10,024	128	261	~~1,894,216~~947,107	166,580	8,000

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	10	2	14	54,545	127,935	2,138
2028	67	11	32	122,681	133,688	2,774
2033	75	11	33	531,497	133,840	2,791
2038	182	20	51	872,176	139,065	3,432
2043	454	29	79	1,212,856	143,845	4,110
2048	805	35	94	1,553,536	147,226	4,615

In the baseline system analysis, the following constraints (Table 4-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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		
Valley South Transformer	N-0	Base case	2021	2022	2022
Auld to Moraga #1	N-0	Base case	2038	2047	
Valley EFG to Tap 39	N-0	Base case	2043		
Valley EFG to Sun City	N-0	Base case	2043		
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 the baseline system are as follows:

1. Without any project in service, the Valley South System transformers are 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 the year 2028, 250 MWh of LAR is observed 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 LAR ranges from 2,600 MWh to 14,500 MWh in a 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 the 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 the year 2048.
4. With the system operating at load levels greater than 1,120 MVA, it becomes increasingly challenging to maintain system N-1 security.
5. In the Effective PV forecast by the year 2028, 67 MWh of LAR 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 LAR ranges from 805 MWh to ~~9,200~~10,000 MWh in a 30-year horizon.

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

The ASP has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

4.3.1 Description of Project Solution

The ASP 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 currently served by the Valley South 115 kV system. Two transformers were 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) currently 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.

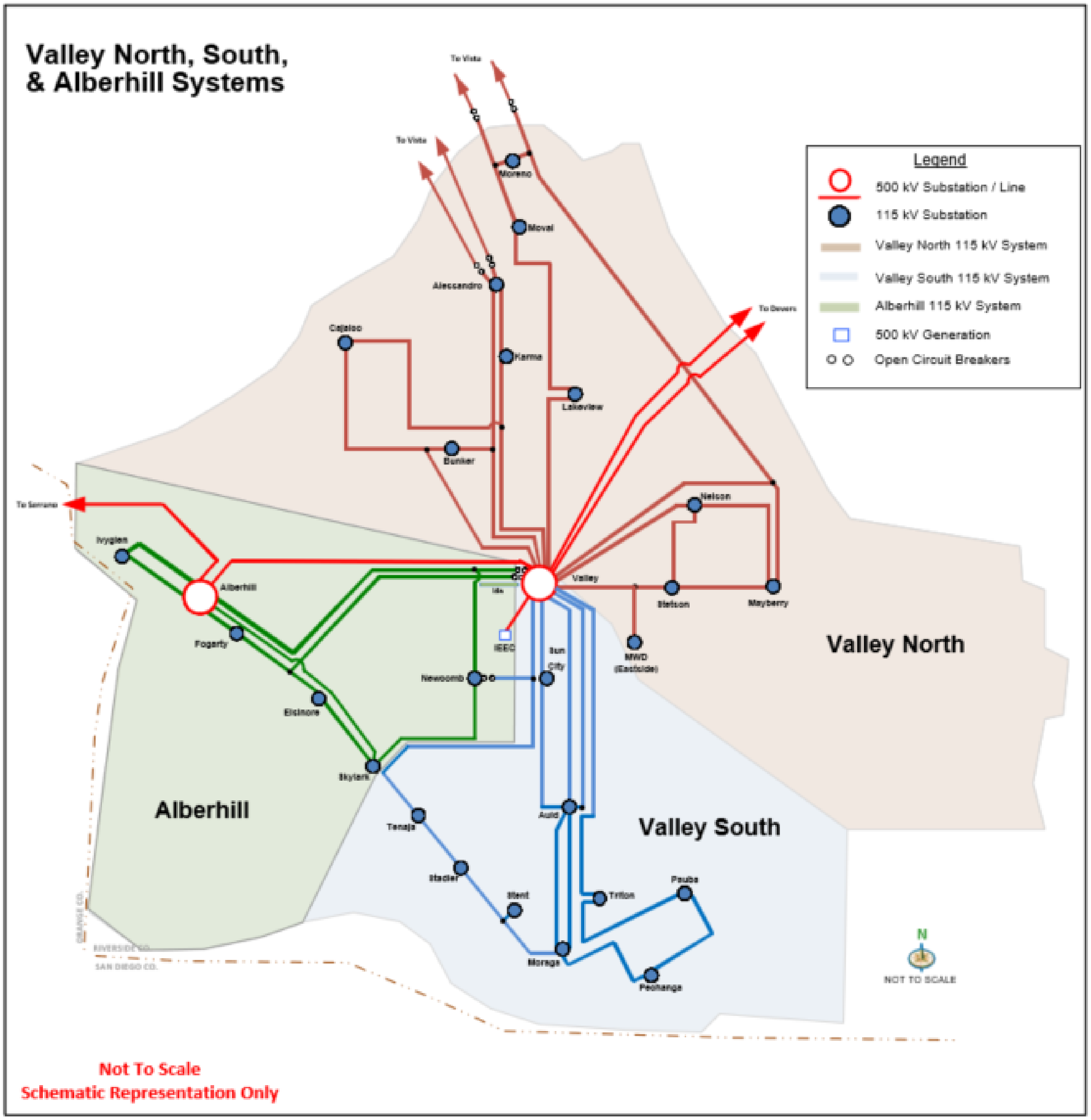


Figure 4-1. Alberhill System Project and Resulting Valley North and South Systems

4.3.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	40,621
2028	0	0	0	42,671
2033	0	0	0	44,380
2038	0	0	0	46,089
2043	0	0	0	47,797
2048	3	2	2	49,506

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	40,954
2022	0	0	0	41,590
2028	0	0	0	43,417
2033	0	0	0	44,939
2038	1	1	1	46,462
2043	28	8	6	47,984
2048	93	14	10	49,506

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

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

4.3.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~22,815~~0	1163	0
2028	0	0	0	~~49,088~~30,438	1516	0
2033	0	0	0	~~70,982~~56,720	1947	0
2038	21	8	4	~~92,876~~83,001	2452	0
2043	84	17	8	~~114,770~~109,283	2954	1
2048	202	24	14	136,664	3345	4

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~22,815~~0	1,229	-
2022	0	0	0	~~31,087~~11,530	1,363	-
2028	0	0	0	~~80,717~~80,713	1,999	-
2033	33	11	5	138,365~~122,076~~	2,593	-
2038	163	22	12	196,017~~163,435~~	3,249	3
2043	530	34	6	253,669~~204,794~~	3,896	11
2048	1,080	43	43	311,321~~246,153~~	4,494	27

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~22,815~~0	1,163	0
2028	0	0	0	~~28,718~~11,254	1,516	0
2033	0	0	0	~~33,638~~20,632	1,526	0
2038	0	0	0	30,011 ~~38,557~~	1,899	0
2043	7	4	2	39,389 ~~43,476~~	2,272	0

2048	30	10	5	48,395	2,559	0

In analyzing the ASP, the following constraints (Table 4-14) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Auld – Moraga #1	N-0	N/A (base case)	2048		
Valley EFG – Sun City	N-0	N/A (base case)	2048		
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 the baseline and the ASP to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 4-15 for the 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	277,608	362,676
N-1	LAR (MWh)	6,282	20,~~339~~327	~~66,742~~69,479
N-1	IP (MW)	428	601	954
N-1	PFD (hr)	1,300	1,907	3,277
N-1	Flex-1 LAR (MWh)	3,901,429	~~5,688,618~~6,024,126	~~23,517,096~~9,664,642

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-1	Flex-2-1 LAR (MWh)	3,657,700	3,779,849	4,101,527
N-1	Flex-2-2 LAR (MWh)	87,801	106,937	141,992
N-0	LAR (MWh)	22,751	56,575	140,566
N-0	IP (MW)	2,713	4,053	6,213
N-0	PFD (hr)	411	811	1,559

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons 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 resilience 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. 3 MWh of LAR is recorded under N-0 condition (Effective PV Forecast) in the year 2048 due to an observed overload of the Alberhill–Fogarty 115 kV line. Across all sensitivities, the benefits range between 22.7 and 140.5 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With the ASP in service, the N-1 benefits in the system range from 6.2 to 66.7 GWh through all forecasts. In the Effective PV Forecast by the 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, or emergency outages throughout the system while also providing significant benefits to address needs under 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 can 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 the load forecast. The available flexibility through system tie-lines provides 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 identify and screen potential alternatives that meet the project objectives detailed in Section 1.2. Each of these alternatives is 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. NWAs include energy storage, demand response, energy efficiency programs, DERs, and other smart grid investments like smart meters. Hybrid solutions are a combination of Conventional and NWAs.

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

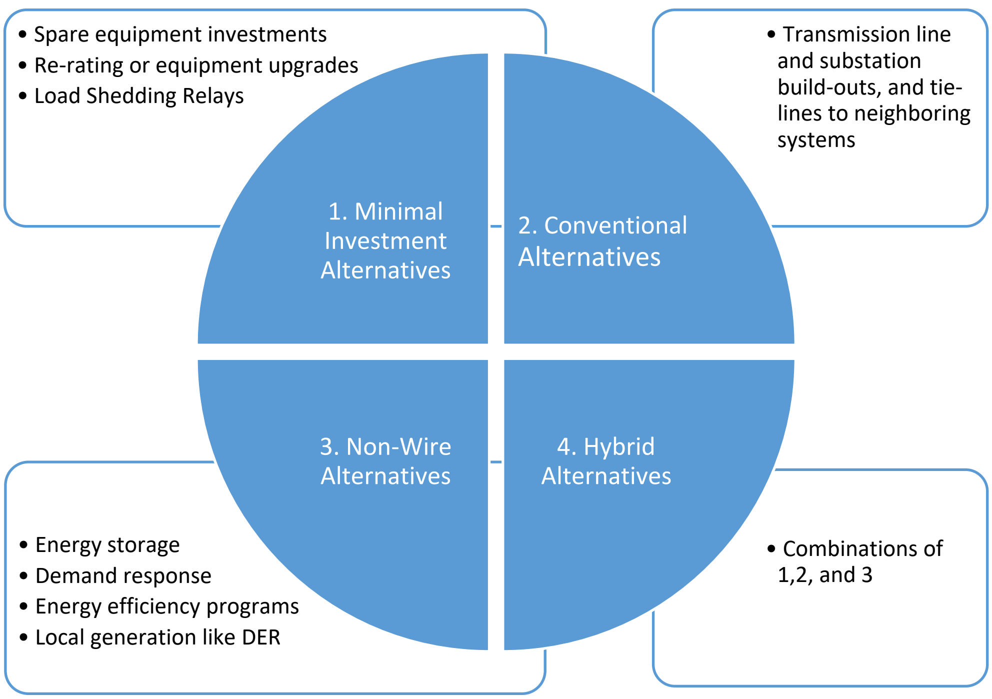


Figure 5-1. Categorization of Considered Alternatives

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

- Use reliability analysis results with no project in service and available reports detailing the 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 was evaluated under the most constraining conditions identified from the "no project" scenario results. Figure 5-2 describes the Valley South System relative to neighboring electrical systems.
- Seek guidance from the LAR metrics to provide the viability of alternatives. For example, the identified MWh need is large and predominantly occurs during off-peak hours of the day when PV-DER type solutions might not be available.

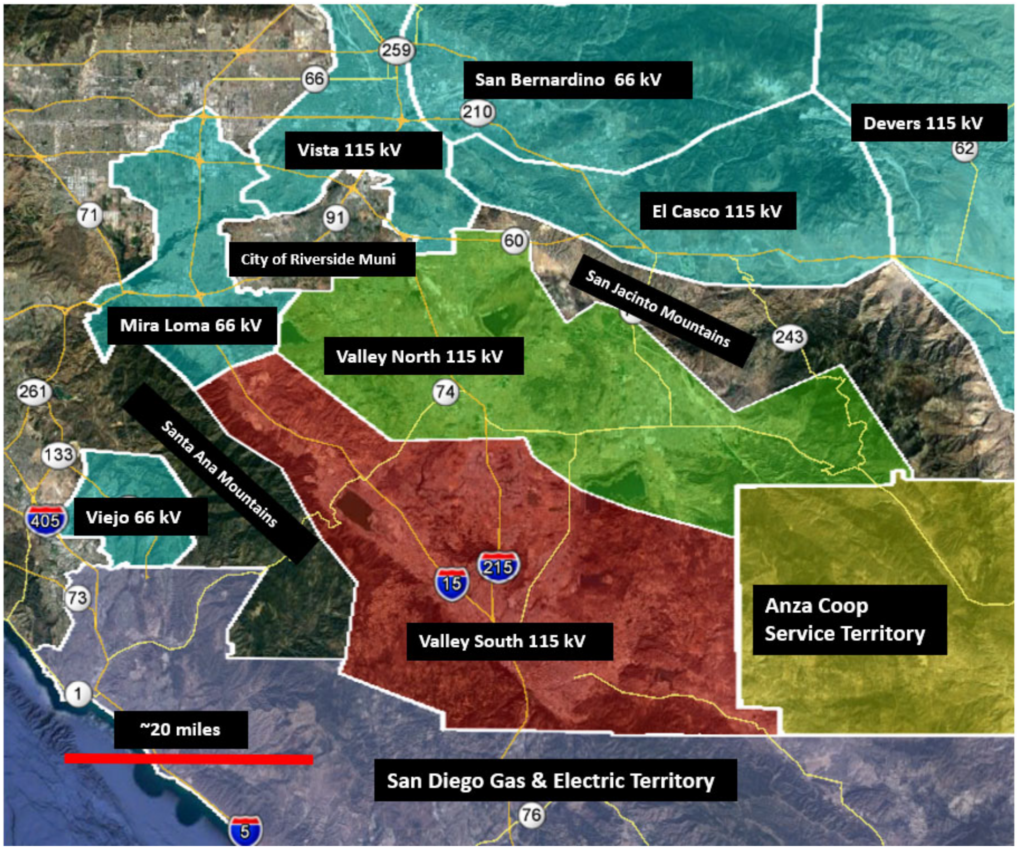


Figure 5-2. Valley System and Neighboring Electrical Systems

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 pertaining to the scope, design, and project performance are described in the upcoming sections. Note that the ASP and project alternatives are identified using an alphabetic character, A through M, which is used throughout this report to refer to 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 the 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 via the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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. The 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 the 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.

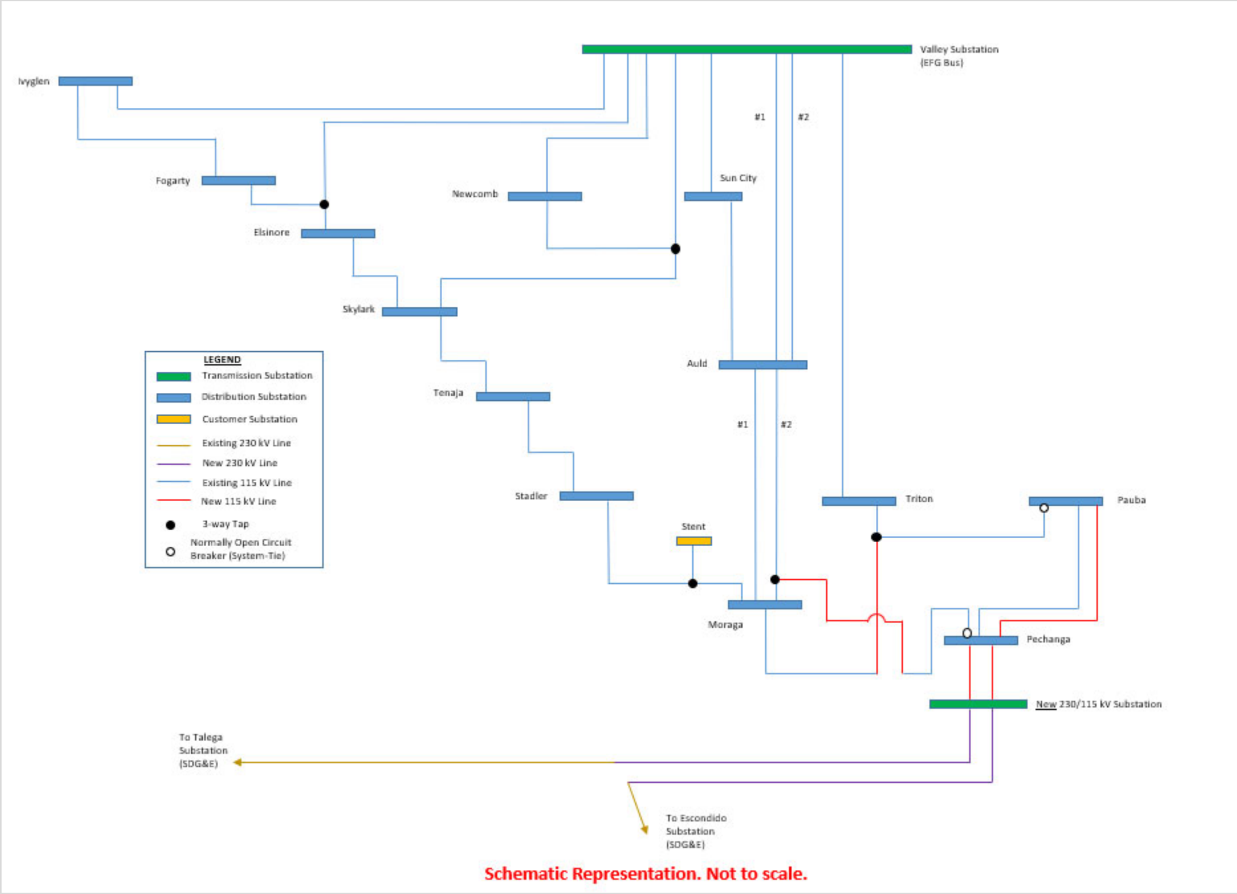


Figure 5-3. SDG&E Project Scope

5.3.1.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	82	31	4	52,481
2048	244	63	7	54,457

