ALBERHILL SYSTEM PROJECT

ADDENDUM TO THE FINAL ENVIRONMENTAL IMPACT REPORT

JUNE 2024

A.09-09-022

SCH NO. 2010041031

PREPARED FOR:

STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION

PREPARED BY:

wsp

Table of Contents

Attachments

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Addendum to Previously Certified Final Environmental Impact Report (EIR)

PROJECT TITLE:
Alberhill System Project

STATE CLEARINGHOUSE NUMBER:
2010041031

AUTHORITY FOR THE ADDENDUM ENVIRONMENTAL IMPACT REPORT:

This Addendum describes the proposed modifications to the proposed Alberhill System Project (ASP) and provides the additional analysis required to adequately address the proposed modifications pursuant to Public Resources Code Section 21166 and the Guidelines for California Environmental Quality Act (CEQA) Section 15000, California Code of Regulations Title 14, Chapter 3 (CEQA Guidelines). Where an applicant has submitted amendments to a project application where an Environmental Impact Report (EIR) has been previously certified and it is subject a discretionary decision by a state or local public agency, the agency, in this case the California Public Utilities Commission (CPUC), must consider what updates, if any, are necessary to the certified EIR to reflect the amended project. In this case, pursuant to CEQA Guidelines §15164 an addendum to a certified EIR must be prepared if only minor technical changes or additions are necessary. In addition, pursuant to CEQA Guidelines §15162, preparation of an addendum to an EIR is appropriate unless the applicant proposes substantial changes to the project, substantial changes occur with respect to the circumstances under which the project is undertaken, or new information of substantial importance becomes available and this information results in new significant impacts or a substantial increase in the severity of previously identified significant impacts. The addendum need not be circulated for public review (CEQA Guidelines §15164[c]); however, an addendum is to be considered by the decision maker prior to deciding on the project (CEQA Guidelines §15164[d]).

PROJECT DESCRIPTION:

The ASP, as described in Southern California Edison's (SCE) third amendment to its application and Proponent's Environmental Assessment (PEA), would include the following components:

- Construct one 1,120 megavolt ampere 500/115-kilovolt (kV) substation (Alberhill Substation).
- Construct two 500-kV transmission lines to connect the proposed substation to the existing Serrano–Valley 500-kV transmission line.
- Convert approximately 10.6 miles of existing single-circuit 115-kV subtransmission lines to double-circuit with structure replacement primarily in the existing right-of-way (ROW).
- Construct about 3 miles of single-circuit 115-kV subtransmission line with distribution line underbuilt on the subtransmission line structures and remove about 3 miles of electrical distribution lines within the existing ROW.
- Install a second 115-kV circuit on approximately 6.2 miles of existing 115-kV subtransmission lines (constructed as part of the Valley–Ivyglen Project).
- Install approximately 550 feet of new 115-kV underground subtransmission circuit within new duct banks and install approximately 4,000 feet of new 115-kV subtransmission circuit within existing duct banks.
- Install fiber optic lines overhead (approximately 9 miles) on sections of the new or modified subtransmission lines and underground (approximately 1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12-kV substations.

- Install a 120-foot microwave antenna tower at the proposed Alberhill Substation site. Install microwave telecommunications dish antennas at the proposed Alberhill Substation, the existing Santiago Peak communications site, and Serrano Substation. Install telecommunications equipment at other existing and proposed substations.
- Install a new position inside Newcomb Substation to accommodate the new Newcomb-Skylark 115-kV line, and modify an existing position at Valley Substation to isolate the existing Valley-Newcomb 115-kV line, which will be taken out of service as part of the proposed ASP.
- Transfer five of the 14 Valley South 115-kV System substations (Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb) to the proposed115-kV Alberhill System.

The Alberhill Substation is proposed to be built on approximately 39 to 44 acres of a 124-acre property located on the northwest corner of the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County. The two new 500-kV transmission lines would each extend approximately 1.5 miles northeast to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV transmission line. The 115-kV subtransmission line modifications and construction would occur southeast from the proposed Alberhill Substation to Skylark Substation (approximately 11.5 miles) and from Skylark Substation to Newcomb Substation (approximately 9 miles).

SCE designed the proposed ASP to meet long-term forecasted electrical demand in the proposed ASP area and to increase electrical system reliability. SCE estimates that construction of the proposed ASP would take approximately 30 months.

CHANGES FROM PROPOSED PROJECT IN CERTIFIED FINAL EIR TO AMENDED PROJECT:

SCE submitted the Third Amended Application for the ASP on June 2, 2023. The Third Amended Application includes “technical design modifications and engineering refinements that decrease project costs and reduce greenhouse gas (GHG) emissions.” The modifications are in recognition of the California Air Resources Board’s Resolution 20-28 that amended the Regulation for Reducing Sulfur Hexafluoride Emissions. Design modifications and engineering refinements include:

- Incorporating air-insulated switchgear at the Alberhill Substation in lieu of gas-insulated switchgear.
- Leveraging the use of existing infrastructure that has already been constructed as part of the Valley–Ivyglen 115 kV Subtransmission Line Project; and
- Using helicopter construction previously analyzed in the Final Environmental Impact Report (FEIR) to eliminate three of the five transmission structure access roads originally proposed.

SCE also submitted an amended PEA that documents the analysis of environmental impacts of the revised ASP scope.

BACKGROUND:

The CPUC published an FEIR in April 2017, and the FEIR was certified in 2018. The CPUC August 31, 2018, Decision (D. 18-08-026) neither issued a Certificate of Public Convenience and Necessity (CPCN) nor denied the CPCN for the ASP. The Decision directed SCE to “supplement the [ASP] record with additional analyses of alternatives which may satisfy the needs of the Valley South System.”

SCE provided these additional analyses to the CPUC Energy Division (ED) as Data Request Responses in May 2019, December 2019, and January 2020. On April 10, 2020, Administrative Law Judge (ALJ) Yacknin issued a ruling via email directing SCE to file:[1]

---

[1] Hallie Yacknin, 2020, Email Ruling Directing Amendment or Showing Cause, A.09-09-022 SCE Alberhill CPCN Application.

(1) A compliance filing (of) its additional analyses of alternatives that may satisfy the needs of the Valley South System to supplement the record Application (A.) 09-09-022, pursuant to D.18-08-026.
(2) An amendment to its application consistent with its additional analyses of alternatives that may satisfy the needs of the Valley South System, including a corresponding amended PEA reflecting the additional analyses as appropriate.

In accordance with ALJ Yacknin's email ruling, on May 11, 2020, SCE submitted its Second Amended Application and amendments to the PEA, which incorporated the additional alternative analyses. SCE also held webinars with the public and the CPUC ED to review the analyses and answer questions regarding SCE's findings. The additional analyses evaluated the ability of a wide range of project alternatives to effectively meet the project objectives and satisfy system planning criteria. The Alberhill System Project Supplement to the Alternatives Screening Report (Attachment C) was developed and provides the results of the screening evaluation for each alternative identified by SCE in its 2020 Planning Study.

As discussed above, SCE submitted its Third Amended Application and PEA for the ASP on June 2, 2023. To document the findings from an independent review and analysis of information furnished by the applicant via the Third Amended PEA, the CPUC's ED developed and prepared the PEA Review Memorandum (Memo) (Attachment A) in addition to the Alberhill System Project Supplement to the Alternatives Screening Report to determine whether the criteria described in CEQA Guidelines Section 15162 are met.

REASONS FOR ADDENDUM:

The Alberhill System Project Supplement to the Alternatives Screening Report (Attachment C) documents the alternatives screening process conducted for the ASP and supplements the information presented in the 2015 Valley–Ivyglen Subtransmission Line and Alberhill System Project Environmental Impact Report (EIR) Alternatives Screening Report and Addendum (as revised in 2017). The Supplement to the Alternatives Screening Report provides:

- The range of alternatives identified and evaluated in the 2017 revision of the ASR; and Third Amended Application
- Screening for the alternatives identified by SCE in their 2020 Planning Study and Third Amended Application
- The approach and methods used for screening each alternative according to the requirements of CEQA
- The results of the screening evaluation for each alternative (i.e., the alternatives eliminated from further consideration or carried forward for further analysis in an appropriate CEQA document supplement to the EIR)

The results of CPUC's screening evaluation for each alternative identified by SCE in its 2020 Planning Study concluded that none of the new alternatives will be carried forward for full analysis under CEQA. No specific circumstance necessitating changes to the previous alternatives screening analysis included in the 2017 Final EIR were identified. See Attachment C for the complete alternatives screening analysis and results.

The PEA Review Memo (Attachment A) documents CPUC's independent review and analysis of SCE's environmental analyses and technical studies. It assessed whether the amended project description would result in the following:

- New significant environmental impacts
- Substantial increases in severity of previously identified significant environmental impacts compared to those impacts considered in the 2017 FEIR
- New mitigation measures (MMs) for any significant and unavoidable environmental impacts previously found to be not feasible and that could in fact be feasible

The PEA Review Memo's analysis of the potential environmental impacts, which are the result of the technical design modifications and engineering refinements outlined in SCE's Third Amended Application and PEA, focuses on the environmental resources considered in the 2017 Final EIR.

The amended ASP, prior to application of mitigation measures, would slightly increase the severity of Impact TT-2, compared to that discussed in the 2017 FEIR. As amended, ASP would increase some delays at the intersection of Menifee Road and Pinacate Road in the AM peak hour. This impact would be reduced to less than significant levels through the extension of MM TT-2, which was included in the 2017 FEIR, to also apply to the intersection of Menifee Road and Pinacate Road in the AM peak hour. Therefore, MM TT-2 would mitigate Impact TT-2 to be a less than significant impact, consistent with the findings of the 2017 FEIR.

As shown in the PEA Review Memo (Attachment A) and environmental data in the proceeding record, the proposed technical design modifications and engineering refinements would not result in new significant environmental effects, a substantial increase in the severity of a previously identified significant environmental effect, new or substantially modified mitigation measures that would reduce one or more significant effects should be applied. No substantial changes have occurred with respect to the circumstances under which the project is being undertaken. With the implementation of previously identified applicant proposed measures and mitigation measures defined in the Mitigation Monitoring, Compliance and Reporting Program (Attachment B),[2] impacts of the proposed technical design modifications and engineering refinements would be minor and not result in a new or substantially more severe impacts compared to those previously disclosed in the 2017 FEIR.

As a result, no major revisions to the certified EIR are recommended. As discussed above, new alternatives that are considerably different from those analyzed in the 2017 FEIR are considered separately in the Alberhill System Project Supplement to the Alternatives Screening Report (Attachment C) but as explained in the report, are not carried forward for further analysis as alternatives under CEQA.

Based on the analyses provided Attachments A and C, the CPUC has determined that an addendum as defined by CEQA Guidelines Section 15164 is appropriate to evaluate the proposed alternatives and modifications to the ASP because none of the conditions calling for the preparation of a subsequent EIR or supplemental EIR, as specified by Public Resources Code Section 21166 or CEQA Guidelines Sections 15162 and 15163, are present.

DETERMINATION TO SUPPORT AN ADDENDUM:

On the basis of the information and analysis provided in the attached Alberhill System Project Supplement to the Alternatives Screening Report and PEA Review Memo, CPUC has determined that an Addendum to a Certified Final EIR is the appropriate document to prepare for the proposed project pursuant to CEQA Guidelines section 15164(b) based on the determination that none of the conditions described in CEQA Guidelines section 15162 calling for the preparation of a subsequent EIR or supplemental EIR have occurred.

Signature: Trevor Pratt Date: June 14, 2024

Name: Trevor Pratt Title: Senior CEQA Project Manager Phone Number: (916) 894-5734

[2] A slightly modified version of MM TT-2 that extends the measure's applicability to also include Menifee Road at Pinacate Rd (SR-74) during the AM peak hour is included in the MMCRP in Attachment B.

Attachment A

Review of SCE Third Amended Application and PEA for the Alberhill System Project Memorandum

MEMO

TO: Trevor Pratt, CPUC Energy Division

FROM: Amy DiCarlantonio, WSP USA Inc.

SUBJECT: **Review of SCE Third Amended Application and PEA for the Alberhill System Project**

DATE: **May 13, 2024**

PROJECT BACKGROUND

The California Public Utilities Commission (CPUC) issued a Final Environmental Impact Report (FEIR) in April 2017, and the FEIR was certified in 2018. The CPUC August 31, 2018, Decision (D. 18-08-026) neither issued a Certificate of Public Convenience and Necessity (CPCN) nor denied the CPCN for the Alberhill System Project (ASP, or the "proposed project"). The Decision directed Southern California Edison (SCE) to "supplement the [ASP] record with additional analyses of alternatives which may satisfy the needs of the Valley South System."

SCE provided additional analyses to the CPUC Energy Division (ED) as part of its amended application in May 2020, in addition to multiple Data Request Responses. SCE also held webinars with the public and ED to review the analyses and answer questions regarding SCE's findings. The additional analyses evaluated the ability of a wide range of proposed project alternatives to effectively meet the project objectives and satisfy system planning criteria. CPUC ED reviewed SCE's analyses which has been documented separately in a CPUC ED Staff Report. A Supplemental Alternatives Screening Report is also being developed separately that will provide the results of the screening evaluation for each alternative identified by SCE in their 2020 Planning Study.

THIRD AMENDED APPLICATION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE ALBERHILL SYSTEM PROJECT

SCE submitted the Third Amended Application for the ASP on June 2, 2023. The Third Amended Application includes "technical design modifications and engineering refinements that decrease project costs and reduce greenhouse gas (GHG) emissions." The modifications are in recognition of the California Air Resources Board (CARB) Resolution 20-28 that amended the Regulation for Reducing Sulfur Hexafluoride Emissions.[1] Design Modifications and engineering refinements include:

[1] California Air Resources Board Resolution 20-28 amended Sections 95350, 95351, 95352, 95353, 95354, 95355, 95356, 95357, 95358 and 95359; and adopted new sections 95354.1, 95357.1 and 95359, Title 17 California Code of Regulations.

- Incorporating air-insulated switchgear at the Alberhill Substation in lieu of gas-insulated switchgear.
- Leveraging the use of existing infrastructure that has already been constructed as part of the Valley-Ivyglen 115 kilovolt (kV) Subtransmission Line Project.
- Utilizing helicopter construction previously analyzed in the FEIR to eliminate three of the five transmission structure access roads originally proposed.

SCE also submitted an amended Proponent's Environmental Assessment (PEA) that documents the analysis of the revised ASP scope.

PROPONENT'S ENVIRONMENTAL ASSESSMENT

The SCE Third Amended Application Chapter 3 (Project Description) and Appendix M: Revised Project Description of the Third Amended PEA describe the principal design modifications and engineering refinements made to the ASP. The results of SCE's environmental analysis associated with the proposed project design are reflected in Appendix O: Revised Environmental Impact Analysis, attached to the Third Amended PEA.

Appendix O: Revised Environmental Impact Analysis (Third Amendment to the PEA Volume 2), "evaluates the potential environmental impacts associated with the ASP with the incorporation of the design modification and additional engineering refinements described in Appendix M: Updated Project Description. This process involved reviewing the changes to the proposed project and comparing them to the baseline conditions identified in the FEIR. The Revised Environmental Impact Analysis section was developed by taking the impact discussions from the FEIR and modifying them."[2]

CALIFORNIA ENVIRONMENTAL QUALITY ACT

California Environmental Quality Act (CEQA) Guidelines Article 11 establishes three types of Environmental Impact Reports (EIRs) when changes to a project occur after an EIR is certified: a subsequent EIR (Section 15162), supplemental EIR (Section 15163), and addendum EIR (Section 15164). As stated in CEQA Section 15164, an addendum to a previously certified EIR is appropriate if "some changes or additions are necessary but none of the conditions described in Section 15162 calling for preparation of a subsequent EIR have occurred." CEQA Section 15162 conditions are described below.

CEQA GUIDELINES SECTION 15162

(a) When an EIR has been certified or a negative declaration adopted for a project, no subsequent EIR shall be prepared for that project unless the lead agency determines, on the basis of substantial evidence in the light of the whole record, one or more of the following:

> (1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

[2] SCE Third Amended PEA, June 2023, Volume 2, Appendix O: Revised Environmental Impact Analysis, p. O-1.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted, shows any of the following:

(A) The project will have one or more significant effects not discussed in the previous EIR or negative declaration;

(B) Significant effects previously examined will be substantially more severe than shown in the previous EIR;

(C) Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or

(D) Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.

(b) If changes to a project or its circumstances occur or new information becomes available after adoption of a negative declaration, the lead agency shall prepare a subsequent EIR if required under subdivision (a). Otherwise, the lead agency shall determine whether to prepare a subsequent negative declaration, an addendum, or no further documentation.

(c) Once a project has been approved, the lead agency's role in project approval is completed, unless further discretionary approval on that project is required. Information appearing after an approval does not require reopening of that approval. If after the project is approved, any of the conditions described in subdivision (a) occurs, a subsequent EIR or negative declaration shall only be prepared by the public agency which grants the next discretionary approval for the project, if any. In this situation no other responsible agency shall grant an approval for the project until the subsequent EIR has been certified or subsequent negative declaration adopted.

(d) A subsequent EIR or subsequent negative declaration shall be given the same notice and public review as required under Section 15087 or Section 15072. A subsequent EIR or negative declaration shall state where the previous document is available and can be reviewed.

WSP USA INC. REVIEW

This memorandum (memo) documents the WSP USA Inc (WSP) review of SCE's Third Amended PEA on behalf of the CPUC. It is an independent review and analysis of information furnished by the applicant via the PEA. The review is framed by CEQA Guidelines Sections 15162–15164 and the three types of environmental documentation that may be required when changes to a project occur after an EIR is certified. WSP, on CPUC's behalf, has reviewed the environmental impact data provided by SCE in the amended PEA and Data Responses and independently analyzed and judged the data as reliable and consistent with the responsibility of the Lead Agency in 14 CCR 15090 (a)(3). This memo documents key findings related to validating SCE's environmental analysis methodologies and impact conclusions. This memo also documents meaningful consideration of applicant-proposed changes to mitigation measures from the FEIR, including previous Applicant Proposed Measures (i.e., Project Commitments). The memo identifies whether an EIR addendum is the appropriate CEQA documentation or if changes or additions are significant and a subsequent or supplemental EIR may be required in relation to the changes to the proposed project by the applicant.

As discussed under the Project Background above, a Supplemental Alternatives Screening Report is being developed separately. This report will provide the results of the screening evaluation for each alternative identified by SCE in the supplemental analyses required by Decision (D. 18-08-026). Therefore, the Supplemental Alternatives Screening Report will address CEQA Guidelines Sections 15162 (a) (3) (D) "alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment."

CEQA Guidelines Section 15162 - Circumstances under which the Project is Undertaken

CEQA Guidelines Section 15162 (a) (2) would require a subsequent or supplemental EIR if "substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration."

Substantial changes have not occurred with respect to the population growth circumstances under which the ASP is undertaken. A review of population growth data in the proposed project area revealed that the population of unincorporated Riverside County and the cities of Lake Elsinore, Perris, and Menifee continued to grow between years 2020 and 2023. City of Menifee's population growth between 2020 and 2023 was 7.3 percent and cities of Lake Elsinore and Perris had a smaller changes, 2.4 percent and 0.3 percent, respectively. The City of Wildomar experienced a small decrease in population between 2020 and 2023. Therefore, overall population growth during this time frame does not reflect a substantial change compared to the 2017 FEIR. Table 1 presents 2020 and 2023 population counts for unincorporated Riverside County and cities within the proposed project area.

Table 1: 2020 and 2023 Population in the Proposed Project Area

LOCATION	SCAG 2020 PROJECTION FROM 2017 FEIR	2020 CENSUS	2023	CHANGE FROM 2020 CENSUS TO 2023	
				TOTAL	PERCENT
Unincorporated Riverside County	386,317	N/A	401,693	N/A	N/A
City of Lake Elsinore	63,041	70,265	71,973	1,708	2.4%
City of Perris	78,147	78,700	78,948	248	0.3%
City of Menifee	93,836	102,527	110,034	7,507	7.3%
City of Wildomar	38,690	36,875	36,336	-539	-1.5%

Sources: Ecology and Environment 2017; U.S. Census Bureau 2020; CDF 2023

The City of Lake Elsinore 2011 General Plan and the City of Menifee 2013 General Plan still remain in effect. The environs surrounding the project site have continued to develop with land uses as allowed for under the respective general plans covering the area. Minor updates to other general plan elements within the proposed project area have occurred. These changes along with other relevant changes related to specific resource areas are documented under the Resource Section Reviews and Findings Section below.

SUMMARY OF FINDINGS

Analysis of potential environmental impacts resulting from the technical design modifications and engineering refinements outlined in SCE's Third Amended Application and PEA focuses on the environmental resources covered in the 2017 FEIR. As shown in the analysis below, the proposed technical design modifications and engineering refinements to the ASP would not result in a substantial increase in the severity of a previously identified significant effect, new significant effects, or findings that new or substantially modified mitigation measures or alternatives that would reduce one or more significant effects. One mitigation measure (MM), MM TT-2, was updated under transportation and traffic Impact TT-2. Consistent with the approach taken in the FEIR for the original proposed project's impacts, the amended proposed project would implement a slightly modified version of mitigation measure MM TT-2 that extends the measure's applicability to also include Menifee Road at Pinacate Road (State Route [SR] 74) during the AM peak hour.

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The analysis also concludes that, with the implementation of previously identified Applicant Proposed Measures (or Project Commitments) and adopted mitigation measures defined in the Mitigation, Monitoring, Compliance, and Reporting Plan, impacts of the proposed technical design modifications and engineering refinements would be minor and less than significant. As a result, no major revisions to the certified FEIR are necessary to reflect the environmental impacts of the amended proposed project.

RESOURCE SECTION REVIEWS AND FINDINGS

AESTHETICS

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. One change of import, critical to the visual aspect of project development, is the use of air-insulated switchgear at the Alberhill Substation in lieu of gas-insulated switchgear. There are several components of the substation that would deviate from the gas-insulated version, including the size of the control building from 7,040 to 10,500 square feet; the height of the surrounding concrete block wall from 8 to 14 feet; and the height of the switch racks from 49 to 65 feet tall. The most notable change is that all switchgear components, previously enclosed within a steel enclosure that was approximately 350 feet long, 60 feet 20 wide, and 49 feet high, would now be constructed in the open. While the substation remains visible from Key Viewpoints 3 and 4 under both the original and amended proposed project, the air-insulated switchgear is more prominent within the landscape than the gas-insulated enclosed structure, as demonstrated through the revised visual simulations provided in the 2023 PEA.

Impact AES-1: Substantial adverse effect on a scenic vista

The 2017 FEIR concluded the proposed project would result in less than significant impacts on a scenic vista. The only designated scenic vista in the proposed project area that would be visible or noticeable is City of Lake Elsinore General Plan Vantage Point 1. Part of 115-kV Segment ASP4 would be visible from Vantage Point 1. Due to distance and intervening terrain and structures, the proposed project would not be noticeable from Vantage Point 2. As previously described in FEIR Section 4.1.1.4, none of the other vantage points are oriented toward components of the ASP. The amended proposed project would not result in visibility from any additional vantage points than the original proposed project; therefore, no new significant impacts would result from the amended proposed project in regard to Impact AES-1, and no major revisions to the FEIR would be warranted.

Impact AES -2 (ASP): Substantially damage scenic resources, including, but not limited to, trees, 2 rock outcroppings, and historic buildings within a State Scenic Highway.

The 2017 FEIR concluded the proposed project would result in significant unavoidable impacts, designated AES-2 in the 2017 FEIR, as Interstate (I) 15 through the project area is an Eligible State Scenic Highway. All Eligible State Scenic Highways were treated the same as Designated State Scenic Highways, to preserve their eligibility for official designation. As described in the FEIR, the Alberhill Substation, portions of the 500-kV transmission lines, and portions of 115-kV Segments ASP1 through ASP5 would be visible from I-15 at Key Viewpoints 3, 4, 5a, and 5b. The project, as amended, would also be visible from viewpoints along I-15. Construction impacts would be similar under both the original proposed project and the amended proposed project. There would be additional staging areas under the amended proposed project, and helicopters would be used in erection of the 500-kV lines.

As described above, the most notable change is the conversion of the gas-insulated switchgear to air-insulated switchgear within the substation. Components previously screened within an enclosed structure would now be highly visible within the landscape, as demonstrated within the revised visual simulations for Key Viewpoints 3 and 4.

The amended proposed project would implement the same commitments and mitigation measures as described in the FEIR for the original proposed project. Under Project Commitment A, as described in 2-13 in the 2017 FEIR, the applicant would develop and implement a Landscaping and Irrigation Plan for the substation site and, pursuant to this plan, maintain the substation site and be responsible for its upkeep as long as the applicant owns the property. The FEIR concluded that landscaping is unlikely to substantially screen views or reduce the contrast of the substation in views from I-15 given the massive scale of the substation structures and given that viewers from I-15 are elevated above the substation. Furthermore, a majority of the substation, transmission structures, and distribution structures would be visible. Impacts on views from I-15 in this area would remain significant even after implementation of Project Commitment A. Several mitigation measures also would be implemented. MM AES-6 would require limiting cut and fill to that necessary to reduce the amount of visual change in topography. MM AES-7 would require the applicant to utilize colors and finishes for the aboveground structures at the Alberhill Substation to reduce its visual impact. Even after mitigation, a majority of the substation, transmission structures, and distribution structures would remain visible and would still result in a marked decrease in vividness, intactness, and unity of views from the eligible scenic highway corridor. MM AES-8 would require treatment of the structures closest to I-15 to be colored to blend with the natural surroundings, with a dark finish. This would help reduce impacts, but the structures would still be silhouetted against the sky above the ridgeline and introduce a new industrial element in a relatively nonindustrial area.

Even with implementation of commitments and mitigation measures, the 2017 FEIR concluded that the ASP would result in significant and unavoidable impacts for AES-2. This conclusion remains valid. The amended proposed project would not have any significant environmental impacts not previously disclosed in the 2017 FEIR, nor would there be a substantial increase in the severity of previously identified significant environmental impacts. Therefore, given the extent of impact to view degradation previously disclosed in the FEIR, no major revisions to the FEIR are recommended.

Impact AES-3 (ASP): Substantially degrade the existing visual character or quality of the site and its surroundings.

The 2017 FEIR concluded the original proposed project would result in significant impacts from degradation to the existing visual character or quality of the site and its surroundings, identified as Impact AES-3, which could be mitigated to be less than significant. Regarding construction impacts, Project Commitment D requires that disturbed areas are revegetated, and the FEIR included MM AES-1, which requires that staging areas are screened with material that is visually consistent with the surrounding area. These would apply to the amended proposed project as well, and therefore, conclusions of less than significant with mitigation remain valid.

The FEIR concluded that 115-kV Segment ASP4 and ASP5 would result in a significant operational and maintenance impacts because of their location in an area where the setting is more rural and there is no or limited existing galvanized steel infrastructure and fewer modifications to natural elements. Location impacts include:

- 115-kV Segment ASP4.
  - From the intersection of Murrieta Road and La Piedra Road to the intersection of Murrieta Road and Craig Avenue.
  - From the intersection of Murrieta Road and Beth Avenue to the intersection of Murrieta Road and Scott Road/Bundy Canyon Road.
- 115-kV Segment ASP5.
  - From the intersection of Murrieta Road and Scott Road/Bundy Canyon Road to 520 feet northeast of the intersection of Citrus Grove and Lemon Street.
  - From the intersection of Almond Street and Lemon Street to the intersection of Waite Street and Jo Ann Court.

The amended proposed project would result in similar impacts. (It should be noted the segments identified as ASP4 and ASP5 in the 2017 FEIR are now labeled ASP5 and ASP6).

The FEIR includes MM AES-9, which would require utilizing poles in these areas that are made of wood, self-weathering, or galvanized steel (with appropriate colors, finishes, or textures), which would result in less contrast with vegetation and development and would result in less of a visual change in quality and character from current wood poles. With implementation of MM

AES-9, visual impacts would be less than significant. This measure would continue to apply to the amended project components (ASP5 and ASP6); no major revisions to the FEIR would be warranted.

Impact AES-4 (ASP): Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area.

The 2017 FEIR concluded the proposed project would result in less than significant impacts after the application of mitigation impacts as identified under Impact AES-4. Some nighttime views could be impacted if construction were required to occur during evening hours. MM AES-5 would reduce construction impacts associated with light and glare. The same mitigation would apply to the amended proposed project and no substantial change in impacts would result.

New sources of nighttime lighting would be introduced at the proposed Alberhill Substation. The applicant would use low-pressure sodium lighting at the proposed substation, which would comply with county ordinances. Additionally, the FEIR concluded that the proposed project could introduce new sources of glare because of the installation of components with reflective surfaces. The amended proposed project would include the same features that could contribute to this potential impact. Like the proposed project, the amended proposed project would implement mitigation measures MM AES-3, MM AES-7, MM AES-8, and MM AES-9. With implementation of this mitigation, the amended proposed project would have a less than significant impact in regard to light and glare. Because the impact of the amended proposed project is consistent with that analyzed in FEIR, no major revisions to the FEIR's impact findings or mitigation measures are warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The proximate segments of both I-15 and SR-74 both remain as "eligible" State Scenic Highways; neither has been officially designated or delisted. The City of Lake Elsinore 2011 General Plan still remains in effect, and no changes to vantage points have occurred since publication of the 2017 FEIR. The environs surrounding the proposed project site have continued to develop with land uses as allowed for under the respective general plans covering the area. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the proposed project would not result in any new or substantially more severe impacts to aesthetics than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in significant and unavoidable impacts with mitigation under Impact AES-2. Mitigation measures for the original proposed project would be applied to the amended proposed project. No additional mitigation is available that would reduce impacts under AES-2. In conclusion, no additional mitigation measures are available to reduce the impacts of the amended proposed project. No major revisions to the FEIR would be required. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

AGRICULTURE AND FORESTRY RESOURCES

(1) **Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;**

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the FEIR, as do most of the various project components. The amended proposed project would result in minor modifications to temporary construction areas and permanent disturbance areas relative to designated farmland.

Impact AG-1: (ASP): Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use.

The 2017 FEIR concluded the proposed project would result in less than significant impacts to important farmland. As discussed in the FEIR, construction activities would temporarily impact about 0.69 acres of Farmland of Statewide Importance. This small area would be negligible (0.0004 percent) compared to the total amount of farmland in Riverside County (196,568 acres). The temporary disturbance of farmland would not occur all at once, would not occur during the entire construction period, and would not result in permanent conversion of farmland to nonagricultural use. One proposed ASP structure would permanently disturb a combined total of about 0.05 acres of farmland. This small area would be negligible (0.00003 percent) compared to the total amount of farmland in Riverside County (196,568 acres). Additionally, existing agricultural uses would continue during operation of the proposed project and the applicant would coordinate maintenance with agricultural landowners (Project Commitment I).