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	44,182
2022	0	0	0	44,715
2028	0	0	0	46,963
2033	0	0	0	48,837
2038	199	56	6	50,710
2043	655	112	12	52,584
2048	1,499	152	28	54,457

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

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

5.3.1.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428 ~~431~~
2028	0	0	0	52,762	17,895	636~~639~~
2033	0	0	0	79,372	21,123	926~~932~~
2038	0	0	0	105,982	24,949	1,274~~1,282~~
2043	0	0	0	132,591	28,757	1,662~~1,672~~
2048	0	0	0	159,201	31,740	1,978 ~~1,990~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	20,830	15,677	468
2022	0	0	0	30,189~~40,890~~	16,727	545
2028	0	0	0	86,343~~161,248~~	21,517	958
2033	0	0	0	133,137~~261,546~~	26,018	1,380
2038	0	0	0	179,931~~361,845~~	31,008	1,889
2043	30	7	4	226,725~~462,143~~	35,874	2,413
2048	196	18	8	273,520~~562,442~~	40,207	2,937

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	20,830	15,152	428
2028	0	0	0	36,859	17,895	636
2033	0	0	0	50,217	17,971~~17,467~~	641~~605~~
2038	0	0	0	63,575	20,763	896
2043	0	0	0	76,933	23,589	1,146
2048	0	0	0	90,291	25,756	1,352

In analyzing the SDG&E project, the following constraints (Table 5-7) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 (base case)	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 the baseline and the SDG&E Project to quantify the overall benefits accrued over a 30-year study horizon. The benefits are quantified as the difference between baseline and SDG&E for each of the metrics.

The accumulative values of benefits over the 30-year horizon are presented in Table 5-8 for the 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 Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	200,879	214,200	249,117
N-1	LAR (MWh)	6,375	21,684	7~~2,688~~5,545
N-1	IP (MW)	467	780	1,321
N-1	PFD (hr)	1,320	1,999	3,432
N-1	Flex-1 (MWh)	3,362,638	5,~~411~~414,~~173~~801	9,902,236~~19,116,843~~
N-1	Flex-2-1 (MWh)	3,167,267	3,217,646	3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,~~509~~689	97,230
N-0	LAR (MWh)	22,748	55,563	132,227
N-0	IP (MW)	2,710	3,726	4,978
N-0	PFD (hr)	410	775	1,444

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 is 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 a longer distance from the 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- and mid-term horizon. This trend is observable across all forecast sensitivities. Under N-0, 240 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 1,500 MWh under the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 132.2 GWh of avoided LAR.
2. With the SDG&E Project in service, the N-1 benefits in the system range from 6.3 to 72.6 GWh through all forecasts. The design of the 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 the Valley South System. In the Spatial Base Forecast, by the 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 the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Following a HILP event, the SDG&E Project can 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 the lower range of forecast sensitivities.

5.3.2 SCE Orange County (Project C)

The SCE Orange County Project was evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 to the new 220/115 kV substation. This configuration would include the construction of the new 230 kV double-circuit transmission line.
3. The proposed solution would transfer SCE's Tenaja and Stadler 115/12 kV Substations to the new 220/115 kV system through the 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.

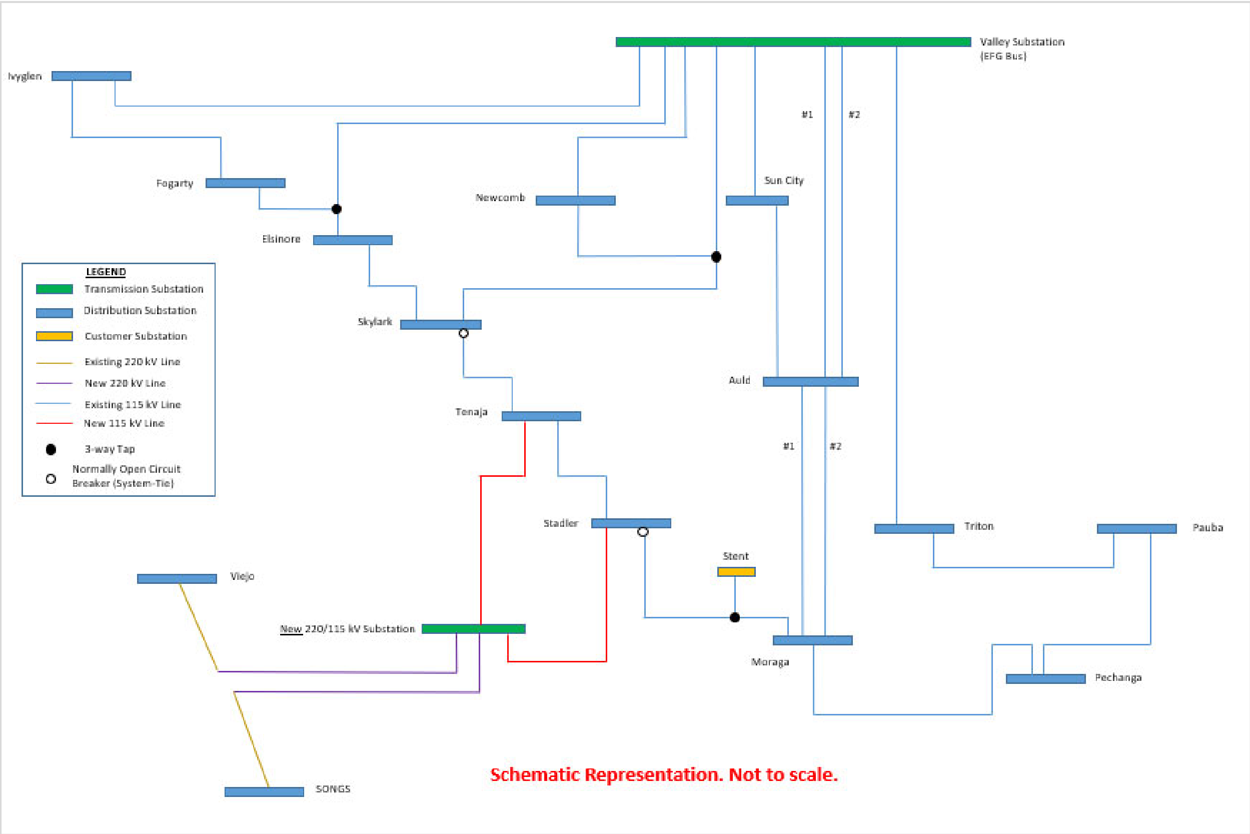


Figure 5-4. SCE Orange County Project Scope

5.3.2.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	2022	0	0	0	43,189
	2028	0	0	0	45,593
	2033	0	0	0	47,596
	2038	0	0	0	49,599
	2043	72	31	4	51,602
	2048	232	65	7	53,605

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
SCE Orange County	2021	0	0	0	43,574
	2022	0	0	0	44,330
	2028	0	0	0	41,444
	2033	0	0	0	45,672
	2038	183	55	5	49,899
	2043	536	111	11	54,126
	2048	1,426	159	27	58,353

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

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

5.3.2.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	2022	0	0	0	55,886	14,219	344 ~~347~~
	2028	13	3	5	142,815 ~~156,480~~	16,791	519~~522~~
	2033	35	3	2	215,046 ~~240,308~~	19,823	769 ~~774~~
	2038	130	14	7	288,277 ~~324,136~~	23,407	1,078 ~~1,085~~
	2043	313	26	14	359,507 ~~407,965~~	27,650	1,413~~1,483~~
	2048	578	36	28	417,292 ~~491,793~~	29,833	1,703~~1,714~~

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	2021	5	3	2	55,886	14,711	375
	2022	10	3	2	77,708.23 ~~99,498~~	15,692	438
	2028	38	5	4	208,643.16 ~~361,174~~	20,192	798
	2033	176	17	8	317,755.59 ~~579,237~~	24,412	1,169
	2038	497	32	24	426,868.03 ~~797,300~~	29,138	1,633
	2043	1,179	46	37	535,980.47 ~~1,015,363~~	33,790	2,108
	2048	2,275	74	56	645,092.91	37,969	2,570

					~~1,233,426~~		

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

	Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
SCE Orange County	**2022**	0	0	0	55,886~~63,777~~	14,219	344
	2028	13	3	5	103,236	16,791	519
	2033	15	3	6	142,695	16,863	523
	2038	32	3	10	182,154	19,485	735
	2043	95	10	21	221,613	22,133	968
	2048	159	16	23	261,072	24,165	1,146

In analyzing the SCE Orange County Project, the following constraints (Table 5-15) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 a 30-year study. The benefits are quantified as the difference between the baseline and the ASP for each of the metrics.

The cumulative value of the benefits over the 30-year horizon is presented in Table 5-16 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	193,424	187,601	203,637
N-1	LAR (MWh)	5,159~~64~~	17,520	59,898~~57,040~~
N-1	IP (MW)	337	447	661
N-1	PFD (hr)	1,055	1,785	2,923
N-1	Flex-1 (MWh)	583,840	1,278,674~~447,937~~	4,209,439~~9,232,289~~
N-1	Flex-2-1 (MWh)	3,200,515	3,255,754	3,449,007
N-1	Flex-2-2 (MWh)	69,270	81,~~316~~467	103,655
N-0	LAR (MWh)	22,751	55,560	133,064
N-0	IP (MW)	2,713	3,724	4,986
N-0	PFD (hr)	411	776	1,456

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 is substantial in the N-1 category and loss reduction. The project's contribution to loss reduction is primarily because it displaces loads at the southern border of the Valley South System service territory, thereby reducing the need for power to travel a longer distance from the source to point of delivery. Additionally, this project displaces loading on subtransmission lines with a 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 the 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- and mid-term horizon. Under N-0, 230 MWh of LAR 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 from 22.7 to 133 GWh of avoided LAR.
2. Considerable reduction in N-1 overloads is observed in the near-term and long-term horizons for all forecasts. With SCE Orange County Project in service, the N-1 LAR 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 the HILP events that occur in the Valley South 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- or mid-term horizon and under the 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. The 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 the 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.
6. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

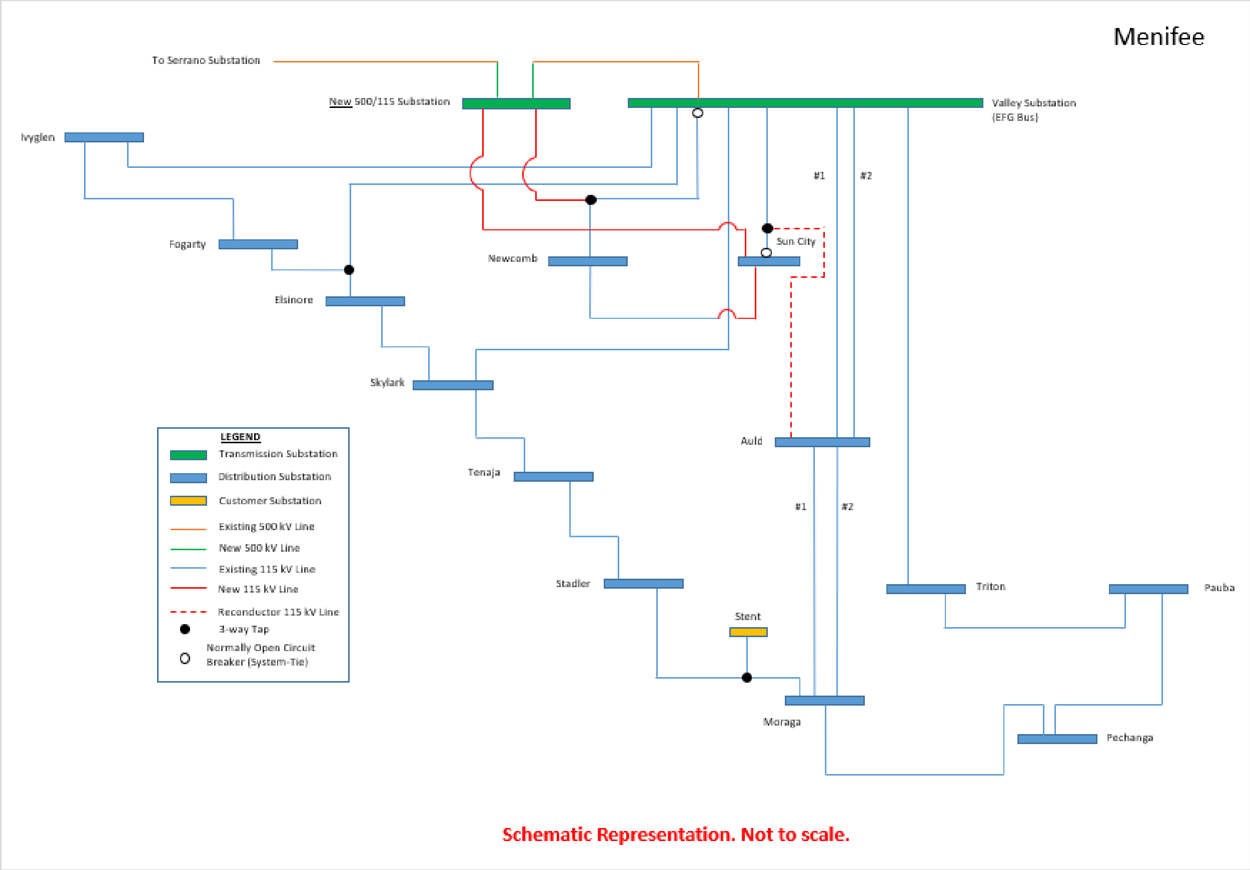


Figure 5-5. Menifee Project Scope

5.3.3.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,898
2028	0	0	0	51,308
2033	0	0	0	53,316
2038	0	0	0	55,324
2043	3	3	1	57,332
2048	114	39	4	59,341

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,287
2022	0	0	0	50,035
2028	0	0	0	53,305
2033	0	0	0	56,030
2038	73	29	4	58,754
2043	385	83	8	61,479
2048	902	130	14	64,204

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

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

5.3.3.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267 ~~40,625~~	571 ~~574~~
2028	0	0	0	54,051	28,475 ~~46,206~~	842 ~~848~~
2033	4	2	2	81,311	33,145 ~~52,058~~	1,161 ~~1,168~~
2038	103	14	19	108,570	38,226 ~~58,178~~	1,586 ~~1,596~~
2043	472	22	67	135,830	42,887 ~~63,655~~	2,025 ~~2,038~~
2048	1040	38	155	163,090	46,332 ~~67,659~~	2,369 ~~2,384~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	25,088	616
2022	0	0	0	~~54,465~~ 31,297	26,706	715
2028	4	2	2	~~253,225~~ 91,039	33,690	1,202
2033	156	18	22	~~418,858~~ 140,824	39,569	1,710
2038	722	37	70	~~584,491~~ 190,610	45,496	2,286
2043	1,968	56	163	~~750,124~~ 240,395	50,845	2,902
2048	3,737	68	272	~~915,757~~ 290,181	55,391	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	24,267	571
2028	0	0	0	46,835	28,475	843
2033	0	0	0	68,082	28,590	850

2038	0.4	0.4	1	89,330	32,641	1,122
2043	47	10	11	110,577	36,471	1,426
2048	138	17	22	131,824	39,242	1,679

In analyzing the Menifee project, the following constraints (Table 5-23) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.3.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-24 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	41,268	33,102	41,920
N-1	LAR (MWh)	5,724	15,368	~~47,913~~51,103
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,370
N-1	Flex-1 (MWh)	2,795,076	5,35~~1,804~~6,744	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	2,860,352	2,~~368,156~~885,882	3,029,498
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	22,751	56,229	136,040
N-0	IP (MW)	2,713	3,930	5,371
N-0	PFD (hr)	411	800	1,519

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Menifee Project. By design, the project includes a permanent transfer of relatively large load centers in the Valley South System during the 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.