The amended proposed project would result in slightly more temporary disturbance—0.71 acres of Prime Farmland and 0.78 acres of Farmland of Statewide Importance from the preparation and use of structure work areas and installation of a new underground duct bank and vault associated with 115-kV Segment ASP8. This small area would still be negligible (0.0008 percent) compared to the total amount of farmland in Riverside County (196,568 acres). Like the original proposed project, the amended proposed project's temporary disturbance would not occur all at once, would not occur during the entire construction period, and would not result in permanent conversion of farmland to nonagricultural use. Permanent areas of disturbance of farmland would be reduced under the amended proposed project from 0.05 to 0.04 acres. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact AG-1, and no major revisions to the FEIR would be warranted.

Impact AG-2 (ASP): Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural use or conversion of Forest Land to non-forest use.

The 2017 FEIR concluded that Impact AG-2 would be less than significant. As described in the FEIR, an agricultural water pipeline that was not in use crosses the proposed Alberhill Substation site. The pipeline is available for local agricultural and industrial uses if needed. Like the original proposed project, the amended proposed project would include relocation of the pipeline to the perimeter of the proposed substation site prior to construction of the substation. If the pipeline is in use during the relocation, a temporary two-day interruption of service could occur; however, this temporary interruption would not result in the conversion of farmland to nonagricultural use. There is no change to this temporary interruption estimate in the amended proposed project. There are no other planned long-term restrictions to land access during construction or operation in the amended proposed project. Like the original proposed project, the amended proposed project and the land defined as *Forest Land* do not overlap. No changes have been made to the amended proposed project that would necessitate changes to these conclusions. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact AG-2, and no major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The State Farmland Mapping and Monitoring Program mapping for Prime Farmland and Farmland of Statewide Importance has not changed within the areas of disturbance for the amended proposed project. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

a. **The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**

b. **Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the proposed project would not result in any new or substantially more severe impacts to agricultural and forestry resources than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded that the proposed project would result in less than significant impacts under this criterion. Because significant impacts were not found under this criterion, new mitigation measures that are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

AIR QUALITY

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

The Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components.

In most instances, one change in the proposed project could affect air quality. Project construction would use a hybrid approach of conventional and helicopter supported construction, which alters the construction emission profile compared to the 2017 FEIR. In addition to light- and heavy-duty helicopters, the applicant would also use medium-duty helicopters during construction of the amended proposed project. Helicopter use during construction of the 500-kV towers has also been further defined in the amended proposed project compared to the original proposed project description included in the 2017 FEIR. The applicant would use medium- and heavy-duty helicopters to facilitate construction of three of the proposed 500-kV transmission line towers in lieu of constructing new access roads. The main operational change for the proposed project, comprised of using air-insulated switchgear for some electric equipment, does not impact operational air quality.

The construction emission estimate for the telecommunication facilities was further updated from the PEA by a data request response from SCE. The emission update added emissions associated with installation of a manhole, duct bank, and underground cable. These components were not included in previous construction emission estimates. The emission totals referenced in the impact discussion below include the updated telecommunication construction emissions (SCE 2024a).

Impact AQ-1 (ASP): Conflict with or obstruct implementation of the applicable air quality plan.

The 2017 FEIR evaluated project construction and operation emissions with regards to relevant plans, policies, and regulations and analyzed conformity with those plans, policies, and regulations. The analysis concluded that the proposed project would be consistent with all applicable plans, policies, and regulations and there would be no impact.

The applicable air quality management plan (AQMP) is the 2022 South Coast Air Quality Management District AQMP. The plan focuses on reducing nitrous oxide (NOx) emissions to meet the 2015 federal ozone standard. To accomplish this, the AQMP emphasizes extensive use of zero-emission technologies for stationary and mobile sources but notes that federal action will be needed to increase use of zero-emission technologies. Measures already in place from previous AQMPs for NOx and other pollutants are carried forward into the 2022 AQMP.

Maximum daily criteria air pollutant construction emissions show decreases in projected construction emissions for both soil import options for the amended proposed project compared to the original proposed project. With regard to NO_x emissions, maximum daily emissions are shown to decrease from 1,090 pounds/day to 806 pounds/day for soil import option 1, and from 1,076 pounds/day to 802 pounds/day for soil import option 2.

The amended proposed project would result in a reduction in maximum daily construction air quality emissions for all criteria pollutants including NO_x when compared to the original proposed project. During operation, emissions from vehicles used for maintenance would be included within AQMP mobile source projections; therefore, no new significant impacts would result from the amended proposed project in regard to Impact AQ-1, and no major revisions to the FEIR are warranted.

Impact AQ-2 (ASP): Violate any air quality standard or contribute substantially to an existing or projected air quality violation.

The 2017 FEIR concluded that the proposed project would result in a significant impact after the application of mitigation measures.

The 2017 FEIR considered two methods for construction: a conventional approach and a helicopter-based approach. Each approach included two soil import options. The amended application evaluates one construction approach—a hybrid construction scenario combining helicopter and conventional construction methods with the two soil import options. Emission factors used for the construction analysis were updated from the values used in the 2017 FEIR to factors appropriate for 2025. The updated factors result in changes to emissions that offset an increase in emissions due to the hybrid construction approach. The hybrid construction scenario with either soil import option in combination with revised emission factors result in a projected decrease in maximum daily air pollutant emissions compared to the 2017 FEIR. However, for the hybrid construction scenario with either soil import option, construction emissions of volatile organic compounds, NOx, particulate matter $(PM)_{10}$ and $PM_{2.5}$ for the revised analysis would continue to exceed regional thresholds.

Operational emissions would be lower for the amended proposed project when compared to the 2017 FEIR except for PM_{10} and $PM_{2.5}$. However, maximum daily criteria pollutant operational emissions would not exceed any regional thresholds which is unchanged from the conclusion reached for the 2017 FEIR.

Mitigation measures identified in the 2017 FEIR would also be applied to the revised project for construction emissions. The mitigation measures are:

— MM AQ-1: Minimize NOx and PM emissions from off-road diesel powered construction equipment.
— MM AQ-2: Oxides of Nitrogen (NOx) credits.
— MM AQ-3: Dust Control Plan.
— MM AQ-5: Volatile Organic Compound credits.

The applicant indicated that only controlled construction emissions of PM10 and PM2.5 would be lower than uncontrolled emissions.

Based on the revised analysis, no new significant or substantially more severe impacts would result from the amended proposed project in regard to Impact AQ-2, which would remain as significant with mitigation. No major revisions to the FEIR would be warranted.

Impact AQ-3 (ASP): Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is nonattainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors).

The 2017 FEIR concluded that the proposed project would result in a significant with mitigation impact.

The proposed project is located in the South Coast air basin, which is designated nonattainment for ozone, PM_{10} and $PM_{2.5}$. In Impact AQ-1 (ASP), the amended proposed project construction emissions of NO_x (a pollutant regulated to control ozone formation) would decrease when compared to the original proposed project. For NO_x, the construction would not result in a net increase.

Based on the revised analysis, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact AQ-3, which would remain as significant with mitigation. No major revisions to the FEIR would be warranted.

Impact AQ-4 (ASP): Expose sensitive receptors to substantial pollutant concentrations.

The 2017 FEIR concluded that the original proposed project would result in a significant with mitigation impact.

Local significance thresholds and methodology used in the 2017 FEIR were applied to the analysis of the amended proposed project's construction emissions. The change in the construction approach to using a hybrid method and application of Project Commitment J would reduce all construction emissions to less than the local significance thresholds. Therefore, the amended proposed project would reduce Impact AQ-4 to less than significant.

During operation and maintenance, the 2017 FEIR concluded that emissions of criteria pollutants and toxic air contaminants from operation and maintenance would be substantially lower than project construction emissions due to reduced level of activity. The changes to the proposed project would not alter this conclusion. Therefore, the operation and maintenance of the amended proposed project would be less than significant. No major revisions to the FEIR would be warranted.

Impact AQ-5 (ASP): Create objectionable odors affecting a substantial number of people.

The 2017 FEIR concluded that this impact would be less than significant and the revised impact for the proposed project remains less than significant. The original analysis evaluated production of odors from construction activity and operation and maintenance. South Coast Air Quality Management District Rule 402 was used as the basis for determining if the proposed project would create an odor nuisance. Rule 402 prohibits discharges from any source in such quantities of air contaminants which cause injury, detriment, nuisance or annoyance to persons and the public.

The 2017 FEIR states that construction vehicle and equipment exhaust would create temporary odors from fuel combustion that affect a few residences in the vicinity of the 500-kV transmission line, 115-kV line and a construction staging area. The amended proposed project would not alter the number of people affected by odors from construction in these areas compared to the original proposed project. Therefore, the revised project would be less than significant. No major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken that result in new significant environmental effects or increase in the severity of previously identified significant effects. The construction phase of the amended proposed project would result in a decrease in emissions of some air pollutants, or a small increase or no change for some pollutants compared to the original proposed project. Impacts AQ-1 (ASP) through AQ-3 (ASP) and AQ-5 (ASP) remain unchanged from the 2017 FEIR. Impact AQ-4 (ASP) is changed from significant with mitigation to less than significant.

(1) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts to air quality than the original proposed project previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the proposed project would result in significant and unavoidable impacts with mitigation under Impact AQ-2, AQ-3, and AQ-4. Mitigation measures for the original proposed project would be applied to the amended proposed project. No additional mitigation is available that would reduce impacts under Impact AQ-2 and AQ-3. The amended proposed project would reduce Impact AQ-4 to less than significant. In conclusion, no additional mitigation measures are available to reduce the impacts of the amended proposed project. No major revisions to the FEIR would be required. As discussed in the Project Background, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

BIOLOGICAL RESOURCES

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. Changes of importance to consider, with respect to biological resources, are the construction and use of new temporary and permanent access roads and modifications to work and staging areas.

There are several elements of the 115-kV subtransmission lines (Segments ASP1 through ASP8), which would deviate from the original proposed project, primarily in Segments ASP2 and ASP8. Changes to Segment ASP2 consists of:

— Reconfiguring the 115-kV at the eastern end of Concordia Ranch Road to turn south and cross the I-15.
— Installing one new tubular steel pole (TSP) and modify two existing TSPs to facilitate adding a second circuit in the Temescal Canyon Road and Bernard Street vicinity.
— Adding undergrounding configuration along Pasadena Avenue within an existing duct bank and approximately 300 feet of new underground duct bank installed to the base of a new riser TSP.

Changes to Segment ASP8 include the installation of approximately three lightweight steel poles, two riser TSPs, 250 feet of underground duct bank, one subtransmission vault, and the replacement of one existing TSP near Murrieta Road in Menifee. Additionally, four 115-kV structures would be removed, and six existing structures would be modified.

Notably, the proposed 500-kV transmission line tower sites would require 24-hour vehicular access during operation of the proposed project for emergency and maintenance activities. As such, approximately 3.4 miles (a reduction of 2.7 miles from the original proposed project) of new or modified access roads, up to 26 feet wide, would be constructed to access the 500-kV transmission line structures. Additional permanent and temporary disturbance areas are anticipated at hilly terrain along the 500-kV transmission line route to support vehicle turnaround and positioning. At certain locations, the permanent, graded disturbance areas may be as wide as 220 feet (an increase of 20 feet from the original proposed project), whereas temporary disturbance areas may be as wide as 350 feet (a decrease of 150 feet from the original proposed project).

The design modification and additional engineering refinements to the proposed project as analyzed in the 2017 FEIR resulted in approximately 11.4 acres of temporary construction areas that have been added to the ASP footprint, which include the addition of four staging areas, six structure sites, one temporary disturbance area, and an extension of one underground trench that were not included in the 2017 FEIR.

Accordingly, the size of the 115-kV disturbance areas evaluated are specific to the resource area that may be impacted. For impacts on biological resources, consistent with the approach in the 2017 FEIR, it is assumed that the entire 115-kV general disturbance area would be disturbed. This approach ensures that the evaluation accounts for the full extent of impacts that could occur to various species.

Impact BR-1 (ASP): Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by the CDFW or USFWS.

The 2017 FEIR concluded the proposed project would result in less than significant impacts with mitigation on species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations or by the California Department of Fish and Wildlife (CDFW) or U.S. Fish and Wildlife Service (USFWS). Impacts would be most severe during construction, which includes the substation site, 500-kV transmission line route, and the proposed 115-kV subtransmission line routes, and would diminish during operations. Similar to the proposed project as analyzed in the 2017 FEIR, the amended proposed project impacts on all special-status species in all project areas within the Multiple Species Habitat Conservation Plan (MSHCP) boundaries are covered under the MSHCP, with the exceptions of impacts on Stephens Kangaroo Rat (SKR) (*Dipodomys stephensi*), which are covered under the SKR Habitat Conservation Plan (HCP).

Accordingly, SCE would obtain Participating Special Entity status through the issuance of a Certificate of Inclusion (COI) from the Riverside Conservation Authority (RCA). SCE would request concurrence from the USFWS and CDFW to allow for MSHCP coverage for the entire alignment of the proposed project.

The MSHCP would dictate the type and extent of avoidance, mitigation, and compensation measures for each covered species unless otherwise specified in project-specific mitigation measures. Furthermore, the proposed mitigation measures outlined in the FEIR would be implemented to reduce potentially significant impacts on special-status species to less than significant levels.

DIRECT AND PERMANENT IMPACTS

Direct and permanent impacts on special-status species or their habitat are associated with the installation of permanent components such as the proposed substation, 500-kV tower, and 115-kV pole footings, and new access roads, as well as the potential direct incidental take caused by construction. The amended proposed project would permanently impact approximately 58.1 acres of land (a reduction of 29.8 acres of permanent impact compared to the permanent impact anticipated from the original proposed project analyzed in the 2017 FEIR).

TEMPORARY IMPACTS

Temporary impacts on special-status species would result from the temporary use of staging areas, conductor pulling, stringing, and tensioning areas, the improvement and use of existing access roads, and the removal of existing towers. Dust, night lighting, and noise generated within and adjacent to components would also result in temporary impacts. The amended proposed project would temporarily disturb approximately 259.0 acres (a reduction of 10.0 acres from the original project analyzed in the 2017 FEIR).

Biological surveys were performed between 2009 and 2011 to identify sensitive plant and wildlife species and critical habitat presence near potential project components for the original proposed project application. On April 21, 2023, SCE accessed the online USFWS Threatened and Endangered Species Active Critical Habitat Report to update previous findings for the amended Proposed Alberhill Project. This online source, which is listed under Table 4.4-4 in the FEIR, identifies the presence of critical habitat.

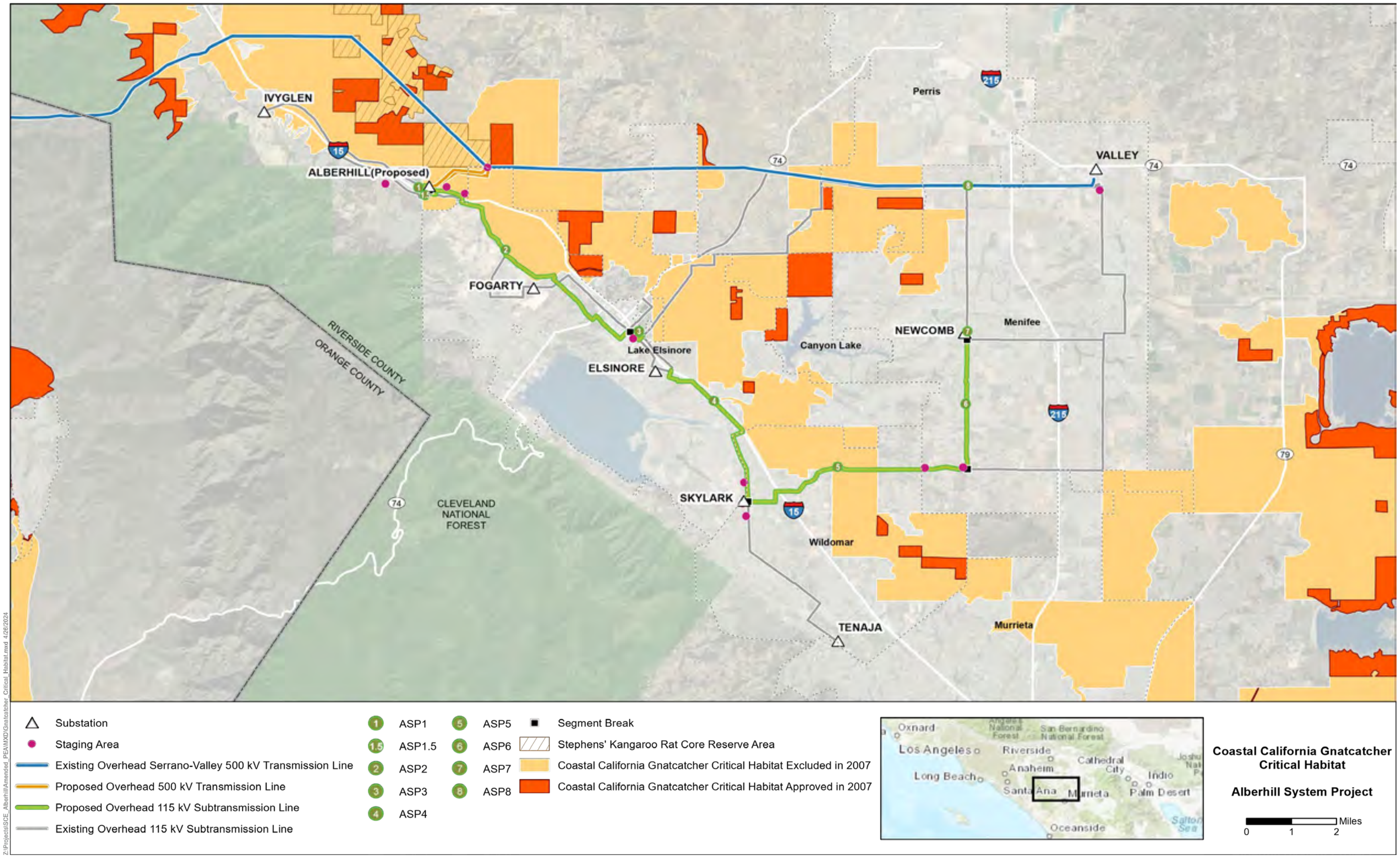
On September 21, 2023, Insignia Environmental performed a supplemental habitat assessment for SCE's Third Amended Application for the ASP. The survey area was limited to about 0.2-acre work area in Segment ASP8 not surveyed during previous vegetation community surveys. The habitat assessment included reviewing topographical maps, California Natural Diversity Database records, hydrological data from the National Hydrography Dataset, and a close transect survey. The survey results confirmed that existing vegetation type and special-status species potential to occur are consistent with the previous results identified in the Draft MSHCP Biological Resources Technical Report and 2017 FEIR, such as nonnative grassland and low-quality habitat for any potential special-status species. Furthermore, this survey area is consistently maintained and trimmed as part of operation and maintenance activities associated with SCE's preexisting transmission line corridor. Therefore, because vegetation types described in Tables 4.4-4, 4.4-5, and 4.4-6 in Appendix O: Revised Environmental Impact Analysis from the Third Amendment to the PEA are consistent with the 2017 FEIR, no further revisions would be required.

The Third Amendment to the PEA for the proposed project involved editing Table 4.4-4 to align with Figure 4.4-2 from the FEIR, which depicted the USFWS critical habitat data from 2000. However, these data are outdated. The USFWS had revised the critical habitat for the coastal California gnatcatcher (CAGN) (*Polioptila californica californica*) in 2007, reducing the area designated in 2000. SCE has since updated the critical habitat data for CAGN to the 2007 revision and confirmed that the amended proposed project's construction activities will not disturb this habitat (see Figure 1). The proposed Alberhill Substation site does not occur within designated critical habitat for CAGN. The nearest critical habitat is along the existing Serrano-Valley 500-kV Transmission Line, adjacent to structures M13-T3 and M13-T2, in the amended proposed project's northwestern portion. The critical habitat for CAGN that lies adjacent to the amended proposed project area would not be impacted by construction, as no ground-disturbing activities are planned within it.

No permanent impacts are anticipated for CAGN given that no ground disturbance would occur within CAGN critical habitat. Any impacts to CAGN in all amended proposed project areas are covered under the MSHCP; therefore, the MSHCP's avoidance, mitigation, and compensation measures for CAGN, consistent with the 2017 FEIR's mitigation measures, would be implemented to mitigate all impacts to less than significant levels.

Given that the ASP, both as analyzed in the 2017 FEIR and as amended, would be covered under the MSHCP and applicable HCP, the amended proposed project would not result in new or substantially more severe significant impacts than as discussed in the 2017 FEIR; therefore, no new significant impacts would result from the amended proposed project in regard to Impact BR-1, and no major revisions to the FEIR would be warranted.

Figure 1: California Gnatcatcher Critical Habitat



Source: SCE 2024b

Impact BR -2 (ASP): Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the CDFW or USFWS.

The 2017 FEIR concluded that the proposed project would result in less than significant impacts with mitigation under Impact BR-2, as direct, permanent impacts on special-status natural communities would result from the removal of vegetation for substation construction, pole/tower installation, helicopter platform, and access road construction. As described in the FEIR, impact analyses for special-status natural communities were completed by overlaying the applicant-provided GIS data for the vegetation communities over the general disturbance area for the ASP. As a result, several natural communities (e.g., chamise chaparral, coast live oak woodland, Riversidean sage scrub, Southern cottonwood-willow riparian woodland, and Southern sycamore-alder riparian woodland) designated as special status by the CDFW were identified at the proposed substation site and along the 500-kV and 115-kV transmission line routes.

Although the amended proposed project includes additional staging areas and access roads, the construction impacts would be similar under both the original and the amended proposed project. Of importance, impacts to Riversidean sage scrub will be reduced under the amended proposed project compared to the original analyzed in the 2017 FEIR. Specifically, approximately 49.06 acres of Riversidean sage scrub (part of sensitive community alliances according to the California Natural Diversity Database and a sensitive community under the MSHCP) would be impacted by the amended proposed project, whereas 55.33 acres of impacts were anticipated under the original.

Impacts on all special-status species in all project areas within the MSHCP boundaries are covered under the MSHCP. Furthermore, the amended proposed project would implement the same commitments and mitigation measures (MMs) as described in the FEIR for the original proposed project. Specifically, MM BR-7 requires the applicant to implement a Habitat Restoration and Revegetation Plan (HRRP) until the restoration success criteria are achieved. The appropriate agencies (CPUC, USFWS, and CDFW) will be consulted during the preparation of the HRRP. Consistent with MM BR-7 from the 2017 FEIR, the HRRP would be subject to the CPUC's approval and oversight. Additionally, the applicant will adhere to the Riverside County General Plan's established policies to protect oak woodlands and the City of Lake Elsinore General Plan Policy 2.2. Therefore, impacts under this criterion would be less than significant with the implementation of proposed project commitments and MMs BR-1 through BR-4, MM BR-6, MM BR-7, MM BR-9 as described in the FEIR. No major revisions to the FEIR would be warranted.

Impact BR-3 (ASP): Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means.

The 2017 FEIR concluded that the proposed project would result in less than significant impacts with mitigation relative to Impact BR-3. Similar to the original proposed project, several wetland drainages or riparian areas, including many known to be subject to federal jurisdiction, have been identified in proximity to the amended proposed project. Numerous vernal pools were also identified and surveyed as potential habitat for branchiopods.

The amended proposed project would consist of constructing new access roads and additional vegetation clearing, which exposes topsoil to weathering and erosion, and the installation of facilities within wetland or upland drainage areas would result in direct, permanent impacts on federally protected wetlands per Section 404 of the Clean Water Act. Additional direct impacts on wetlands may result from topographic changes that affect wetland hydrology and input of pollutants.

The potential permanent impacts anticipated to waters under the jurisdiction of the CDFW remain the same as was expected in the original proposed project. However, the anticipated total temporary impacts to waters increased in the amended proposed project to 1.3 (previously 0.5 acres) acres under U.S. Army Corps of Engineers (USACE) jurisdiction and 3.7 acres (previously 1.71 acres) under CDFW jurisdiction. No new major water features were identified to be impacted by the construction of the amended proposed project. Furthermore, the mitigation measures described in the FEIR also apply to the amended proposed project. MMs BR-1, BR-2, and BR-3, which would limit construction to designated areas and protect aquatic resources, require site-specific surveys and biological monitoring. MM BR-15 would control erosion, sedimentation, and input of pollutants. The mitigation measures identified in the 2017 FEIR, when applied to the additional areas would reduce the impacts to those additional areas to a less than significant level. Therefore, the FEIR conclusion of less than significant with mitigation remains valid and no major revisions to the FEIR would be warranted.

Impact BR-4 (ASP): Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites.

The 2017 FEIR concluded that the proposed project would result in less than significant impacts relative to Impact BR-4. The FEIR evaluated specific ASP sites that would be located in existing blocks of contiguous habitat for covered species and corridors for species per the MSHCP.

Impacts under BR-4 are consistent with the original proposed project as analyzed in the 2017 FEIR. As discussed under Impact BR-1, a supplemental habitat assessment performed on September 21, 2023, did not identify any potential special-status species that were not previously considered. Additionally, the surveyed area contains very limited and low-quality habitat for any potential special-status species in the vicinity due to nonnative grasses being maintained (i.e., trimmed) at ground level. No substantive changes to this impact discussion from the 2017 FEIR are warranted.

Impact BR-5 (ASP): Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance.

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts relative to Impact BR-5. Given that the amended proposed project would occur in the same local jurisdictions as described in the 2017 FEIR for the original proposed project, no additional conflicting local policies or ordinances protecting biological resources, such as tree preservation policies or ordinances are anticipated.

Therefore, the amended proposed project would still comply with all applicable local ordinances and policies. The construction of the substation and other project components would still require the removal of approximately 12 oak trees and trimming numerous more. Several local policies and ordinances govern the removal or trimming of such trees (e.g., Riverside County Roadside Tree Ordinance 12.08.050, Section 5.116 of the City of Lake Elsinore Municipal Code, Riverside County's General Plan, City of Lake Elsinore General Plan Policy 2.2). These ordinances require permits to remove or trim certain types of trees. The applicant would obtain all necessary permits before removing or trimming these trees. For these reasons, no new or substantially more severe significant impacts would result and no major revisions to the FEIR are warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

Impact BR-6 (ASP): Conflict with the provisions of an adopted Habitat Conservation Plan, Community Conservation Plan, or other approved local, regional, or state habitat conservation plan.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation (i.e., issuance and adherence of the SKR HCP Implementation Agreement and MSHCP COI). No substantial changes have occurred concerning the circumstances under which the amended proposed project is being undertaken. The amended proposed project would still be covered under the SKR HCP. The HCP area would still be impacted by directly removing suitable SKR habitat during construction. Accordingly, the applicant finalized an SKR HCP Implementation Agreement on October 15, 2012, which provides a process through which the applicant may obtain take authorization of SKR per the SKR HCP. This Implementation Agreement is also applicable on lands owned by Castle and Cooke.

All project components, except for an approximately 2-mile-long section of 115-kV Segment ASP2, would be constructed in MSHCP-covered areas. However, the applicant will still enter into an agreement with the RCA to allow for coverage of the entire project, including ASP2, under the MSHCP. The applicant will need to finalize a COI before construction, and the finalized COI would be included in the Notice to Proceed (NTP) request for the ASP.

Furthermore, the mitigation measures described in the FEIR also apply to the amended proposed project. The applicant will be required to consult with the USFWS, CDFW, RCA, and Riverside County Habitat Conservation Agency (RCHCA) before, during, and after construction of the proposed project (as applicable) regarding oak trees, special-status plants, nesting birds, burrowing owl impact avoidance and reduction. Additional measures would be implemented to avoid take of SKR within the Lake Mathews-Estelle Mountain Core Reserve and avoid disturbance of occupied SKR habitat to the maximum extent feasible. Because the impacts of the amended proposed project are consistent, even where modified, with the impacts discussed in the 2017 FEIR and will be mitigated to a less than significant level through the implementation of the mitigation measures in the 2017 FEIR, no revisions to the FEIR are warranted. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) **New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete, or the Negative Declaration was adopted:**

   a. **The project will have one or more significant effects not discussed in the previous EIR or negative declaration; or**

   b. **Significant effects previously examined will be substantially more severe than shown in the previous EIR.**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with biological resources than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

   c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

   d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts with mitigation and less than significant impacts (without mitigation) under this criterion. Because significant impacts were not found under this criterion, new mitigation measures, which are considerably different from those analyzed in the previous FEIR, that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the Project Background Section, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

CULTURAL RESOURCES

(1) **Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;**

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original project in the FEIR, as do most of the various project components. One change of importance to cultural resources is that the amended proposed project included an additional 11.4 acres of temporary construction areas that were not previously covered by a previous cultural resource study for the original proposed project. The additional temporary construction areas include four staging areas, six structure work areas, one temporary disturbance area, and an extension of one underground trench.

Based on the new amended proposed project footprint the Area of Potential Impact (API) changed (referred to as the *Supplemental API*). SCE conducted a cultural resources analysis to identify survey gap areas in the Supplemental API. SCE used previous studies for the ASP and the Valley-Ivyglen Project and other previous studies in the area to identify survey gap areas. Previous studies and record searches conducted in 2008 and 2019 did not identify any previously recorded cultural resources within the Supplemental API, nor any newly identified resources within the project area analyzed in the 2017 FEIR. Based on this review, SCE determined 11.5 acres of land had not been included in previous cultural resources studies and a supplemental survey was required. A pedestrian survey of the 11.5-acre additional project areas was conducted on May 4 and 5, 2023. The 2023 pedestrian survey (Rincon Consultants 2023) did not identify any new or previously recorded cultural resources within the Supplemental API.

Impact CR-1 (ASP): Substantial adverse change in the significance of an historical resource or an archaeological resource.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to a substantial adverse change in the significance of an historical resource or an archaeological resource.

The FEIR disclosed that there are no known prehistoric-age resources or unique archaeological resources on the Alberhill Substation site or immediately adjacent to 115-kV Segments ASP1 and ASP1.5 and the 500-kV transmission lines. There is one known prehistoric-age isolate along 115-kV Segments ASP2 through ASP8, which was previously determined to be not eligible for the National Register of Historic Places or California Register of Historic Resources, and therefore is not a historical resource as defined by CEQA. There are 16 known historic-age resources in, on, or adjacent to the Alberhill Substation site and 115-kV and 500-kV transmission line segments, however only eight were determined or assumed to be historical resources as defined by CEQA in the FEIR. The FEIR determined that impacts would be less than significant with implementation of mitigation measure CR-1b to avoid seven of the historical resources, and that impacts to Temescal Valley Road would be less than significant without avoidance.

The amended proposed project did not change the feasibility of avoidance of the seven historical resources, nor are the proposed project activities on Temescal Valley Road so changed that they may alter the finding of less than significant impact.

The amended proposed project includes four staging areas, six structure work areas, one temporary disturbance area, and an extension of one underground trench outside the previous cultural study boundaries. SCE conducted a records search at the Eastern Information Center and pedestrian survey for these additional areas. The study did not identify any new or previously recorded cultural resources (Rincon Consultants 2023).