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, 114 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 985 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.7 to 135.6 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 LAR benefits in the system range from 5.7 to 48 GWh through all forecast sensitivities.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, the Menifee Project can serve a total of approximately 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.4.1 Description of Project Solution

1. Construct a 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 the 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 the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

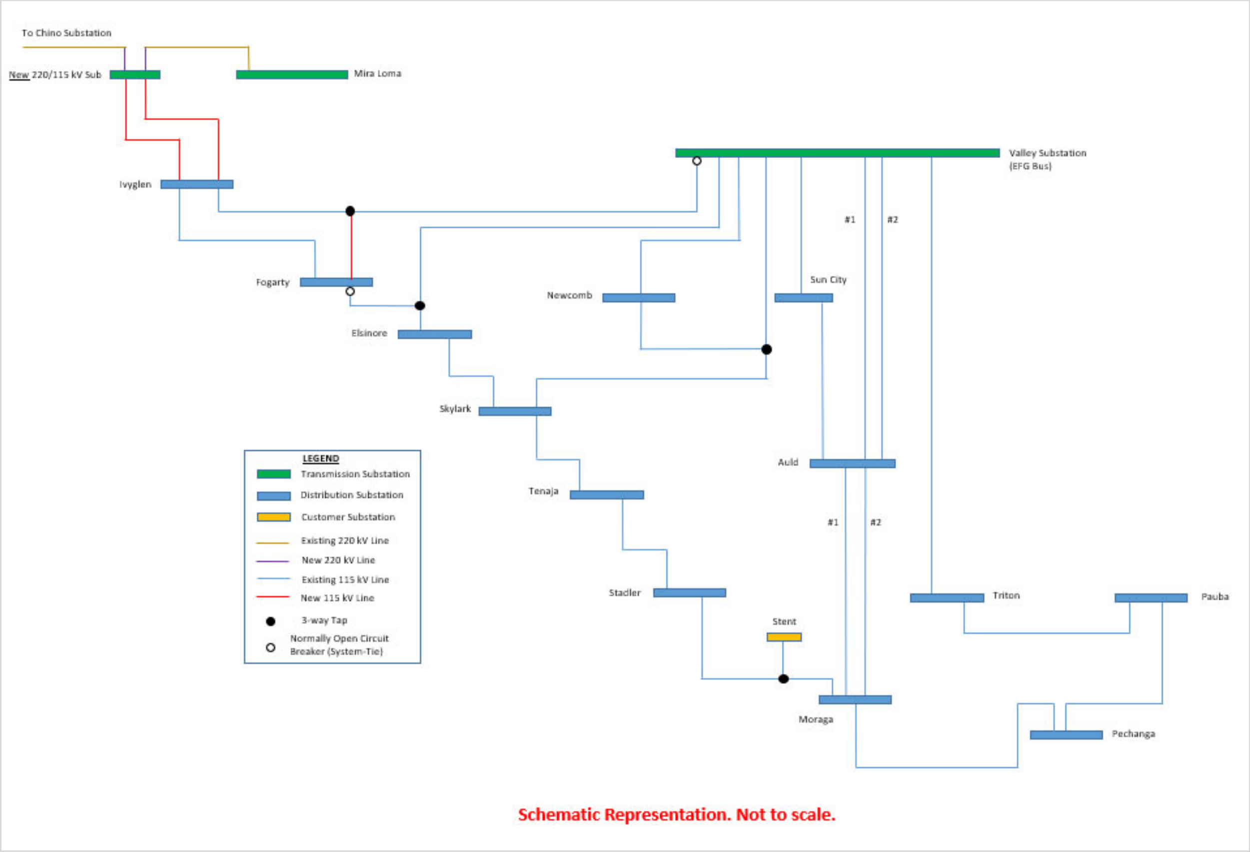


Figure 5-6. Tie-line to Mira Loma Project Scope

5.3.4.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	82	31	4	53,021
2038	314	84	9	55,097
2043	807	138	22	57,173
2048	1,905	184	30	59,250

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	106	38	4	42,629
2033	607	104	12	48,041
2038	1,449	172	29	53,453
2043	3,365	238	45	58,864
2048	4,958	294	81	64,276

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

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

5.3.4.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650~~4~~
2028	0	0	0	99,638	87,598	944~~9~~
2033	18	4	7	149,889	93,115	1,299~~306~~
2038	94	15	27	200,140	98,884	1,~~777~~766
2043	493	30	66	250,391	104,047	2,~~232~~219
2048	1,151	40	127	300,643	107,821	2,~~624~~609

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	39,336	83,384	708
2022	0	0	0	~~91~~56,~~765~~324	85,427	828
2028	12	4	7	158,254~~406,336~~	93,744	1,345
2033	253	19	39	243,197~~668,479~~	100,380	1,885
2038	822	36	114	328,139~~930,622~~	106,913	2,513
2043	2427	57	246	413,081~~1,192,765~~	112,783	3,150
2048	4599	77	442	498,023~~1,454,907~~	117,771	3,772

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	39,336	82,321	650
2028	0	0	0	93,650	87,598	944
2033	0	0	0	138,912	87,737	951
2038	4	2	4	184,174	92,531	1,259
2043	64	9	16	229,436	96,915	1,601
2048	~~203~~197	20	29	274,697	100,017	1,852

In analyzing the Mira Loma Project, the following constraints (Table 5-31) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-	-
Tap 39-Elsinore #1	N-0	N/A (base case)	2044	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2032	2038	2048
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	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	2038

5.3.4.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-32 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	48,851	40,333	47,004
N-1	LAR (MWh)	~~2,548~~5,454	15,237	4~~2,681~~5,012
N-1	IP (MW)	~~42~~355	421	603
N-1	PFD (hr)	1,~~011~~041	1,125	214
N-1	Flex-1 (MWh)	623,316	3,25~~1,880~~5,037	6,~~363,238~~500,106
N-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	~~64~~65,~~919~~168	82,069
N-0	LAR (MWh)	~~18,924~~19,577	~~50~~44,~~134~~963	~~110,252~~98,703
N-0	IP (MW)	1,720	2,270	2,721
N-0	PFD (hr)	362	554	935

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 LAR 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 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, 1,905 MWh of LAR is recorded under the Effective PV Forecast for 2048. Similarly, the LAR of 5,000 MWh is recorded in the Spatial Base Forecast. Across all sensitivities, the benefits range from 18.9 to 110 GWh of avoided LAR.
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 benefits in the system range from 2.5 to 42.6 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South system.
4. Following a HILP event, Mira Loma can 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 the 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics.

The project was considered to leverage the capabilities of tie-lines to move loads between the Valley South System and the Valley North System. However, this transfer would not satisfy the short-term and long-term objectives of the projects. No incremental benefits are provided to the 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 the construction of new 115 kV lines.
2. Normally-open circuit breakers at the Valley South bus and 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. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

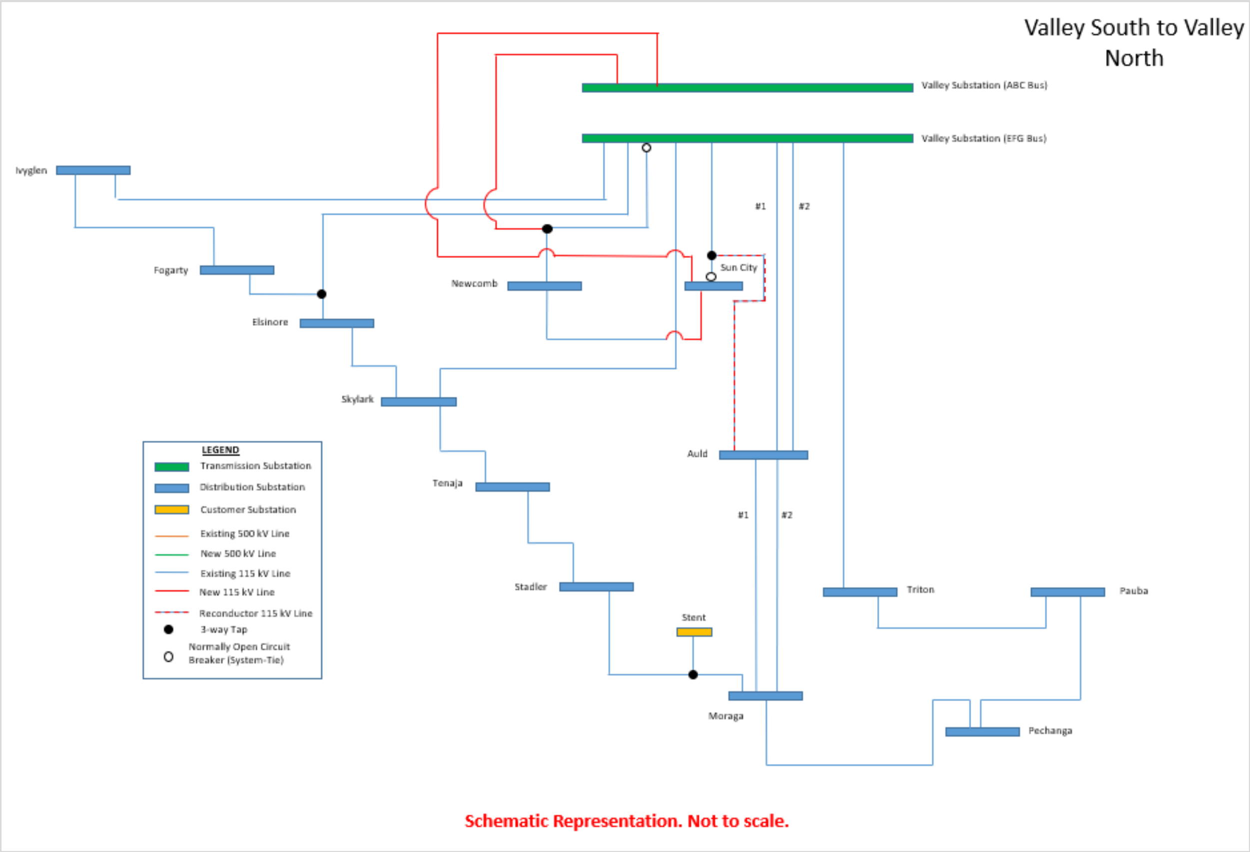


Figure 5-7. Tie-lines between Valley South and Valley North Project Scope

5.3.5.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	779	44	20	57,898
2048	2,680	192	55	59,939

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,468	173	56	59,336
2043	8,146	310	104	62,104
2048	16,818	433	165	64,872

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.5.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571~~574~~
2028	0	0	0	54,051	133,688	843~~848~~
2033	4	2	2	81,311	139,702	1,161 ~~1,168~~
2038	103	14	19	108,570	145,991	1,586~~1,596~~
2043	472	27	67	135,830	151,619	2,025~~2,038~~
2048	1040	38	155	163,090	155,733	2,369 ~~2,384~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	~~54,465~~31,297	140,388	1,202
2028	4	2	2	~~253,225~~91,039	140,388	1,202
2033	156	18	22	~~418,858~~140,824	147,622	1,710
2038	722	37	70	~~584,491~~190,610	154,744	2,286
2043	1968	56	163	~~750,124~~240,395	161,142	2,902
2048	3737	68	272	~~915,757~~290,181	166,580	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South Project, the following constraints (Table 5-39) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.5.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-40 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	~~47,913~~50,734
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,35~~1,804~~6,743	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	20,124	45,492	40,848
N-0	IP (MW)	1,910	3,211	2,380
N-0	PFD (hr)	328	537	288

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Valley South to Valley North Project. By design, the project includes a 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 the year 2030 in the Spatial Base Forecast and 2036 in the Effective PV Forecast.

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 the year 2043. However, the transfer of loads results in overloads on the Valley North transformer by the year 2037. 2,600 MWh of LAR is recorded under N-0 condition in the Effective PV Forecast and 16,800 MWh in the Spatial Base Forecast in the year 2048. Across all sensitivities, the benefits range from 20.1 to 45.4 GWh of avoided LAR.
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 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. During potential HILP events impacting Valley Substation, the project is unable to serve incremental load in the Valley South system.

5. Overall, the Valley South to Valley North Project did not demonstrate comparable levels of performance to the 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)

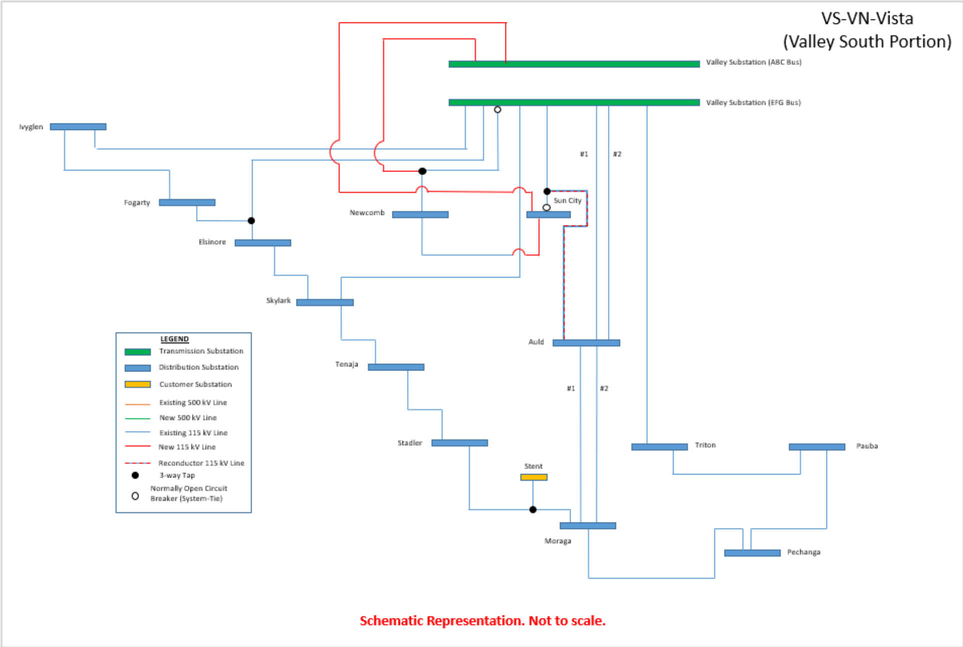
The objective of this project would be to transfer the loads at Newcomb and Sun City Substations to the Valley North System (identical to Project F). Additionally, the load at Moreno Substation in the Valley North System would be transferred to the Vista 220/115 kV system. The premise of this methodology 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 at 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 the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the 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.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

Figure 5-8 presents a high-level representation of the proposed configuration.