There is a potential for discovery of previously unknown prehistoric-age and historic-age cultural resources and unique archaeological resources during substation and 115-kV alignment construction activities. The FEIR disclosed that construction impacts could potentially include physical damage or alteration, change in visual elements of a resource, and destruction of a resource. Impacts to previously unknown cultural resources would be significant if the resources are considered historic resources and if the impacts are substantial and adverse. Project Commitment B would require the applicant to prepare a Worker Environmental Awareness Plan which would include information on recognition of cultural resources and when to suspend work if a cultural resource is encountered. MM CR-1a requires the applicant to ensure surveys have been conducted in all work areas and staging areas prior to construction. MM CR-1b requires preparation of a plan outlining the procedures for analyzing a previously unknown resource discovered during construction activities. MM CR-2 outlines monitoring requirements, including involvement of Native American tribes and groups to determine Native American monitoring locations. There would be no potential to affect known or previously unknown historic-age or prehistoric-age historical resources or unique archaeological resources during operation and maintenance. With implementation of Project Commitment B, MM CR-1a, MM CR-1b, and MM CR-2 impacts to previously undiscovered cultural resources would be less than significant.

The amended proposed project would not result in any new or more severe impacts to previously undiscovered cultural resources than the original proposed project. As described above, the 2023 pedestrian survey did not identify any new or previously recorded cultural resources within the Supplemental API. The amended proposed project would still implement Project Commitment B, MM CR-1a, MM CR-1b, and MM CR-2; therefore, no new significant impacts would result from the amended proposed project in regard to Impact CR-1, and no major revisions to the FEIR would be warranted.

Impact CR-2 (ASP): Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature.

The 2017 FEIR concluded the proposed project would result in less than significant impacts with mitigation relative to destruction of a unique paleontological resource or site or unique geologic feature. The FEIR disclosed that there are no known unique paleontological resources or sites or unique geologic features in the proposed project area; however, undiscovered surface and subsurface paleontological resources could occur. Construction ground disturbance and excavation could destroy undiscovered paleontological resources and result in a significant impact. MM CR-4 would require monitoring where there is a reasonable potential for discovery of fossils in the project area and MM CR-5 outlines procedures to follow if a paleontological resource is discovered during construction. There would be no potential to affect known or previously unknown unique paleontological resources or unique geologic features during operation and maintenance. With implementation of MM CR-4 and MM CR-5, impacts would be less than significant.

The project, as amended, would not result in any new or more severe impacts to a known unique paleontological resource or site or unique geologic feature than originally proposed. The amended proposed project would implement MM CR-4 and MM CR-5; therefore, no new significant impacts would result from the amended proposed project in regard to Impact CR-2, and no major revisions to the FEIR would be warranted.

Impact CR-3 (ASP): Disturb any human remains, including those interred outside of formal cemeteries.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to the disturbance of any human remains. The FEIR disclosed that there are no known Native American or other human remains in the project area. As noted in the FEIR, one potential archaeological resource located approximately 0.8 miles from the Alberhill Substation site may contain human remains. There is a possibility that previously unknown human remains may be encountered during construction activities that would be a potentially significant impact. MM CR-7 would require adherence to applicable laws as well as training of workers of the appropriate procedures to follow if human remains are discovered. There would be no potential to disturb human remains during operation and maintenance. With implementation of MM CR-7, impacts would be less than significant.

The project, as amended, would not result in any new or more severe impacts related to the disturbance of human remains than originally proposed. The amended proposed project would implement MM CR-7; therefore, no new significant impacts would result from the amended proposed project in regard to Impact CR-3, and no major revisions to the FEIR would be warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete, or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration; or**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR.**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with cultural resources that previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**
- **d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

GEOLOGY, SOILS, AND MINERAL RESOURCES

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant

environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. One change of importance to the construction and erosional impacts of the proposed project is SCE's intent to use helicopter construction methods, previously acknowledged in the FEIR, which would eliminate the need to construct certain access roads and thereby reduce temporary and permanent impacts associated with constructing those roads.

Impact GE-1 (ASP): Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving rupture of a known earthquake fault as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault (refer to Division of Mines and Geology Special Publication 42); strong seismic ground shaking; seismic-related ground failure including liquefaction; or landslides.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to earthquake faults or other seismic-related hazards. The FEIR disclosed that strong seismic ground shaking could cause damage to certain project components. Underground and aboveground components of the telecommunications system and transmission system would be subject to ground shaking. Ground shaking could cause poles to topple over and underground conduit to crack, potentially causing harm to people and damage to property. This impact would be significant. Project Commitment F would require the applicant to complete a geotechnical study and incorporate recommendations from the study into final engineering designs. With implementation of Project Commitment F, impacts would be less than significant.

The project, as amended, would not result in any new or more severe seismic-related impacts than originally proposed. The amended proposed project design is similar in respect to construction of poles and structures as the design analyzed in the FEIR and would implement Project Commitment F; therefore, no new significant impacts would result from the amended proposed project in regard to Impact GE-1, and no major revisions to the FEIR would be warranted.

Impact GE-2 (ASP): Result in substantial soil erosion or the loss of topsoil.

The 2017 FEIR concluded the original proposed project would result in potentially significant impacts relative to soil erosion or the loss of topsoil due its construction. The applicant would implement Project Commitment D, which would require restoration of temporarily disturbed areas and prevent erosion after construction. Project Commitment E would require preparation of a grading plan that would in part aim to reduce erosion. Project Commitment D would not address impacts during construction, and Project Commitment E would address erosion only from grading activities. Therefore, the FEIR also included MM BR-15, which would require implementation of certain erosion BMPs during construction as part of the stormwater pollution prevention plan (SWPPP) developed for the proposed project. The FEIR then concluded impacts would be less than significant after implementation of MM BR-15.

Construction impacts would be similar under both the original proposed project and the amended proposed project. There would be additional staging areas under the amended proposed project, and helicopters would be used in erection of the 500-kV lines, which would eliminate the need to construct certain access roads, thereby reducing temporary and permanent impacts associated with constructing those roads The amended proposed project would implement the same commitments and mitigation measures as describes in the FEIR for the original proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact GE-2, and no major revisions to the FEIR would be warranted.

Impact GE-3 (ASP): Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or offsite landslide, lateral spreading, subsidence, liquefaction or collapse;

Impact GE-4 (ASP): Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code, creating substantial risks to life or property.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to unstable or expansive soils. As disclosed in the FEIR, the proposed project would be located in areas with potential for landslides, liquefaction, and soil collapse. Subsidence may also occur, but the potential for subsidence is low. The shrink-swell potential of soils underlying the proposed project is also generally low. These various forms of soil instability could lead to damage to project components such as poles and conduit and may cause harm to people nearby in the event of collapse. Project Commitment F would require the applicant to complete a geotechnical study and incorporate recommendations from the study into final engineering designs.

The amended proposed project would result in similar risks and impacts as the geologic units and soils underlying the project component remain virtually unchanged. With implementation of Project Commitment F, impacts would be less than significant. This measure would continue to apply to the amended project components; no major revisions to the FEIR would be warranted.

Impact GE-5 (ASP): Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater.

The 2017 FEIR disclosed that the proposed Alberhill Substation site is not served by a public sewer system. A stand-alone, prefabricated, permanent restroom would be installed within the amended Alberhill Substation perimeter near the control building. The restroom would discharge to an onsite septic system. This plan is unchanged in the amended application.

The soils present at the proposed Alberhill Substation site are sandy and should accommodate septic system installation. There is a possibility that the soils may be inadequate to support a septic system, which would be a potentially significant impact. If a septic system is installed, the applicant would conduct a geotechnical investigation according to Project Commitment F, which would include a soils investigation. If, during the site-specific geotechnical investigation, some soils are found to be inadequate for supporting a septic system, the information obtained would be used to design a septic system that would be appropriate for site conditions pursuant to County permit requirements. Impacts would be less than significant. No new significant impacts would result from the amended proposed project in regard to Impact GE-5, and no major revisions to the FEIR would be warranted.

Impact GE-6 (ASP): Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state; and

Impact GE-7 (ASP): Result in the loss of availability of a locally important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to loss of a known mineral resource. The proposed project area includes areas with economically viable deposits of clay, sand, gravel, and stone products. Most of the proposed project area and western Riverside County are classified MRZ-3 (undetermined mineral resource significance), but areas along the I-15 corridor north of Lake Elsinore are classified MRZ-2 (areas where there are or there is a significant likelihood of significant mineral deposits). Project activities and structures would occur close to existing roadways, where mineral resource recovery is unlikely to occur. Construction activities and structures would therefore not conflict with existing mineral resource recovery activities, nor create a new impediment to future use of significant mineral resources.

The amended proposed project would result in similar impacts as the project components/footprints remain relatively unchanged. Therefore, no major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The City of Lake Elsinore General Plan (2011) and County of Riverside General Plan Multi-Purpose Open Space Element (2015) still remain in effect, and no changes to mineral resource zones designated by the City or County have occurred since publication of the 2017 FEIR. The environs surrounding the project site have continued to develop with land uses as allowed for under the respective general plans covering the area. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete, or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration; or**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR.**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with geology and soils than those previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts with mitigation and less than significant impacts (without mitigation) under this criterion. Because significant impacts were not found under this criterion, new mitigation measures that are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the Project Background Section, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

GREENHOUSE GASES

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components.

There are three changes to the amended proposed project: two changes in the construction phase and one change in the operational phase that affect GHG emissions but do not change the prior conclusion of less than significant.

Impact GHG-1: Generate GHG emissions, either directly or indirectly, that may have a significant impact on the environment.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts on GHG. The 2017 FEIR considered two methods for construction: a conventional approach and a helicopter-based approach along with two soil import options. The amended application evaluates one construction approach – a hybrid construction scenario combining helicopter and conventional construction methods with the two soil import options. The construction emission estimate for the telecommunication facilities was further updated from the PEA by a data request response from SCE. The emission update added emissions associated with installation of a manhole, duct bank and underground cable. These components were not included in previous construction emission estimates. The emission totals referenced in the impact discussion below include the updated telecommunication construction emissions (SCE 2024a).

The hybrid construction scenario (with either soil import option) and the telecommunication construction increase GHG emissions by approximately 850 metric tons (MT) of carbon dioxide equivalent (CO_2e) compared to the 2017 FEIR. In the amended application, construction with soil import option 1 results in total GHG emissions of 6,178 MT CO_2e; with soil import option 2, total GHG emissions would be nearly identical at 6,182 MT CO_2e. For the hybrid construction scenario with either soil import options, construction GHG emissions would remain below the threshold of 10,000 MT CO_2e, as established in the 2017 FEIR. No new significant impacts would result from the amended proposed project in regard to Impact GHG-1, and no major revisions to the FEIR would be warranted.

The proposed project would reduce the use of sulfur hexafluoride (SF6) insulating gas in electrical equipment from 65,000 pounds to 12,772 pounds, with a corresponding reduction in GHG emissions due to leakage from 3,361 MT CO_2e, as documented in the 2017 FEIR, to 660 MT CO_2e per year. As previously described in the 2017 FEIR, GHG emissions from the original proposed project operational phase would be below the threshold established in the 2017 FEIR of 10,000 MT CO_2e. The project, as amended would result in a reduction in GHG emissions from SF6 leakage due to the use of air-insulated switchgear instead of gas-insulated switchgear as originally proposed; therefore, no new significant impacts would result from the amended proposed project in regard to Impact GHG-1, and no major revisions to the FEIR would be warranted.

Impact GHG-2 (ASP): Conflict with any applicable plan, policy or regulation adopted for the purpose of reducing the emission of GHGs.

The FEIR evaluated project construction and operation emissions with regards to relevant plans, policies, and regulations, and analyzed conformity with those plans, policies, and regulations. The analysis concluded the original proposed project would be consistent with all applicable plans, policies, and regulations, and there would be no impact.

Subsequent to the 2017 FEIR, CARB Resolution 20-28 was approved, amending and adding several sections of the California Code of Regulations Title 17. The goal of the regulation changes is to reduce the quantity of SF6 used in electric equipment such as switchgear and circuit breakers. The project, as amended, would use air-insulated switchgear in place of gas-insulated switchgear and conform with CARB's updated regulations. Circuit breakers at Alberhill (500 kV) and 115-kV circuit breakers at Alberhill, Valley and Newcomb would be SF6 gas insulated. These circuit breakers would conflict with CARB's updated regulations unless the equipment meets exceptions in Subsection 3.1 § 95352 (a). SCE intends to phaseout SF6 gas-insulated equipment, in accordance with the CARB ruling. In the event project requirements—or factors outside of SCE's control—preclude SCE from phasing out said gas-insulated equipment by the proscribed phaseout dates, SCE will seek a Phaseout Exemption pursuant to Section 95357 of California Code of Regulations Title 17 (SCE 2023). Therefore, the amended proposed project would not alter the conclusions with respect to applicable plans, policies, and regulations due to the adoption of

CARB 20-28 subsequent to the 2017 FEIR and use of some gas-insulated electrical equipment. No major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken that result in new significant environmental effects or increase in the severity of previously identified significant effects. The construction phase would result in an increase in GHG emissions compared to the 2017 FEIR; however, the revised total GHG emissions would remain well below the thresholds of significance established in the FEIR. For the operational phase, the reduction in use of gas-insulated switchgear reduces the potential GHG emissions of SF6 from 3,361 MT CO_2e to 660 MT CO_2e, therefore Impact GHG-1 remains less than significant and Impact GHG-2 remains no impact.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts to GHG than previously disclosed in the 2017 FEIR, due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**
- **d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impact and no impact under this criterion. Because significant impacts were not found under this criterion, new mitigation measures that are considerably different from those analyzed in the 2017 FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

HAZARDS AND HAZARDOUS MATERIALS

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components.

Impact HZ-1 (ASP): Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials; and

Impact HZ-2 (ASP): Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to the routine transport, use, or disposal of hazardous materials or through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. The FEIR disclosed that construction and operation of the original proposed project would include the use, transport, and disposal of hazardous materials.

Specifically, construction of the amended Alberhill Substation would require the transportation of approximately 103,500 gallons of transformer oil. The amended proposed project would be required to comply with federal and state laws that regulate transport of hazardous materials. Furthermore, construction waste, including hazardous wastes, would be managed in accordance with federal, state, and local regulations and requirements. During operations, the applicant would store up to 103,500 gallons of transformer oil used as insulating media for the 500/115-kV transformers; approximately 960 gallons of diesel (Low-Sulfur Diesel No. 2) for the backup generator; and lead-calcium batteries would be stored in the control room at the proposed Alberhill Substation.

The applicant would transport, use, or dispose of hazardous materials and petroleum products in accordance with all applicable federal, state, and local regulations, including the preparation and implementation of a Spill, Prevention, Control, and Countermeasure plan (40 Code of Federal Regulations [CFR] Part 112) and a Hazardous Materials Business Plan (Riverside County Ordinance 651.3, California Health and Safety Code Section 25500) for construction and operation of the proposed Alberhill Substation. Additionally, the applicant would prepare and require all site workers to participate in Worker Environmental Awareness Plan training prior to construction, as described in Project Commitment B. The amended proposed project, like the original proposed project, would develop and implement a SWPPP as per MM BR-15 that would address prevention, control, and cleanup of upset and accident conditions involving the release of hazardous materials.

Hazardous material or waste sites were identified in proximity to the proposed project components, and unrecorded hazardous material sites may also be present. It remains possible that hazardous materials or wastes from undocumented releases may be encountered along the proposed routes because soil contamination in these areas has not been thoroughly investigated. Improper handling and disposal of soils from contaminated sites would result in a significant impact. The amended proposed project would implement Project Commitment F, which would include testing for soil contaminants as indicated by the Phase 1 results. The applicant would avoid or appropriately remove and dispose of such soil during construction. Furthermore, the amended proposed project would continue to implement Project Commitment B. Finally, the amended proposed project would continue to be conditioned to implement MM HZ-2, which would require the applicant to develop a Contaminated Soil/Groundwater Contingency Plan that would define procedures for soil and groundwater testing if unanticipated contamination is encountered and MM HZ-3, which would require the applicant to contact affected private landowners to determine if septic systems and associated leach fields, as well as other underground facilities, may be impacted by construction. Implementation of MM HZ-2 and HZ-3 would reduce impacts to a level less than significant.

The project, as amended, would not result in any new or more severe hazardous materials-related impacts than the original proposed project as considered in the 2017 FEIR. The amended proposed project would implement MM BR-15, MM HZ-2, and MM HZ-3, along with Project Commitments B and F; therefore, no new significant impacts would result from the amended proposed project in regard to Impacts HZ-1 or HZ-2, and no major revisions to the FEIR would be warranted.

Impact HZ-3 (ASP): Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within 0.25 miles of an existing or proposed school.

The 2017 FEIR disclosed that 12 schools are located within 0.25 miles of the proposed project 115-kV subtransmission segments. No schools are located within 0.25 miles of the proposed Alberhill Substation site or 500-kV transmission line routes. Construction and operation of the 115-kV subtransmission segments would not involve the handling or emission of hazardous or acutely hazardous materials as defined by CEQA Section 21151.4 in quantities equal to or greater than the state threshold quantities specified in Section 25532 of the California Health and Safety Code.

As discussed under Impact HZ-1 and Impact HZ-2, like the original proposed project, the amended proposed project could result in the release of hazardous materials during construction or operation of the proposed project. However, Project Commitments B and F and implementation of MM HZ-1, MM HZ-2, MM HZ-3, and MM BR-15, in addition to compliance with applicable laws and regulations, would reduce impacts under this criterion to less than significant levels. Therefore, because the impacts and mitigation measures are consistent with the 2017 FEIR, no major revisions would be warranted.

Impact HZ-4 (ASP): Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a significant hazard to the public or the environment.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to hazardous materials sites compiled pursuant to Government

Code Section 65962.5. As disclosed in the FEIR, the original proposed project would not be located on a Cortese List site. No other solid waste disposal sites, sites with cease and desist orders or cleanup and abatement orders, or the Department of Toxic Substances Control EnviroStor and hazardous waste sites were found within 1,000 feet of components of the proposed project. Two open-case leaking underground storage tank (LUST) sites, however, were listed in the California State Water Resources Control Board Geotracker database that would be located less than 100 feet from 115-kV Segment ASP4. It is not anticipated that excavation along 115-kV Segment ASP4 would expose contaminated soils, but impacts could occur if the fuel leaks have spread underground from the LUST sites into the right-of-way (ROW) or if undocumented sites or releases are discovered. This would lead to a potentially significant impact. The amended proposed project would be required to implement MM HZ-2, and like the original proposed project, impacts under this criterion would be less than significant with mitigation. No major revisions to the FEIR would be warranted.

Impact HZ-5 (ASP): For a project located within an airport land use plan or, where such a plan has not been adopted, within 2 miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area; and

Impact HZ-6 (ASP): For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to hazards associated with public airports or private airstrips. The FEIR disclosed that the proposed 115-kV Segment ASP8 would be located approximately 1.6 miles southeast of Perris Valley Airport but would not be located within a Perris Valley Airport Land use zone under the adopted Perris Valley Airport Land Use Compatibility Plan (Riverside County ALUC 2004a).115-kV Segment ASP8 would be located within the Perris Valley Airport Compatibility Zone E under the draft version of the revised Perris Valley Airport Land Use Plan (Riverside County ALUC 2010). Proposed structures are less than 150 feet in height; therefore, installation of these structures would not require airspace review under the draft version of the revised Perris Valley Airport Land Use Plan. Therefore, the amended proposed project would also result in less than significant impacts.

Sections of 115-kV Segments ASP4 and ASP5 would be located less than 1,000 feet east of Skylark Field Airport. Because the proposed structures would be less than 120 feet in height, installation of structures along ASP4 and ASP5 within the vicinity of the Skylark Field Airport would not result in a safety hazard for people working in the project area. The amended proposed project would also result in less than significant impacts, and no major revisions to the FEIR would be warranted.

Impact HZ-7 (ASP): Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to emergency response plan impairment. The 2017 FEIR disclosed that no emergency or evacuation routes are identified in relevant plans covering the project area. Consistent with the original proposed project, the amended proposed project would develop and implement traffic control plans for construction. No operational impacts would result from the original or amended proposed project. Therefore, impacts would remain less than significant under the amended proposed project and no major revisions to the FEIR would be warranted.

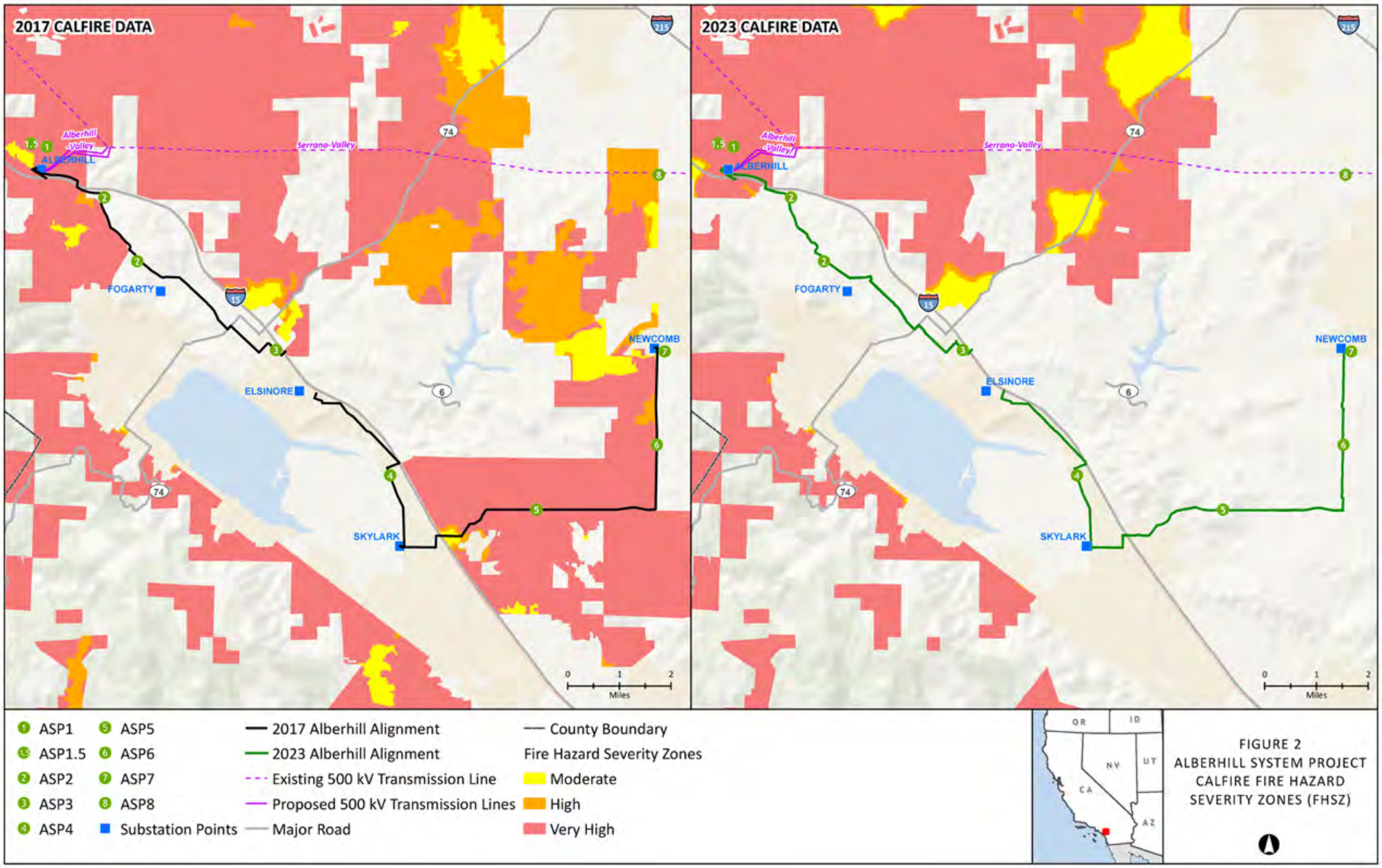
Impact HZ-8 (ASP): Expose people or structures to a significant risk of loss, injury, or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to wildland fire. The 2017 FEIR disclosed that components of the ASP project would be located in Very High Fire Hazard Severity Zones (FHSZ) and in areas identified by CAL FIRE as having significant potential for large, destructive wildfires (see Figure 2). Therefore, construction of the proposed project would substantially increase fire risk regardless of fire prevention systems that would be installed, vegetation clearing, and compliance with applicable laws, regulations, and standards. Operation of the proposed project would also increase fire risk.

Similar to the original proposed project, the amended proposed project would implement Project Commitment A, which requires the irrigation and continued maintenance of landscaping. The amended proposed project also would comply with California Public Resources Code vegetation management and CPUC requirements.

The amended proposed project's 500-kV transmission lines intersect with Very High FHSZ for approximately 1.87 miles, compared to 1.84 miles in the 2017 FEIR. The 115-kV Segments ASP1, ASP1.5, and ASP2 of the amended proposed project intersect with Very High FHSZ for approximately 2.31 miles compared to 2.11 miles in the 2017 FEIR. In addition, the Moderate, High, and Very High FHSZ designations were eliminated along 7.35 miles of the amended proposed project 115-kV Segments ASP3, ASP5, ASP6, ASP7, and ASP8 (see Figure 2). Impacts of the amended proposed project would be consistent with those identified in the 2017 FEIR (i.e., potentially significant given nearby residential areas), therefore, like the original proposed project, the amended proposed project also would be required to implement MM HZ-4, which requires the applicant to develop and implement a Fire Control and Emergency Response Plan that would reduce the risk of fire and impacts that would result should a fire occur. Implementation of MM HZ-4 would ensure that impacts under this criterion are less than significant during construction and operation. Because all impacts and mitigation measures are consistent with the 2017 FEIR, no major revisions are warranted.

Figure 2: Alberhill System Project CalFire Fire Hazard Severity Zones



Impact HZ-9 (ASP): Result in substantial safety risks to hang gliders.

The 2017 FEIR concluded that no impacts to hang gliders would result from implementation of the ASP. As noted in the 2017 FEIR, the vacant fields adjacent to Interstate-15 (I-15) where it crosses Nichols Road are used as a landing zone for hang gliders west of I-15. No changes in the height of 115kV lines would occur under the amended proposed project in proximity to the landing zone. No major revisions to the FEIR are warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

As discussed above, no substantial changes have occurred with respect to the circumstances (e.g., newly constructed schools, changes to airstrip land use plans, or listed hazardous waste sites) under which the proposed project is being undertaken. Fire Hazard Severity Zones in State Responsibility Areas are currently in regulatory review. September 29, 2023, Cal Fire maps indicate that project components in the northern portion of the project area, such as the Alberhill Substation, 500-kV transmission lines, and 115-kV Segments ASP1, ASP1.5 and ASP2, are located Very High Fire Hazard Severity Zones. Project components in the southern portion of the project area such as the 115-kV Segments ASP3 and ASP5 through ASP8 are no longer located in a Moderate, High, Very High Fire Hazard Severity Zones (as proposed) (Cal Fire 2023); however, none of these changes would alter the previous determination that the proposed project would result in impacts that are mitigated to a less than significant level. For this reason, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete, or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration; or**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR.**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with hazards and hazardous materials than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**
- **d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more**

significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation, less than significant impacts (without mitigation), and no impact under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

HYDROLOGY AND WATER QUALITY

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. One change of importance to the construction and erosional impacts is SCE's intent to use helicopter construction methods previously acknowledged in the FEIR, which would eliminate the need to construct certain access roads for the 500-kV project component, thereby reducing temporary and permanent impacts associated with constructing those roads.

An additional 16.5 acres of temporary construction areas would be required outside of the 2017 FEIR's identified general disturbance area for the Alberhill 115-kV project components. In total for all 115-kV project components there is a reduction of approximately 13.5 acres disturbed during construction, an additional 5.3 acres temporarily disturbed, and a reduction of 18.4 acres permanently disturbed. An additional external detention basin for a total of two detention basins are proposed on the Alberhill Substation site. Preliminary engineering indicates 120,000 cubic yards will be cut (an additional 29,000 cubic yards of soil than the original proposed project) and 185,000 cubic yards be filled (an additional 27,300 cubic yards than the original proposed project) at the Alberhill Substation site. Four proposed staging areas were deleted, and an additional four staging areas were added for the overall project.

Impact WQ-1 (ASP): Violate any water quality standards or waste discharge requirements.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to violation of water quality standards and waste discharge requirements. The FEIR disclosed that construction activities associated with the Alberhill Project would include activities that could result in the release of hazardous materials or sediment to waterbodies and drainages. Temporary ground disturbance, in aggregate, could result in substantial soil erosion and increase sedimentation. Resulting sedimentation, the release of existing contaminants into waters or drainage systems, and/or spills of hazardous materials during construction could adversely affect water quality and violate water quality standards resulting in a significant impact.

The applicant would implement Project Commitment D, which would require restoration of temporarily disturbed areas and prevent erosion after construction. Project Commitment B would require that workers be trained in hazardous materials spill notification procedures. Project Commitment E would require preparation of a grading plan that would in part aim to reduce erosion and sedimentation. However, the applicant did not propose measures to reduce the potential for hazardous materials spills, to clean up spills, to avoid situations that would result in sedimentation and erosion, to address water quality effects of blasting, and to reduce sedimentation and erosion caused by ground disturbance. The FEIR therefore also included MM BR-15, which would require implementation of certain erosion and sedimentation BMPs during construction as part of the SWPPP developed for the proposed project. The SWPPP would also include hazardous materials management, handling, transport, disposal, and emergency response plan. MM WQ-2 outlines procedures for drainage crossings and MM WQ-3 requires implementation of methods for access road construction that reduce erosion. MM BR-7 requires attainment of success criteria when implementing the restoration plan required under Project Commitment D. MM WQ-4 requires any discharged water be removed from the site or discharged away from waters of the United States and/or waters of the state. The FEIR then concluded water quality impacts during construction would be less than significant after implementation of the Project Commitments and mitigation measures and operational impacts would be less than significant.

Construction impacts would be similar under both the original proposed project and the amended proposed project. There would be additional staging areas under the amended proposed project, and helicopters would be used in erection of the 500-kV lines, which would eliminate the need to construct certain access roads, thereby reducing temporary and permanent impacts associated with constructing those roads. The amended proposed project, as amended, would not result in any new types of construction activities. The amended proposed project, including all project components, would have a reduction in approximately 29.63 acres of permanent ground disturbance compared to the impacts disclosed in the FEIR. The amended proposed project will result in an increase of 0.0129 acres of permanent impacts to waters of the United States and waters of the state. This represents a less than 1 percent increase in permanent impacts. As stated in the FEIR, to comply with Sections 404 and 401 of the CWA and the Porter-Cologne Water Quality Control Act, prior to discharging water, fill, or other materials in waters of the United States or waters of the state, the applicant would be required to apply for permits from the USACE and RWQCB. SCE would be required to submit a preconstruction notification to the USACE, obtain 401 Water Quality Certification from the RWQCB, and adhere to all conditions and mitigation included in the permits. The amended proposed project would implement the same Project Commitments as described in the FEIR for the original proposed project. Project Commitment D requires restoration of temporarily disturbed areas to preconstruction conditions, which would reduce the long-term sedimentation impacts of grading and ground disturbance. The 2017 FEIR disclosed that permanent impacts would occur on up to 87.9 acres after implementation of Project Commitment D. Under the amended proposed project, permanent impacts would occur on up to 58.1 acres after implementation of Project Commitment D (which represents a reduction of 29.8 acres). The amended proposed project would also implement the same mitigation measures as described in the FEIR for the original proposed project (as described above). The amended proposed project's operation and maintenance would not involve any new ground disturbance and the occasional use of access roads would not result in discharge of fill materials to waters of the state. Therefore, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact WQ-1, and no major revisions to the FEIR would be warranted.

Impact WQ-2 (ASP): Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted).

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to substantially depleting groundwater supplies or interfering substantially with groundwater recharge. As disclosed in the FEIR, water use for the proposed project would be temporary and not substantially deplete groundwater supplies in the Elsinore Groundwater Basin or the San Jacinto Groundwater Basin. In addition, dewatering activities would not affect groundwater levels in the aquifers used for groundwater supply. Impervious surfaces created by the project components would not interfere with groundwater recharge.

The amount of water required for construction would be the same under both the original proposed project and the amended proposed project. Anticipated dewatering activities during construction would be the same under the original proposed project and the amended proposed project. There would be a reduction in 1.9 acres of impervious surface created at the Alberhill Substation under the amended proposed project. Water usage during operations and maintenance would be the same under the original proposed project and the amended proposed project. Therefore, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact WQ-2, and no major revisions to the FEIR would be warranted.

Impact WQ-3 (ASP): Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on- or off-site.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to substantially altering the existing drainage pattern of the site or area that would result in substantial erosion or siltation. The FEIR disclosed that grading the Alberhill Substation site could substantially change drainage patterns and potentially result in substantial erosion and sedimentation on or off site. Grading and excavation required for the remaining project components could also alter existing drainage patterns at project sites and cause increased erosion due to soil disturbance. Temporary ground disturbance, in aggregate, could result in substantial soil erosion and increase sedimentation, particularly where there are drainage crossings. The applicant would implement Project Commitment A, which would require development and implementation of a landscaping and irrigation plan that would minimize erosion and sedimentation potential for the substation site. Project Commitment D would require restoration of temporarily disturbed areas and prevent erosion after construction. Project Commitment E would require preparation of a grading plan that would in part aim to reduce erosion and sedimentation. Impacts from erosion and siltation would be a significant impact after implementation of the Project Commitments. The FEIR therefore also included MM WQ-7, which would require designing the detention basin in accordance with the Riverside County Stormwater Quality Best Management Practice Design Handbook. MM BR-7 requires attainment of success criteria when implementing the restoration plan required under Project Commitment D. MM BR-15 would require implementation of certain erosion and sedimentation BMPs during construction as part of the SWPPP developed for the proposed project. MM WQ-2 outlines procedures for drainage crossings and MM WQ-3 requires implementation of methods for access road construction that reduce erosion. The FEIR concluded erosion and sedimentation impacts during construction would be less than significant after implementation of the Project Commitments and mitigation measures and that there would be no impact during project operation and maintenance.

Construction impacts would be similar under both the original proposed project and the amended proposed project. There would be additional staging areas under the amended proposed project, and helicopters would be used in erection of the 500-kV lines, which would eliminate the need to construct some access roads, thereby reducing temporary and permanent impacts associated with constructing those roads. The ASP, as amended, would include an additional external detention basin for a total of two detention basins at the Alberhill Substation site. Between 39 and 44 acres of land (an additional 4 to 5 acres than the original proposed project) would be required for the construction of the proposed Alberhill Substation depending on the soil import option. Preliminary engineering indicates 120,000 cubic yards will be cut (an additional 29,000 cubic yards of soil than the original proposed project) and 185,000 cubic yards be filled (an additional 27,300 cubic yards than the original proposed project) at the Alberhill Substation site. However, the permanent ground disturbance for the Alberhill Substation site, portions of 115-kV Segments 1 and 1.5, and the Import Source Soil Area is reduced slightly under the amended proposed project to 42.5 acres compared to 42.9 acres under the original proposed project. The amended proposed project, including all project components, would reduce permanent ground disturbance compared to the impacts disclosed in the FEIR by approximately 29.63 acres. The amended proposed project would implement the same Project Commitments and mitigation measures as described in the FEIR for the original proposed project. The amended proposed project operation and maintenance would not involve any new ground disturbance and there would be no impact related to substantial erosion or sedimentation. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact WQ-3, and no major revisions to the FEIR would be warranted.

Impact WQ-4 (ASP): Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to substantially altering the existing drainage pattern of the site or area that would result in flooding on or off site. The FEIR disclosed that access roads and retaining walls could increase runoff and result in flooding or ponding. Roads may also cross and alter drainages that could result in flooding and ponding. Flooding may occur if the detention basin is insufficient in size to handle runoff from the Alberhill Substation site. Impacts from flooding would be a potentially significant impact. The FEIR therefore included MM WQ-3, which requires implementation of erosion control measures that would also reduce the potential for stormwater to cause flooding. MM WQ-5 would be implemented to maintain capacity and connectivity of drainages crossed by access roads to reduce the risk of flooding. MM WQ-6 would require written confirmation from the Riverside County Flood Control and Water Conservation District that project elements would not impede flood control functions. MM WQ-7 would be implemented to ensure that detention basin/s are an adequate size to capture anticipated stormwater flows. The FEIR then concluded flooding impacts during construction would be less than significant after implementation of the mitigation measures.

Construction impacts would be similar under both the original proposed project and the amended proposed project. There would be additional staging areas under the amended proposed project, and helicopters would be used in erection of the 500-kV lines, which would eliminate the need to construct some access roads, thereby reducing temporary and permanent impacts associated with constructing those roads. The project, as amended, would include an additional external detention basin for a total of two detention basins at the Alberhill Substation site. Between 39 and 44 acres of land (an additional 4 to 5 acres than the original proposed project) would be required for the construction of the proposed Alberhill Substation depending on the soil import option. Preliminary engineering indicates 120,000 cubic yards will be cut (an additional 29,000 cubic yards of soil than the original proposed project) and 185,000 cubic yards be filled (an additional 27,300 cubic yards than the original proposed project) at the Alberhill Substation site. There would be a reduction in 1.9 acres of impervious surface created at the Alberhill Substation under the amended proposed project. In addition, the permanent ground disturbance for the Alberhill Substation site, portions of 115-kV Segments 1 and 1.5, and the Import Source Soil Area is reduced slightly under the amended proposed project to 42.5 acres compared to 42.9 acres under the original proposed project. The amended proposed project, including all project components, would have a reduction in approximately 29.63 acres of permanent ground disturbance compared to the impacts disclosed in the FEIR. The amended proposed project would implement the same mitigation measures as described in the FEIR for the original proposed project. Implementation of MM WQ-3, MM WQ-5, and MM WQ-6 would reduce the potential for stormwater to cause flooding. MM WQ-7 would be implemented to ensure that detention basin capacity is constructed to capture anticipated stormwater flows. Implementation of these mitigation measures from the FEIR would result in impacts consistent with those disclosed in the FEIR (i.e., mitigated to a less than significant level). The amended proposed project's operation and maintenance would not involve any new ground disturbance that would alter drainage patterns. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact WQ-4, and no major revisions to the FEIR would be warranted.

Impact WQ-5 (ASP): Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to contributing runoff water that would exceed capacity of stormwater drainage systems or providing substantial additional sources of polluted runoff. As disclosed in the FEIR, there would be a significant impact if the detention basin and outflow to

Temescal Wash were insufficient to handle runoff water from the Alberhill Substation site. MM WQ-7 would be implemented to ensure that detention basin/s are adequate size to capture anticipated stormwater flows in accordance with Riverside County standards. The FEIR then concluded flooding impacts would be less than significant after implementation of MM WQ-7 and less than significant during project operation and maintenance.

The project, as amended, would not result in any new or more severe runoff-related impacts than originally proposed. The project, as amended, would include an additional external detention basin for a total of two detention basins at the Alberhill Substation site. There would be a 1.9-acre reduction of impervious surface created at the Alberhill Substation under the amended proposed project. The amended proposed project would implement the same mitigation measure, MM WQ-7, as described in the FEIR for the original proposed project, such that the same sizing requirements, in accordance with Riverside County standards, would be implemented. Implementation of this measure would result in impacts consistent with those disclosed in the FEIR (i.e., mitigated to a less than significant level). Water usage during operations and maintenance would be the same under the original proposed project and the amended proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact WQ-5, and no major revisions to the FEIR would be warranted.

Impact WQ-6 (ASP): Otherwise substantially degrade water quality.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to substantially degrading water quality. The FEIR disclosed the pesticides may be used for vegetation management activities and normal application would not be in sufficient quantities that would substantially degrade water quality. The applicant would also follow all project specifications and regulation for herbicide application. The project, as amended, would not result in any new or more severe water quality-related impacts than originally proposed; no major revisions to the FEIR would be warranted.

Impact WQ-7 (ASP): Place within a 100-year flood hazard area structures which would impede or redirect flood flows.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to placement of structures within a 100-year flood hazard area, which would impede or redirect flood flows. While sections of several 115-kV Segments (portions of ASP1, ASP1.5, ASP2, ASP3, and ASP4) and three staging areas (Staging Areas ASP4, ASP7, and ASP9) would be located within or adjacent to 100-year flood hazard areas as designated by the Federal Emergency Management Agency (FEMA), structures, equipment, and materials would not impede or redirect flood flows. As disclosed in the 2017 FEIR, lightweight steel poles would be up to 3 feet in diameter at their bases, while TSP foundations would be up to 8 feet in diameter but would only extend up to 2 feet above the ground surface. These structures would not impede or redirect flood flows, as flood flows would go around the structures. Staging Areas ASP4, ASP7, and ASP9 would be located within 100-year flood hazard areas as designated by FEMA. Equipment and materials would be stored at staging yards; no permanent structures would be located in these areas. Flood flows would go through the staging area. Equipment and materials would not impede or redirect flood flows. Impacts would be less than significant.

As disclosed in the 2017 FEIR, the Alberhill Substation site; 500-kV transmission lines; 115-kV Segments ASP5 through ASP8; Staging Areas ASP1, ASP2, ASP3, ASP5, and ASP6, and access roads would not be located within 100-year flood hazard areas. There would be no impact in these areas.

The project, as amended, would not add new sections of 115-kV segments within the 100-year flood hazard area beyond those previously discussed in the FEIR. ASP11, ASP14, and ASP15 would not be located within 100-year flood hazard areas. There would be no impact in these areas. One staging area located within the 100-year flood hazard area that was discussed in the FEIR, ASP9, was removed in the amended proposed project. One new staging area, ASP12, was added as part of the amended proposed project and is located within the 100-year flood hazard area. Similar to the original proposed project, equipment and materials would be stored at Staging Area ASP12; no permanent structures would be located in these areas. Flood flows would go through the staging area; and equipment and materials would not impede or redirect flood flows. The project, as amended, would not result in any new or more severe impedance or redirection of flood flow related impacts than originally proposed; impacts are consistent with those disclosed in the FEIR (i.e., less than significant). No major revisions to the FEIR would be warranted.

Impact WQ-8 (ASP): Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam.

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts with mitigation relative to exposing people or structures to a significant risk of flooding. The FEIR disclosed that dam inundation areas represent about 32 percent of the 115-kV subtransmission line and 500-kV transmission line alignments, while 100-year flood hazard zones represent about 15 percent of the 115-kV subtransmission line alignment. The Alberhill Substation site is located in a dam inundation area. Although unlikely, dam failure while construction workers were present would be a significant impacts. MM HZ-4 would require development of a Fire Control and Emergency Response Plan, which would outline evacuation procedures and require training on those procedures. The FEIR then concluded flooding impacts due to dam failure during construction and operation and maintenance would be less than significant after implementation of MM HZ-4.

Most of the FEMA maps that cover the project area are dated 2008 and 2014, and have not been updated since the FEIR. The 2017 FEIR Figure 4.9-4 used the 2014 FEMA data. ASP Segments 6 and 7 cross a FEMA map panel that was updated in 2017. ASP Segments 5 and 6 were not located in a flood or dam inundation zone in 2014. ASP7 and ASP8 were located in a dam inundation zone. A visual review of the FEMA map that was updated in 2017 indicated no new flood or dam inundation zones are crossed by the project components.

The amended proposed project would result in similar risks and impacts as the overall location of project components with dam inundation areas would remain virtually unchanged (FEMA 2017).

With implementation of MM HZ-4, impacts would be less than significant. This measure would continue to apply to the amended proposed project; no major revisions to the FEIR would be warranted.

Impact WQ-9 (ASP): Expose people or structures to a significant risk of loss, injury, or death involving inundation by seiche, tsunami, or mudflow.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to exposing people or structures to a significant risk of inundation by seiche, tsunami, or mudflow. As disclosed in the FEIR, there is no risk of tsunami in the project area. There is a potential for seiche on Lake Elsinore, however, based on the location of the nearest project components there is no potential for inundation of the project area by seiche. Project components are not located in areas such as washes at the base of mountains where mudflows may occur and expose people or structures to a significant risk of loss, injury, or death. The FEIR then concluded impacts would be less than significant.

The amended proposed project would result in similar risks and impacts as the overall location of project components with would remain virtually unchanged. Therefore, no major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the amended proposed project is being undertaken. According to the Final 2018 California Integrated Report, Temescal Wash and the Santa Ana River are still listed as impaired under Section 303(d) of the CWA. The 2006 Riverside County Stormwater Quality Best Management Practice Design Handbook is still current. The majority of the FEMA maps depicting the 100-year flood hazard areas and dam failure inundation hazard area remain the same. The 2017 FEIR used 2014 FEMA data. FEMA updated the map of the area crossed by ASP Segments 6 and 7 in 2017. A visual review of the map that was updated in 2017 indicated no new flood or dam inundation zones are crossed by the project components. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with hydrology and water quality than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the proposed project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant** effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation and less than significant impacts (without mitigation) under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

LAND USE AND PLANNING

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components.

Impact LU-1 (ASP): Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect.

The 2017 FEIR concluded the original proposed project would result in no impacts under this criterion. As disclosed in the FEIR, a land use consistency analysis was conducted to indicate whether components would potentially conflict with a local policy, regulation, or ordinance meant to avoid an environmental impact. None of the land use policy conflicts disclosed in the FEIR would themselves result in an environmental impact because the conflicts would not cause a physical change in the environment.

The project, as amended, would not result in any new land use policy conflicts. The amended proposed project location and footprint remain largely unchanged from the FEIR; as do most of the various project components. The amended proposed project would not result in any new land use policy conflicts with the plan, policies, or regulations included in the FEIR land use consistency analysis (Table 4-10.4 Alberhill Land Use Plans, Policies, and Regulations Consistency Analysis). Therefore, no new significant impacts would result from the amended proposed project in regard to Impact LU-1, and no major revisions to the FEIR would be warranted.

Impact LU-2 (ASP): Conflict with any applicable habitat conservation plan or natural community conservation plan.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation. No substantial changes have occurred concerning the circumstances under which the proposed project is being undertaken. The amended proposed project would still be covered under the Stephens Kangaroo Rat (SKR) Habitat Conservation Plan (HCP). The HCP area would still be impacted by directly removing suitable SKR habitat during construction. Accordingly, the applicant finalized an SKR HCP Implementation Agreement on October 15, 2012, which provides a process through which the applicant may obtain take authorization of SKR per the SKR HCP. This Implementation Agreement is also applicable on lands owned by Castle and Cooke.

Similarly, all project components, except for an approximately 2-mile-long section of 115-kV Segment ASP2, would be constructed in Multiple Species Habitat Conservation Plan (MSHCP)-covered areas. However, as disclosed in the 2017 FEIR, the entire project would be covered under the SKR HCP and SCE is entering into an agreement with the RCA to allow for coverage of this section of ASP2 under the MSHCP. The applicant will need to finalize a COI before construction, and the finalized COI would be included in the NTP request for the proposed project.

Furthermore, the mitigation measures described in the FEIR also apply to the amended proposed project. Under those mitigation measures, the applicant will be required to consult with the USFWS, CDFW, RCA, and RCHCA before, during, and after construction of the ASP (as applicable) regarding oak trees, special-status plants, nesting birds, burrowing owl impact avoidance and reduction. Additional measures would be implemented to avoid take of SKR within the Lake Mathews-Estelle Mountain Core Reserve and avoid disturbance of occupied SKR habitat to the maximum extent feasible. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The City of Lake Elsinore 2011 and the City of Menifee 2013 General Plans still remain in effect. The Riverside Country General Plan Circulation Element was updated in 2020 and the Land Use Element and the Elsinore Area Plan were updated in 2021. Of the general plan updates, only one policy included in the FEIR land use consistency analysis had minor modification (the 50-foot setback stipulated in LU 13.4 for new development adjacent to Designated and Eligible State and County Scenic Highways was modified to an "appropriate setback" based on local surrounding development, topography, and other conditions). The environs surrounding the project site have continued to develop with land uses as allowed for under the respective general plans covering the area. For these reasons, no new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) **New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:**

a. **The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**

b. **Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with land use and planning than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation and no impact under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

NOISE AND VIBRATION

(1) **Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;**

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. Project construction would use a hybrid approach of conventional and helicopter supported construction which was previously analyzed in the 2017 FEIR. Helicopter use during construction has also been further defined in the amended proposed project. In addition to light- and heavy-duty helicopters, the applicant would also use medium-duty helicopters during construction of the amended proposed project. The applicant would use medium- and heavy-duty helicopters to facilitate construction of three of the proposed 500-kV transmission line towers in lieu of constructing new access roads.

Impact NV-1 (ASP): Exposure of persons to generation of noise levels in excess of standards established in the local government plan or noise ordinance, or applicable standards of other agencies.

The amended proposed project would occur in the cities of Lake Elsinore, Wildomar and Menifee, and in portions of unincorporated Riverside County. Implementation of Project Commitment H and MM NV-1 would reduce impacts to less than significant after mitigation, consistent with the FEIR impact determination.

Additional substation modifications would occur at existing SCE substations and would not contribute to the operational noise at these locations. Therefore, noise from the operation of these modifications would not result in exposures to persons or generation of noise above applicable standards. No impacts would occur in association with additional substation modifications.

Impact NV-2 (ASP): Exposure of persons to or generation of excessive ground borne vibration or ground borne noise levels.

Consistent with the FEIR, construction of the amended proposed project would create perceptible ground-borne vibration from use of heavy-duty construction equipment (e.g., trucks, backhoes, excavators, loaders, and cranes), the tamping or compacting of ground surfaces, the passing of trucks on uneven surfaces, and the excavation of trenches.

Consistent with the original proposed project, the construction of the amended proposed project would be located within 25 feet of certain residential receptors in Lake Elsinore, Wildomar, Menifee, and unincorporated Riverside County. As discussed in the FEIR, construction in these areas would occur during daytime hours, when residences are least sensitive to noise. Construction in these would also be temporary, and vibration would be intermittent. Vibration impacts during construction would be substantially the same as those discussed in the FEIR and would remain less than significant, consistent with the FEIR impact determination.

Maintenance activities would be infrequent and temporary and are the same as those discussed in the FEIR. Impacts from maintenance activities would be less than significant, consistent with the FEIR.

Impact NV-3 (ASP): Substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project.

Consistent with the threshold of significance identified in the FEIR, a substantial noise increase is defined as 10 dBA. As discussed in the FEIR, an increase of 10 dBA is perceived as a doubling in loudness. The average ambient noise level in the project area is 65 dBA. An increase would therefore be substantial if it increased ambient noise levels to 75 dBA.

Construction noise would not be permanent and therefore would not cause a permanent increase in ambient noise levels in the project vicinity. Construction of the amended proposed project would have no impact, consistent with the FEIR impact determination.

Operation of the Alberhill Substation, 500-kV transmission lines, 115-kV subtransmission lines, and Serrano Substation and Santiago Peak Communications Site would not result in a substantive difference in noise levels compared to the original proposed project as discussed in the FEIR and would all have less than significant impact on permanent ambient noise levels.

The additional substation modifications at existing SCE substations included in the amended proposed project would not contribute to the operational noise at these locations. Therefore, noise from the operation of these modifications would not result in a substantive difference in noise levels compared to the original proposed project as discussed in the FEIR and would not result in a permanent increase to ambient noise levels and no impact would occur. No substantial changes to the project impacts discussed in the FEIR are anticipated as a result of the amended proposed project.

Impact NV-4 (ASP): Substantial temporary or periodic increase in ambient noise levels in project vicinity above levels existing without the project.

Consistent with the threshold of significance identified in the FEIR, a substantial noise increase is defined as 10 dBA. As discussed in the FEIR, an increase of 10 dBA is perceived as a doubling in loudness. The average ambient noise level in the project area is 65 dBA. An increase would therefore be substantial if it increased ambient noise levels to 75 dBA.

Noise generated from construction equipment and vehicle and helicopter use would result in temporary contributions to the ambient noise levels in the project vicinity during the overall 30-month construction period.

Construction activities at the Alberhill Substation property would generate noise up to 65 dBA at the closest residence to the proposed substation site. This noise level would not be a substantial increase in noise therefore the construction of the proposed Alberhill Substation would have less than significant impact on temporary ambient noise levels.

As discussed in the 2017 FEIR, construction of the 500-kV transmission lines would result in a substantial increase in ambient noise levels at the nearest sensitive receptor. The increase in noise levels would result in a significant impact that would require implementation of Project Commitment H to reduce noise at the nearest noise-sensitive receptor to below the applicable threshold.

Similar to the original proposed project, for all sections of the 500-kV transmission lines of the amended proposed project, the applicant would use a light-duty helicopter for sock-line threading—the stringing of a lightweight pilot line (a sock line) between power line structures. The use of a heavy-duty helicopter was anticipated in the FEIR's analysis of the original proposed project to facilitate construction in lieu of constructing access roads or where the proposed 500-kV transmission line towers would be located on terrain on which a crane could not be used or some of the required equipment and materials could not be delivered by truck. The amended proposed project description clarifies, consistent with the FEIR's broader discussion, that a heavy-duty helicopter would be used to facilitate construction at three of the proposed 500-kV transmission line towers. In addition, permanent helicopter platforms are included in the amended application, which would be installed at three of the new 500-kV transmission towers. Each platform would be approximately 25 feet wide by 25 feet long. Consistent with the FEIR, helicopters would be used only during daylight hours consistent with applicable laws and regulations; however, helicopters would increase ambient noise levels by 10 dBA or more during landing/take-off operations at staging areas, and when flying over residential areas at a height of 500 feet. Impacts from helicopters would be temporary, but significant and unavoidable.

Construction of the subtransmission lines would generate noise levels up to 94 dBA at the nearest residential areas and would result in substantial temporary increase in noise along all segments other than 115-kV Segments ASP1 and ASP1.5. Implementation of Project Commitment H and MM NV-1 would reduce short-term significant increases in ambient noise levels, but not to a level less than significant. Helicopter noise resulting from the construction of subtransmission lines would be temporary, but significant and unavoidable under this criterion.

Construction of underground telecommunications components would result in a temporary increase in ambient noise levels at sensitive receptors located within 20 feet of construction. Implementation of Project Commitment H would reduce noise levels; however, ambient noise levels would remain above 10 dBA compared to ambient noise levels. Therefore, impacts, consistent with those disclosed in the 2017 FEIR, would be significant and unavoidable under this criterion.

Use of heavy equipment at Staging Areas ASP3, ASP4, and ASP14 would create unmitigated noise levels at surrounding noise-sensitive receptors in excess of 75 dBA. Implementing Project Commitment H would reduce noise levels below 75 dBA at Staging Areas ASP3 and ASP4; however, impacts would remain significant and unavoidable at Staging Area ASP14.

Noise impacts at Valley, Skylar, Ivyglen, Newcomb, Tenaja, and Fogarty Substations would not result in a substantial temporary periodic increase in noise during construction. Therefore, impacts would be less than significant under this criterion.

The amended proposed project would implement the same mitigation measures as described in the FEIR for the original proposed project. Implementation of MM NV-1 would require construction noise reduction measures such as preparation of a Noise Control Plan. Implementation of this mitigation measure from the FEIR would help reduce impacts from temporary ambient noise increases, however, consistent with the FEIR impact determination, impacts would still be significant and unavoidable after the implementation of MM NV-1.

Operation of the proposed project would not result in any short-term increases in ambient noise levels. However, maintenance activities would have similar impacts on short-term increases to ambient noise levels as construction activities. Although maintenance activities would occur infrequently, impacts would be significant and unavoidable after the implementation of Project Commitment H, consistent with 2017 FEIR impact determination. Operation and maintenance activities associated with the amended proposed project would be similar to those currently performed by SCE for existing facilities and include routine inspections and emergency repairs. Operation and maintenance activities also include monthly and annual inspections along with equipment testing and maintenance similar to those currently performed. A review of updated best practices that could reduce the increase in ambient noise levels found no new technologies, equipment, or approaches that would reduce the temporary increase in ambient noise levels (Diaz 2024).

Impact NV-5 (ASP): Exposure to people residing or working in the project area to excessive noise levels within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport.

As discussed in the FEIR, a portion of the 115-kV Segment ASP8 is approximately 1.5 miles south of the Perris Valley Airport. The change to ASP8 is within Compatibility Zone E in the Riverside County Airport Land Use Compatibility Plan for Perris Valley Airport, which is subject to occasional noise of 55 dB Community Noise Equivalent Level from Perris Valley Airport (Riverside County ALUC 2004b), which is below the ambient noise level of the project area of 65 dBA. Construction, maintenance and operation of ASP8, where within Compatibility Zone E (Impact NV-5) was found to be less than significant in the FEIR for the original proposed project.

The amended proposed project includes changes to ASP8 within Compatibility Zone E. Specifically, the amended proposed project would underground a short segment where it crosses the existing Serrano-Menifee 500-kV transmission line and McLaughlin Road near the intersection with Murrieta Road, rather than using an overhead crossing, Construction of the underground portion would generate 94 dBA which is unchanged from the original proposed project, as analyzed in the FEIR. This noise would be temporary in nature, and not substantially more severe than that discussed in the FEIR, Therefore, no change to the FEIR's impact determination is warranted by the amended proposed project.

Impact NV-6 (ASP): Exposure to people residing or working in the project area to excessive noise levels within the vicinity of a private airship.

Skylark Field Airport is a private airport located approximately 1,000 feet from proposed 115-kV Segments ASP4 and ASP5. This airport provides gliding and skydiving services to the community and visitors. Consistent with the original proposed project discussed in FEIR, during construction of the amended proposed project, the Skylark Field Airport would also be used as the helicopter staging and fueling area.

Given the transient nature of the construction and maintenance activities in the proximity of the Skylark Field Airport, the temporary helicopter use anticipated for the 500-kV construction line, the small air traffic capacity existing at the airstrip, and proper compliance of workers hearing protection, the FEIR found that impacts would be less than significant. Because there is no substantial change in the construction plans for the Segments ASP4 and ASP5 nor the proposed helicopter use at Skylark Field Airport from the original proposed project, this impact will be consistent with that discussed in the FEIR, and no changes to the FEIR are warranted,

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

While minor updates have occurred to relevant general plans and municipal codes related to noise and vibration in the project area since the FEIR, the updates do not specifically relate to changes in the threshold of significance nor other circumstance of the overall ASP. Therefore, none of the determinations of environmental effects published in the 2017 FEIR are changed.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;

b. **Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with noise and vibration than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in significant and unavoidable impacts with mitigation under Impact NV-4. Mitigation measures for the original proposed project would be applied to the amended proposed project. As discussed above, no additional mitigation is available that would reduce impacts under NV-4. A review of updated best practices that could reduce the increase in ambient noise levels found no new technologies, equipment, or approaches that would reduce the temporary increase in ambient noise levels. In conclusion, no additional mitigation measures are available to reduce the impacts of the amended proposed project. No major revisions to the FEIR would be required. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

POPULATION AND HOUSING/RECREATION

(1) **Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;**

Impact PH-1: Induce substantial population growth in an area, either directly (for example, 20 by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure).

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts relative to population growth. Construction of the project would mostly use local labor sourced from surrounding communities. During operation, the components of the proposed project would be unstaffed and existing local SCE staff would be adequate to conduct the occasional maintenance or emergency repairs. Therefore, operation and maintenance of the proposed project would have no direct impact on population. The amended proposed project consists generally of the same components and would not result in any substantial changes to construction or operations and therefore, would also result in less than significant impacts on induced population growth, consistent with the conclusions of the 2017 FEIR. No major revisions to the FEIR are required.

Impact PH-2: Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere.

The 2017 FEIR concluded that the ASP project would result in no impact relative to the displacement of housing. The 2017 FEIR disclosed that the proposed new and modified 115-kV subtransmission lines would be located primarily within or along the applicant's existing ROW. In locations where a ROW is not currently held by the applicant, the proposed 115-kV subtransmission line routes would not displace existing housing units or necessitate the construction of replacement housing elsewhere. The amended proposed project consists generally of the same components and would not result in any substantial changes to routing of infrastructure. None of the minor changes to infrastructure design will displace existing housing. Therefore, the amended proposed project would also result in no impact relative to displacement of housing. No major revisions to the FEIR are required.

Impact RE-1: Increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated.

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts on recreational facilities. Construction of the project would mostly use local labor sourced from surrounding communities. During operation, the components of the proposed project would be unstaffed and existing local SCE staff would be adequate to conduct the occasional maintenance or emergency repairs. Therefore, operation and maintenance of the proposed project would have no direct impact on demand for recreational facilities. The amended proposed project consists generally of the same components and would not result in any substantial changes to construction or operations and therefore, would also result in less than significant impacts on recreational facilities. No major revisions to the FEIR are required.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred with respect to the circumstances under which the proposed project is being undertaken. The City of Lake Elsinore 2011 and the City of Menifee 2013 General Plans still remain in effect. No new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete, or the Negative Declaration was adopted:

   a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration; or

   b. Significant effects previously examined will be substantially more severe than shown in the previous EIR.

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with population and housing or recreation than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

c. **Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**

d. **Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts and no impact under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

PUBLIC SERVICES AND UTILITIES

(1) **Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;**

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. One change of importance to the public services and utility impacts of the amended proposed project is SCE's intent to use helicopter construction methods previously acknowledged in the FEIR, which would eliminate the need to construct certain access roads for the 500-kV project component, thereby reducing temporary and permanent impacts associated with constructing those roads. In addition, an additional external detention basin for a total of two detention basins at the Alberhill Substation site. There would be a reduction in 1.9 acres of impervious surface created at the Alberhill Substation under the amended proposed project.