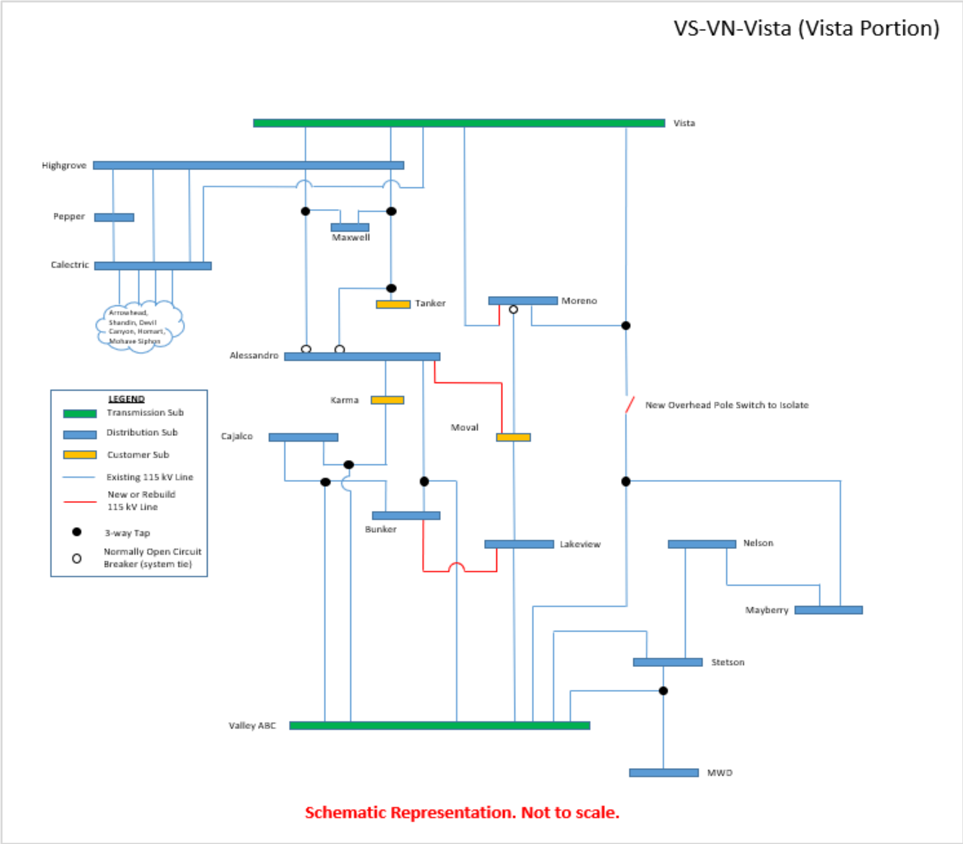


Figure 5-8. Tie-lines between Valley South to Valley North to Vista

5.3.6.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	54,225
2038	0	0	0	55,858
2043	83	31	6	57,898
2048	852	121	22	59,939

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	756	112	23	59,336
2043	3,843	246	66	62,104
2048	9,003	365	119	64,872

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

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

5.3.6.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	~~574~~571
2028	0	0	0	54,051	133,688	~~848~~843
2033	4	2	2	81,311	139,702	1,~~168~~161
2038	103	14	19	108,570	145,991	1,~~596~~586
2043	472	27	67	135,830	151,619	2,~~038~~025
2048	1040	38	155	163,090	155,733	2,~~384~~370

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	21,339	129,095	616
2022	0	0	0	~~54,465~~31,297	140,388	1,202
2028	4	2	2	~~253,225~~91,039	140,388	1,202
2033	156	18	22	~~418,858~~140,824	147,622	1,710
2038	722	37	70	~~584,491~~190,610	154,744	2,286
2043	1968	56	163	~~750,124~~240,395	161,142	2,902
2048	3737	68	272	290,181~~915,757~~	166,580	3,458

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,339	127,935	571
2028	0	0	0	46,835	133,688	843
2033	0	0	0	68,082	133,840	850
2038	0	0	1	89,330	139,065	1,122
2043	47	10	11	110,577	143,845	1,426
2048	138	17	22	131,824	147,226	1,679

In analyzing the Valley North to Valley South to Vista Project, the following constraints (Table 5-47) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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	-
Valley EFG-Tap 39 #1	N-0	N/A (base case)	2042	-	-
Auld-Moraga #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	2048	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	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	-	-
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.6.4 Evaluation of Benefits

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

The accumulative value of benefits over the 30-year horizon is presented in Table 5-48 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,221	26,468
N-1	LAR (MWh)	5,724	15,368	~~47,913~~50,735
N-1	IP (MW)	366	453	636
N-1	PFD (hr)	1,196	1,098	1,371
N-1	Flex-1 (MWh)	2,795,076	5,~~351~~356,~~804~~743	~~14,163,311~~9,661,860
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,~~175~~398	87,588
N-0	LAR (MWh)	22,613	53,700	91,349
N-0	IP (MW)	2,638	3,569	3,422
N-0	PFD (hr)	399	725	824

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. By design, the project includes a 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 the year 2041 in the Effective PV Forecast. The project also includes a transfer of load from the Valley North System to the Vista System. This temporarily remedies the system overload but does not provide relief over the long-term horizon.

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 results in overloads on the Valley North System transformers in the year 2041, with a transfer of loads to the Vista System. Under N-0, 852 MWh of LAR is recorded in the Effective PV Forecast for 2048 and 9,000 MWh in the Spatial Base Forecast. Across all sensitivities, the benefits range from 22.6 to 91.3 GWh of avoided LAR.
2. N-1 overloads are observable in the mid-term and long-term horizons for all forecasts. With the project in service, the N-1 benefits in the system range from 5.7 to 47.9 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South 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 the 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

5.3.7 Centralized BESS in Valley South Project (Project H)

The premise of this solution is to utilize 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 the need year 2021/2022 (depending on the need year from forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

5.3.7.1 Description of Project Solution

The proposed project would include the following components:

1. The point of interconnection would be near Pechanga and/or Auld Substations following the 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 through Table 5-51.
4. Due to the radial design of the Valley South System under the 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 of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-49. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	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)

Year	Total Battery Size			
	Pechanga		Auld	
	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/ 1666 MWh**				

Table 5-51. Storage Sizing and Siting – PVWatts Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	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.

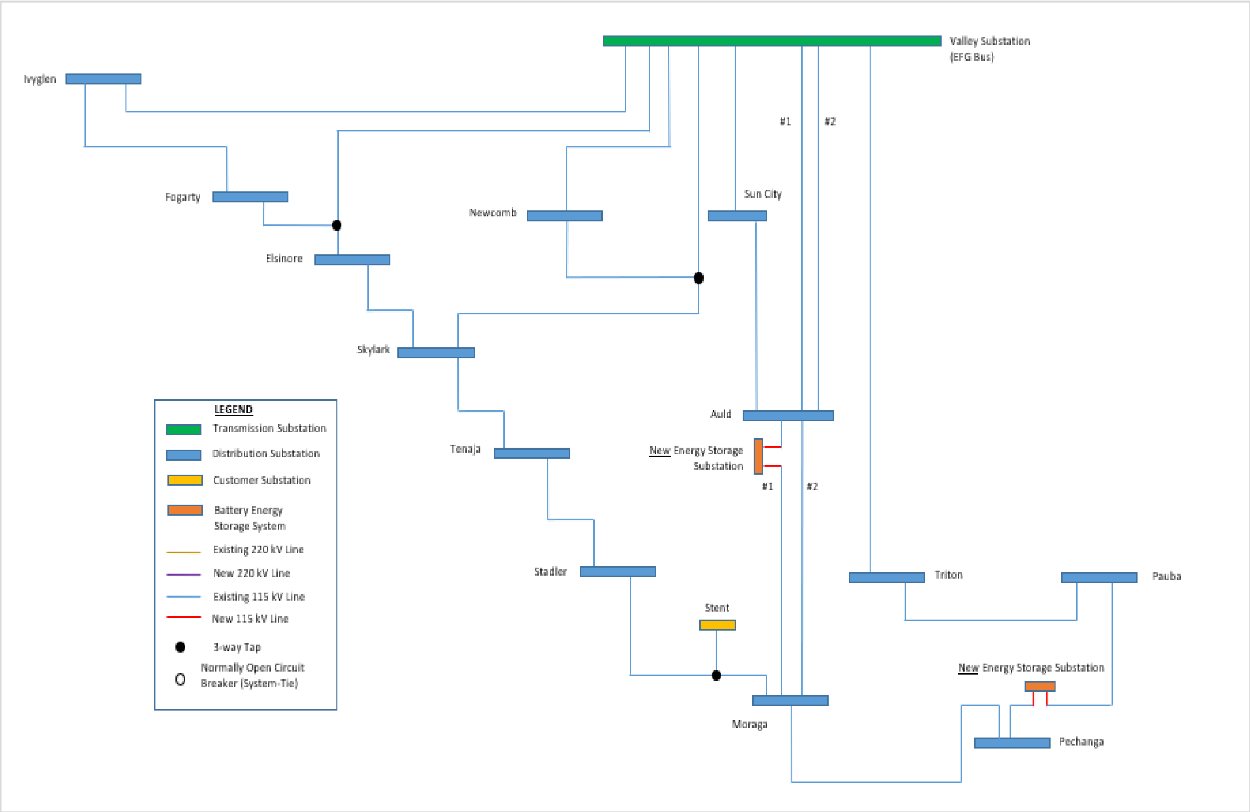


Figure 5-9. Energy Storage at Pechanga and/or Auld Substation as part of the Centralized BESS in the Valley South Project Scope

5.3.7.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,531
2028	0	0	0	50,808
2033	0	0	0	52,705
2038	0	0	0	54,602
2043	0	0	0	56,499
2048	0	0	0	58,396

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

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

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

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

5.3.7.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	26,492~~39,866~~	127,935	2,138~~2,150~~
2028	0	0	0	81,951 ~~100,979~~	133,688	2,765 ~~2,781~~
2033	0	0	0	123,478 ~~151,907~~	139,702	3,483~~3,504~~
2038	0	0	0	165,004 ~~202,835~~	145,991	4,337~~4,362~~
2043	0	0	0	206,531 ~~253,763~~	151,619	5,136~~5,166~~
2048	0	0	0	248,058 ~~304,690~~	155,733	5,738~~5,772~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~39,866~~26,492	129,095	2,253
2022	0	0	0	32,545~~52,459~~	131,322	2,486
2028	0	0	0	68,868~~128,019~~	140,388	3,577
2033	0	0	0	99,136~~190,985~~	147,622	4,567
2038	0	0	0	129,405~~253,952~~	154,744	5,595
2043	0	0	0	159,674~~316,918~~	161,142	6,584
2048	31	7	4	189,942~~379,885~~	166,580	7,466

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~39,866~~26,491	127,935	2,138
2028	0	0	0	~~57,449~~47,161	133,688	2,765
2033	0	0	0	64,385~~72,101~~	133,840	2,780

2038	0	0	0	~~86,753~~81,609	139,065	3,404
2043	0	0	0	~~101,405~~98,833	143,845	4,047
2048	0	0	0	116,058	147,226	4,516

In analyzing the Centralized BESS in Valley South Project, the following constraints (Table 5-58) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 the baseline and the Centralized BESS in Valley South Project to quantify the overall benefits accrued over the 30-year study horizon. The benefits are quantified as the difference between the baseline and the Centralized BESS in Valley South.

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-59 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	52,822	50,796	67,206
N-1	LAR (MWh)	6,375	21,684	~~73,275~~75,132
N-1	IP (MW)	467	780	1,375
N-1	PFD (hr)	1,320	1,999	3,456
N-1	Flex-1 (MWh)	~~2,757,800~~2,938,356	~~3,190,086~~4,067,234	~~21,406,139~~10,993,065
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	834	~~1,487~~2,111	5,182

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	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

The analysis demonstrates the range of benefits accrued over the near-term and long-term horizons by the Centralized BESS in Valley South Project. 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, or emergency conditions in the system. The batteries alone cannot complement the system needs during HILP events since they are not configured to operate as microgrids, nor are they 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 from 22.7 to 140.9 GWh of avoided LAR.
2. Minimal N-1 overloads are observable in the long-term horizon for all forecasts. With the project in service, the N-1 LAR 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 HILP events that occur in the Valley South 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, the Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from forecast under study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 exceed 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.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.

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

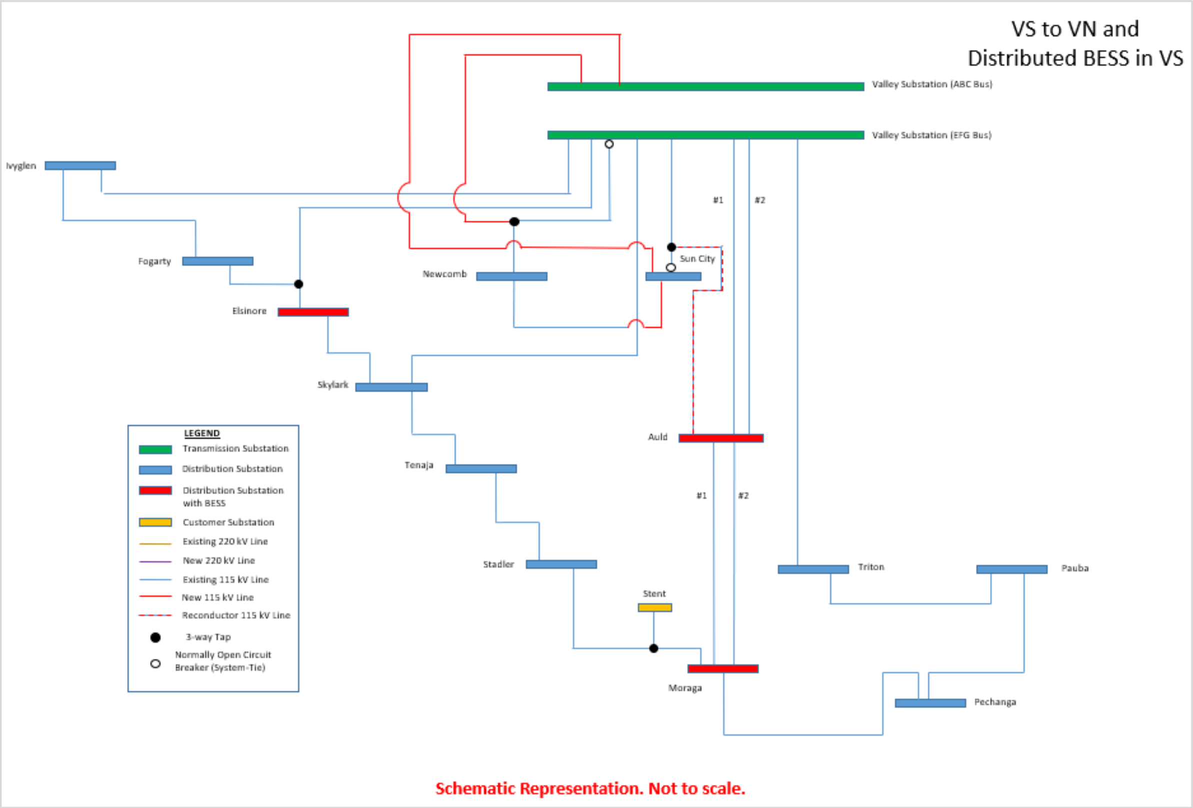


Figure 5-10. Tie-lines between Valley South and Valley North and Distributed BESS in Valley South Project Scope

5.3.8.2 System Performance under Normal Conditions (N-0)

Findings from the 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 South N-0 System Performance (Effective PV Forecast)

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	136	14	4	55,858
2043	775	43	19	57,898
2048	2,567	156	57	59,923

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	305	56	13	56,568
2038	2,388	143	51	59,310
2043	7,789	253	102	62,034
2048	16,127	371	159	64,749

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	94	49	6	54,713
2048	750	202	19	56,399

5.3.8.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,330~~17,489~~	127,935	571
2028	0	0	0	44,298	133,688	843
2033	4	2	2	68,743~~66,640~~	139,702	1,161
2038	103	14	19	92,170 ~~88,981~~	145,991	1,586
2043	324	18	45	113,095~~111,322~~	151,619	2,025
2048	614	23	80	~~133,664~~134,586	155,733	2,370~~2,366~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~17,489~~21,331	129,095	616
2022	0	0	0	27,808~~70,726~~	131,322	715
2028	4	2	2	66,672~~390,153~~	140,388	1,202
2033	156	18	22	99,058~~656,341~~	147,622	1,710
2038	488	23	69	131,445~~922,530~~	154,744	2,247
2043	1357	33	155	163,831~~1,188,719~~	161,142	2,823
2048	2506	65	243	196,218~~1,454,907~~	166,580	3,320

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~17,489~~	127,935	571
2028	0	0	0	46,816 ~~43,874~~	133,688	843
2033	0	0	0	68,054 ~~65,861~~	133,840	850
2038	0.4	0.4	1	89,293~~87,849~~	139,065	1,122
2043	47	10	11	110,530 ~~109,836~~	143,845	1,426
2048	138	17	22	131,768~~131,824~~	147,226	1,679

In analyzing the Valley South to Valley North and Distributed BESS in Valley South Project, the following constraints (Table 5-66) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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 #2	N-1	Auld-Moraga #1	2033	2038	2043
Valley EFG-Tap 39	N-1	Valley EFG-Newcomb-Skylark	2043	-	-
Tap 39-Elsinore	N-1	Valley EFG-Newcomb-Skylark	2033	2038	2043
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	-
Moraga-Pechanga	N-1	Valley EFG-Triton	2028	2033	-

5.3.8.4 Evaluation of Benefits

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-67 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	26,508	19,245.60	27,277.58
N-1	LAR (MWh)	5,724	17,090.60	~~55,520.05~~57,832
N-1	IP (MW)	366	526.95	790.25
N-1	PFD (hr)	1,196	1,389	1,459
N-1	Flex-1 (MWh)	~~2,847,054~~2,275,927	~~5,801,041~~5,741,522	~~6,669,106~~10,977,462
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,4058	88,541
N-0	LAR (MWh)	20,124	45,854	45,131

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	IP (MW)	1,910	3,416	2,967
N-0	PFD (hr)	328	561	330

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. By design, the project includes a permanent transfer of large load centers from 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 presence of a distributed BESS solution in the Valley South System alleviates the capacity needs in the Valley South System in the Effective PV Forecast, but not under the 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.