Impact PS-1 (ASP): Result in substantial adverse physical impacts on governmental facilities or from the need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times, or other performance objectives for any of the following: (1) fire protection, (2) police protection, (3) schools, (4) parks, or (5) other public facilities.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to substantial adverse physical impacts on governmental facilities or from the need for new or physically altered government facilities. As disclosed in the FEIR, increased demand on emergency service providers could occur in the event of traffic- or equipment-related accidents, vandalism, or fires. The applicant would make Material Safety Data Sheets or equivalent documentation for all hazardous materials in use at the construction site available to all site workers, install a chain-link fences around the Alberhill Substation site, and implement vegetation management per California Public Resources Code Sections 4291-4299. Potential for vandalism would remain at areas outside the substation but would not require new policing facilities and would therefore would not be a significant impact. MM HZ-4 would require the applicant to implement site-specific fire control and emergency response plans to address the risk of fire or other emergencies during construction, operations, and maintenance of the proposed project. The FEIR concluded potential impacts on fire, police, and emergency service ratios would be less than significant after implementation on MM HZ-4. Construction workers may temporarily relocate to the project area for approximately 28 months and the relocated construction workers could cause a minor increase in the service ratios of schools, libraries, and other public facilities. The FEIR concluded that due to the number and variety of facilities in the project vicinity that could accommodate the temporary increase in use by construction workers there would be no significant impact to service ratios. The FEIR concluded construction and operation of the original proposed project would not physically alter schools, libraries, or public facilities in the proposed project area.

The amended proposed project would not result in any new or more severe adverse physical impacts on governmental facilities or require new or physically altered government facilities. The amended proposed project would include the same estimated number of construction workers per day. The duration of construction for the amended proposed project would be approximately 30 months, two months longer than the estimate for the original proposed project. Consistent with the 2017 FEIR, the applicant would make Material Safety Data Sheets or equivalent documentation for all hazardous materials in use at the construction site available to all site workers, install a chain-link fences around the Alberhill Substation site, and implement vegetation management per California Public Resources Code Sections 4291-4299. Similar to the original proposed project, the amended proposed project would have potential for vandalism at areas outside the substation but would not require no new policing facilities and would therefore would not be a significant impact. Construction workers may temporarily relocate to the project area for approximately 30 months and the relocated construction workers could cause a minor increase in the service ratios of schools, libraries, and other public facilities. Consistent with the 2017 FEIR conclusions, since the estimated number of construction workers per day is the same as the original proposed project and the number and variety of facilities in the project vicinity could accommodate the temporary increase in use by construction workers there would be no significant impact to service ratios. The amended proposed project would also implement the same mitigation measure, MM HZ-4, as described in the FEIR for the original proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact PS-1, and no major revisions to the FEIR would be warranted.

Impact PS-2 (ASP): Require or result in the construction of new water treatment facilities or expansion of existing facilities.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to the need to construct new or expand existing water treatment facilities. The 2017 FEIR disclosed that the increase in demand on local water agencies for the construction and operation of the proposed project would not require new water treatment facilities or expansion of existing facilities. No new or expanded connections to water treatment facilities would be constructed as part of the proposed project. An agricultural water pipeline that traverses the middle of the Alberhill Substation site would be relocated to the perimeter of the site prior to substation construction. The 2017 FEIR disclosed that because the water pipeline was not currently in use and would be out of service for less than two days during relocation that impacts on potential users of the pipeline or the water facilities that serve the pipeline would be less than significant. Impacts under PS-2 would be less than significant.

The amended proposed project would not require additional water needs or facilities for project operations than those previously discussed in the 2017 FEIR. Therefore, the amended proposed project would not result in any new or more severe impacts related to water treatment facilities compared to the original proposed project. The duration of construction for the amended proposed project would be approximately 30 months, two months longer than the estimate for the original proposed project. However, the design modifications would not result in an increase in demand on local water agencies for the construction and operation of the amended proposed project that would require new water treatment facilities or expansion of existing facilities. The relocation of the agricultural water pipeline would occur as planned in the original proposed project and no new or expanded connections to water treatment facilities would be necessary or constructed. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact PS-2, and no major revisions to the FEIR would be warranted.

Impact PS-3 (ASP): Require or result in the construction of new storm water drainage facilities or expansion of existing facilities.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to the need to construct new storm water drainage facilities or expand existing facilities. A 13.5 acre-foot detention basin would be constructed at the Alberhill Substation site. Drainage facilities would also be constructed along access roads. Project Commitment E would require consultation with Riverside County prior to finalizing drainage designs. Best management practices would be developed to minimize impacts associated with storm water runoff. MM BR-1 would be implemented to ensure construction is limited to designated areas. The applicant would construct all drainage facilities in accordance with National Pollutant Discharge Elimination System (NPDES) and grading permits and as directed by the Santa Ana Regional Water Quality Control Board, Riverside County Flood Control and Water Conservation District, and Riverside County Planning Department. The FEIR concluded new public storm water drainage facilities or the expansion of existing public facilities would not be required and impacts under this criterion would be less than significant with the implementation of MM BR-1.

The project, as amended, would not result in any new or more severe stormwater runoff-related impacts than originally proposed. The project, as amended, would include an additional external detention basin for a total of two detention basins at the Alberhill Substation site. There would be a reduction in 1.9 acres of impervious surface created at the Alberhill Substation under the amended proposed project. Approximately 3.4 miles (a reduction of 2.7 miles from the original proposed project) up to 26 feet wide of new or modified access roads would be constructed to access the 500-kV transmission line structures. This reduction in the number of access roads would also reduce the amount drainage facilities required. The amended proposed project would implement the same Project Commitment and mitigation measure as described in the FEIR for the original proposed project. The applicant would also construct all drainage facilities in accordance with NPDES and grading permits and as directed by the Santa Ana Regional Water Quality Control Board, Riverside County Flood Control and Water Conservation District, and Riverside County Planning Department. New public storm water drainage facilities or the expansion of existing public facilities would not be required. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact PS-3, and no major revisions to the FEIR would be warranted.

Impact PS-4 (ASP): Insufficient water supplies available to serve the project from existing entitlements and resources or new or expanded entitlements required.

Impact PS-5 (ASP): Served by a landfill without sufficient permitted capacity to accommodate the project's solid waste disposal needs.

Impact PS-6 (ASP): Noncompliance with federal, state, or local statutes and regulations related to solid waste.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to insufficient water supplies available to serve the proposed project, insufficient landfill capacity to accommodate the proposed project's solid waste disposal needs, and noncompliance with regulations related to solid waste. The 2017 FEIR disclosed that Elsinore Valley Municipal Water District (EVMWD) operates wells north of the Alberhill Substation site and has adequate supplies to provide water required for construction and operation of the proposed project. The Eastern Municipal Water District has adequate supplies to provide water for construction outside of EVMWD's boundaries. Once a year during operation, the Eastern Municipal Water District would provide deionized water for cleaning electrical equipment at the Alberhill Substation. The applicant would connect to EVMWD's potable water system for use during operation of the Alberhill Substation.

The landfills located within 30 miles of the project components have sufficient remaining permitted capacity to accept the amount of nonhazardous solid waste estimated to be generated by construction and operation of the proposed project. Very small volumes of waste are expected during routine operation and maintenance of the proposed project and local waste management facilities would be open and have adequate capacity to accept solid waste that could not be recycled or salvaged if extensive maintenance activities were required. Construction and operation of the proposed project would result in the generation of various nonhazardous solid wastes and require limited use of hazardous materials. The applicant would dispose of hazardous waste at an appropriate permitted facility. The applicant would comply with all federal, state, and local statutes and regulations related to solid waste during construction and operation of the proposed project. The 2017 FEIR concluded impacts under PS-4, PS-5, and PS-6 would be less than significant.

The amended proposed project would not result in any new or more severe impacts under PS-4, PS-5, and PS-6 than originally proposed. The amount of water required for construction and operation would be the same under both the original proposed project and the amended proposed project. No additional solid waste is projected to be generated by the amended proposed project during construction or operation. In addition, consistent with the 2017 FEIR, the applicant would comply with all federal, state, and local statutes and regulations related to solid waste during construction and operation of the amended proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact PS-4, PS-5, and PS-6, and no major revisions to the FEIR would be warranted.

(2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or

No substantial changes have occurred, based on readily available public service information, with respect to the circumstances under which the proposed project is being undertaken. El Sobrante and Badlands landfills, located within 30 miles of the project components, have sufficient remaining permitted capacity to accept the amount of nonhazardous solid waste estimated to be generated by construction and operation of the proposed project. No new effects would result from a change in circumstances, and no major revisions to the FEIR are warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with public services and utilities than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**
- **d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation and less than significant impacts (without mitigation) under this criterion. Because significant impacts were not found under this criterion, new mitigation measures which are considerably different from those analyzed in the previous FEIR that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

TRANSPORTATION AND TRAFFIC

(1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;

As described above, the Third Amended Application for the ASP would result in changes to various project components. The general extent of the amended proposed project, location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. There would be additional staging areas under the amended proposed project. Project construction would use a hybrid approach of conventional and helicopter supported construction which was previously analyzed in the 2017 FEIR. Helicopter use during construction has also been further defined in the amended proposed project. In addition to light- and heavy-duty helicopters, the applicant would also use medium-duty helicopters during construction of the amended proposed project. The applicant would use medium- and heavy-duty helicopters to facilitate construction of three of the proposed 500-kV transmission line towers in lieu of constructing new access roads.

Impact TT-1 (ASP): Conflict with an applicable plan, ordinance or policy establishing a measure of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to conflicts with an applicable plan, ordinance or policy establishing a measure of effectiveness for the performance of the circulation system. The FEIR analysis for Impact TT-1 focused on level of service (LOS) based on an evaluation presented in the traffic impact analysis of existing conditions plus project build-out conditions. Impacts that may occur on public transit, bikeways, or pedestrian facilities are discussed under Impact TT-6. Impacts to Congestion Management Program (CMP) intersections are discussed under Impact TT-2.

The FEIR disclosed that the construction of the original proposed project over a 28-month period would result in a temporary increase in traffic volumes on the regional and local roadways that provide access to the construction areas. A temporary increase in traffic is also expected during construction of the proposed Alberhill Substation. Traffic would be generated by construction worker commute trips and material deliveries. Construction trip generation estimates, categorized by zones (e.g., Alberhill Substation, Staging Areas, etc.), for the original proposed project were provided in Table 4.15-14 of the FEIR. Overall, the applicant estimated the daily workforce would include as many as 200 workers on a peak day of construction (i.e., if multiple components of the original proposed project were being constructed simultaneously). The impacts of project-related construction traffic during the AM peak hour (7:00 to 9:00 a.m.) and the PM peak hour (4:00 to 6:00 p.m.) were evaluated based on analysis of existing traffic conditions plus project build-out traffic conditions at 12 key intersections. No intersection LOS would be significantly impacted as a result of construction of the original proposed project. The FEIR concluded impacts would be less than significant, and no mitigation would be required. Installation of the proposed 115-kV subtransmission lines would also require roadway crossings during installation of the proposed overhead lines, temporary structure installation, and wire-stringing activities along roadways. Temporary lane closures would reduce the traffic capacity of the roadways and could temporarily disrupt automobile traffic patterns which could result in a significant impact. MM TT-1 would require development of a Traffic Management and Control Plan. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-1.

The 2017 FEIR disclosed that the Alberhill Substation would be unstaffed during operation so impacts would be negligible. Inspection activities for the transmission and subtransmission lines would occur on a yearly basis and routine maintenance activities for the substation and telecommunications system would not require more than a few vehicles. The FEIR then concluded that operations and maintenance impacts would be less than significant.

The amended proposed project would increase the number of construction trips. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. There would be additional staging areas under the amended proposed project. The construction period would be extended to 30 months. Similar to the original proposed project, the applicant estimates the daily workforce would include as many as 200 workers on a peak day of construction. Linscott, Law & Greenspan, Engineers completed an updated traffic study on March 4, 2024, based on the amended project description to determine if any new significant transportation impacts or if any substantial increase in the severity of previously identified significant impacts would occur (SCE 2024c). Similar to the original proposed project, the impacts of the amended proposed project–related construction traffic during the AM peak hour and the PM peak hour were evaluated based on analysis of existing traffic conditions plus project build-out traffic conditions at the same 12 key intersections as the original proposed project. The resulting existing traffic conditions plus project build-out LOS (AM and PM) at the 12 key intersections for the amended proposed project were the same as the original proposed project except at the Horsethief Canyon Road/Temescal Canyon Road intersection where the PM LOS changed from a LOS B in the original proposed project to a LOS C in the amended proposed project. Consistent with the threshold of significance in the FEIR, the Horsethief Canyon Road/Temescal Canyon Road intersection is in Riverside County where the minimum acceptable LOS is LOS C, therefore, the intersection LOS is not significantly impacted. No intersection LOS would be significantly impacted as a result of construction of the amended proposed project. Impacts would be less than significant which is consistent with the conclusion disclosed in the FEIR.

Similar to the original proposed project, temporary lane closures are anticipated during the installation of the proposed 115-kV subtransmission lines of the amended proposed project that could temporarily disrupt automobile traffic patterns. The amended proposed project would include additional crossings of I-15 (e.g., 115-kV Segment 1.5) and minor modifications of 115-kV alignment adjacent to the ROW of public roadways. However, any potential disruption to automobile traffic patterns during lane closures at the additional crossings would be temporary in nature and would not result in a more severe significant impact. The amended proposed project would also implement the same mitigation measure, MM TT-1, as described in the FEIR for the original proposed project requiring development of a Traffic Management and Control Plan prior to commencement of construction activities. Implementation of this measure would result in impacts consistent with those disclosed in the FEIR (i.e., mitigated to a less than significant level). Operation and maintenance activities would be the same under the original proposed project and the amended proposed project. Therefore, no new significant or substantially more severe significant impacts would result from the amended proposed project in regard to Impact TT-1, and no major revisions to the FEIR would be warranted.

Impact TT-2 (ASP): Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways.

The 2017 FEIR concluded the project would result in less than significant impacts with mitigation relative to conflicts with an applicable congestion management program. The FEIR analysis for Impact TT-2 focused on LOS based on the Riverside County CMP's minimum acceptable LOS E. The impacts of project-related construction traffic during the AM peak hour (7:00 to 9:00 a.m.) and the PM peak hour (4:00 to 6:00 p.m.) were evaluated based on analysis of existing traffic conditions plus project construction traffic conditions at the 14 key CMP intersections. The FEIR disclosed that implementation of the original proposed project would cause the intersection of Lake Street at the I-15 Northbound Ramps to operate below the minimum acceptable LOS (LOS D) in the AM and Menifee Road at Pinacate Road (SR-74) intersections to operate below the minimum acceptable LOS in the PM. Impacts to LOS at these intersections would be significant. MM TT-2 would require the applicant to avoid use of the Lake Street and I-15 northbound ramp for all heavy truck traffic during the AM peak hour and construction traffic for the project at the Menifee Road and SR-74 intersection during the PM peak hour. Implementation of MM TT-2 would return the LOS at these intersections to existing condition levels. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-2 since no intersections would operate below the minimum acceptable CMP LOS as a result of the project. Installation of the proposed project 115-kV subtransmission lines would also require roadway crossings during installation of the proposed overhead lines and temporary structure installation, cable pulling, and wire-stringing activities would occur along CMP roadways I-15 and SR-74. These activities could temporarily disrupt automobile traffic patterns and increase delays for vehicles which could result in a significant impact. As described in the FEIR Appendix L Responses to Comments (Comment 135-353) a Highway Closure Plan will be prepared as part of applicant's Caltrans encroachment permit application.

The 2017 FEIR disclosed that the Alberhill Substation would be unstaffed during operation so impacts would be negligible. Inspection activities for the transmission and subtransmission lines would occur on a yearly basis and routine maintenance activities for the substation and telecommunications system would not require more than a few vehicles. The FEIR then concluded that operations and maintenance impacts would be less than significant.

The amended proposed project would increase the number of construction trips. The general extent of the amended proposed project, the location and footprint, remains largely unchanged from the original proposed project in the FEIR, as do most of the various project components. There would be additional staging areas under the amended project. As discussed under Impact TT-1, Linscott, Law & Greenspan, Engineers completed an updated traffic study on March 4, 2024, based on the amended proposed project description to determine whether any new significant transportation impacts or if any significant increase in the severity of impacts would occur. Similar to the original proposed project, the impacts of the amended proposed project–related construction traffic during the AM peak hour and the PM peak hour were evaluated based on based on analysis of existing traffic conditions plus project construction traffic conditions at the 14 key CMP intersections. Like the original proposed project, implementation of the amended proposed project would cause the intersections of Lake Street at the I-15 Northbound Ramps and Menifee Road at Pinacate Road (SR-74) to operate below the minimum acceptable LOS (LOS D). The intersection of Lake Street at the I-15 Northbound Ramps, without mitigation, would operate below the minimum acceptable LOS in the AM and have a significant impact (same as the original proposed project). The Menifee Road at Pinacate Road (SR-74) intersection, without mitigation, would operate below the minimum acceptable LOS in both the AM and PM and have a significant impact (the original project only identified operation below the minimum acceptable LOS in the PM peak hour, and only the PM peak hour would have a significant impact). Importantly, Menifee Road and Pinacate Road (SR-74) currently operates below the minimum acceptable LOS, at LOS F with 144.6 seconds of delay; the amended project will result in 3.6 additional seconds of delay (i.e., a less than a 2.5 percent increase) in the AM peak hour. Consistent with the approach taken in the FEIR for the original project's impacts, the amended proposed project would implement a slightly modified version of mitigation measure MM TT-2 that extends the measure's applicability to also include Menifee Road at Pinacate Rd (SR-74) during the AM peak hour. Consistent with the original FEIR, mitigation measure MM TT-2 would require the applicant to avoid use of the Lake Street and I-15 northbound ramp for all heavy truck traffic during the AM peak hour and restrict construction traffic for the proposed project at the Menifee Road at Pinacate Road (SR-74) intersection during both the AM and PM peak hours:

Updated Mitigation Measure MM TT-2:

> **MM TT-2: Heavy Vehicle Traffic Restrictions[3].** The applicant shall minimize heavy vehicle traffic for the project at the Lake Street and I-15 northbound ramp during the AM peak hour (7:00 AM to 9:00 AM) for the duration of project construction. Heavy vehicles traveling to project sites during the AM peak hour shall be diverted to the

---

[3] Components of MM TT-2 relates to the Valley-Ivyglen Project and not the Alberhill System Project, and are retained as an implemented component of the certified 2017 FEIR.

Indian Truck Trail and I-15 northbound ramp. Prior to the start of construction, the applicant shall alert truck drivers associated with the project.

The applicant shall also minimize construction traffic for the project at the Menifee Road and SR-74 intersection during the AM peak hour (7:00 AM to 9:00 AM) and PM peak hour (4:00 PM to 6:00 PM). The applicant may require construction traffic to exit Staging Area ASP7 prior to or after the AM and PM peak hours but not during the AM peak hour (7:00 AM to 9 AM) and PM peak hour (4:00 PM – 6 PM). ~~and Staging Area VIG2 prior to 4:00 PM or after 6:00 PM~~. Alternatively, the applicant may provide an alternative access route.

Implementation of this measure would result in impacts mitigated to a less than significant level, consistent with those disclosed in the FEIR.

Similar to the original proposed project, installation of the amended proposed project 115-kV subtransmission lines would also require roadway crossings during installation of the proposed overhead lines, temporary structure installation, cable pulling, and wire-stringing activities along CMP roadways I-15 and SR-74. The amended proposed project would include additional crossings of I-15 (e.g., 115-kV Segment 1.5) and minor modifications of 115-kV alignment adjacent to the ROW of public roadways. However, any potential disruption to automobile traffic patterns and increases to delays for vehicles during lane closures at the additional crossings would be temporary in nature and would not result in a substantially more severe significant impact. Similar to the original proposed project, a Caltrans Highway Closure Plan will be prepared as part of applicant's Caltrans encroachment permit application. Operation and maintenance activities would be the same under the original proposed project and the amended proposed project.

Therefore, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact TT-2 after the application of the updated MM TT-2, and no major revisions to the FEIR would be warranted.

Impact TT-3 (ASP): Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to changes in air traffic patterns. The FEIR disclosed that helicopters would be used for construction of the 500-kV structures that are inaccessible from access roads. Helicopters would be used for wire-stringing activities along all sections of the 500-kV transmission line routes and one section of 115-kV Segment ASP5 between Lost Road and Bundy Canyon Road. Helicopter fueling, takeoff, and landing areas would be limited to established helicopter landing areas (e.g., facilities at Skylark Field Airport), the proposed Alberhill Substation site, Staging Area ASP1, or Staging Area ASP3. During stringing activities, the helicopter would take off and land adjacent to pull sites along the 500-kV transmission line routes (including Staging Area ASP2). The 2017 FEIR outlines specifications and the Federal Aviation Administration (FAA) and Occupational Safety and Health Administration (OSHA) requirements for helicopter use during construction. As noted in the 2017 FEIR, flights in close proximity to residences or congested areas could result in safety impacts, however safe operation can be assured through the implementation of Mitigation Measure MM TT-4, would require submittal of a Helicopter Lift Plan to the FAA prior to operations in proximity to residences or congested areas. The FEIR also disclosed that helicopters would be used to inspect transmission and subtransmission lines once per year and would not be expected to impact air traffic. Flights in proximity to residences or congested areas may result in significant safety impacts. MM TT-4 would require submittal of a Helicopter Lift Plan to the FAA prior to such operations. Impacts would be less than significant with mitigation. The FEIR then concluded that operations and maintenance impacts would be less than significant after implementation of MM TT-4.

In addition, equipment exceeding Skylark Field Airport's imaginary slope (i.e., a safety buffer extending from the runway that rises one foot for every 50 vertical feet up to 10,000 vertical feet) may pose a safety hazard to air traffic, which would be a significant impact. MM TT-5 would require the applicant to obtain a no hazard determination from the FAA when notification under 14 CFR 77 is required. The FEIR concluded that construction impacts would be less than significant after implementation of MM TT-4 and TT-5.

The 2017 FEIR disclosed that during operation 115-kV Segments ASP1 though ASP3, ASP6, and ASP7 would be less than 200 feet tall and would not overlap with Skylark Field Airport's imaginary slope; therefore, impacts would be less than significant. 115-kV Segments ASP4 and ASP5 would be located approximately 1,000-feet from the Skylark Field Airport, and therefore, poles greater than 20 feet tall located approximately 1,000 feet from the Skylark Field Airport could overlap with the Skylark Field Airport's imaginary slope. Per Project Commitment G, prior to construction, the applicant would consult with the FAA and ensure the required forms are filed and applicable requirements under Federal Aviation Regulations Part 77, Objects Affecting Navigable Airspace are met, however impacts would still be significant because Project Commitment G did not require that the applicant implement any measures to reduce hazards. MM TT-5 would be implemented to reduce airspace hazards from encroachment of structures. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-5.

The project, as amended, further defined helicopter use during construction. Staging Area ASP11 was added as a helicopter landing area in addition to the landing areas identified in the original proposed project. The applicant would use medium- and heavy-duty helicopters to facilitate construction of three of the proposed 500-kV transmission line towers in lieu of constructing new access roads. In addition to Skylark Field Airport and Perris Valley Airport (discussed in the 2017 FEIR), helicopter fueling, takeoff, and landing may also occur at French Valley Airport. French Valley Airport is a public use airport with an asphalt runway that is approximately 6,000 feet long located approximately 6.4 miles southeast of 115-kV Segments ASP5 and ASP6. The use of helicopters for wire stringing would remain the same as the original proposed project. The amended proposed project would adhere to the same specifications and FAA and OSHA requirements for helicopter use during construction that were outlined in the 2017 FEIR. The amended proposed project would also implement the same mitigation measures, MM TT-4 and TT-5, as described in the FEIR for the original proposed project such that a Helicopter Lift Plan would be submitted to the FAA prior to operations in proximity to residences or congested areas the applicant would obtain a no hazard determination from the FAA when notification under 14 CFR 77 is required. Implementation of these measures would result in mitigating the impacts to a less than significant level, consistent with those impacts disclosed in the FEIR. Project proximity to Skylark Field Airport and helicopter use during operations and maintenance would be the same under the original proposed project and the amended proposed project. Therefore, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact TT-3, and no major revisions to the FEIR would be warranted.

Impact TT-4 (ASP): Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment).

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to substantially increasing hazards due to a design feature or incompatible uses. The FEIR disclosed that access roads constructed to accommodate construction of the original proposed project would be used for maintenance access and are not expected to be accessible to the public. Love Lane, sections of which would be within the footprint of the proposed Alberhill Substation site, would be relocated 130 to 180 feet west of its current location. Project access roads would be designed to avoid hazardous features for the safety of operation and maintenance crews. The relocated Love Lane design would be approved by Riverside County. The FEIR concluded that these impacts would be less than significant. Within the proposed Alberhill Substation, a series of driveways would be constructed to facilitate vehicular movement and access to substation equipment. Safety issues may occur as large, slow trucks enter and exit the substation site into faster traffic on Temescal Canyon Road. In addition, trucks accessing staging areas could result in similar safety issues. The FEIR concluded that this could cause significant hazards impacts.

Construction of the original proposed project would require the use of overweight or oversized vehicles for the delivery of construction equipment and materials which can shorten the life of the pavement and eventually lead to rutting and cracking. Damage to the roadway, without repairing such damage, would result in a significant impact, however, public roads would be repaired in accordance with local franchise agreements. Installation of the 115-kV subtransmission lines would require roadway crossings during installation of the overhead lines, temporary structure installation, cable pulling, and wire-stringing activities along roadways. These activities could temporarily cause safety impacts to motorists, bicyclists, and pedestrians. The 2017 FEIR outlines the safety devices and methods that the applicant would implement prior to the initiation of wire-stringing activities. Safety impacts may be significant, depending on how these measures are implemented. MM TT-1 would require development of a Traffic Management and Control Plan prior to commencement of construction activities to reduce potential safety hazards, such as outlining hazards during wire-stringing activities and posting warning signs so that motorists can be prepared for slow trucks. MM TT-6 would require SCE to repair private road damage directly caused by project vehicle traffic and activities. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-1 and TT-6.

The 2017 FEIR disclosed that during operation of the proposed project facilities, construction of additional roads or driveways would not be required. SCE would adhere to safety precautions if any line stringing is needed for repairs. Some slow trucks may exit from the substation site, but the volume of trucks would be negligible. Heavy truck traffic would be limited such that it would not cause a noticeable acceleration in pavement degradation. The FEIR then concluded that operation and maintenance impacts would be less than significant.

The project, as amended, would not substantially increase hazards due to a design feature or incompatible uses compared to the impacts discussed in the 2017 FEIR and, therefore, would not result in any new or more severe significant impacts. The location and footprint of the amended proposed project remain largely unchanged from the FEIR; as do most of the various project components. The amended proposed project would include fewer linear miles of access roads from the deletion of three access roads in the revised project, however access roads would be approximately 20 feet wider (in permanent impact area) than those analyzed in the 2017 FEIR, but with a narrower temporary impact width compared to those analyzed in the 2017 FEIR. All of the access road alignments in the amended proposed project were part of the original proposed project description analyzed in the 2017 FEIR. Similar to the original proposed project, those access roads would accommodate construction of the amended proposed project, be used for maintenance access, and are not expected to be accessible to the public. Love Lane would be relocated approximately 105 to 180 feet west of its current alignment, potentially relocating the road slightly closer to its existing alignment than discussed in the 2017 FEIR. Consistent with the original proposed project, the relocated Love Lane design would be approved by Riverside County. Within the proposed Alberhill Substation, a series of driveways would be constructed and safety issues may occur as large, slow trucks enter and exit the substation site into faster traffic on Temescal Canyon Road. There would be additional staging areas under the amended proposed project. Trucks accessing staging areas could result in similar safety issues as the Alberhill Substation driveways. Construction of the amended proposed project would require the use of overweight or oversized vehicles for the delivery of construction equipment and materials which can shorten the life of the pavement. Public roads would be repaired in accordance with local franchise agreements. The amended proposed project would include additional crossings of I-15 (e.g., 115-kV Segments 1.5) and minor modifications of 115-kV alignment adjacent to the ROW of public roadways. Roadway crossings during 115-kV installation activities could temporarily cause safety impacts to motorists, bicyclists, and pedestrians. The safety devices and methods that the applicant would implement prior to the initiation of wire-stringing activities as outlined in the 2017 FEIR would be the same. The amended proposed project would also implement the same mitigation measures, MM TT-1 and TT-6, as described in the FEIR for the original proposed project requiring development of a Traffic Management and Control Plan prior to commencement of construction activities to reduce potential safety hazards and repair of private road damage directly caused by project vehicle traffic and activities. Implementation of these measures would result in impacts consistent with those disclosed in the FEIR (i.e., mitigated to a less than significant level). Operation and maintenance activities would be the same under the original proposed project and the amended proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact TT-4, and no major revisions to the FEIR would be warranted.

Impact TT-5 (ASP): Result in inadequate emergency access.

The 2017 FEIR concluded that the original proposed project would result in less than significant impacts with mitigation relative to inadequate emergency access. The FEIR disclosed that lane closures that could impede emergency access along those roadways may be required where project work crosses roadways, such as for relocation of the agricultural water pipeline from beneath the Alberhill Substation site and places where the components of the original proposed project's electrical lines span a road. This could result in a significant impact, if no mitigation were implemented. MM TT-7 would require coordination with local emergency services providers so that the local emergency service providers can anticipate road closures. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-7.

The 2017 FEIR disclosed that during operation no permanent or temporary road or lane closures are planned during operations. Maintenance activities that would occur outside access roads or structure pads or require disturbance of public roadways would be infrequent. MM TT-7 would require coordination with local emergency services providers so that access for emergency vehicles would be maintained. The FEIR then concluded that operation and maintenance impacts would be less than significant after implementation of MM TT-7.

The amended proposed project, consistent with the original proposed project described in the 2017 FEIR, would require lane closures that could impede emergency access along those roadways where project work crosses roadways, such as for relocation of the agricultural water pipeline from beneath the Alberhill Substation site and places where the components of the original proposed project's electrical lines span a road. The amended proposed project would include additional crossings of I-15 (e.g., 115-kV Segment 1.5) and minor modifications of the 115-kV alignments adjacent to the ROW of public streets. Examples of minor modifications of the 115-kV alignments along public roadways include: the adjustment of the Segment ASP2 crossing of I-15 and Lake Street, alignment west of Lake Street, and underground configuration along Pasadena Street and Third Street; the elimination of two new tubular steel poles at the I-15 crossing within Segment ASP5; and the adjustment of two new tubular steel pole locations along Murrieta Road within Segment ASP6. Similar to the original proposed project, the construction of the amended proposed project would result in temporary roadway closures/lane closures at several locations where the construction activities would be located within or immediately adjacent to the ROW of public streets and highways. The amended proposed project would also implement the same mitigation measures, MM TT-7, as described in the FEIR for the original proposed project requiring coordination with local emergency services providers so that the local emergency service providers can anticipate road closures. Implementation of mitigation measure MM TT-7 would result in impacts consistent with those disclosed in the FEIR (i.e., mitigated to a less than significant level). Maintenance activities would be the same under the original proposed project and the amended proposed project. Therefore, no new significant impacts would result from the amended proposed project in regard to Impact TT-5, and no major revisions to the FEIR are warranted.