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 results in overloads on the Valley North System transformers by the year 2037. Under N-0, 2,600 MWh of LAR is recorded in the Effective PV Forecast for 2048, and 16,200 MWh is recorded under the Spatial Base Forecast sensitivity. Across all sensitivities, the benefits range from 20.1 to 45.1 GWh of avoided LAR.
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 benefits in the system range from 5.7 GWh to 55 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South System.
4. Should a HILP event affect Valley Substation, this solution is unable to serve incremental load in the 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, the 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 SDG&E 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 the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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. The 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 the 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 the 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 exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-68 through Table 5-70, 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. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-68. Storage Sizing and Siting – Effective PV Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	MW	MWh
2039	65	189
2044	25	130
Total Battery Size (including contingency): **90 MW/319 MWh**		

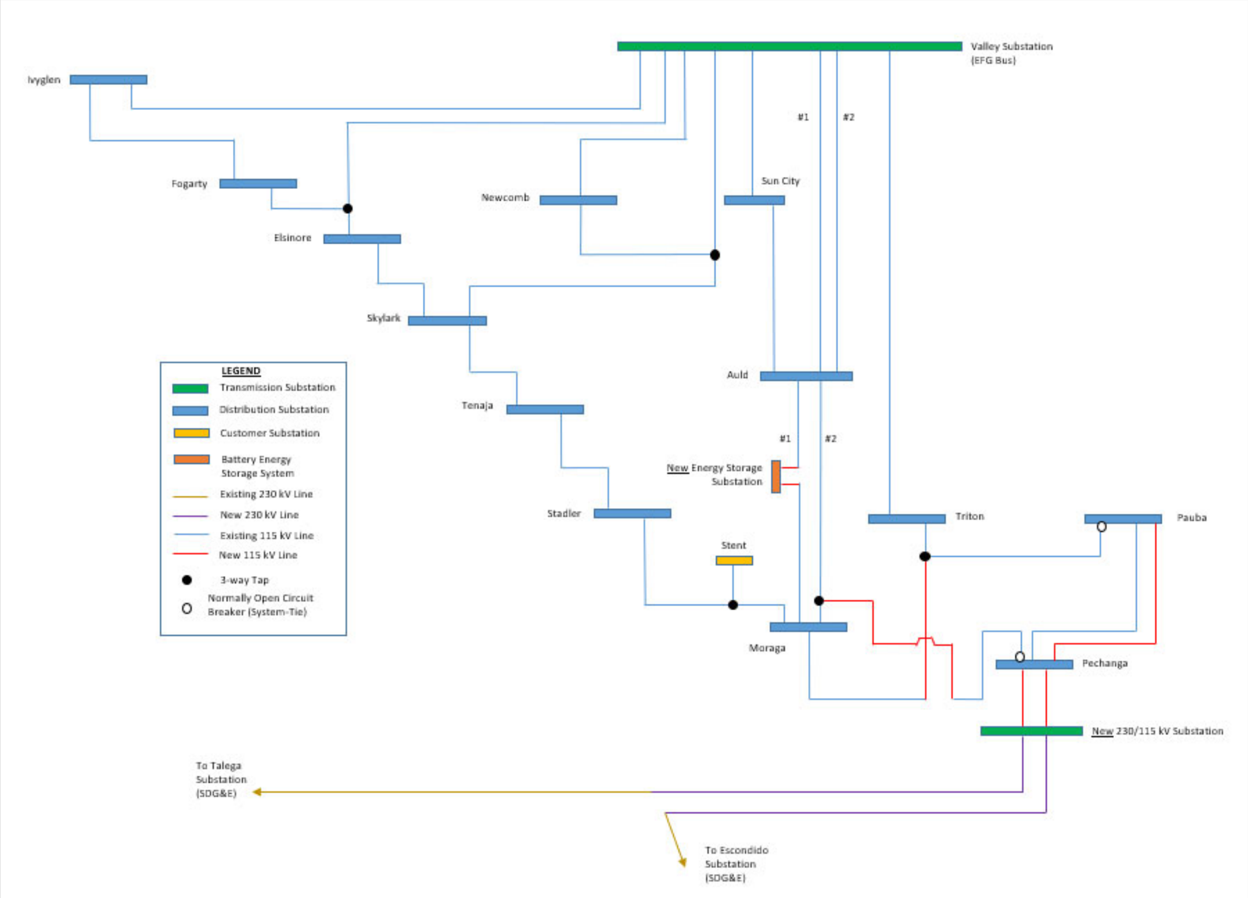
Table 5-69. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Auld	
	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)

Year	Total Battery Size	
	Auld	
	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 the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	44,182
2028	0	0	0	46,553
2033	0	0	0	48,529
2038	0	0	0	50,505
2043	0	0	0	51,023
2048	0	0	0	51,176

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

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

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

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

5.3.9.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428~~431~~
2028	0	0	0	42,455	17,895	636 ~~639~~
2033	0	0	0	63,537 ~~63,867~~	21,123	926 ~~932~~
2038	0	0	0	84,920 ~~85,279~~	24,949	1,274~~1,282~~
2043	0	0	0	106,303~~106,690~~	28,757	1,662~~1,672~~
2048	0	0	0	128,102	31,740	1,977~~1,990~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	16,761	15,677	468
2022	0	0	0	~~29,302~~22,124	16,727	545
2028	0	0	0	54,299~~104,551~~	21,517	958
2033	0	0	0	81,112~~167,259~~	26,018	1,380
2038	0	0	0	107,924~~229,966~~	31,008	1,889
2043	0	0	0	134,737~~292,674~~	35,874	2,409
2048	0	0	0	161,550~~355,381~~	40,207	2,924

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	16,761	15,152	428
2028	0	0	0	33,355	17,895	636
2033	0	0	0	47,182	17,971	641
2038	0	0	0	61,010	20,763	896
2043	0	0	0	74,838	23,589	1,146
2048	0	0	0	88,666	25,756	1,352

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

The accumulative value of the benefits over the 30-year horizon is presented in Table 5-77 for the 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 Forecast*	Cumulative Benefits over 30-year Horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	195,515	214,367	249,947
N-1	LAR (MWh)	6,375	21,684	~~73,367~~76,225
N-1	IP (MW)	467	780	1,397
N-1	PFD (hr)	1,320	1,999	3,468
N-1	Flex-1 (MWh)	~~236,636~~3,439,502	~~519,519~~5,894,261	~~667,575~~11,526,786
N-1	Flex-2-1 (MWh)	~~3,439,502~~3,167,267	~~5,885,944~~3,217,646	~~22,072,661~~3,402,545
N-1	Flex-2-2 (MWh)	65,442	76,689~~509~~	97,285
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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 is substantial in the N-1 category and N-0 category. However, the flexibility benefits offered by the solution are limited in comparison to the 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 from 22.7 to 140.9 GWh of avoided LAR.

2. With SDG&E and Centralized BESS in Valley South Project in service, the N-1 LAR 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 the HILP events that occur in the Valley South System. However, these benefits are not as significant in comparison to the ASP.
4. Should a HILP event occur and impact Valley Substation, the SDG&E and Centralized BESS in Valley South Project can 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, the SDG&E and Centralized BESS Project did not demonstrate comparable levels of performance to the 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 the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3.

5.3.10.1 Description of Project Solution

1. Construct a 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 the 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 the new system at Valley Substation and Fogarty Substation, respectively.
4. The proposed project would construct new double-circuit 115 kV subtransmission lines from the new 220/115 kV substation to Ivyglen Substation in the Valley South System.
5. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
6. BESS would be installed near Pechanga or Auld Substations following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
7. 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.

8. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-78 through Table 5-80, for all forecasts.
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. Due to the radial design of the Valley South system under the study, locating the BESS interconnection near Pechanga or Auld Substations would not result in significant differences to N-0 system performance and reliability indices.
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-78. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga		Auld	
	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)

Year	Total Battery Size	
	Pechanga	
	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)

Year	Total Battery Size	
	Pechanga	
	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.

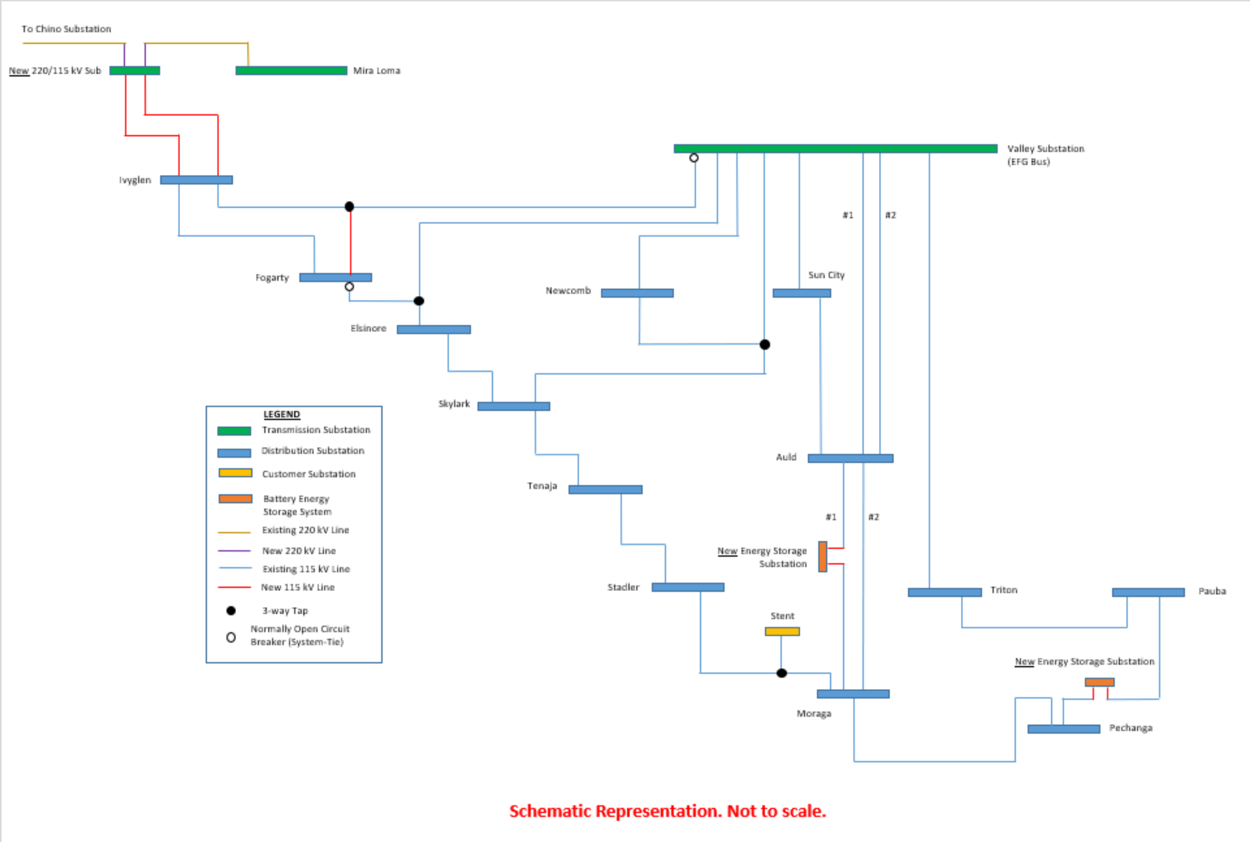


Figure 5-12. Tie-line to Mira Loma and Centralized BESS in Valley South Project Scope

5.3.10.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,456
2028	0	0	0	48,017
2033	0	0	0	50,408
2038	0	0	0	53,323
2043	0	0	0	56,238
2048	0	0	0	59,154

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	48,849
2022	0	0	0	49,618
2028	0	0	0	42,629
2033	0	0	0	48,041
2038	0	0	0	53,453
2043	0	0	0	58,864
2048	0	0	0	64,276

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	48,453
2028	0	0	0	50,945
2033	0	0	0	53,021
2038	0	0	0	55,097
2043	0	0	0	57,173
2048	0	0	0	59,250

5.3.10.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120~~24,348~~	82,321	650~~654~~
2028	0	0	0	87,130~~61,672~~	87,598	944~~949~~
2033	0	0	0	130,912~~92,776~~	91,967	1,299~~1,230~~
2038	0	0	0	174,909~~123,879~~	98,884	1,766~~1,777~~
2043	5	2.5	2	218,906~~154,983~~	104,047	2,217~~2,230~~
2048	15.2	2.5	9	262,902~~186,086~~	107,821	2,602~~2,617~~

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~24,348~~34,121	83,384	708
2022	0	0	0	43,257~~69,128~~	85,427	828
2028	0	0	0	98,075~~337,812~~	93,744	1,345
2033	0	0	0	143,757~~561,716~~	100,380	1,885
2038	11	3	6	189,439~~785,619~~	106,913	2,508
2043	35	4	20	253,121~~1,009,523~~	112,783	3,132
2048	182	11	61	280,803~~1,233,426~~	117,771	3,729

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	34,120~~24,348~~	82,321	650
2028	0	0	0	86,222~~178,252~~	87,598	944
2033	0	0	0	129,639~~123,172~~	87,737	951
2038	0	0	0	173,057~~168,092~~	92,531	1,259

2043	0	0	0	216,474~~213,012~~	96,915	1,601
2048	0	0	0	259,892~~257,932~~	100,017	1,852

In analyzing the Mira Loma and Centralized BESS in Valley South project, the following constraints (Table 5-87) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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		
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 the 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 the baseline and the project for each of the metrics.

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-88 for the 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 Forecast*	Cumulative Benefits over 30-year horizon (until 2048) *Spatial Base Forecast*
N-0	Losses (MWh)	50,251	41,338	51,951
N-1	LAR (MWh)	6,375	21,303	72,541~~83~~
N-1	IP (MW)	467	760	1,333
N-1	PFD (hr)	1,320	1,962	3,152
N-1	Flex-1 (MWh)	~~1,052,000~~893,598	~~5,000,736~~3,831,571	~~9,673,818~~9,614,215

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-1	Flex-2-1 (MWh)	1,252,410	1,263,410	1,326,687
N-1	Flex-2-2 (MWh)	55,850	~~64,946~~65,194	82,304
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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 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 from 22.7 to 140.9 GWh of avoided LAR.
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 benefits in the system range from 6.3 to 72.5 GWh through all forecasts.
3. The project offers limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that may occur in the Valley South System.
4. Should a HILP event occur and impact Valley Substation, the Mira Loma and Centralized BESS in Valley South Project can 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, the Mira Loma and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 a 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 Valley 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North system have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for the study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in Section 3.2.3

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 the 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. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
5. BESS would be installed near Pechanga in Valley South and Allesandro Substation in Valley North following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
6. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-89 through Table 5-91, for all forecasts.
7. 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).
8. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

Table 5-89. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	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)

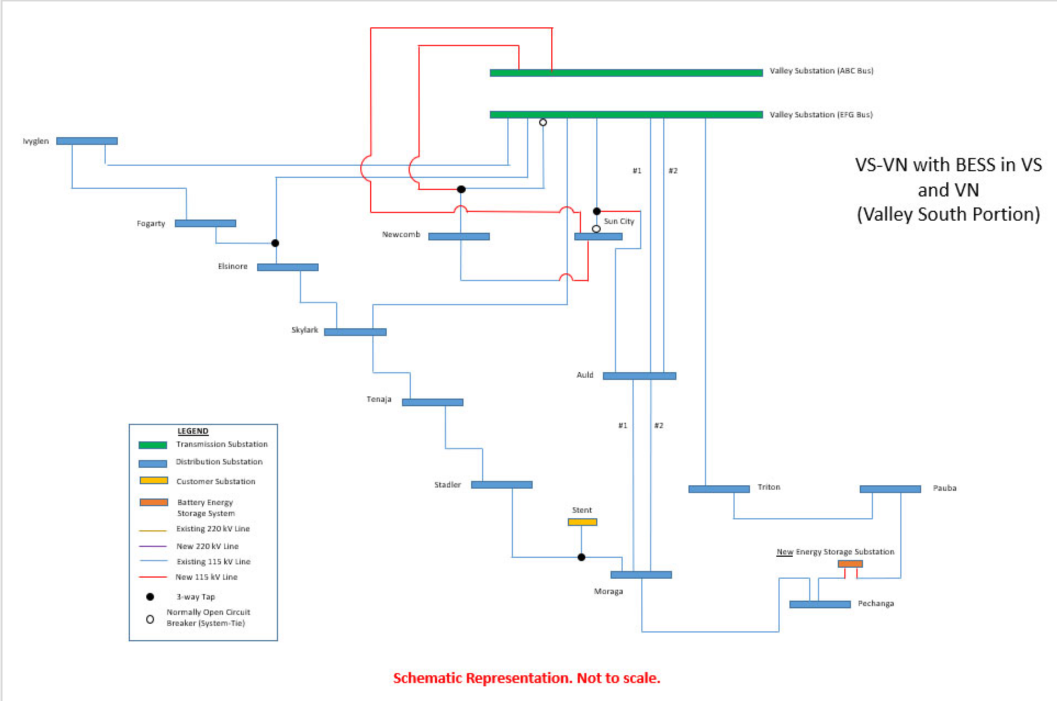
Year	Total Battery Size	
	Pechanga (VS)	Alessandro (VN)

	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)

Year	Total Battery Size			
	Pechanga (VS)		Alessandro (VN)	
	MW	MWh	MW	MWh
2040	0	0	67	204
2045	0	0	27	140
Total Battery Size: **94 MW/ 344 MWh**				