Impact TT-6 (ASP): Conflict with adopted policies, plans, or programs regarding public transit, bikeways, or pedestrian facilities, or otherwise substantially decrease the performance or safety of such facilities.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation relative to conflicts with adopted policies, plans, or programs regarding public transit, bikeways, or pedestrian facilities, or otherwise substantially decrease the performance or safety of such facilities. The FEIR disclosed that staging of equipment during construction may require the temporary closure of existing bus stops along roadways in the project area but bus stop closure would not conflict with adopted policies, plans, or programs regarding public transit or otherwise substantially decrease the performance or safety of such facilities. The FEIR also disclosed that pedestrian, and bicycle circulation may temporarily be affected by construction activities for short periods, including utility pole installation and wire stringing. Construction activities are not expected to impede pedestrian or bicyclist movement such that no suitable alternative routes would be available. However, work near roadways could result in a safety hazard for bicyclists and pedestrians, which is a significant impact. MM TT-1 would require development of a Traffic Management and Control Plan prior to commencement of construction activities to reduce potential safety hazards. The FEIR then concluded that construction impacts would be less than significant after implementation of MM TT-1.

The FEIR concluded that operational impacts would be negligible because the original proposed project would not result in the permanent closure of bicycle, pedestrian, or public transit facilities. Routine maintenance activities for the original proposed project would require a few vehicles and, therefore, would have a less than significant impact during maintenance.

The project, as amended, would not result in any new or more severe impacts relative to conflicts with adopted policies, plans, or programs regarding public transit, bikeways, or pedestrian facilities, or otherwise substantially decrease the performance or safety of such facilities than originally proposed. The location and footprint of the amended proposed project remain largely unchanged from the FEIR; as do most of the various project components. The staging of equipment during construction of the amended proposed project may require the temporary closure of existing bus stops along roadways in the project area but temporary bus stop closure would not conflict with adopted policies, plans, or programs regarding public transit or otherwise substantially decrease the performance or safety of such facilities. The minor changes in the locations of certain project components from the original proposed project have the potential to temporarily impede pedestrian or bicyclist movement, consistent with the impacts of those same components from the original proposed project. As disclosed in the 2017 FEIR suitable alternative routes would be available. The amended proposed project would implement MM TT-1 to reduce potential safety hazards to bicyclists and pedestrians; therefore, no new significant impacts would result from the amended proposed project in regard to Impact TT-6, and no major revisions to the FEIR would be warranted.

Impact TT-7 (ASP): Result in inadequate parking that would result in a significant impact on the environment.

The 2017 FEIR concluded the original proposed project would result in less than significant impacts relative to inadequate parking. The FEIR disclosed that construction of project components would not require on-street parking since construction worker vehicle parking and construction equipment can be accommodated in staging areas or the ROW for the transmission, subtransmission, distribution, and telecommunications project components. Installation of the 115-kV lines would require roadway crossings and wire-stringing activities along roadways that may require lane closures that could temporarily limit on-street parking in Riverside County and the City of Lake Elsinore. A minimal number of parking spots would be unavailable at any given time since most of the affected streets are not extensively used for on-street parking. Stringing of 115-kV Segment ASP4 could result in the temporary closure of the car dealership parking lot on Auto Center Road, and parking lots for businesses located along Malaga Road. Temporary closure of parking lots in a commercial area would not result in a significant impact on the environment. The FEIR then concluded that construction impacts would be less than significant.

The FEIR concluded that operation and maintenance of the original proposed project would have less than significant impacts on parking. Operation of the original proposed project would use parking at the proposed substation so on-street parking would not be impacted. Maintenance activities that would occur outside access roads or structure pads or that would require closure of public roadways and parking areas would be infrequent and temporary such that parking impacts would be negligible.

The ASP, as amended, would not result in any new or more severe impacts relative to inadequate parking than originally proposed. The location and footprint of the amended proposed project remain largely unchanged from the original proposed project, as do most of the various project components. Construction of project components would not require on-street parking, consistent with the description for the original proposed project analyzed in the FEIR. A minimal number of parking spots would be unavailable at any given time during temporary lane closures when 115-kV lines are installed. Operation and maintenance activities would be the same under the original proposed project as described above and the amended proposed project. Impacts are consistent with those disclosed in the FEIR (i.e., less than significant level). Therefore, no new or substantially more severe significant impacts would result from the amended proposed project in regard to Impact TT-7, and no major revisions to the FEIR would be warranted.

(3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted:

- **a. The project will have one or more significant effects not discussed in the previous EIR or negative declaration;**
- **b. Significant effects previously examined will be substantially more severe than shown in the previous EIR;**

As described under (1) and (2) above, the amended proposed project would not result in any new or substantially more severe impacts associated with transportation and traffic than previously disclosed in the 2017 FEIR due to either changes in the amended proposed project or changes in the context of the project location and regulatory setting.

- **c. Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or**
- **d. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.**

The 2017 FEIR concluded the original proposed project would result in less than significant impacts with mitigation and less than significant impacts (without mitigation) under this criterion. Because significant impacts were not found under this criterion, new mitigation measures, which are considerably different from those analyzed in the FEIR, that would substantially reduce one or more significant effects on the environment are not addressed here. As discussed in the introduction, new alternatives that are considerably different from those analyzed in the 2017 FEIR are being analyzed separately in a Supplemental Alternatives Screening Report.

REFERENCES

Cal Fire (California Department of Forestry and Fire Protection). 2023. "Fire Hazard Severity Zones." Maps. Accessed December 15, 2023. https://osfm.fire.ca.gov/what-we-do/community-wildfire-preparedness-and-mitigation/fire-hazard-severity-zones.

Diaz, Tom. 2024. Email communication from Tom Diaz, Southern California Edison to WSP. February 5, 2024.

Ecology & Environment. 2017. Valley-Ivyglen 115-kV Subtransmission Line and Alberhill System Projects Final Environmental Impact Report. Prepared by Ecology & Environment.

FEMA (Federal Emergency Management Agency). 2017. "FEMA National Flood Hazard Layer (NFHL Viewer)" in USGS The National Map: Orthoimagery. Map. Data refreshed December 2021. Accessed May 10, 2024. https://hazards-fema.maps.arcgis.com/apps/webappviewer/index.html?id=8b0adb51996444d4879338b5529aa9cd.

Rincon Consultants, Inc. 2023. *Supplemental Cultural Resources Assessment for Southern California Edison's Alberhill System Project*, Alberhill, California.

Riverside County ALUC (Airport Land Use Commission). 2004a. Perris Valley Airport Influence Areas. December 29.

———. 2004b. Riverside County Airport Land Use Compatibility Plan. October 14.

———. 2010. Riverside County Airport Land Use Compatibility Plan: Volume 2. Background Data: Perris Valley Airport and Environs. July.

Southern California Edison (SCE). 2023. Response to CPUC Data Request 018, Question DG-MISC-89. Email to CPUC. September 13, 2023.

———. 2024a. Response to CPUC Data Request 021, Question DG-MISC-93-Follow-up_2_Suppl_1. Email to CPUC. March 29, 2024.

———. 2024b. Coastal California Gnatcatcher Critical Habitat. Map. April 2024.

———. 2024c. Response to CPUC Data Request 021, Question DG-MISC-93-Follow-up_2. Email to CPUC. March 7, 2024.

U.S. Census Bureau. 2020. 2020 Census Data. Accessed January 8, 2024. data.census.gov.

———. 2023. E-5 City/County Population and Housing Estimates. January 1, 2023. Accessed January 8, 2024. https://dof.ca.gov/forecasting/demographics/estimates/e-5-population-and-housing-estimates-for-cities-counties-and-the-state-2020-2023/.

Attachment B

Mitigation Monitoring, Compliance, and Reporting Plan

9. Mitigation Monitoring, Compliance, and Reporting Plan

The purpose of this Mitigation Monitoring, Compliance, and Reporting Plan (MMCRP) is to ensure effective implementation of the Project Commitments and Mitigation Measures required by the California Public Utilities Commission (CPUC) that Southern California Edison (the applicant) has agreed to implement as part of the proposed Alberhill System Project (proposed Alberhill Project). The MMCRP, which is outlined in Tables 9-1, includes:

- Each impact evaluated in the Environmental Impact Report (EIR);
- Project Commitments and mitigation measures that the applicant is required to implement as part of the proposed project;
- Compliance documentation and consultation requirements for each Project Commitment and mitigation measure;
- Monitoring requirements; and
- Timing for implementation of the Project Commitments and mitigation measures.

This MMCRP is a draft program. The CPUC will finalize this MMCRP prior to construction to include protocols that will be followed prior to, during, and after construction by the CPUC's and the applicant's designated environmental monitors and project staff. Drafted language for the following topics is provided below:

- Roles/ Responsibilities;
- Communication;
- Compliance Verification and Reporting;
- Project Changes, including Minor Project Refinements; and
- Dispute Resolution.

The CPUC will develop the final language of the MMCRP in consultation with the applicant.

A CPUC Monitor (see Section 9.2.1, "CPUC Project Manager and Compliance Managers and Monitors") will monitor construction of the approved project to ensure full implementation of each Project Commitment and mitigation measure. The CPUC Compliance Manager (see Section 9.2.1) will issue a warning for non-compliance activities that don't present an immediate risk to environmental resources. Continued non-compliance of low risk activities or non-compliance activities that present a more severe risk to environmental resources will be reported to the CPUC Project Manager (see Section 9.2.1). Any decisions to halt work due to non-compliance will be made by the CPUC Project Manager. The CPUC Compliance Manager will keep a record of any incidents of noncompliance with mitigation measures, Project Commitments, or other conditions of project approval. The CPUC Compliance Manager will provide copies of these documents to the applicant and CPUC Project Manager.

If the CPUC approves the proposed project and mitigation measures, further project construction–related details will be added to the MMCRP.

9.1 Regulatory Background

Under California Environmental Quality Act (CEQA) Guidelines Section 15097, the Lead Agency (in this case, CPUC) is responsible for developing a mitigation monitoring or reporting program to ensure that all project revisions and mitigation measures described in the findings associated with approval of the project are implemented. Monitoring refers to the ongoing or periodic process by which project construction and operation are overseen by the lead agency and ensures that the applicant's compliance with project conditions is checked on a regular basis. Reporting, which comprises written reviews of the applicant's compliance with Project Commitments and mitigation measures, ensures that the lead agency is informed of compliance with Project Commitments and mitigation measures. The CPUC views the MMCRP as a working guide to facilitate not only the applicant's implementation of Project Commitments and mitigation measures, but also the monitoring, compliance, and reporting activities of the CPUC and its monitors. The CEQA Guidelines encourage lead and responsible agencies to cooperate in mitigation monitoring and reporting, where possible.

9.2 Roles and Responsibilities

This section outlines roles and responsibilities specific to the MMCRP.

9.2.1 CPUC Project Manager and Compliance Managers and Monitors

The CPUC Project Manager will assign monitoring and reporting responsibilities to a third-party contractor as described below and will oversee the work of the third-party contractor through review of weekly and monthly status reports. The CPUC Project Manager will be notified of non-compliance situations and may suggest measures to help resolve the issue(s). All minor project refinement requests (further discussed in Section 9.4, "Minor Project Refinements") will be submitted to the CPUC Project Manager for review and approval.

The CPUC Project Manager will assign a Compliance Manager (CPUC Compliance Manager) as the designated point of contact. The CPUC Compliance Manager will be a third-party contractor and will report to the CPUC Project Manager. The CPUC Compliance Manager will consult with the CPUC Project Manager to determine the appropriate level of inspection frequency and intensity and will also oversee one or more Compliance Monitors. Compliance Monitors are on-the-ground personnel responsible for observing and reporting compliance with the terms and conditions of the CPUC Certificate of Public Convenience and Necessity. The number of Compliance Monitors and frequency of site inspections will depend on the number of concurrent construction activities and their locations. The CPUC Compliance Manager will be an integral part of the project team and will stay apprised of construction activities, schedule changes, and construction progress. The CPUC Compliance Manager and Compliance Monitors will document compliance through daily site inspection forms, the use of tables tracking Project Commitments and mitigation measures, and monthly reports to the CPUC Project Manager.

9.2.2 Construction Personnel

Applicant Construction Management Team

The applicant's construction management team will oversee, manage, and coordinate with the Construction Crews or Contractor, if utilized, to ensure overall project construction is completed as required by the project conditions and contract, and within the schedule. The applicant's construction management team must ensure that Project Commitments, mitigation requirements, and project conditions are implemented and that any work stoppages are appropriately communicated and coordinated.

Construction Crews/Contractors

The Construction Crews/Contractors will provide daily construction work schedules and describe the number, types, and activities of the construction scheduled to occur to ensure adequate monitoring resources are provided. The Construction Crews/Contractors will also report deviations from compliance and any spills (e.g., fuel or water) to the Compliance Monitors.

The Construction Crews/Contractors will be responsible for compliance with the environmental requirements of the project. They will be responsible for incorporating all Project Commitments, mitigation requirements, and project conditions into daily construction activities.

Key environmental responsibilities for Construction Crews/Contractors include, but are not limited to:

- Verifying that all construction workers attend the project environmental training program prior to beginning work;
- Reviewing and understanding the Project Commitments, mitigation requirements, and project conditions; and
- Implementing Project Commitments, mitigation requirements, and project conditions during construction and maintaining compliance with the MMCRP.

9.2.3 Monitoring

As the Lead Agency under CEQA, the CPUC is required to monitor the project to ensure that the Project Commitments, mitigation requirements, and project conditions are implemented. The CPUC will have primary responsibility for ensuring full compliance with the provisions of the monitoring program. The Compliance Monitors, under the supervision of the CPUC Compliance Manager, will monitor construction activities in the project areas on a regular basis, particularly when construction activities have the potential to impact a sensitive resource.

The applicant may elect to have one or more full-time environmental monitor on site on a daily basis to coordinate specialty monitors (such as biologists and archaeologists), assist construction crews with interpreting Project Commitments and mitigation measures, and help correct any compliance issues in a timely manner. Environmental monitors will also provide environmental training.

9.2.4 Enforcement

The CPUC has the authority to halt any construction activity associated with the project if the activity is determined to be a deviation from the approved project, adopted Project Commitments, mitigation measures, or conditions of approval. CPUC Compliance Monitors will inform the applicant's environmental monitor or construction contractor of a compliance issue and report compliance issues to the CPUC Project Manager via the CPUC Compliance Manager.

9.2.5 Mitigation Compliance

The applicant is responsible for successfully implementing all the adopted Project Commitments and mitigation measures listed in the MMCRP. The applicant shall inform the CPUC Project Manager and CPUC Compliance Manager in writing of any mitigation measures that are not or cannot be successfully implemented. The CPUC Project Manager and CPUC Compliance Manager will identify the appropriate subsequent actions.

9.3 Communication

Communication is a critical component of a successful environmental compliance program. To avoid project delays and possible work stoppages, environmental and construction representatives will need to interact regularly and maintain professional, responsive communications at all times. Similarly, representatives of the applicant will need to coordinate closely with the Compliance Monitors to address and resolve issues in a timely manner. A communication protocol to accurately disseminate information regarding ongoing surveys and mitigation measures, construction activities, contractors, and planned or upcoming work to all levels of the project will be established prior to the commencement of construction.

9.3.1 Monthly Environmental Compliance Report

The applicant will prepare and distribute a monthly environmental compliance report to the CPUC Project Manager and CPUC Compliance Manager. The CPUC Compliance Manager will review the monthly report to ensure that the status of Project Commitments and mitigation measures is consistent with observations in the field. The monthly environmental compliance report will also be used to keep all parties informed of construction progress and any schedule changes.

9.3.2 Coordination with Other Agencies

Several local, state, and federal agencies have jurisdiction over portions of the land in the project area. In addition, some Project Commitments and mitigation measures were derived from specific agency input. The applicant will be responsible for contacting agencies and immediately notifying them of compliance issues within their jurisdiction. The CPUC Compliance Manager may request copies of email correspondences, phone logs, or other documentation between the applicant and agencies to avoid direct involvement of Compliance Monitors. However, if an issue regarding compliance with an Project Commitment, mitigation measure, or permit requirement under the jurisdiction of an agency remains unresolved, the Compliance Monitors may elect to contact the agency to discuss resolution.

9.4 Minor Project Refinements

This section describes the CPUC's process for staff approval of a minor project refinement (MPR) requested by the applicant. An MPR may be necessary as a result of the applicant's final engineering of project elements. The CPUC will only grant approval of an MPR if the refinement achieves or exceeds the level of environmental protection approved in the Final EIR, is consistent with CEQA requirements, and complies with the intent of the mitigation measures in the Final EIR. The CPUC will require a Petition for Modification for any request that does not meet all of the criteria of an MPR.

9.4.1 Minor Project Refinements Request Process

The applicant's request for CPUC staff approval of an MPR must be made in writing and should include the following information:

- A detailed description of the proposed MPR, including an explanation of why the MPR is necessary;
- Photos, maps, and other supporting documentation illustrating the difference between the existing conditions in the project area, the approved project, and the proposed MPR;
- A discussion of each environmental impact of the proposed MPR with supporting data verifying that the proposed MPR would not increase an existing impact of the project or create a new impact, after application of previously adopted mitigation;
- Whether the MPR conflicts with any Project Commitments or mitigation measures;
- Whether the MPR conflicts with any applicable guideline, ordinance, code, rule, regulation, order, decision, statute, or policy; and
- Construction schedule of the MPR.

The CPUC staff may request additional information, agency consultations, or a site visit in order to process the request. The CPUC staff will process the MPR once it is determined that sufficient information about the MPR has been received. The CPUC Project Manager will provide the applicant with a denied MPR with provided justification or a signed, approved MPR.

9.4.2 Requirements for Staff Approval of Minor Refinements

An MPR must meet all of the following requirements for CPUC staff approval. An MPR must not:

- Be outside the geographic boundary of the study area as defined in the CEQA document;
- Create a new significant impact or a substantial increase in the severity of a previously identified impact, based on the thresholds used in the environmental document;
- Trigger less restrictive or new discretionary permit requirements;[1]
- Conflict with any Project Commitments or mitigation measures or any applicable guideline, ordinance, code, rule, regulation, order, decision, statute, or policy; or
- Require new conditions for approval, without which the refinements would result in a new significant impact or a substantial increase in the severity of a previously identified impact.

Examples of refinements that may be approved by staff after final engineering include, but are not limited to:

- Adding a temporary extra work area or substituting a work area, including lay-down and staging, for another work area that is as suitable as or more suitable than the originally proposed work area. The temporary extra work area or substitute work area must be located in a disturbed area, must be restored to either its initial condition[2] or an improved condition,[3] and must not create any new significant impacts or a substantial increase in the severity of a previously identified impact.

---

[1] For example: In the event that dredging activities are added to a project, new conditions may be required under a Clean Water Act Section 404 permit or a California Fish and Game Code Section 1602 Lake or Streambed Alteration Agreement.

[2] The initial condition of the area is the condition prior to its use as a work area.

[3] For example, trash has been cleaned up that was originally on the site, or the site is replanted with native vegetation.

- Adjusting the alignment of a project component within the study area that was defined in the original environmental analysis to avoid sensitive resources or effects on homeowners, or adapt to conditions on the ground that vary from the conditions that existed at the time of the original environmental analysis, so long as the adjustment does not create a new significant impact or a substantial increase in the severity of a previously identified impact.
- Finalizing the engineering design for a project component that was not specifically described in the Final EIR or that requires adjustments in order to facilitate construction. The finalized design must not create a new significant impact or a substantial increase in the severity of a previously identified impact.

9.5 Dispute Resolution

The following procedure will be observed for dispute resolution between CPUC staff and applicant:

- Disputes and complaints should be directed to the CPUC Project Manager for resolution.
- Should this informal process fail, the CPUC Project Manager may initiate enforcement or compliance action to address deviations from the approved project.

9.6 Mitigation, Monitoring, Compliance, and Reporting Program

Table 9-1 presents the MMCRP, which incorporates all changes to the proposed project and mitigation measures that were made as a result of public review of the Draft EIR and further consideration of the proposed project by the CPUC. If the CPUC Commissioners approve the proposed project, CPUC staff will compile the Final MMCRP based on this table and the final project conditions.

Table 9-1 is the core document for the proposed project's environmental requirements and will serve as the primary guideline for determining compliance with the MMCRP. A copy of the table should be kept with each crew working on the proposed project, and all supervisory staff working on the proposed project should be familiar with the content of the table. CPUC staff will use a modified version of the MMCRP table to accurately track the status of Project Commitments and mitigation measures, which will also be used by the applicant's Environmental Monitors, Compliance Monitors, project managers, supervisory staff, and other members of the project team.

9.6.1 Effectiveness Review

The CPUC may conduct a comprehensive review of conditions that are not effectively mitigating impacts at any time it deems appropriate, including as a result of the Dispute Resolution procedure outlined in section 9.2, "Roles and Responsibilities." If the CPUC determines that, based on the review, any conditions are not adequately mitigating significant environmental impacts caused by the project, the CPUC may impose additional reasonable conditions to effectively mitigate these impacts. These reviews will be conducted in a manner consistent with the CPUC's rules and practices.

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Aesthetics			
Impact AES-2: Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a State Scenic Highway.	Project Commitment A: Landscaping and Irrigation Plan.	Verify preparation and implementation of landscaping and irrigation plan	After construction
	Project Commitment D: Habitat Restoration and Revegetation Plan.	Verify preparation and implementation of habitat restoration and revegetation plan	Prior to Construction and after construction
	MM AES-1: Staging Area Screening. Staging areas will be screened with perimeter screening fences at least 8 feet tall. Perimeter screening fences will be dark in color and covered with a dark-colored (e.g., dark green, brown, or black) fabric or other material that provides at least 50 percent screening.	Verify staging areas are screened	During construction
	MM AES-7: Alberhill Substation Visual Treatments. The applicant will prepare a surface treatment plan for the aboveground non-steel structural elements associated with the Alberhill Substation. Colors will be selected according to their ability to reduce the aesthetic impact of the substation and ancillary infrastructure. The applicant will consult with the California Public Utilities Commission prior to start of construction, and the CPUC will approve the plan. All color finishes will be flat and non-reflective. Structural steel associated with the Substation will not be dulled.	Verify implementation of visual treatments as recommended by a CA RLA	Prior to, during, and post construction
	MM AES-8: Treatment of 500-kV Transmission Towers. 500-kV Towers SA2/R4, VA2/R5, SA3/R7, VA3/R8, SA4/R12, and VA4/R11 will have color finishes that help blend the structures with their natural surroundings. The CPUC will approve the final color choices.	Verify implementation of visual treatments	Prior to, during, and post construction
Impact AES-3: Substantially degrade the existing visual character or quality of the site and its surroundings.	Project Commitment D: Habitat Restoration and Revegetation Plan. MM AES-1: Staging Area Screening.	See above	See above
	MM AES-9. Use wood, self-weathering steel, or galvanized steel poles. Wood or self-weathering or galvanized steel poles with surface coatings with appropriate colors, finishes and textures to most effectively blend the structures with the visible backdrop landscape	Verify pole material	Prior to, during, and post construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	shall be used on all of 115-kV Segment ASP6 (except where undergrounding is required per MM AES-10) and 115-kV Segments ASP5 and ASP6 in the following locations: • 115-kV Segment ASP5 - From the intersection of Murrieta Road and Scott Road/Bundy Canyon Road to 520 feet northeast of the intersection of Citrus Grove and Lemon Street. - From the intersection of Almond Street and Lemon Street to the intersection of Waite Street and Jo Ann Court. • 115-kV Segment ASP6 - From the intersection of Murrieta Road and La Piedra Road to the intersection of Murrieta Road and Craig Avenue. - From the intersection of Murrieta Road and Beth Avenue to the intersection of Murrieta Road and Scott Road/Bundy Canyon Road.		
	MM AES-10. Undergrounding on Murrieta Road: 115-kV Segment ASP6 shall be undergrounded between Craig Avenue and Beth Drive along Murrieta Road.	Verify placement of subtransmission line	Prior to, during, and post construction
Impact AES-4: Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area.	MM AES-3: Glare Reduction. MM AES-7: Alberhill Substation Visual Treatments. MM AES-8: Treatment of 500-kV Transmission Towers. MM AES-9. Use wood, self-weathering steel, or galvanized steel poles.	See above	See above
	MM AES-5: Night Lighting during Construction. To minimize the effect on any nearby sensitive receptors, lighting for construction activities, staging areas, and maintenance activities will be the minimum necessary to ensure safety and security for nighttime activities. All lighting used for nighttime construction activities will be oriented downward and shielded to eliminate off-site light spill at times when the lighting is in use. Any new safety and security lighting at staging areas or other areas established for long-duration construction activities, such as laydown areas, will be motion-activated or use timers to reduce impacts of nighttime lighting.	Verify utilization of night lighting	During construction
Agriculture and Forestry			
Impact AG-1: Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the FMMP of	Project Commitment I: Agricultural Uses	Verify continued agricultural use	Post construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
the California Resources Agency, to non-agricultural use.			
Air Quality			
Impact AQ-2: Violate any air quality standard or contribute substantially to an existing or projected air quality violation.	Project Commitment J: Air Emissions Controls.	Verify utilization of fugitive dust control measures	During construction
	MM AQ-1: Minimize NO_X and PM emissions from off-road diesel powered construction equipment. To the extent available, the applicant shall utilize off-road diesel-powered construction equipment with engines greater than 150 horsepower that comply with Tier 4 interim or Tier 4 road emission standards (Tier 4 Standards). In the event that equipment with a Tier 4 Standards compliant engine is not available, that equipment shall be operated with tailpipe retrofit controls that reduce NO_X and PM to no more than Tier 3 emission standards (Tier 3 Standards) levels. Equipment with a non-Tier 4 Standards compliant engine shall be utilized only when the applicant has made an unsuccessful good faith effort to locate equipment with a Tier 4 Standards compliant engine in the Valley–Ivyglen Project and Alberhill System Project vicinity (defined as within 200 miles of the applicable project site). Each such good faith effort shall be documented with written correspondence (or signed statement and electronic mail) by the appropriate construction contractor, along with written correspondence from at least two construction equipment rental firms within the defined vicinity confirming the unavailability of equipment with a Tier 4 Standards compliant engine. The applicant shall make available to the California Public Utilities Commission (CPUC) a copy of the certified tier specification, best available control technology documentation, and/or CARB or SCAQMD operating permit for each piece of construction equipment, as applicable, at the time the equipment is mobilized. In addition, the applicant shall: • Maintain construction equipment according to manufacturing specifications and use low-emissions equipment; • Reduce emissions of PM and other pollutants by using, whenever feasible, alternative clean fuel technology to power vehicles and equipment instead of gasoline- or diesel-powered engines (e.g., electric, hydrogen fuel cell, propane,	Verify utilization of Tier 4 Standard equipment	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	natural gas, or compressed natural gas-powered equipment with oxidation catalysts); • Ensure that all construction equipment is properly tuned and maintained and shut off when not in direct use; • Prohibit engine tampering to increase horsepower; • Locate engines, motors, and equipment as far as possible from residential areas and other sensitive receptors, such as schools, daycare centers, and hospitals; • Encourage carpooling to and from staging yards to construction sites to minimize private vehicle use; • Minimize construction-related transport of workers and equipment including trucks; and • Require that on-road vehicles utilized during construction meet CARB fleet regulations.		
	MM AQ-2: Oxides of Nitrogen (NO_X) Credits. The remaining emissions of NO_X resulting from construction of the proposed projects shall be mitigated through the purchase of Regional Clean Air Incentive Market Trading Credits (RTCs), Mobile Source Emission Reduction Credits (MSERCs), or a combination of RTCs and MSERCs for every pound of NO_X in excess of the SCAQMD regional significance threshold of 100 pounds per day, as measured per project. The total amount of NO_X RTCs to be purchased shall be calculated once the construction schedules for each project are finalized. The applicant shall purchase and submit documentation of purchase of the required RTCs to the SCAQMD prior to the start of construction of each project. The applicant shall also track actual daily emissions during construction of each project according to a monitoring plan, which shall require keeping records of equipment and vehicle usage for each project.	Verify the purchase of NOx credits	Prior to and after construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	MM AQ-3: Dust Control Plan. The applicant shall prepare a Dust Control Plan based on final engineering and pursuant to Rule 403 of the SCAQMD. The applicant shall submit the Plan to the CPUC prior to commencement of ground disturbing activities.	Verify utilization of fugitive dust control measures	During construction
	MM AQ-5: Volatile Organic Compounds Credits. The remaining emissions of VOC/reactive organic gas (ROG) resulting from construction of the proposed Alberhill Project shall be mitigated through the purchase of Emissions Reduction Credits (ERCs)/Short-Term Emission Reduction Credits (STERCs), Mobile Source Emission Reduction Credits (MSERCs), or a combination of ERCs/STERCs and MSERCs for every pound of VOC/ROG in excess of the SCAQMD regional significance threshold of 75 pounds per day, as measured. The total amount of VOC/ROG ERCs/MSERCs to be purchased shall be calculated once the construction schedule is finalized. The applicant shall purchase and submit documentation of purchase of the required ERCs/MSERCs to the SCAQMD prior to the start of construction. The applicant shall also track actual daily emissions during construction according to a monitoring plan, which shall require keeping records of equipment and vehicle usage for the project.	Verify the purchase of VOC credits	Prior to and after construction
Impact AQ-3: Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is nonattainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors).	Project Commitment J: Air Emissions Controls. MM AQ-1: Minimize NO_X and PM emissions from off-road diesel powered construction equipment. MM AQ-2: Oxides of Nitrogen (NO_X) Credits. MM AQ-3: Dust Control Plan. MM AQ-5: Volatile Organic Compounds (VOC) Credits.	See above	See above
Impact AQ-4: Expose sensitive receptors to substantial pollutant concentrations	Project Commitment J: Air Emissions Controls. MM AQ-1: Minimize NOx and PM emissions from off-road diesel powered construction equipment. MM AQ-3: Additional Fugitive Dust Controls.	See above	See above

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Biological Resources			
Impact BR-1: Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the CDFW or USFWS.	Project Commitment B: Worker Environmental Awareness Plan.	Verify the preparation and implementation of worker environmental awareness plan	Prior to and during construction
	Project Commitment C: Raptor Protection on Power Lines.	Verify implementation of APLIC recommendations	Prior to and during construction
	Project Commitment D: Habitat Restoration and Revegetation Plan.	See above	See above
	Project Commitment H: Noise Control.	Verify implementation of noise control measures	During construction
	MM BR-1: Limit Construction to Designated Areas and Avoid Riparian, Aquatic, and Wetland Areas. Vehicular traffic (including movement of all equipment) shall be restricted to approved access roads and established construction areas shown in Figure 2.6 of the EIR. These areas shall be delineated in the field with flagging and signage. If disturbance is required outside the established construction areas, CPUC notification and approval shall be required. Sensitive resources such as waterbodies, oak trees, and special status plant populations shall be clearly marked for avoidance with flagging and signage. Nighttime lighting, if necessary adjacent to aquatic areas, shall be shielded away from these areas to prevent impacts on aquatic wildlife.	Verify avoidance of wetlands	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	MM BR-2: Preconstruction Surveys. Qualified biologists shall conduct preconstruction surveys within two weeks of the start of construction in any given project construction area. Surveyors shall focus on areas proposed for vegetation removal or ground disturbance that are within habitat that a qualified biologist has deemed suitable for sensitive species. As part of preconstruction surveys, the composition of the vegetation community shall be surveyed to establish baseline conditions prior to construction and to guide post-construction restoration efforts. The surveys shall be conducted to determine the presence of special status plants, noxious weeds, and all wildlife species for the purpose of preventing direct loss of vegetation and wildlife and the spread of noxious plant species. Preconstruction surveys shall be performed for each discrete work area prior to the start of ground disturbance, or if work has lapsed for longer than 30 days. Biologists shall document survey results in a daily logbook or report.	Verify the completion of survey	Prior to construction
	MM BR-3: Biological Monitoring During Construction. In areas where sensitive resources may be impacted by construction activities, a qualified biological monitor shall be present during construction activities. The monitor shall have the authority to temporarily stop work that he or she determines to be threatening to a special status wildlife or plant species or nesting bird. The monitor shall determine appropriate action, and work will resume once the monitor determines there is no longer a threat to the special status species or approval has been obtained from the appropriate wildlife agencies or CPUC. Biologists shall document monitoring observations in a daily logbook.	Verify the monitoring of construction activities	During construction
	MM BR-4: Limit Removal of Native Vegetation Communities and Trees. The removal of native vegetation and trees shall be limited to the minimum practicable area required for construction of the project. Grading, grubbing, graveling, or paving shall only occur where required for construction and operations. The applicant shall use temporary staging areas in a way that facilitates post-construction restoration, and shall restore these areas to as close to pre-construction conditions as possible, or to the conditions agreed upon between the applicant and landowner.	Verify the minimization of native vegetation removal	During construction
	MM BR-5: California gnatcatcher protection measures. In accordance with the MSHCP, removal of Riversidean sage scrub habitat will not occur during the coastal California gnatcatcher breeding season. (February 15 to August 15). Should nesting coastal California gnatcatcher be observed during preconstruction surveys, outside of the breeding season, vegetation removal and other construction-related disturbance shall not commence within the applicable nest buffer area, as identified in the projects' Nesting Bird Management Plan, until the nest is determined to be inactive.	Verify the implementation of protection measures	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	MM BR-6: Oak tree protection measures. This measure applies to oak trees in all project areas. Preventive measures shall be taken during construction activities to minimize impacts in the protected zone of each oak tree. The protected zone commences at a point 5 feet outside the dripline and extends inward to the trunk of the tree. All work conducted in the protected zone of oak trees shall be performed using hand implements and in the presence of a certified arborist. If it is determined that oak tree removal is necessary, the applicant shall relocate oak trees to a place outside of the area of anticipated impacts under the direction of the certified arborist. If the applicant cannot feasibly relocate oak trees that are removed, 1-gallon oak trees shall be planted at a 12:1 ratio within the appropriate habitat to replace removed trees. These replacement trees shall be indigenous coast live oak trees that have been grown in a natural form (no topping or street tree forming). The applicant shall be responsible for monitoring and maintaining the relocated or replacement trees for a minimum of two years (to include at least two complete California rainy seasons, here defined as the period of the year from November – May). In addition, the following minimization measures shall be implemented under the direction of the certified arborist: • Equipment, materials, and vehicles shall not be stored, parked, or operated within the protected zone of an oak tree, except on sites approved for this use by a certified arborist. • Removal of the natural leaf mulch within the protected zone of oak trees is prohibited except where absolutely necessary. • All trees not approved for removal shall be fenced or flagged for avoidance and to designate the protected zone. • Any pruning, including removal of dead wood, shall be performed in compliance with the latest American National Standards Institute pruning standards by a certified arborist (or certified tree worker). • Any root-pruning required within the protected zone of an oak shall be limited to the minimum amount necessary. All root-pruning shall consist of clean, 90-degree angle cuts utilizing sharp hand tools. Any major roots (2 inches or greater in diameter) encountered shall be preserved to the extent possible and wrapped in	Verify the implementation of protection measures	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	moist burlap until the soil is replaced. Soil shall be replaced around preserved roots as soon as possible. To evaluate whether or not this type of mitigation is successful over the long-term, the relocated oak trees and replacement oaks will be revisited by a certified arborist in the fifth, tenth, and fifteenth years after relocation or planting to assess the survival/mortality rate of these oaks, and to evaluate the health of the surviving individuals. The applicant will prepare an initial report on the implementation of this measure after the second year of monitoring and maintenance has been completed. A Final Report will be prepared after the Year-15 assessment has been carried out; the Final Report will be submitted to the CPUC, and copies shall be sent to the USFWS (Palm Springs Fish and Wildlife Office), to the CDFW (Inland/Desert Regional Office), and to the California Native Plant Society's Conservation Program staff.		
	MM BR-7: Habitat Restoration and Revegetation Plan Requirements. Pursuant to Project Commitment D, the applicant shall develop a Habitat Restoration and Revegetation Plan to address ground disturbance in all project areas. In addition to including the provisions set forth in Project Commitment D, the Habitat Restoration and Revegetation Plan shall detail topsoil segregation and conservation methodology; restoration of special status plant species habitat; vegetation removal and revegetation methods, including seed mixes, rates, and transplants; criteria to monitor and evaluate revegetation success; and alternative restoration and revegetation methods in the event that the revegetation success criteria are not initially reached. The applicant shall implement the Habitat Restoration and Revegetation Plan until the restoration success criteria are achieved. Appropriate agencies (CPUC, USFWS, and CDFW) shall be consulted during the preparation of the Habitat Restoration and Revegetation Plan. A copy of the final Habitat Restoration and Revegetation Plan, along with documentation of agency review and incorporation of comments into the final version, shall be provided to the CPUC, the USFWS, and the CDFW for approval prior to the CPUC issuing a notice to proceed.	Verify the preparation and implementation of habitat restoration and revegetation plan	Prior to, during, and post construction
	MM BR-8: Special Status Plant Avoidance and Mitigation Measures. For project areas not covered by the MSHCP, the applicant shall avoid the special status plant populations listed in Appendix G, Table 1. However, where avoidance is not feasible, special status plants in project work areas shall be identified in the field, and the following avoidance measures shall be implemented to minimize the possibility of inadvertent encroachment: • A qualified biologist shall flag or otherwise mark special status plants. Construction crews will avoid direct or indirect impacts on these flagged areas. Should impacts	Verify the implementation of protection measures	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	on special status plants be unavoidable, the applicant will implement the following measures: - A qualified botanist shall determine if transplantation is feasible. If determined feasible, a qualified botanist shall develop and implement a transplantation plan in coordination with appropriate agencies (CDFW, USFWS, RCA). The special status plant transplantation plan shall identify a suitable transplant site, moving the plant material and seed bank to the transplant site, collecting seed material and propagating it in a nursery, and monitoring the transplant sites to document recruitment and survival rates. - If transplantation is infeasible, the applicant shall replace impacted special status plants at a 2:1 ratio within the project area within one year of the end of construction. Measures to restore special status plants shall be implemented in accordance with the Habitat Restoration and Revegetation Plan (MM BR-7).		
	MM BR-9: Invasive Plant Control Measures. The applicant shall develop an Invasive Plant Management Plan outlining measures to prevent the spread of invasive plants such as tamarisk (*Tamarix* sp.) and giant reed (*Arundo donax*) during construction of the projects. The Invasive Plant Management Plan shall include, but is not limited to, the following measures: • All vehicles and equipment shall be cleaned prior to arrival at the work site. • Straw or hay bales used for sediment barrier installations or mulch distribution shall be obtained from weed-free sources. The Invasive Plant Management Plan will be submitted to the CDFW and CPUC for review and comment no more than three months prior to the start of construction. A copy of the final Invasive Plant Management Plan, along with documentation of agency review (CDFW and CPUC) and incorporation of comments into the final version, shall be provided to the CPUC for approval prior to the CPUC issuing a notice to proceed.	Verify the preparation and implementation of invasive plant management plan	Prior to and during construction
	MM BR-10: Prevent Wildlife Entrapment. In all project work areas, the applicant shall install covers, ramps, and/or fencing to avoid trapping wildlife in excavations or trenches. Covers must be weighted at the edges or installed in a way that prevent wildlife from attempting to burrow beneath the cover. Fine-gauge fencing shall be used to prevent small animals from passing through the fence. Ramps with an angle of less than 45 degrees shall be utilized. The applicant's biological monitor will check open trenches and excavations for	Verify the prevention of wildlife entrapment	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	trapped wildlife each morning prior to the start of work on the trench or excavation. Trenches and excavations that are covered for more than one week will be inspected on a weekly basis. In addition, where retaining walls or another method of slope stabilization are required, the facility shall be sited, designed, and oriented to avoid impacts on the movement of native wildlife species and established wildlife corridors in coordination with the wildlife agencies (USFWS, CDFW, RCA).		
	MM BR-11: Migratory Birds and Raptors Impact Reduction Measures. The applicant shall develop a Nesting Bird Management Plan in consultation with the USFWS and CDFW that outlines protective measures and BMPs that shall be employed in all project work areas to prevent disturbance of active nests. The final Plan shall be submitted to the CPUC for approval. The Nesting Bird Management Plan shall include the following components: species-specific buffer distances (including vertical buffers in areas where helicopters will be used) and conditions under which these buffer distances can be reduced, including concurrence by the CDFW, USFWS, and CPUC for special status species; dates of local breeding seasons during which nest surveys shall be conducted; preconstruction nest survey timing, methods, and surveyor qualifications; nest deterrent methods, including vegetation clearing; monitoring and reporting protocols during construction; protocols for determining whether a nest is active; protocols for documenting, reporting, and protecting active nests within construction areas; and avian monitor qualifications. If preconstruction survey protocols exist for a certain species, the Nesting Bird Management Plan shall incorporate these protocols. The survey area shall include the construction area, plus an additional distance large enough to accommodate the protective buffer of bird species likely to occur in proximity to the construction area. The Nesting Bird Management Plan shall further specify that active bird nests shall not be removed during breeding season unless the projects are expressly permitted to do so by the USFWS or CDFW; all project-related nest failures shall be reported to the USFWS and CDFW; and the biological monitor shall halt work if he or she determines that active nests would be disturbed by construction activities. If construction begins during the breeding season (February 1 through August 31), the Nesting Bird Management Plan shall be submitted to the USFWS and CDFW for review and comment no less than two months prior to the start of construction, with the intent that the plan will be finalized no less than one month prior to the start of construction. A copy of the final Nesting Bird Management Plan, along with documentation of agency review (CDFW, USFWS, CPUC) and incorporation of comments into the final version, shall be provided to the CPUC for approval prior to the CPUC issuing a notice to proceed during the breeding season.	Verify the preparation and implementation of nesting bird management plan	Prior to and during construction
	MM BR-12: Burrowing Owl Impact Reduction Measures. To reduce impacts on burrowing	Verify the	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	owls, the applicant shall implement the following measures in all project work areas: • Surveys for burrowing owls will be conducted by a qualified biologist within 30 days of construction during the non-breeding season and within 14 days of construction during the breeding season (February 1 through August 31) to confirm whether burrowing owls occupy the site. Surveys shall be performed throughout the project areas that contain suitable burrowing owl habitat, with a potential to be impacted by construction activities, plus an additional area extending 300 feet from the projects' boundaries. • If an occupied burrow is identified, the applicant shall adhere to buffer distances detailed in the *Staff Report on Burrowing Owl Mitigation* (CDFG 2012). • The biologist will report all project-related impacts on burrowing owl to the appropriate resource agencies (CDFW and RCA). If appropriate buffers cannot be maintained, and impacts on burrowing owls or occupied burrows are unavoidable, the applicant shall develop and implement a Determination of Biologically Equivalent or Superior Preservation (DBESP), in compliance with MSHCP Section 6.3.2, and as approved by CDFW and RCA. The DBESP shall describe the compensatory measures that will be undertaken to address the loss of burrowing owl burrows within the project area. The compensatory mitigation shall be determined on a site-specific analysis, but may include restoration of temporarily impacted habitat and acquisition and or enhancement of off-site mitigation lands as determined in consultation with CDFW. If, in consultation with CDFW it is determined that project activities require removal of occupied burrows, eviction and burrow closure may be required to ensure against "take" of owls or nests. However, this will only occur after the preparation of a Burrowing Owl Exclusion Plan, as approved by CDFW.	implementation of protection measures	
	MM BR-13: Trash Abatement. The applicant shall keep project areas free of trash and debris. Food-related trash items shall be stored in enclosed containers and regularly removed from site.	Verify trash removal	During construction
	MM BR-14: Protection of Special Status Species on Castle and Cooke Land. The applicant is entering into an agreement with the RCA, with USFWS and CDFW concurrence, to allow for coverage of the Valley–Ivyglen and Alberhill Projects' obligations under the MSHCP on Castle and Cooke property, which falls outside MSHCP boundaries and thus is exempt from mitigation under the MSHCP. If this agreement is finalized prior to the start of construction, it shall be in effect for the duration of the projects or until SCE opts out. Should SCE opt out of the MSHCP, or if this agreement with the RCA is not finalized, the applicant	Verify the implementation of protection measures	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	shall implement the same or a greater level of species-specific avoidance, mitigation, restoration, and compensation measures as would have been required under the MSHCP. This may include additional consultation with USFWS and CDFW to obtain Incidental Take Authorization pursuant to the Federal California Endangered Species Acts. These additional measures would include MM BR-1, MM BR-4, and MM BR-8.		
	MM BR-16: Stephens' Kangaroo Rat Take Avoidance within Core Reserve. The applicant shall ensure that take of SKR within the Lake Mathews-Estelle Mountain Core Reserve does not occur during any project construction activity. To avoid take of SKR, the following measures shall be implemented: *Daylight Hours Only* • No vehicle or equipment use for any project construction activity shall occur within the Core Reserve or on its roadways within 30 minutes prior to sunset or 30 minutes after sunrise except during an emergency condition. If an emergency condition occurs and nighttime access or use is necessary, the CPUC shall be notified within 24 hours. To the extent feasible, biological monitors qualified to monitor for SKR shall be present during emergency access to the Core Reserve. *Monitoring* • No more than 14 days prior to conducting any project construction activity within the Core Reserve, biological monitors qualified to monitor for SKR shall complete preconstruction surveys and flag confirmed and potential SKR burrow complexes (including burrows that may be used by other kangaroo rat species) for avoidance. Surveyed and flagged areas shall include all 500-kV ROWs to be accessed within the Core Reserve plus a 25-foot buffer area (except in areas inaccessible by foot) on each side of these roads. *Vehicle Use* • Vehicle use and worker access within the Core Reserve shall be minimal. Vehicles shall not travel faster than 10 miles per hour within the Core Reserve. All construction vehicles and equipment shall remain on existing access and maintenance roads used to access the applicant's 500-kV towers within the Core Reserve. • Biological monitors qualified to monitor for SKR shall accompany all workers to and from all work sites within the Core Reserve, and shall conduct daily clearance	Verify the implementation of protection measures	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	sweeps immediately prior to any project construction activity for all areas within the Core Reserve to be accessed that day. • If activities at 500-kV tower sites adjacent to the Core Reserve require equipment to back up into the Core Reserve on areas that are not existing access roads, biological monitors qualified to monitor for SKR shall monitor the process of backing up and exiting the Core Reserve areas and all activities that occur in proximity to the equipment while it is located within the Core Reserve area. Equipment shall be carefully inspected by the monitors for SKR prior to backing up or exiting the Core Reserve area. If SKR are present, the equipment shall not be moved until all SKR have left the equipment and all areas within 20 feet of the equipment. *Signage* • Clearly marked and visible signs listing the required speed limit and reminding drivers to watch for and avoid kangaroo rats shall be posted at the entry point into the Core Reserve and at regular intervals thereafter (at minimum every 0.25 miles) along all roads to be accessed within the Core Reserve. *Other Requirements* • The applicant shall not access the 0.5-mile access road segment located within the Core Reserve between 500-kV Towers M13-=T2 and M13-T1 other than by foot or helicopter. If accessed by foot or helicopter, no more than 14 days prior to access, preconstruction surveys shall be conducted along the 0.5-mile Hilltop Road segment to identify and flag potential kangaroo rat burrow complexes for avoidance. No activities other than grounding and wire snubbing and vehicle use required for these activities shall occur at 500-kV tower sites located within the Core Reserve. MM BR-18: Implementation of All Project Commitments. The applicant will implement all Project Commitments as stated in this EIR, except in cases where they are superseded or modified by Mitigation Measures. The Project Commitments will be incorporated into the Mitigation Monitoring and Compliance Reporting Program.		
Impact BR-2: Have a substantial adverse effect on any riparian	Project Commitment B: Worker Environmental Awareness Plan.	See above	See above

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the CDFW or USFWS.	Project Commitment D: Habitat Restoration and Revegetation Plan. MM BR-1: Limit Construction to Designated Areas and Avoid Riparian, Aquatic, and Wetland Areas. MM BR-2: Preconstruction Surveys. MM BR-3: Biological Monitoring During Construction. MM BR-4: Limit Removal of Native Vegetation Communities and Trees. MM BR-6: Oak tree protection measures. MM BR-7: Habitat Restoration and Revegetation Plan Requirements. MM BR-9: Invasive Plant Control Measures.		
Impact BR-3: Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means.	MM BR-1: Limit Construction to Designated Areas and Avoid Riparian, Aquatic, and Wetland Areas. MM BR-2: Preconstruction Surveys. MM BR-3: Biological Monitoring During Construction.	See above	See above
	MM BR-15: Stormwater Pollution Prevention Plan (SWPPP). The SWPPP shall include Best Management Practices (BMPs) sufficient to acquire authorization under the Construction General Permit and protect waters in the project vicinity from sediment and other pollutants during construction. Per SCE, BMPs from the California Stormwater BMP Handbook that would be included in the SWPPP include but are not limited to WM-1 Material and Delivery Storage, WM-4 Spill Prevention and Control, WM-5 Solid Waste Management, WM-6 Hazardous Waste Management, WM-8 Concrete Waste Management, NS-9 Vehicle and Equipment Fueling, and NS-10 Vehicle and Equipment Maintenance. Verification of Construction General Permit authorization and the associated SWPPP shall be provided to the CPUC at least 15 days prior to start of construction. Updated SWPPPs shall be provided to the CPUC during construction upon request.	Verify the implementation of protection measures	During construction
Impact BR-6: Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or	MM BR-2: Preconstruction Surveys. MM BR-3: Biological Monitoring During Construction.	See above	See above

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
other approved local, regional, or state habitat conservation plan.	MM BR-6: Oak tree protection measures. MM BR-7: Habitat Restoration and Revegetation Plan Requirements. MM BR-8: Special Status Plant Avoidance and Mitigation Measures. MM BR-9: Invasive Plant Control Measures. MM BR-11: Migratory Birds and Raptors Impact Reduction Measures. MM BR-12: Burrowing Owl Impact Reduction Measures. MM BR-16: Stephens' Kangaroo Rat Take Avoidance within Core Reserve. MM BR-18: Implementation of All Project Commitments		
Cultural Resources			
Impact CR-1: Substantial adverse change in the significance of an historical or archaeological resource.	Project Commitment B: Worker Environmental Awareness Plan.	See above	See above