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



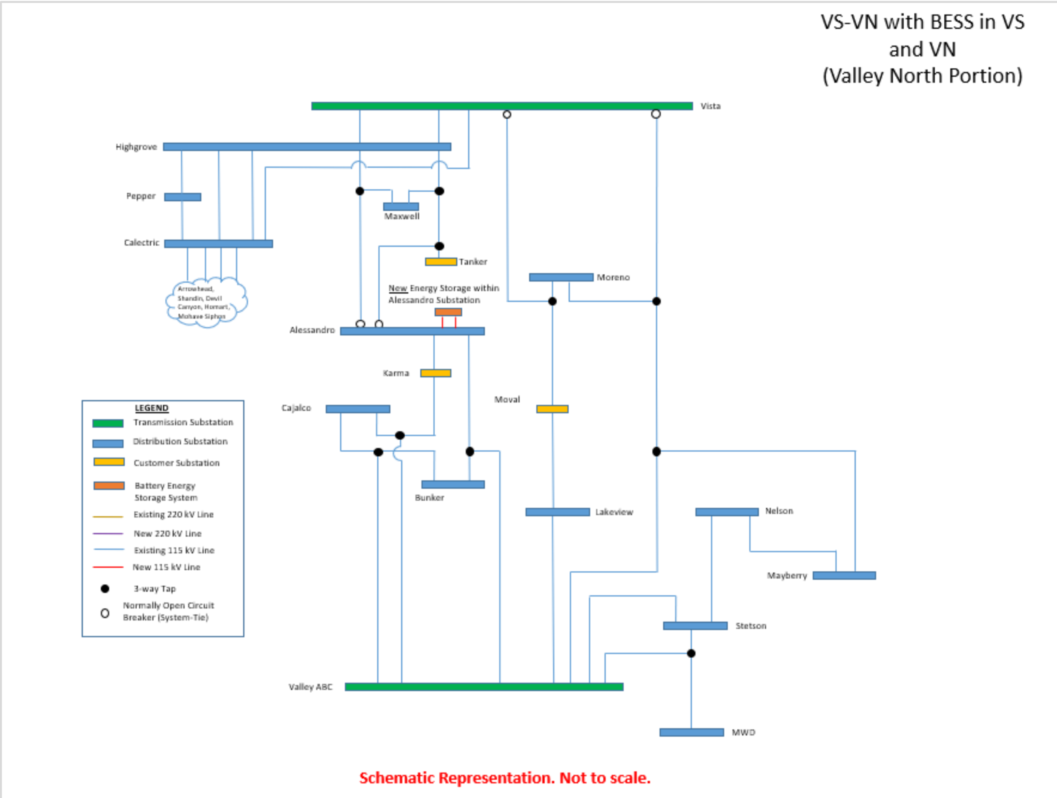


Figure 5-13. Valley South to Valley North and Centralized BESS in Valley South and Valley North

5.3.11.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	0	0	0	57,893
2048	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	0	0	0	59,306
2043	0	0	0	62,024
2048	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	0	0	0	56,399

5.3.11.3 System Performance under Normal Conditions (N-1)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331~~25,483~~	127,935	571~~574~~
2028	0	0	0	64,547	133,688	843~~848~~
2033	4	2	2	84,028~~97,100~~	139,702	1,161 ~~1,168~~
2038	103	14	19	116,572 ~~129,653~~	145,991	1,586~~1,596~~
2043	351	24	45	146,858 ~~162,206~~	151,619	2,025~~2,037~~
2048	506	27	73	194,760	155,733	2,366 ~~2,381~~

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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~25,483~~21,083	129,095	616
2022	0	0	0	25,681~~43,949~~	131,322	715
2028	4	3	2	53,273~~154,747~~	140,388	1,202
2033	156	19	22	72,267~~247,078~~	147,622	1,710
2038	445	23	66	99,260~~339,410~~	154,744	2,284
2043	1,063	29	135	122,253~~431,741~~	161,142	2,889
2048	1,845	76	205	145,246~~524,073~~	166,580	3,429

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~25,483~~	127,935	571
2028	0	0	0	46,816 ~~49,808~~	133,688	843

2033	0	0	0	68,054 ~~70,079~~	133,840	850
2038	0.4	0.4	1	89,293~~9~~ ~~0,350~~	139,065	1,122
2043	47	10	11	110,531 ~~110,622~~	143,845	1,426
2048	138	17	22	131,769 ~~130,893~~	147,226	1,679

In analyzing the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project, the following constraints (Table 5-98) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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
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
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.11.4 Evaluation of Benefits

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

The accumulative values of benefits over the 30-year horizon are presented in Table 5-99 for the three forecasts.

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

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	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386~~59,548~~
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927 ~~2,751,701~~	5,140,766.57 ~~4,868,325~~	11,694,529 ~~19,588,877~~
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408~~185~~	87,739
N-0	LAR (MWh)	22,751	56,581	140,939
N-0	IP (MW)	2,713	4,056	6,291
N-0	PFD (hr)	411	815	1,617

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. By design, the project includes a 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.

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 from 22.7 to 140.9 GWh of avoided LAR.
2. N-1 overloads are observable in the near-term and long-term horizons for all forecasts. With the project in service, N-1 benefits in the system range from 5.7 to 59.54 GWh through all forecasts.
3. The project provides limited flexibility to address planned, unplanned, or emergency outages in the system and HILP events that occur in the Valley South 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, the Valley South to Valley North and Centralized BESS in Valley South and Valley North Project did not demonstrate comparable levels of performance to the 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 a 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 LAR (N-0) reliability metric was amended to include monitoring loading of the Valley North transformers. Potential N-1 impacts on the Valley North System have not been considered in the metrics. The project has been evaluated under the need year 2021/2022 (depending on the need year from the forecast used for study), 2028, 2033, 2038, 2043, and 2048. Each of the reliability metrics established in Section 3.2.4 has been calculated using the study methodology outlined in 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 a transfer of Moreno Substation.
3. Normally-open circuit breaker at Moreno Substation to provide a system tie-line between the Vista and Valley North Systems.
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 the construction of new 115 kV lines (see Project F).
5. Normally-open circuit breakers at the Valley South bus and the Sun City Substation are maintained as system ties between the Valley North and Valley South Systems for transfer flexibility.
6. Reconductor existing Auld–Sun City 115 kV line, which would become the Valley–Auld–Sun City 115 kV line.
7. Reconductor approximately 7.7 miles of existing Auld–Moraga 115 kV line to 954 ACSR conductors.
8. BESS would be installed near Pechanga Substation following the construction of necessary 115 kV substation facilities and 115 kV line reconfiguration.
9. Storage investments are made in 5-year increments during identified need years when the Valley South System transformers exceed their rated capacity. The following storage sizes have been established and detailed in Table 5-100 and Table 5-101, for all forecasts. No batteries were required at Valley South in the PVWatts Forecast.
10. 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).
11. At each site, a contingency reserve of 10 MW / 50 MWh is maintained per SCE planning criteria and guidelines for N-1 conditions.

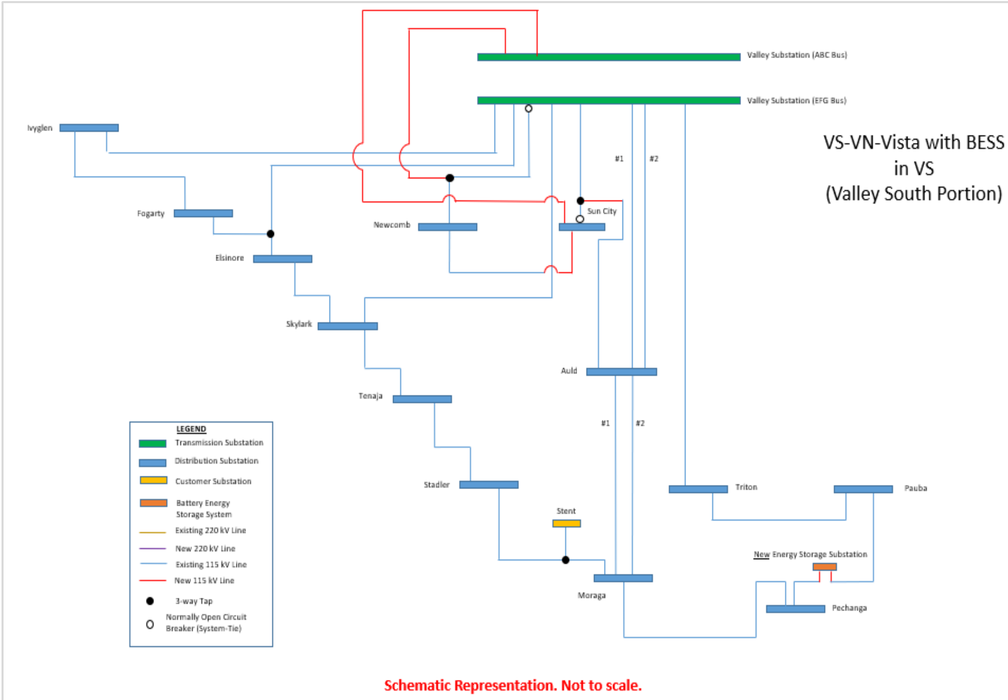
Table 5-100. Storage Sizing and Siting – Spatial Base Forecast (Storage MW and MWh)

Year	Total Battery Size	
	Pechanga	
	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)

Year	Total Battery Size	
	Pechanga	
	MW	MWh
2043	39	108
2046	10	42
Total Battery Size (including contingency): **49 MW / 150 MWh**		

Figure 5-14 presents a high-level representation of the proposed configuration.



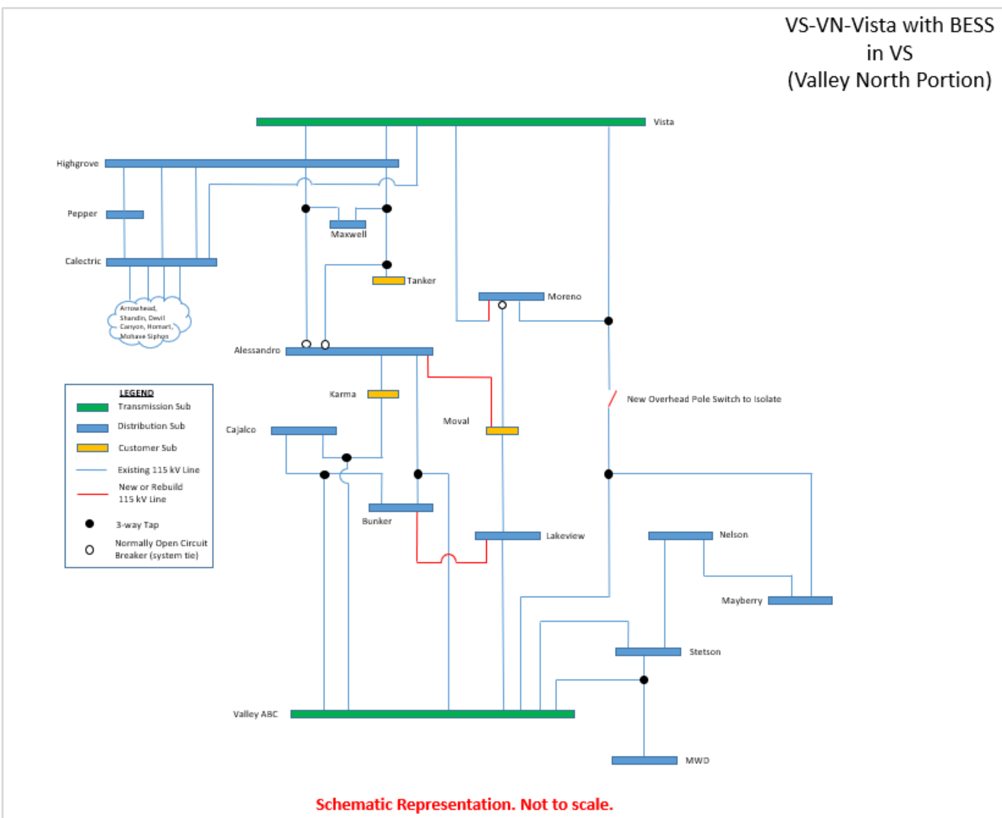


Figure 5-14. Valley South to Valley North to Vista and Centralized BESS in Valley South

5.3.12.2 System Performance under Normal Conditions (N-0)

Findings from the 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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	51,777
2033	0	0	0	53,817
2038	0	0	0	55,858
2043	78	30	5	57,893
2048	735	83	18	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2021	0	0	0	49,723
2022	0	0	0	50,479
2028	0	0	0	53,801
2033	0	0	0	56,568
2038	676	81	17	59,306
2043	3416	162	58	62,024
2048	8000	232	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	LAR (MWh)	IP (MW)	PFD (hr)	Losses (MWh)
2022	0	0	0	49,328
2028	0	0	0	50,960
2033	0	0	0	51,342
2038	0	0	0	53,028
2043	0	0	0	54,713
2048	68	37	5	56,399

5.3.12.3 System Performance under Normal Conditions (N-1)

Findings from the system analysis under N-1 conditions in the system are presented in Table 5-105 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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	21,331 ~~25,483~~	127,935	571 ~~574~~
2028	0	0	0	64,547 ~~64,547~~	133,688	843~~848~~
2033	4	2	2	84,028 ~~97,100~~	139,702	1,160~~1,168~~
2038	103	14	19	116,572 ~~129,653~~	145,991	1,586~~1,596~~
2043	351	24	45	146,858 ~~162,206~~	151,619	2,025 ~~2,037~~
2048	506	27	73	194,760	155,733	2,366 ~~2,381~~

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	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2021	0	0	0	~~25,483~~21,083	129,095	616
2022	0	0	0	25,681~~43,949~~	131,322	715
2028	4	3	2	53,273~~154,747~~	140,388	1,202
2033	156	19	22	76,267~~247,078~~	147,622	1,710
2038	445	23	66	99,260~~339,410~~	154,744	2,284
2043	1,063	29	135	122,253~~431,741~~	161,142	2,889
2048	1,845	76	205	~~524,073~~145,247	166,580	3,429

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

Year	LAR (MWh)	IP (MW)	PFD (hr)	Deficit Flex-1 (MWh)	Deficit Flex-2-1 (MWh)	Deficit Flex-2-2 (MWh)
2022	0	0	0	~~25,483~~21,330	127,935	571

2028	0	0	0	46,816 ~~49,808~~	133,688	843
2033	0	0	0	68,054 ~~70,079~~	133,840	850
2038	0.4	0.4	1	89,292 ~~90,350~~	139,065	1,122
2043	47	10	11	110,530 ~~110,622~~	143,845	1,426
2048	138	17	22	131,768 ~~130,893~~	147,226	1,679

In analyzing the Valley South to Valley North to Vista and Centralized BESS in Valley South Project, the following constraints (Table 5-108) were found to be binding under N-0 and N-1 conditions. These are the key elements that contribute to the LAR 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
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
Moraga-Pechanga	N-1	Valley EFG - Triton	2028	2033	2038

5.3.12.4 Evaluation of Benefits

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

The accumulative values of the benefits over the 30-year horizon are presented in Table 5-109 for the three forecasts.

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

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	19,322	27,375
N-1	LAR (MWh)	5,724	17,603	62,386~~59,548~~
N-1	IP (MW)	366	503	803
N-1	PFD (hr)	1,196	1,456	1,740
N-1	Flex-1 (MWh)	2,795,927 ~~2,751,701~~	5,140,766.57~~4,868,325~~	11,694,529~~19,588,877~~
N-1	Flex-2-1 (MWh)	-	-	-
N-1	Flex-2-2 (MWh)	59,402	69,408~~69,185~~	87,739
N-0	LAR (MWh)	22,613	54,062	96,778
N-0	IP (MW)	2,638	3,687	4,380
N-0	PFD (hr)	399	741	939

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. By design, the project includes a 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 effectively reducing LAR to zero 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.

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 are avoided in the near-term and long-term horizon. Additionally, the 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 LAR.
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 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 HILP events that occur in the Valley South 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, the Valley South to Valley North to Vista and Centralized BESS in Valley South Project did not demonstrate comparable levels of performance to the 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 a 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, LAR, and flexibility (Flex-1 and Flex-2) provide valuable insight into the reliability, capacity, resilience, and flexibility objectives of project performance. Table 5-110 through 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 Project	Centralized BESS in Valley South Project	Mira Loma and Centralized BESS in Valley South Project	Valley South to Valley North and Distributed BESS in Valley South Project	Menifee Project	Mira Loma Project	SCE Orange County Project	Valley South to Valley North and Centralized BESS in Valley South and Valley North Project	Valley South to Valley North to Vista and Centralized BESS in Valley South Project	SDG&E and Centralized BESS in Valley South Project	Valley South to Valley North Project
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	20	21	15	21	21	17	15	15	17	18	18	21	15
N-2	**Available Flex-1**	6,024 ~~5,689~~	5,415~~5,411~~	5,357~~5,352~~	4,067~~3,190~~	3,831 ~~5,001~~	5,742~~5,801~~	5,357 ~~5,352~~	3,2554~~3,252~~	1,279~~448~~	5,141~~4,868~~	5,141~~4,868~~	5,894~~5,886~~	5,357~~5,352~~
N-2	**Available Flex-2-1**	3,780	3,218	-	-	1,263	-	2,368	1,263	3,256	-	-	3,218	-
N-2	**Available Flex-2-2**	107	77	69	1	65	69	69	65	81	69	69	77	69
N-0	**LAR**	57	56	54	57	57	46	56	50	56	57	54	57	45

Table 5-111. Cumulative Benefits: Spatial Base Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	69~~7~~	76~~3~~	51~~48~~	~~73~~76	~~73~~76	~~56~~58	~~48~~51	~~43~~45	~~57~~60	~~60~~62	~~60~~62	~~73~~76	~~48~~51
N-2	**Available Flex-1**	9,665 ~~23,517~~	9,902~~19,117~~	9,662~~14,163~~	10,993~~21,406~~	9,614~~9,674~~	10,977~~6,669~~	9,662~~14,163~~	6,500~~6,363~~	4,209~~9,232~~	11,694~~19,589~~	11,694~~19,589~~	11,526~~22,073~~	9,662~~14,163~~
N-2	**Available Flex-2-1**	4,102	3,403	-	-	1,327	-	3,030	1,327	3,449	-	-	3,403	-
N-2	**Available Flex-2-2**	142	97	88	5	82	-	88	82	104	88	88	97	88
N-0	**LAR**	141	132	91	141	141	89	136	110	133	141	97	141	41

Table 5-112. Cumulative Benefits: PVWatts Forecast

		Project ID												
Category	**GWh**	**A**	**B**	**G**	**H**	**K**	**I**	**D**	**E**	**C**	**L**	**M**	**J**	**F**
N-1	**LAR**	6	6	6	6	6	6	6	5~~3~~	5	6	6	6	6
N-2	**Available Flex-1**	~~3,901~~4,205	3,363	2,795	2,~~758~~939	~~1,052~~894	~~2,847~~2796	2,795	623	584	2,796~~52~~	~~2,752~~2,796	3,440	2,795
N-2	**Available Flex-2-1**	3,658	3,167	-	-	1,252	-	2,860	1,252	3,201	-	-	3,167	-
N-2	**Available Flex-2-2**	88	65	59	1	56	59	59	56	69	59	59	65	59
N-0	**LAR**	23	23	23	23	23	20	23	19	23	23	23	23	20

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

1. The Valley South System is vulnerable to the 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 South 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 the Valley South System service territory.
4. Dependency on NWA solutions (e.g., 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 or 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 the Valley South System, they aggravate the condition in the adjacent subtransmission system. For example, with a 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 a 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 NWAs. 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 to 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 to adequately meet the range of forecast sensitivities while meeting the overall project objectives. Except for the projects that did not meet the objectives over the study horizon and those with significant implementation difficulty, wire-based alternatives offer the highest benefits.
8. In all considered forecasts, the ASP provided the highest aggregated benefits. Aggregated benefits are derived from the cumulative value of LAR and Flex Metrics that translate into capacity, reliability, resilience, and flexibility needs in the Valley South service area. The ASP consistently provides the highest aggregated benefits across all considered forecasts.
9. From a capacity perspective, the ASP, SDG&E, and Hybrid solutions (SDG&E and Centralized BESS in Valley South) provide the most relief. Taking into consideration the combination of flexibility and resilience needs, the ASP, Orange County Project, and SDG&E Project are the most preferable alternatives.

6 BENEFIT-COST ANALYSIS (BCA)

6.1 Introduction

The objective of this task was to perform a detailed benefit-cost and risk analysis of the ASP and alternative projects introduced in Section 5. This framework provides an additional basis for the 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.

The benefit is defined as the value of the impact of a project on 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 LAR, Interrupted Power, and Period of Flexibility Deficit 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 the present worth of costs and benefits (Sections 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 BCA, $/unit benefit analysis, and incremental BCA. 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 section are maintained in a spreadsheet outlining the calculations and associated costs. Hence, three spreadsheets[11] are provided that cover three study forecasts (Spatial Base, Effective PV, and PVWatts). These spreadsheets are provided with this submission.

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 the incremental benefit-cost analysis.
- Cost Assumptions
  - Outlines the key study inputs and assumptions.
- Baseline System Analysis
  - Raw reliability Indices.
  - The monetized value of the baseline reliability metrics.

[11] 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.
  - The 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 Projects' Cost

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 the applicable discount rate. The cost of components associated with the design of projects is aggregated to develop the Total capital expenditure. For projects that include BESS, the PVRR costs are offset by revenues generated from market participation. Information regarding the scope of the projects has been summarized in Sections 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 the 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	$474	$545	$474	$545	$474	$545
B	SDG&E	$453	$540	$453	$540	$453	$540
C	SCE Orange County	$748	$951	$748	$951	$748	$951
D	Menifee	$331	$396	$331	$396	$331	$396
E	Mira Loma	$309	$369	$309	$365	$309	$365
F	Valley South to Valley North	$207	$221	$207	$221	$207	$221
G	Valley South to Valley North to Vista	$290	$317	$290	$317	$309	$365
H	Centralized BESS in Valley South	$525	$1,474	$848	$2,363	$381	$1,004
I	Valley South to Valley North and Distributed BESS in Valley South	$232	$326	$228	$354	$200	$218
J	SDG&E and Centralized BESS in Valley South	$531	$923	$658	$1,473	$479	$685
K	Mira Loma and Centralized BESS in Valley South	$560	$1,396	$601	$2,194	$448	$920
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$367	$1,172	$700	$2,616	$255	$572
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$289	$505	$404	$986	$269	$307

Table 6-2. Present Worth of Market Participation Revenues

Wholesale Energy and Ancillary Service markets				
#	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	-

Capacity and Resource Adequacy Markets				
#	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	$48,515	$74,932	$34,058
I	Valley South to Valley North and Distributed BESS in Valley South	$863	$2,105	-
J	SDG&E and Centralized BESS in Valley South	$3,579	$13,712	-
K	Mira Loma and Centralized BESS in Valley South	$18,124	$36,287	$6,395
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$10,185	$37,148	$2,798
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,000	$7,841	-

6.3.2 Baseline System Analysis

From the baseline system, the raw reliability indices computed in Section 4.2 are reflective of the overall impact on 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 Section 3.3 and derived as present worth. Table 6-3 presents the aggregated costs, taking into consideration the combination of Residential, Small & Medium Business and Commercial & Industrial customers.

Table 6-3. Baseline System Monetization

Category	Effective PV Forecast	Spatial Base Forecast	PVWatts Forecast
Monetized Value for EENS - N-1	12~~8,357~~6,010	~~436~~428,~~189~~178	35,~~182~~200
Monetized Value for EENS - – N-0	2,530,518,587	~~6,000,480,385~~5,999,276,476	1,029,268,277
Monetized Value for Flex-1	6,191,361	9,~~548,557~~670,328	4,309,495~~973,430~~
Monetized Value for Flex-2 ($)	1,765,322,893	1,816,115,205	1,722,124,246
Aggregate ($M)	**4,302**	**7,825~~7~~**	**2,756**

The results demonstrate that the aggregated range of cost impacts accrued by the customer range from 2.7$B to 7.8$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 the 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 – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,882	11.73
F	Valley South to Valley North	$2,156	10.41
I	Valley South to Valley North and Distributed BESS in Valley South	$2,165	9.33
A	Alberhill System Project	$4,282	9.03
B	SDG&E	$4,001	8.84
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$2,479	8.58
G	Valley South to Valley North to Vista	$2,470	8.52
E	Mira Loma	$2,601	8.42
J	SDG&E and Centralized BESS in Valley South	$4,041	7.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$2,542	6.93
K	Mira Loma and Centralized BESS in Valley South	$3,132	5.59
C	SCE Orange County	$4,021	5.38
H	Centralized BESS in Valley South	$2,535	4.83

Table 6-5. SCE Spatial Base Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$7,201	21.76
A	Alberhill System Project	$7,788	16.43
B	SDG&E	$7,218	15.93
G	Valley South to Valley North to Vista	$4,617	15.92
E	Mira Loma	$4,766	15.42
F	Valley South to Valley North	$2,618	12.65
I	Valley South to Valley North and Distributed BESS in Valley South	$2,736	12.00
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$4,771	11.81
J	SDG&E and Centralized BESS in Valley South	$7,523	11.43
K	Mira Loma and Centralized BESS in Valley South	$6,604	10.99
C	SCE Orange County	$7,258	9.70
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$6,016	8.59
H	Centralized BESS in Valley South	$6,008	7.08

Table 6-6. PVWatts Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$2,381	7.19
A	Alberhill System Project	$2,740	5.78
B	SDG&E	$2,520	5.56
J	SDG&E and Centralized BESS in Valley South	$2,520	5.26
E	Mira Loma	$1,512	4.89
I	Valley South to Valley North and Distributed BESS in Valley South	$955	4.77
F	Valley South to Valley North	$955	4.61
L	Valley South to Valley North and Centralized BESS in Valley South and Valley North	$1,039	4.07
M	Valley South to Valley North to Vista and Centralized BESS in Valley South	$1,036	3.85
K	Mira Loma and Centralized BESS in Valley South	$1,625	3.63
G	Valley South to Valley North to Vista	$1,036	3.57
C	SCE Orange County	$2,533	3.39
H	Centralized BESS in Valley South	$1,032	2.71

As Table 6-4 demonstrates, for the effective PV forecast the Menifee project renders the largest benefit to cost ratio of 11.02. Although the Menifee project has the largest benefit to cost ratio, its cost of $331M is 60% higher than the least expensive project, i.e. Valley South to Valley North with a cost of $207M (Table 6-1). However, the benefit-to-cost ratio of the Valley South to Valley North is 10.41, which is 6% higher. In other words, the additional 40% cost of the Menifee project as compared to the Valley South to Valley North project renders 6% of additional benefit. The benefit-to-cost ratio is one element to consider in determining whether or not a project should be implemented. While it provides an indication of each project's performance, it does not adequately provide a measure to compare alternatives.

The best project among a set of alternative projects is not necessarily the one that maximizes the benefit-to-cost ratio. The benefit-to-cost analysis is a measure consider in the determination to reject or approve a project. But when it comes to the selection among alternatives and the process of reliability improvement projects, an incremental benefit-cost analysis should be conducted. The incremental benefit-to-cost analysis methodology is based on the principle of spending each dollar funding the project that will result in the most benefit, resulting in an optimal budget allocation that identifies the projects that should be funded [10].

To conduct a correct selection among alternative projects with widely disparate benefits an incremental analysis approach to evaluating benefits and costs is necessary [9]. 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 ascending order of the present worth of costs. The do-nothing with zero cost is then selected as the baseline, i.e. alternative “0”. The next expensive project is then considered, and the incremental benefit-to-cost analysis is then conducted to determine if such a selection should be made or not. 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. Alternative “F” versus baseline incremental benefit-cost ratio was evaluated using the present worth of monetized benefits versus PVRR costs.

In general, a project is selected if the incremental benefits exceed its incremental cost. This approach can be conducted for non-monetized and monetized benefits. The non-monetized selection is qualitative and subjective as the selection is based on individual indices performance. The monetized analysis is solely based on a single incremental benefit-to-cost ratio. Both non-monetized and monetized incremental cost-benefit analyses are depicted in the following tables. As the selection under non-monetized analysis is subjective, the results are presented for demonstration only.

For monetized incremental cost-benefit analysis, if the incremental ratio is larger than unity the next expensive project “F” is selected. Once a selection is made, the selected alternative replaces the baseline. This selection is demonstrated as “0→F” in Table 6-8. The process continues through the list of alternative projects, which are ranked in ascending cost order until the list is exhausted.

At the next step, the second least expensive project, i.e. “I” is compared to the baseline project “F”. Project “I” was not selected as the incremental benefit-to-cost ratio is less than unity, and hence “F” remains as the baseline project. The incremental benefit-cost analysis will continue by iterating between the baseline and the next expensive alternative. The selection will stop once the incremental benefit-cost ratio becomes unfavorable or the list is exhausted. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks. Again, while this incremental approach is preferred relative to a traditional BCA for comparing alternatives but needs to be balanced with other project considerations such as environmental impact and risks.

For monetized benefits, the criteria to move forward to the next expensive project is considered as a positive (total) aggregated value greater than unity. As one moves along the trajectory of the 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 is 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 is 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→ M	I → G	I → E	I →D	I → L	I → B	B → A	A → H	A → J	A → K	A → C
N-1	LAR	-11.27	-6.50	-0.94	2.80	2.73	1.64	-0.42	-2.32	5.23	-2.20	-1.97	-1.22	1.61
N-1	IP	-0.54	-0.28	0.04	0.12	0.17	0.07	0.02	-0.16	0.97	-0.41	-0.36	-0.22	0.10
N-1	PFD	-1.58	-1.07	-0.16	0.46	0.44	0.27	-0.07	-0.35	0.49	-0.21	-0.19	-0.08	0.08
N-1	Available Flex-1	-5,893.06	-3,339.83	2,223.74	1,439.58	7,537.63	843.39	938.91	317.75	-9,549.32	10,147.65	1,604.86	6,728.74	4,329.79
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	-5,555.36	-9,860.00	0.00	-4,889.92	-7,682.16	24,377.09	2,889.84	9,482.20	560.54
N-1	Available Flex-2-2	-95.59	-0.02	0.00	0.01	15.28	0.01	0.00	-9.02	-346.00	566.20	130.16	123.05	22.44
N-0	LAR	-36.29	-1.28	-15.50	-14.69	3.84	-10.93	-8.24	-4.59	-4.67	-0.01	-0.01	-0.01	0.36
N-0	IP	-3.70	-0.74	-0.57	-0.38	2.44	-0.58	-0.51	-0.16	-1.55	-0.01	-0.01	0.00	0.12
N-0	PFD	-0.57	-0.10	-0.35	-0.31	0.12	-0.26	-0.20	-0.10	-0.18	-0.01	-0.01	0.00	0.01
Decision to move forward (Y/N)		Y	Y	N	N	N	N	N	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F → I	F → M	M → G	M → E	E →D	D → L	D → B	B → A	A → H	A → J	A → K	A → C
N-0	EENS	10.356	0.373	3.948	-9.313	-23.358	23.629	0.290	-0.235	1.812	0.003	0.003	0.002	-0.123
N-0	Losses	0.001	0.000	0.000	-0.001	0.018	-0.007	-0.006	0.023	0.055	-0.073	-0.021	-0.045	-0.005
N-1	EENS	0.000	0.000	0.000	-0.009	-0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
N-1	Flexibility-1	0.020	0.009	0.000	0.026	-0.107	0.098	-0.001	-0.008	0.105	-0.044	-0.030	-0.036	-0.016
N-1	Flexibility-2-1	0.000	0.000	0.000	0.000	29.576	34.485	-37.505	1.191	10.992	-33.935	-4.135	-13.246	-0.802
N-1	Flexibility-2-2	0.036	0.000	0.000	0.000	-0.022	0.020	0.000	0.006	0.136	-0.217	-0.051	-0.048	-0.009
Total	Sum of ΔB/ΔC (aggregate)	10.413	0.382	3.947	-9.297	6.087	58.233	-37.216	0.954	13.044	-34.192	-4.213	-13.329	-0.949
Decision to move forward (Y/N)		Y	N	Y	Y	Y	Y	N	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F→ I	I → G	I →E	I → D	I → M	M → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-1	LAR	-33.49	-37.60	12.74	17.76	6.87	-2.55	-33.16	31.64	-5.17	-3.91	4.25	4.87	-1.91
N-1	IP	-0.75	-0.86	0.29	0.28	0.18	-0.03	-1.66	2.46	-0.41	-0.32	0.13	0.23	-0.15
N-1	PFD	-2.16	-0.13	0.04	1.72	0.03	-0.20	-4.41	1.04	0.04	-0.14	0.86	0.22	-0.06
N-1	Available Flex-1	-9,712.04	-12,207.92	4,134.94	11,626.02	2,488.99	-799.25	7,106.92	-1,615.54	1,112.01	-1,621.04	-1,390.76	4,664.64	-419.28
N-1	Available Flex-2-1	0.00	0.00	0.00	-5,369.71	-9,643.82	0.00	-22,563.56	-9,103.32	6,786.12	1,038.97	5,737.98	650.75	3,467.34
N-1	Available Flex-2-2	-113.44	-4.86	1.65	18.85	0.99	0.50	-50.26	-485.96	110.90	55.44	56.05	31.36	94.63
N-0	LAR	-50.38	-18.14	-88.77	-60.88	-96.09	-33.99	-71.33	-41.13	-0.27	-0.19	-0.15	2.84	-0.09
N-0	IP	-4.06	-3.03	-1.72	1.87	-3.25	-1.20	-1.36	-7.01	-0.06	-0.04	-0.03	0.52	-0.02
N-0	PFD	-0.59	-0.22	-1.18	-0.77	-1.43	-0.49	-1.08	-0.62	-0.05	-0.03	-0.03	0.04	-0.02
Decision to move forward (Y/N)		Y	Y	Y	N	N	N	Y	Y	Y	N	N	N	N

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

Category		Alternative selection												
		0 → F	F→ I	I → G	G→E	E → D	D → M	D → B	B → A	A→ K	A→ J	A→ L	A→ C	A→ H
N-0	EENS	12.57	5.62	30.35	-23.03	76.11	-14.85	-1.16	13.86	0.10	0.07	0.05	-0.97	0.03
N-0	Losses	0.00	0.00	0.00	0.02	-0.01	0.00	0.03	0.08	-0.04	-0.01	-0.02	-0.01	-0.01
N-1	EENS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	Flexibility-1	0.03	0.03	-0.01	-0.17	0.14	0.01	-0.01	0.12	-0.02	-0.01	0.00	-0.02	0.00
N-1	Flexibility-2-1	0.00	0.00	0.00	31.04	34.42	-18.45	1.28	12.89	-9.32	-1.47	-7.85	-0.92	-4.74
N-1	Flexibility-2-2	0.04	0.00	0.00	-0.03	0.02	0.00	0.01	0.19	-0.04	-0.02	-0.02	-0.01	-0.04
Total	Sum of ΔB/ΔC (aggregate)	12.64	5.65	30.34	7.81	110.69	-33.29	0.11	27.07	-9.28	-1.43	-7.82	-1.93	-4.75
Decision to move forward (Y/N)		Y	Y	Y	Y	Y	Y	Y	Y	N	Y	Y	N	N

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

Category		Alternative selection												
		0 → I	I → F	I → L	L →M	L→ G	L → E	L→ D	L → H	L → K	L→ B	B → A	A → J	A → C
N-1	LAR	-4.72	0.00	0.00	0.00	0.00	0.51	0.00	-0.52	-0.34	-0.33	0.40	-1.69	0.59
N-1	IP	-0.45	0.00	0.00	0.00	0.00	0.03	0.00	-0.09	-0.06	-0.05	0.17	-0.71	0.06
N-1	PFD	-1.51	0.00	0.00	0.00	0.00	0.12	0.00	-0.10	-0.07	-0.07	0.09	-0.37	0.15
N-1	Available Flex-1	-3,475.85	29.81	0.00	0.00	5.89	9,466.51	2.75	-78.96	2,261.87	-594.68	-11,884.27	43,746.18	3,460.14
N-1	Available Flex-2-1	0.00	0.00	0.00	0.00	0.00	-7,882.61	-12,775.72	0.00	-2,205.50	-5,394.24	-7,225.14	30,345.58	516.40
N-1	Available Flex-2-2	-89.61	0.00	0.00	0.00	0.00	19.50	0.00	141.18	5.46	-8.89	-287.42	1,207.16	18.02
N-0	LAR	-17.11	0.00	-4.37	0.81	0.32	6.52	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	IP	-2.64	0.00	-1.38	0.44	0.17	2.03	0.00	0.00	0.00	0.00	-0.01	0.00	0.00
N-0	PFD	-0.37	0.00	-0.15	0.07	0.03	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	N	N	N	N	Y	Y	N

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

Category		Alternative selection												
		0 → I	I → F	I → L	L → M	L→ G	L → E	E → D	D → H	D → K	D → B	B → A	A → J	A → C
N-0	EENS	4.73	0.00	1.53	-0.19	-0.08	-2.09	5.14	0.00	0.00	0.00	0.00	0.00	0.00
N-0	Losses	0.00	0.00	0.00	0.00	0.00	0.01	-0.01	0.00	0.00	0.02	0.06	-0.28	0.00
N-1	EENS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-1	Flexibility-1	0.01	0.00	0.00	0.00	0.00	-0.04	0.10	-0.02	-0.02	0.00	0.09	-0.35	-0.01
N-1	Flexibility-2-1	0.00	0.00	0.00	0.00	0.00	10.89	34.26	-26.84	-6.44	1.12	10.19	-42.82	-0.73
N-1	Flexibility-2-2	0.03	0.00	0.00	0.00	0.00	-0.01	0.02	-0.13	0.00	0.01	0.11	-0.46	-0.01
Total	Sum of ΔB/ΔC (aggregate)	4.77	0.00	1.53	-0.19	-0.08	8.74	39.52	-26.98	-6.46	1.12	10.39	-43.63	-0.75
Decision to move forward (Y/N)		Y	Y	N	Y	N	N	Y	Y	N	N	Y	Y	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 (LAR through PFD) is calculated for each alternative. For example, in Table 6-13, 0.16 as listed under column A and row N-1 LAR is the ratio of Alberhill project $474 M (Table 6-1) net present cost to present worth of N-1 LAR over study horizon of 2,896 MWh.

A smaller N-1 LAR value implies a more cost-effective solution. Along each row, the ratios are ranked using heat-mapping, with green and red marking the most favorable and the most unfavorable ends of the spectrum. The rightmost three columns, Alternative Rankings, identifies the first three projects 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 Alternative

Effective PV Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.16	0.15	0.12	0.17	0.19	0.09	0.14	0.14	0.30	0.14	0.11	0.18	0.09	F	I	M
N-1	IP ↓	3.57	2.94	2.62	3.42	3.70	1.97	2.99	2.95	7.12	3.17	2.50	3.45	1.87	F	I	M
N-1	PFD ↓	1.13	1.05	0.88	1.22	1.31	0.65	1.01	0.96	1.88	1.01	0.79	1.23	0.63	F	I	M
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	F	I	G
N-1	Flex-2-1↓	3.81E-04	4.20E-04			1.31E-03		4.09E-04	7.22E-04	6.86E-04			4.92E-04		A	D	B
N-1	Flex-2-2↓	1.62E-02	2.08E-02	1.47E-02	1.65E+00	3.02E-02	1.17E-02	1.68E-02	1.67E-02	3.25E-02	1.86E-02	1.46E-02	2.44E-02	1.05E-02	F	I	M
N-0	LAR ↓	0.05	0.05	0.03	0.06	0.06	0.03	0.04	0.04	0.09	0.04	0.03	0.06	0.03	F	I	M
N-0	IP ↓	0.56	0.55	0.36	0.62	0.66	0.30	0.39	0.52	0.91	0.43	0.35	0.62	0.27	F	I	M
N-0	PFD ↓	3.24	3.17	2.10	3.58	3.81	1.93	2.28	2.78	5.24	2.50	2.07	3.62	1.76	F	I	M
Count of Rank #1		1	0	0	0	0	0	0	0	0	0	0	0	8			

Table 6-14. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

Spatial Base Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.05	0.05	0.04	0.09	0.06	0.03	0.05	0.05	0.10	0.09	0.05	0.07	0.03	I	F	G
N-1	IP ↓	2.28	1.75	1.86	3.21	2.32	1.31	2.13	1.99	5.16	3.93	2.27	2.47	1.33	I	F	B
N-1	PFD ↓	0.70	0.65	0.65	1.21	0.89	0.51	0.74	0.69	1.21	1.44	0.83	0.94	0.46	F	I	B
N-1	Flex-1↓	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	F	G	A
N-1	Flex-2-1↓	3.66E-04	4.10E-04			1.38E-03		3.33E-04	3.11E-04	6.69E-04			5.95E-04		E	D	A
N-1	Flex-2-2↓	1.31E-02	1.74E-02	1.23E-02	1.10E+00	2.72E-02	9.67E-03	1.41E-02	1.32E-02	2.71E-02	2.98E-02	1.72E-02	2.53E-02	8.81E-03	F	I	G
N-0	LAR ↓	0.02	0.02	0.02	0.04	0.03	0.02	0.02	0.01	0.04	0.03	0.02	0.03	0.02	E	D	G
N-0	IP ↓	0.36	0.38	0.29	0.63	0.45	0.25	0.27	0.25	0.63	0.52	0.36	0.49	0.25	F	E	I
N-0	PFD ↓	1.70	1.71	1.45	2.98	2.11	1.80	1.21	1.13	2.80	2.46	1.90	2.31	1.70	E	D	G
Count of Rank #1		0	0	0	0	0	2	0	3	0	0	0	0	4			

Table 6-15. Levelized Cost Analysis (Present Worth of Cost $/Present Worth of Benefit) for each Alternative

PVWatts Forecast

		Alberhill System Project	SDG&E	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	SCE Orange County	Valley South to Valley North and Centralized BESS in Valley South and Valley North	Valley South to Valley North to Vista and Centralized BESS in Valley South	SDG&E and Centralized BESS in Valley South	Valley South to Valley North	Alternative Ranking		
Reliability Metrics		A	B	G	H	K	I	D	E	C	L	M	J	F	#1	#2	#3
N-1	LAR ↓	0.47	0.45	0.31~~0.33~~	0.38	0.44	0.21	0.35	0.34~~0.61~~	0.89	0.27	0.29	0.47	0.22	I	F	L
N-1	IP ↓	4.91	4.52	3.25~~3.45~~	3.80	4.47	2.24	3.70	3.51~~12.58~~	9.37	2.85	3.01	4.78	2.31	I	F	L
N-1	PFD ↓	1.51	1.43	0.96~~1.02~~	1.21	1.42	0.66	1.09	1.04~~1.15~~	2.75	0.84	0.89	1.52	0.68	I	F	L
N-1	Flex-1↓	0.0005	0.0006	0.0004	0.0006	0.0014	0.0003	0.0005	0.0017	0.0065	0.0004	0.0004	0.0006	0.0003	I	F	L
N-1	Flex-2-1↓	3.89E-04	4.24E-04			1.05E-03		3.41E-04	7.26E-04	6.94E-04			4.48E-04		D	A	B
N-1	Flex-2-2↓	1.84E-02	2.30E-02	1.72E-02	2.87E+00	2.66E-02	1.12E-02	1.85E-02	1.83E-02	3.60E-02	1.42E-02	1.50E-02	2.43E-02	1.16E-02	I	F	L
N-0	LAR ↓	0.13	0.12	0.08	0.10	0.12	0.06	0.09	0.10	0.20	0.07	0.07	0.13	0.06	I	F	L
N-0	IP ↓	0.79	0.75	0.49~~0.52~~	0.63	0.74	0.38	0.55	0.55~~0.63~~	1.24	0.42	0.45	0.79	0.39	I	F	L
N-0	PFD ↓	5.78	5.53	3.59~~3.82~~	4.65	5.46	2.71	4.04	4.04~~4.14~~	9.12	3.11	3.32	5.84	2.80	I	F	L
Count of Rank #1		0	0	0	0	0	8	1	0	0	0	0	0	0			

6.4 Risk Analysis

The risk analysis performed within this assessment is deterministic. 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	9.03	16.43	5.78
SDG&E	8.84	15.~~94~~93	5.56
Valley South to Valley North to Vista	8.52	15.92	3.57~~35~~
Centralized BESS in Valley South	4.83	7.08~~9~~	2.71
Mira Loma and Centralized BESS in Valley South	5.59	10.99	3.63
Valley South to Valley North and Distributed BESS in Valley South	9.33	12.00~~1~~	4.77
Menifee	11. 73~~02~~	21.76	7.19
Mira Loma	8.42	15.42	4.89
SCE Orange County	5.38	9.70~~1~~	3.39
Valley South to Valley North and Centralized BESS in Valley South and Valley North	6.93	8.59~~60~~	4.07~~8~~
Valley South to Valley North to Vista and Centralized BESS in Valley South	8. 58~~54~~	11.81	3.85
SDG&E and Centralized BESS in Valley South	7.61	11.43	5.26
Valley South to Valley North	10.41	12.65	4.61

6.5 Summary of Findings

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

1. Without a project in service to address the needs in the Valley South System, the aggregate cost impacts accrued by the customer range from 2.7$B to 7.8$B over the horizon of forecast uncertainties captured by this analysis.
2. The benefit-cost analysis demonstrates Menifee as the project with the highest B-C ratio in Effective PV, Spatial Base, and PVWatts forecast. This is followed by the Alberhill System project and San Diego Gas & Electric. In the case of Valley South to Valley North alternatives, the project's low cost overrides the performance benefits and drive the ratios higher. The Menifee alternative has an advantage of lower cost while providing superior performance to Valley South to Valley North alternatives in select (Flex-2) categories. However, the benefits are realized only in the short

term horizon, with limited long-term benefits. A quick review of the overall benefits in Section 6.3.3 and raw reliability performance in Section 5.3.3, 5.3.5 and 5.3.6 further justifies this claim. The benefits accrued by ASP were found to be substantial over the horizon maintaining its rank across all three forecasts.

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 6.3.5.
4. Wire-based solutions demonstrate higher $/Unit benefit performance under the Effective PV and Spatial Base forecasts of load growth.
5. The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected. 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. An overall assessment of the top-ranking alternatives with consideration of risks, demonstrate the superiority of ASP to meet all the short term and long-term project objectives in the Valley South System.

7 CONCLUSIONS

SCE retained Quanta Technology to supplement the existing record in the CPUC proceedings for SCE's 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 BCA) 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 the year 2048). The forecast findings were used to verify and validate SCE's currently adopted forecasting practices.

The screening process for alternatives used 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 used 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 the industry-accepted forecasting practices, two distinct methodologies were implemented to develop load forecasts, namely conventional and spatial forecasts. (The load forecasting methodologies and findings are documented in detail within Section 2 of this report.)
  - The two forecasts have been developed consistent with the load-growth trend currently observed within the region, and CEC's IEPR projections for load-reducing technologies.
  - Sensitivity analysis was performed to address the uncertainties of load-reducing technologies and California's electrification goals.
  - Across the three 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 used to quantitatively assess the performance of each alternative under consideration. An evaluation of alternative performance demonstrated that the ASP provides the highest benefits across the study horizon. These benefits are the aggregate of the ASP contribution toward the capacity, reliability, resilience, and operational flexibility needs in the Valley South System.

Considering the aggregated benefits under normal and emergency[12] conditions, the ASP results in 76 gigawatt-hours (GWh) of cumulative reduced unserved energy, and $4.3 billion in cost savings to the customers. The alternatives demonstrating the highest benefits following the ASP are SDG&E, SCE Orange County, and SDG&E with Centralized BESS in Valley South.

- The BCA framework was implemented to evaluate and compare individual alternatives' performance.
  - NWAs remained cost-effective only under reduced load forecast levels (e.g., reduced trend and low sensitivities of the conventional forecasts). In the other forecasts, NWAs accrue significant additional costs over time due to the 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.
  - Menifee, ASP, SDG&E, and Valley South to Valley North alternatives exhibit the highest benefit-to-cost ratio. Menifee and Valley South to Valley North have lower costs relative to the ASP while providing sizably lower benefits than the ASP.
- The benefit-to-cost ratio is one measure to consider in determining if any project should be implemented. However, when it comes to the selection among alternatives, an incremental BCA should be conducted. Incremental BCA methodology determines whether additional incremental cost is economically justifiable on the basis that the additional benefits realized exceeds the incremental cost.
- The incremental benefit-cost framework was implemented to justify alternative selection, and the results demonstrated that the ASP is the preferred alternative. The analysis is indicative of unrealized benefits should a lower cost alternative be selected.
- Risk analysis associated with forecast uncertainties demonstrate that:
  - The costs associated with the incremental size of the NWAs (to keep pace with peak load values) are substantial and result in reduced benefit-cost ratios.
  - The benefits attributed to operational flexibility from NWAs 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-year horizon.

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. Quanta Technology is only responsible to the extent the client's use of this information is consistent with the statement of work.

[12] N-0, N-1 and operational flexibility.

8 REFERENCES

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9 APPENDIX: N-2 PROBABILITIES

The N-2 probabilities associated with circuits that share a common tower structures are presented in this table.

	Auld-Moraga #2	Auld-Sun City	Fogarty-Ivyglen	Moraga-Pechanga	Pauba-Triton	Valley-Auld #1	Valley-Auld #2	Valley-Elsinore-Fogarty	Valley-Newcomb	Valley-Newcomb-Skylark	Valley-Sun City	Valley-Auld-Triton	Valley-Ivyglen
Auld-Moraga #2				0.0088	0.0194							0.02696	
Auld-Sun City										0.0304			
Fogarty-Ivyglen													0.0032
Moraga-Pechanga	0.0088												
Pauba-Pechanga													
Pauba-Triton	0.01944											0.002	
Valley-Auld #1							0.0698						
Valley-Auld #2						0.0698						0.016	
Valley-Elsinore-Fogarty									0.024				
Valley-Newcomb								0.024					
Valley-Newcomb-Skylark		0.0304									0.0309		
Valley-Sun City										0.03096			
Valley-Auld-Triton	0.02696				0.002		0.016						
Valley-Ivyglen			0.0032										