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	MM CR-1a: Ensure preconstruction survey coverage of all work areas and staging areas. Prior to construction, the applicant shall compare the limits of the work areas and staging areas to project maps that show where areas have been previously surveyed for cultural resources at the Intensive Cultural Resources Inventory level. The applicant shall verify the proposed work areas and staging areas have been surveyed at the Intensive Cultural Resources Inventory level. An Intensive Cultural Resources Inventory level of survey is defined here as consisting of pedestrian surveys with transects spaced no farther apart than 15 meters except where field conditions such as exceptionally dense vegetation or steep slopes make walking transects difficult. In order to rely upon a prior survey for a work area, all areas that can be reasonably covered by transect surveys within such work area shall have been surveyed. If such a prior survey has been completed in the proposed work area or staging area, work can commence as follows: • If no known resources are located in the work area or staging area, work or staging can proceed in the area. Previously unknown resources that are discovered during work activities shall be subject to MM CR-1b. • If known resources are located in the work area or staging area, they must be handled pursuant to MM CR-1b. Previously unknown resources that are discovered during work activities shall be subject to MM CR-1b. If such a prior survey has not been completed in the proposed work area or staging area, then work may not commence until an Intensive Cultural Resources Inventory has been completed by a CPUC-approved archaeologist or cultural resources specialist and Native American tribal monitor(s) and reviewed and approved by the CPUC. If a resource is found during the survey, the applicant shall adhere to MM CR-1b procedures for unanticipated resources.	Verify completion of survey	Prior to construction
	MM CR-1b: Avoid impacts to known and undiscovered historic resources and unique archaeological resources (except for site P33-000714). SCE shall prepare a Cultural Resources Monitoring and Treatment Plan (CRMTP) for known and unknown resources that are eligible or potentially eligible for the California Register or are unique archaeological resources, except P33-000714, which is subject to MM CR-6. The CRMTP shall be reviewed and approved by the CPUC prior to the start of construction. To implement MM CR-1b SCE shall:	Verify the preparation and implementation of cultural resources monitoring and treatment plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• Retain a qualified archaeologist who shall: prepare the CRMTP; oversee archaeological and Native American monitors; and evaluate discoveries and prepare Evaluation and Data Recovery Plans and subsequent reports. This archaeologist shall, at the minimum, meet the Secretary of Interior's Professional Qualifications Standards for archaeology and be approved by the CPUC. • Provide Native American Tribes that have expressed interest in the projects (Soboba and Pechanga) the opportunity to consult with the qualified archaeologist and provide input on the draft CRMTP during its preparation, including the Evaluation Plan and Data Recovery Plan. Upon completion of the draft CRMTP, Native American Tribes shall be given at least 30 days to provide input on the draft CRMTP. Evidence of consultation with the Tribes shall be submitted to the CPUC. • Prepare the CRMTP, which shall include the following. - Mapping. The CRMTP shall map all known California Register eligible or potentially eligible resources in and within 100 feet of work areas. Maps shall be updated as necessary to incorporate any new information obtained pursuant to MM CR-1a. - Environmentally Sensitive Areas (ESA) Delineation. The CRMTP should describe how California Register eligible or potentially eligible resources will be delineated and avoided as ESAs during construction. ESAs containing cultural resources shall not be identified on the ground or on maps to be used by anyone other than the qualified archaeologist, Native American monitors, cultural resource monitors, or other cultural resource professionals. They shall be labeled on maps and with signage in the field as "environmentally sensitive areas." The preferred method of mitigation in the CRMTP for known resources shall be total avoidance of the resource (preservation in place), per CEQA Guidelines section 15126.4(b)(3)(A). The preferred method of mitigation in the CRMTP for unanticipated resources shall be total avoidance (preservation in place). If avoidance is determined to be infeasible, the applicant shall prepare a Data Recovery Plan. - Unanticipated resource discovery. The CRMTP shall contain a description of procedures to be used if unanticipated cultural resources are discovered during construction. The CRMTP shall require that work shall be temporarily halted within 100 feet of the resource, appropriate temporary protective barriers shall be installed along with signage identifying the area only as an		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	“environmentally sensitive area” and forbidding entry into the area by all but authorized personnel, and the qualified archaeologist and the CPUC shall be notified. No work will resume in the area until the qualified archaeologist and the CPUC agree to an appropriate buffer or until mitigation has been completed. The preferred method of mitigation in the CRMTP shall be total avoidance of the resource (preservation in place), per CEQA Guidelines section 15126.4(b)(3)(A). If the resource can be completely avoided, no additional mitigation is necessary. If the resource cannot be completely avoided, the qualified archaeologist shall then follow the procedures delineated for resources where it is not known whether the resource is historical. If an unanticipated resource is avoided, it shall nonetheless be recorded on California Department of Parks and Recreation 523 forms and filed at the Eastern Information Center. - Determination if a resource is an historical resource. The qualified archaeologist, in consultation with the CPUC, shall determine if there is a potential for the resource to be an historical resource. If there is no potential for the resource to qualify as an historical resource, work shall resume after CPUC concurrence. The CRMTP shall include a framework for evaluating cultural resources. If there is a potential for the resource to be an historic resource, the qualified archaeologist shall prepare an Evaluation Plan. - Evaluation Plan. The resource-specific Evaluation Plan shall detail the procedures to be used to determine if the discovery is an historical resource. The Evaluation Plan shall include sufficient discussion of background and context to allow the evaluation of the resource against the historic resource criteria. It shall include a description of procedures to be used in the gathering of information to allow the evaluation. These techniques may include (but are not limited to): excavation, written documentation, interviews, and/or photography. For archaeological resource testing, the Evaluation Plan should describe the archaeological testing procedures, including, but not limited to: surface collection (if surface artifacts are discovered), test excavations (including type, number, and location of test pits and/or trenches), analysis methods, and reporting procedure. The Evaluation Plan shall be submitted to CPUC for review. Once approved, the Evaluation Plan shall be implemented in the field. The report resulting from this work shall include evaluation of the discovery, based on the significance criteria set forth in the Evaluation Plan, indicating if it is an historic resource. If the discovery is not found to be an		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	historic resource, and CPUC concurs with that determination, protective barriers may be removed, and work may proceed in the area of the discovery. If the discovery is determined to be an historic resource, SCE shall prepare a Data Recovery Plan. - Data Recovery Plan. Data recovery plans for historic resources that cannot be fully avoided shall be prepared in accordance with CEQA Guidelines section 15126.4(b)(3)(C) and PRC section 21083.2, as applicable. The Data Recovery Plan shall outline how the recovery of data from the resource will mitigate impacts to that resource to below a level of significance. The Data Recovery Plan shall describe the level of effort, including numbers and kinds of excavation units to be dug, excavation procedures, laboratory methods, samples (e.g., pollen, sediment, as appropriate) to be collected and analyzed, analysis techniques that will yield information relevant to the aspects of the site that make it an historic resource, and reporting procedure. This plan shall be submitted to the CPUC for review and approval. Once approved, the applicant shall implement the approved plan. Once the data recovery field work is complete, a Data Recovery Field Memo shall be prepared. - Data Recovery Field Memo. Following implementation of the Data Recovery Plan, the Data Recovery Field Memo shall be prepared. The Data Recovery Field Memo shall briefly describe the data recovery procedures in the field and summarize (at a field catalog level) the materials recovery. The Data Recovery Field Memo shall also identify the number and kind of samples recovered that are appropriate for special analyses, including radiocarbon dating, obsidian sourcing, pollen analysis, microbotanical analysis, and others, as applicable. The Data Recovery Field Memo shall be submitted to CPUC for review and approval. Once the Data Recovery Field Memo has been approved, protective barriers may be removed, and work may proceed in the area of the discovery. If the Data Recovery Field Memo concerns Native American resources or archaeological or prehistoric resources, the Data Recovery Field Memo shall also be submitted to the Native American Tribe per the procedures outlined in the Data Recovery Plan. A Data Recovery Report shall then be prepared. - Data Recovery Report. Within 90 days of submittal of the Data Recovery Field Memo, a Data Recovery Report shall be prepared. The Data Recovery Report shall present the results of the data recovery program, including a		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	description of field methods, location and size of excavation units, analysis of materials recovered (including results of any special analyses conducted), and conclusions drawn from the work. The Data Recovery Report shall also indicate where artifacts, samples, and documentation resulting from the data recovery program will be curated. The Data Recovery Report shall specify that the curation facility meets the requirements of 36 CFR 79. The Data Recovery Report shall be submitted to the CPUC for review and approval. Once approved, the Data Recovery Report shall be filed with the Eastern Information Center. All impacted known resources and all unanticipated resources shall be recorded on California Department of Parks and Recreation 523 forms and filed at the Eastern Information Center with the Data Recovery Report. If the Data Recovery Report concerns Native American resources or archaeological or prehistoric resources, the Data Recovery Report shall also be submitted to the Native American Tribe per the procedures outlined in the Data Recovery Plan. - The CRMTP shall include a summary of the California laws regarding the discovery of human remains, including: CEQA Guidelines section 15064.5(e); PRC sections 5097.94, 5097.98, and 5097.99; and California Health and Safety Code section 7050.5. In addition, the plan shall include the contact information for the Riverside County Medical Examiner. The CRMTP shall specify that the curation facility, where artifacts, samples, and documentation resulting from the data recovery program shall be curated, meets the requirements of 36 CFR 79.		
	MM CR-2: Monitor ground disturbing activities (includes Native American monitoring). Archaeological monitoring shall be required for ground disturbing activities in areas with moderate to high archaeological sensitivity. In some areas where previous disturbance has occurred, spot checking may be appropriate and will be defined in the CRMTP. The archaeological monitor(s) shall be approved by CPUC staff prior to the start of construction. If any cultural resources are discovered, the archaeological monitor has the authority to stop ground-disturbing activities in the immediate area of the discovery. The process outlined in the CRMTP required under MM CR-1b shall then be followed. One Native American monitor from each tribe that has requested involvement (the Pechanga Tribe and the Soboba Band) shall be retained, at the Tribes' option, to observe ground-disturbing activities and all work at P33-00714, subject to the conditions outlined in this mitigation measure. SCE shall consult with Native American tribes that have requested	Verify monitoring of ground disturbing activities	Monitoring = During construction Native American notification = 30 days prior to the start of construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	involvement (including Pechanga and Soboba) to determine where additional Native American monitoring is required. SCE shall document consultation efforts that show queries to the NAHC and tribes on the NAHC contact list regarding culturally sensitive sites and shall provide this documentation to the CPUC for review and approval prior to any ground-disturbing activities and prior to work at resource P33-00714. Native American monitoring shall be subject to the following conditions: • Tribes requesting presence at construction or excavation activities shall be given 30 days advance notice prior to the start of construction and shall be provided the opportunity to monitor construction activities as requested in consultation with SCE subject to the terms of this mitigation measure. The applicant shall make a good-faith best effort to schedule construction when a monitor is available. • Attendance by Native American monitors during these activities is ultimately at the discretion of the Tribe and the absence of a Native American monitor shall not delay work if the Native American tribe has been given 30 days advance notice. Documentation of consultation activities shall be included in the monitoring plan. • The Native American monitors shall have the ability to temporarily halt work or redirect grading from the immediate vicinity of a potential unanticipated archaeological find that may require recordation and evaluation. The archaeological monitor shall be notified immediately to determine the procedure to follow per MM CR-1b.		
Impact CR-2: Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature.	MM CR-4: Monitor Paleontologically Sensitive Areas. SCE shall retain a qualified paleontologist to monitor ground-disturbing activities in paleontologically sensitive areas as defined in the Paleontological Resource Monitoring Plan (PRMP). The qualified paleontologist shall be approved in advance by the CPUC. The qualified paleontologist shall prepare a brief Paleontological Resource Monitoring Plan that includes methods of paleontological monitoring and includes construction maps delineating areas of ground disturbance that shall be monitored for paleontological resources. These shall include areas where: • There is a high or undetermined paleontological sensitivity. • There is a potential for fossils to occur at a level shallow enough to be adversely affected by project activities.	Verify monitoring of ground disturbing activities	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	Areas where fossils would likely occur include but are not limited to the Silverado Formation. Areas where fossils are not reasonably likely to be discovered include areas of igneous substrate, such as the Estelle Mountain volcanic rock. Qualifications for proposed paleontological monitors shall be submitted to the CPUC for review and approval. Only CPUC-approved paleontological monitors shall serve on this project. The paleontological monitor shall have the authority to halt construction in the vicinity of any potential finds in order to begin implementation of MM CR-5. A reduction in monitoring activities will be determined based on field observations and in coordination with SCE and CPUC.		
	MM CR-5: Follow Paleontological Resource Discovery Protocol. In the case that a previously unknown paleontological resource is discovered during construction activities, all work within 15 meters of the resource shall be stopped, and the CPUC-approved paleontologist shall determine whether the resource can be avoided. If the resource cannot be avoided, the paleontologist shall determine whether the resource is unique under Part V of CEQA Guidelines Appendix G. A paleontological resource shall be considered unique if it meets the definition of a significant paleontological resource under the 2010 Society of Vertebrate Paleontology *Standard Procedures for the Assessment of Adverse Impacts to Paleontological Resources* definition: Significant paleontological resources are fossils and fossiliferous deposits, here defined as consisting of identifiable vertebrate fossils, large or small, uncommon invertebrate, plant, and trace fossils, and other data that provide taphonomic, taxonomic, phylogenetic, paleoecologic, stratigraphic, and/or biochronologic information. Paleontological resources are considered to be older than recorded human history and/or older than middle Holocene (i.e., older than about 5,000 radiocarbon years) (Society of Vertebrate Paleontology 2010). Substantiation of the uniqueness conclusion shall be provided to the CPUC for review and approval. Work shall be allowed to continue if the resource is not unique. If the resource is unique, then work shall remain stopped until the approved paleontologist has consulted with SCE and the CPUC and a feasible approach, approved by the CPUC, has been developed that will prevent destruction of the resource by site protection or recovery. Methods of recovery, testing, and evaluation shall adhere to current professional standards for recovery, preparation, identification, analysis, and curation, such as the 2010 Society of Vertebrate Paleontology *Standard Procedures for the Assessment of Adverse*	Verify implementation of resource discovery protocol	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	Impacts to Paleontological Resources. Work can commence following recovery and CPUC approval.		
Impact CR-3: Disturb any human remains, including those interred outside of formal cemeteries.	MM-CR-7: Follow Necessary Procedures for Unanticipated Discovery of Human Remains. The CRMTP (MM CR-1b) shall include a summary of the applicable laws concerning human remains, including: CEQA Guidelines section 15064.5(e); PRC sections 5097.94, 5097.98, and 5097.99; and California Health and Safety Code section 7050.5. These laws require Native American consultation for Native American burial sites. The CPUC shall be notified immediately after the legally-mandated notification of the county medical examiner if any human remains are encountered during construction. Workers shall be trained in procedures to follow in case of unanticipated discovery of human remains as part of the Worker Environmental Awareness Plan.	Verify implementation of resource discovery protocol	During construction
Geology, Soils, and Mineral Resources			
Impact GE-1: Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving rupture of a known earthquake fault as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault (refer to Division of Mines and Geology Special Publication 42); strong seismic ground shaking; seismic-related ground failure including liquefaction; or landslides.	Project Commitment B: Worker Environmental Awareness Plan. Project Commitment A: Landscaping and Irrigation Plan. Project Commitment D: Habitat Restoration and Revegetation Plan. Project Commitment E: Grading Plan. Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards..	Verify completion of study and implementation of recommendations	Prior to and during construction
Impact GE-2: Result in substantial soil erosion or the loss of topsoil.	Project Commitment A: Landscaping and Irrigation Plan. Project Commitment D: Habitat Restoration and Revegetation Plan. MM BR-15: Stormwater Pollution Prevention Plan (SWPPP) Best Management Practices (BMPs).	See above	See above
	Project Commitment E: Grading Plan.	Verify preparation and implementation of grading plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Impact GE-3: Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or offsite landslide, lateral spreading, subsidence, liquefaction or collapse.	Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards.	See above	See above
Impact GE-4: Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property.	Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards.	See above	See above
Impact GE-5: Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water.	Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards.	See above	See above
Greenhouse Gases			
No measures apply.			
Hazards and Hazardous Materials			
Impact HZ-1: Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials.	Project Commitment A: Landscaping and Irrigation Plan. Project Commitment B: Worker Environmental Awareness Plan. Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards. MM BR-15: Stormwater Pollution Prevention Plan (SWPPP).	See above	See above
	MM HZ-2: Contaminated Soil/Groundwater Contingency Plan. Prior to the start of construction, to the extent not otherwise included within plans required by the Riverside County Hazardous Materials Management Division, the applicant shall develop a Contaminated Soil/Groundwater Contingency Plan to address the unearthing or exposure of buried hazardous materials or contamination or contaminated groundwater during construction of the projects. The Plan shall detail steps that the applicant or its contractor will take to prevent the spread of contamination, the sampling necessary if contamination is	Verify preparation and implementation of contaminated soil/groundwater contingency plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	discovered, and remedial action to be taken. The Plan, at minimum, shall include the following: 1. Contact information for federal, regional, and local agencies, the applicant's environmental coordinator(s) responsible for the cleanup of contaminated soil or groundwater, and licensed disposal facilities and haulers. 2. Procedures to minimize environmental impacts in the event that hazardous soils, contaminated groundwater, or other hazardous materials are encountered during construction including stopping work; securing and marking the contaminated area; preventing the spread of contamination; testing; primary, secondary, and final cleanup procedures; and proper disposal in accordance with applicable laws and regulations. 3. Training requirements for construction workers performing excavation activities including training on types of contamination including common contaminants (e.g., petroleum hydrocarbons, lead, mercury, and metals, asbestos, acetone, nitrate, semi-volatile organic compounds and volatile organic compounds (benzene), polychlorinated biphenyls, sanitary waste, and pesticides) and *hazardous materials* (as defined by the California Health and Safety Code) and identifying potentially hazardous contamination (e.g., stained or discolored soil and odor). 4. Dewatering procedures including storage, testing, treatment, and disposal requirements and dewatering BMPs set forth in the applicant's Storm Water Pollution Prevention Plan. The applicant shall submit the plan to CPUC for review and approval at least 60 days prior to the start of construction. The applicant shall implement the plan during construction of the projects.		
Impact HZ-2: Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment.	MM BR-15: Stormwater Pollution Prevention Plan (SWPPP). MM HZ-2: Contaminated Soil/Groundwater Contingency Plan. MM HZ-3: Contacting Affected Landowners Regarding Underground Facilities. Prior to construction the applicant shall contact affected private landowners to determine if septic systems and associated leach fields as well as other underground facilities may be impacted by construction of the projects. Final engineering plans for the projects shall be designed to avoid damage to underground facilities, both public and private. The applicant shall immediately notify by telephone the owner of underground facilities that may have been damaged or dislocated during construction of the projects.	Verify utilization of digalert	During construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Impact HZ-3: Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within 0.25 miles of an existing or proposed school.	Project Commitment B: Worker Environmental Awareness Plan. Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards. MM BR-15: Stormwater Pollution Prevention Plan (SWPPP). MM HZ-2: Contaminated Soil/Groundwater Contingency Plan. MM HZ-3: Contacting Affected Landowners Regarding Underground Facilities.	See above	See above
Impact HZ-4: Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a significant hazard to the public or the environment.	Project Commitment B: Worker Environmental Awareness Plan. Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards. MM HZ-2: Contaminated Soil/Groundwater Contingency Plan.	See above	See above
Impact HZ-8: Expose people or structures to a significant risk of loss, injury, or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands.	MM HZ-4: Fire Control and Emergency Response. The applicant, in consultation with its contractors, shall develop and implement site-specific fire control and emergency response plans to address the risk of fire or other emergencies (e.g., flooding) during construction, operation, and maintenance of the projects. The plans and a record of contact and coordination with the fire departments with jurisdiction over each worksite shall be submitted to the CPUC for review and approval prior to start of construction. The plans shall describe fire prevention and response practices that the applicant and its contractors will implement to minimize the risk of fire, and in the event of fire or other emergencies, provide for immediate response. The site-specific plans shall specify that the applicant or its contractors will furnish supervision, labor, tools, equipment, and materials for the prevention of fire and extinguishing and controlling the spread of fires started as a result of project activities. During Construction: • The applicant or its designee shall designate a full time Fire Risk Manager who will be present during construction activities, whose sole responsibility will be to monitor the contractor's fire-prevention activities, and who will have full authority to stop construction as needed to prevent fire hazards. The Fire Risk Managers shall: - Serve as liaisons to fire departments and act as a point of contact for fire departments in the event of fire or other emergency;	Verify preparation and implementation of fire control and emergency response plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	- Manage the prevention, detection, control, and extinguishing of fires set accidentally as a result of construction activity; - Review site-specific fire control and emergency response plans prior to starting work; - Ensure that all construction personnel are trained in fire safety measures relevant to their responsibilities. At minimum, construction personnel shall be trained in fire and emergency reporting and incipient-stage fire prevention, control, and extinguishing (i.e., the fire can be controlled or extinguished by portable fire extinguishers, small hose systems, or portable water supplies without the need for protective clothing or breathing apparatus). Each member of the construction workforce shall be trained and equipped to extinguish small fires; - Be equipped with radio and cellular telephone access for the duration of each work day; - Ensure that all construction personnel are provided with operational radio and cellular telephone access at each worksite to allow for immediate reporting of fires or other emergencies and ensure that communication pathways and equipment are tested and confirmed operational each day prior to initiating construction activities at each worksite; and - Maintain an updated key personnel and emergency services contact (telephone and email) list onsite and available to construction personnel. • Construction workers shall immediately report all fires to the nearest Fire Risk Manager. During All Project Phases: • Equipment installed and maintained as part of the project shall include: - Spark arresters that are in good working order and meet applicable regulatory standards for all internal combustion engines (both stationary and mobile); - Fire suppression equipment on all motorized vehicles that includes, at minimum, one shovel and one pressurized chemical fire extinguisher;		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	- A fire extinguisher capable of extinguishing any equipment-caused fire on all heavy construction equipment; and - Portable communication devices (e.g., radios or cellular telephones) and communication protocols for project workers to coordinate with local agencies and emergency personnel in the event of fire or other emergencies. • Measures to be undertaken by the applicant or its contractors shall include: - Prohibiting smoking during the operation of light or heavy construction equipment; in wildland areas; and within 30 feet of any area where combustible materials (e.g., fuels, gases, and solvents) are stored; - Limiting smoking to paved areas or areas cleared of all vegetation; - Posting no-smoking signs and fire rules on project bulletin boards, at contractor field offices, and in other areas visible to workers during fire season; - Maintaining all worksites in an orderly, safe, and clean manner. Maintaining staging areas and parking areas free of extraneous flammable materials. Removing all oily rags and used oil filters from worksites; - Confining hot-work activities (e.g., welding, brazing, soldering, grinding, and arc cutting) to cleared areas with a minimum 10-foot clearance radius measured from place of hot-work activity; - Ensuring an appropriate fire extinguisher is present before initiating each hot-work activity; - Preventing vehicles with hot exhaust manifolds from idling on roads with combustible vegetation under the vehicles; - Ensuring all Blasting Plan (MM WQ-1) BMPs are followed, e.g., pre-blast and post-blast inspections; - Notifying the fire department with jurisdiction over the worksite in advance of all planned burning activities (e.g., to clear vegetation). Special care shall be taken to prevent damage to adjacent structures, trees, and vegetation during planned burning activities; and		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	- Any additional fire prevention and detection measures to lower the risk of wildland fires. • Measures to be undertaken by the applicant or its contractors for days when the National Weather Service issues a Red Flag Warning for a project area shall include: - Abiding by all restrictions and requirements that may be imposed by fire departments during Red Flag Warning periods (e.g., parking restrictions; road closures; and work activity and equipment use restrictions and requirements); and - Prohibiting smoking at all worksites.		
Hydrology and Water Quality			
Impact WQ-1: Violate any water quality standards or waste discharge requirements.	Project Commitment A: Landscaping and Irrigation Plan. Project Commitment B: Worker Environmental Awareness Plan. Project Commitment D: Habitat Restoration and Revegetation Plan. Project Commitment E: Grading Plan. MM BR-15: Stormwater Pollution Prevention Plan (SWPPP). MM BR-7: Habitat Restoration and Revegetation Plan Requirements.	See above	See above
	MM WQ-1: Blasting Plan and Best Management Practices. The applicant or its contractors shall prepare and implement a detailed Blasting Plan for the Valley–Ivyglen Project. This plan shall identify the scope of blasting, all blasting locations, the proximity of facilities to each blasting location, and the types and estimated amounts of blasting agent required for each blasting location. The plan shall be submitted to and approved by the CPUC prior to start of blasting and the plan shall be resubmitted for approval if changes are required. The intent of th plan is to: • Reduce the potential for increased turbidity in groundwater and surface water; • Prevent debris from entering drainages, waters of the state, and waters of the United States; and • Avoid mishandling of hazardous materials associated with blasting. BMPs shall include, but are not limited to:	Verify preparation and implementation of blasting plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• Conduct pre-blast surveys and inspections and conduct post-blast surveys and inspections for blast performance and fire hazards (e.g., undetonated explosive agent or smoldering materials); • Remove and manage muck piles (blast debris) to prevent water contamination; • Place matting or padding to contain flyrock and add an appropriate blasting agent to reduce flyrock near sensitive biological and cultural resources; • Select an explosive with appropriate water resistance for the blast site to reduce impacts on groundwater; • Clean loading equipment in an area where waste can be contained and kept away from drainages and other surface water; • Manage muck piles to avoid contact with stormwater and remove them from the project area as soon as reasonably feasible; and Handle hazardous materials located during blasting in accordance with MM HZ-2.		
	MM WQ-2: Drainage crossing procedures and practices. Within two weeks following a significant precipitation event (e.g., >0.6 inches within a 24-hour period) and prior to construction-related drainage crossing, a qualified aquatic monitor shall inspect any drainages that must be crossed. The inspector shall determine whether the drainage may be crossed without a bridge, crossed with a bridge, or avoided until conditions become more suitable for crossing. If a temporary or permanent bridge is required in order to avoid impacts, the following measures shall be implemented: • Any temporary or permanent bridges shall be installed to avoid placement below the Ordinary High Water Mark of the drainage as feasible. • Prior to construction, the applicant shall obtain all necessary permits and approvals from the USACE, Santa Ana RWQCB, and CDFW.	Verify implementation drainage crossing procedures	During construction
	MM WQ-3: Design of access roads with erosion control measures. Access roads shall be designed and built to minimize adverse erosion and siltation impacts. Measures to be incorporated into unpaved roadway design and construction shall include, but are not limited to: • Design road with insloping, outsloping, or crowning;	Verify erosion minimization measures	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• Incorporate rolling dips; • Incorporate water bars; • Avoid overgrading; and • Build ditches.		
	MM WQ-4: Disposal of groundwater from dewatering excavations. Groundwater extracted as a result of dewatering during construction shall not be discharged to waters of the state without written authorization from the Santa Ana RWQCB. Extracted groundwater shall be disposed of on-site in one of the following manners: • Discharged to an upland area where it will not enter waters of the state but would instead evaporate or infiltrate; • Used for dust control; • Used for irrigation water; • Used for other construction needs; or • Disposed of at a licensed facility if water is suspected of being contaminated or degraded.	Verify disposal of dewatered groundwater	During construction
Impact WQ-3: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on- or off-site.	Project Commitment A: Landscaping and Irrigation Plan. Project Commitment D: Habitat Restoration and Revegetation Plan Project Commitment E: Grading Plan. The Riverside County Flood Control and Water Conservation District shall be consulted regarding grading plans for construction and operation of the proposed projects. MM BR-7: Habitat Restoration and Revegetation Plan Requirements. MM WQ-2: Drainage crossing procedures and practices. MM WQ-3: Design of access roads with erosion control measures.	See above	See above
	MM WQ-7: Design detention basin to adequate size. SCE shall design the detention basin on the Alberhill Substation site in accordance with the Riverside County Stormwater Quality Best Management Practice Design Handbook (Riverside County Flood Control and Water Conservation District 2006).	Verify design adequacy of detention basin	Prior to construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Impact WQ-4: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site.	MM WQ-3: Design of access roads with erosion control measures. MM WQ-7: Design detention basin to adequate size.	See above	See above
	MM WQ-5: Maintain capacity and connectivity of drainages. SCE shall design and construct access roads to maintain the capacity and connection of drainages that are adjacent to and crossed by access roads for the proposed projects. Methods to maintain drainage characteristics include installation of culverts or designing low water crossings. Prior to any alteration of a drainage, including grading or the placement of fill material or culverts in a drainage, SCE shall obtain any permits required by the USACE, Santa Ana RWQCB, and CDFW.	Verify implementation of drainage protection measures	During construction
	MM WQ-6: Avoid impeding of MDP implementation and function. Prior to construction, SCE shall consult with the RCFCWCD for project elements located within MDP areas. Construction within MDP areas shall not be allowed to proceed until SCE consults with the RCFCWCD about whether project elements located in these areas would not impede the function of flood control facilities and would not prevent implementation of the MDP.	Verify avoidance of MDP areas	During construction
Impact WQ-5: Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.	MM WQ-7: Design detention basin to adequate size.	See above	See above
Impact WQ-8: Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam.	MM HZ-4: Fire Control and Emergency Response.	See above	See above

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Land Use and Planning			
Impact LU-2: Conflict with any applicable habitat conservation plan or natural community conservation plan.	MM BR-2: Preconstruction Surveys. MM BR-3: Biological Monitoring During Construction. MM BR-6: Oak tree protection measures. MM BR-7: Habitat Restoration and Revegetation Plan Requirements. MM BR-8: Special Status Plant Avoidance and Mitigation Measures. MM BR-9: Invasive Plant Control Measures. MM BR-11: Migratory Birds and Raptors Impact Reduction Measures. MM BR-12: Burrowing Owl Impact Reduction Measures. MM BR-16: Stephens' Kangaroo Rat Take Avoidance within Core Reserve.	See above	See above
Noise			
Impact NV-1 : Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies	Project Commitment H: Noise Control.	Verify implementation	During construction
	MM NV-1 Construction Noise Reduction Measures. Prior the start of construction, the applicant shall prepare and submit to the CPUC a Noise Control Plan, which shall detail the frequency, location, and methodology for noise monitoring prior to and during the proposed construction activities, such as for activities within the Cities of Lake Elsinore and Perris. The Noise Control Plan will shall also detail the actions and procedures that the applicant will implement to avoid significant impacts from temporary ambient noise increases. Measures in the Noise Control Plan shall include, but not be limited to the following: • Reducing the number of pieces of equipment concurrently operating near sensitive receptors, as feasible. • Where feasible and available, using construction equipment specifically designed for low noise emissions (i.e., equipment that is powered by electric or natural gas engines instead of diesel or gasoline reciprocating engines). Electric engines have been reported to have lower noise levels than internal combustion engines.	Verify preparation and implementation of noise monitoring plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• Compensating residents for temporary relocation during high-noise activities that cannot be reduced to less than 90 dBA. • The applicant shall monitor construction and maintenance noise levels in hourly equivalent averages Leq(h) before and during construction activities planned within 20 feet of noise sensitive receptors. During the project construction period, noise measurements shall be taken on a daily basis and reported to the CPUC on a monthly basis, within 15 days of the end of the monitoring period. • Where applicable, the hours of construction may be altered from Project Commitment H to include a 12-hour day in accordance with a local jurisdiction. Within the City of Wildomar, for instance, construction may occur between the hours of 6:00 a.m. and 6:00 p.m. instead of 7:00 a.m. and 7:00 p.m. The applicant shall submit the Noise Control Plan to the CPUC for review and approval at least 30 days prior to the start of project construction. The applicant shall comply with all requirements of the approved Noise Control Plan whenever it applies during construction and maintenance activities for the projects.		
Impact NV-4: Substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project	Project Commitment H: Noise Control. MM NV-1 Construction and Maintenance Noise Reduction Measures.	See above	See above
Population and Housing			
No measures apply			

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
Public Services and Utilities			
Impact PS-1: Result in substantial adverse physical impacts on governmental facilities or from the need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times, or other performance objectives for any of the following: (1) fire protection, (2) police protection, (3) schools, (4) parks, or (5) other public facilities.	MM HZ-4: Fire Control and Emergency Response.	See above	See above
Impact PS-3: Require or result in the construction of new storm water drainage facilities or expansion of existing facilities.	Project Commitment E: Grading Plan. The Riverside County Flood Control and Water Conservation District shall be consulted regarding grading plans for construction and operation of the proposed projects. Project Commitment F: Geotechnical Study, Soil Testing, and Seismic Design Standards. MM BR-1: Limit Construction to Designated Areas and Avoid Riparian, Aquatic, and Wetland Areas.	See above	See above
Recreation			
No measures apply			
Transportation and Traffic			
Impact TT-1: Conflict with an applicable plan, ordinance or policy establishing a measure of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but	Project Commitment H: Noise Control	See above	See above
	MM TT-1: Traffic Management and Control Plan As part of the encroachment permit, the applicant shall prepare a Traffic Management and Control Plan that may include measures to ensure that: • Traffic flow, bicycle access, and pedestrian access is not completely restricted on any roadway for longer than 15 minutes, or a detour is provided; • Emergency access is maintained at all times; and • Lane closures do not create safety hazards.	Verify the preparation and implementation of Traffic Management and Control Plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit.	In addition to measures required by agencies with jurisdictions over the project, this plan also may provide for the following: • Include a discussion of work hours, haul routes, work area delineation, traffic control, and flagging; • Identify all access and parking restriction and signage requirements; • Require workers to park personal vehicles at the approved staging area and take only necessary project vehicles to the work sites; • Lay out plans for pre-construction notifications to and a process for communication with affected residents and landowners. Advance public notification shall include posting of notices and appropriate signage regarding construction activities. The written notification shall include the construction schedule, the exact location and duration of activities within each street (i.e., which roads/lanes and access point/driveways/parking areas would be blocked on which days and for how long), and a toll-free telephone number for receiving questions or complaints; • Require posting of warning signs so that motorists are prepared for slow trucks; • Require notification of emergency service providers regarding the timing, location, and duration of construction activities. • Require all roads to remain passable to emergency service vehicles at all times; • Identify all roadway locations where special construction techniques (e.g., night construction) would be used to minimize impacts to traffic flow; • Require emergency vehicle access to be maintained at all times; • Encourage full use of the full roadway width that existed prior to construction during non-working hours, if possible; • Restrict deliveries of large equipment during peak traffic hours to the extent feasible in accordance with applicable local ordinances; • Ensure that traffic control is performed in accordance with final engineering plans and approved drawings attached to any permit issued;		

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• When required, such as during egress of slow traffic onto public roadways, traffic shall be controlled by flaggers who shall be in constant communication with each other during flagging operations; • Require removal of all dirt from the roadway each day before the completion of work; and • Require streets to be maintained in drivable condition at all times. The Traffic Management and Control Plan shall be submitted to the CPUC for review and approval prior to submittal of the permit application to Caltrans. The plan will account for Caltrans standards and guidelines.		
Impact TT-2: Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways	MM TT-2: Heavy Vehicle Traffic Restrictions. The applicant shall minimize heavy vehicle traffic for the project at the Lake Street and I-15 northbound ramp during the AM peak hour (7:00 AM to 9:00 AM) for the duration of project construction. Heavy vehicles traveling to project sites during the AM peak hour shall be diverted to the Indian Truck Trail and I-15 northbound ramp. Prior to the start of construction, the applicant shall alert truck drivers associated with the project. The applicant shall also minimize construction traffic for the project at the Menifee Road and SR-74 intersection during the AM peak hour (7:00 AM to 9:00 AM) and PM peak hour (4:00 PM to 6:00 PM). The applicant may require construction traffic to exit Staging Area ASP7 prior to or after the AM and PM peak hours but not during the AM peak hour (7:00 AM to 9 AM) and PM peak hour (4:00 PM – 6 PM). Alternatively, the applicant may provide an alternative access route.	Verify the restriction of heavy vehicles	During construction
Impact TT-3: Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks	Project Commitment G: Aircraft Flight Path Safety Provisions and Consultations.	Verify consultation with FAA	Prior to construction
	MM TT-4: Helicopter Lift Plan. SCE's helicopter contractor shall coordinate with the FAA and obtain FAA-required approvals for helicopter operations. The applicant contractor's submittal to the FAA shall include a Helicopter Lift Plan for operations within 500 feet of a congested area or within 500 feet of residences in compliance with 14 CFR 133.33, which requires that flights be conducted so emergency landings and release of external load can be accomplished without safety risks to people or property when operating over congested areas. The Helicopter Lift Plan shall include the following measures, to the extent feasible: • Designation of a responsible party for equipment inspections; • Communication procedures;	Verify preparation and implementation of helicopter lift plan	Prior to and during construction

Table 9-1 Draft Mitigation Monitoring, Compliance, and Reporting Plan for the Alberhill Project

Impact	Alberhill Project Project Commitments and Mitigation Measures	Monitoring Requirements	Timing
	• Identification of exclusion zones where pedestrians will not be allowed; and • Training of personnel in safety requirements and procedures. The Helicopter Lift Plan and evidence of FAA approval of the plan shall be provided to the CPUC prior to commencing helicopter operations.		
	MM TT-5. FAA No-Hazard Determination SCE shall obtain a determination of no hazard from the FAA when notification under 14 CFR 77 is required for: • Use of construction equipment, such as cranes; or • Installation of structures, such as lattice steel towers. SCE shall provide documentation of the FAA finding to the CPUC prior to the use of equipment or installation of structures that require notification under 14 CFR 77	Verify determinations from FAA	Prior to construction
Impact TT-4: Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment).	MM TT-1: Traffic Management and Control Plan	See above	See above
	MM TT-6: Road Damage Repair. SCE shall restore and repair to pre-project conditions any private roads damaged by project vehicle traffic. SCE shall document roadway conditions with photographs prior to the project along roads identified for heavy vehicle use in the project's Traffic Impact Analysis. SCE shall also take photographs after the project and after completion of any repairs to document restoration of pre-project pavement conditions	Verify the documentation and restoration of damaged roads	Prior to and post construction
Impact TT-5: Result in inadequate emergency access	MM TT-7: Emergency Service Provider Notification. SCE shall notify local emergency service providers (i.e., police departments, ambulance services, and fire departments) of road closures at least one week prior to the closure. SCE shall notify the provider of the location, date, time, and duration of closure. SCE shall also coordinate with local emergency service providers to ensure emergency vehicle access at all times during construction by, for example, keeping metal plates available to cover open trenches.	Verify notification of emergency service providers	Prior to and during construction
Impact TT-6:Conflict with adopted policies, plans, or programs regarding public transit, bikeways, or pedestrian facilities, or otherwise substantially decrease the performance or safety of such facilities	MM TT-1: Traffic Management and Control Plan	See above	See above

Attachment C

The Alberhill System Project Supplement to the Alternatives Screening Report

Alberhill System Project

Final Supplement to the Alternatives Screening Report

Lead Agency:
California Public Utilities Commission

Prepared by:
WSP USA, Inc.

June 2024

TABLE OF CONTENTS

LIST OF APPENDICES

Appendix A: Final Alberhill System Project Energy Division Staff Report

LIST OF TABLES

LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS

Alberhill Substation	new 500/115-kilovolt (kV) substation proposed as part of the Alberhill System Project
ALJ	Administrative Law Judge
applicant	Southern California Edison
ASP	proposed Alberhill System Project
ASR	Alternatives Screening Report
BESS	Battery energy storage system
California ISO	California Independent System Operator
CCR	California Code of Regulation
CEQA	California Environmental Quality Act
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
Decision	Decision (D.) 18-08-026
ED	Energy Division
EIR	Environmental Impact Report
ENA	Electrical Needs Area
FEIR	Final Environmental Impact Report
FEMA	Federal Emergency Management Agency
Energy Division Staff Report	Final Alberhill System Project Energy Division Staff Report
HCP	Habitat conservation plan
I-15	Interstate 15
IEEC	Inland Empire Energy Center
kV	kilovolt
LAR	Load at Risk
Mira Loma and Centralized BESS in VS	Mira Loma and Centralized BESS in Valley South
MVA	megavolt ampere
MW	megawatt
MWh	megawatt-hours
NCCP	Natural community conservation plan

NERC	North American Electric Reliability Corporation
PEA	Proponent's Environmental Assessment
PRC	Public Resources Code
proposed Project	Alberhill System Project
ROW	Right-of-way
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SDG&E and Centralized BESS in VS	San Diego Gas & Electric and Centralized Battery Energy Storage System in Valley South
SR-74	State Route 74
TES	Threatened and endangered species
VS to VN and Centralized BESS in VS and VN	Valley South to Valley North and Centralized BESS in Valley South and Valley North
VS to VN and Distributed BESS in VS	Valley South to Valley North and Distributed BESS in Valley South
VS to VN to Vista Centralized BESS in VS	Valley South to Valley North to Vista and Centralized BESS in Valley South
WECC	Western Electricity Coordinating Council

1. Introduction

Southern California Edison (SCE, or the applicant) filed an application (A.09-09-022) and Proponent's Environmental Assessment (PEA) with the California Public Utilities Commission (CPUC) on September 30, 2009, to construct the Alberhill System Project (proposed Project).[1] The proposed Project would include a new 500/115-kilovolt (kV) substation (Alberhill Substation), two new 500 kV transmission lines, new and modified 115 kV subtransmission lines, and telecommunications system installations. The applicant filed an amendment to the application on March 12, 2010, (Application A.09-09-022, amended) and filed amended sections of the PEA on April 11, 2011, which were deemed complete on May 26, 2011 (SCE 2011). The CPUC issued a Final Environmental Impact Report (FEIR) in April 2017.

On August 31, 2018, the CPUC issued Decision (D.) 18-08-026 (Decision), which considered, in part, whether to approve the CPCN for the Alberhill Project. The Decision neither issued nor denied the Certificate of Public Convenience and Necessity (CPCN) for the proposed Project. Rather, it directed SCE to "supplement the Alberhill Project's record with additional analyses of alternatives which may satisfy the needs of the Valley South System." In response, SCE performed additional analyses to supplement the administrative record with quantitative and qualitative metrics to evaluate the ability of the proposed Project and each alternative under consideration to meet the needs of the Valley South System.

SCE provided additional analyses to the CPUC Energy Division (ED) as Data Request Responses in May 2019, December 2019, and January 2020. SCE also held webinars with the public and ED to review the analyses and answer questions regarding SCE's findings. The additional analyses evaluated the ability of a wide range of project alternatives to effectively meet the project objectives and satisfy system planning criteria. SCE also evaluated all alternatives using a cost/benefit analysis based on forward-looking system performance metrics and a range of monetized and non-monetized risks.

---

[1] The applicant filed an amendment to their initial application on March 15, 2010, (A.09-09-022) to change the application for a Permit to Construct to an application for a CPCN. Refer to the proposed Project website to access the initial and amended applications at: https://www.cpuc.ca.gov/environment/info/ene/alberhill/Alberhill.html.

On April 10, 2020, Administrative Law Judge (ALJ) Yacknin issued a ruling via email directing SCE to file: (1) a compliance filing (of) its additional analyses of alternatives that may satisfy the needs of the Valley South System to supplement the record Application (A.) 09-09-022, pursuant to D.18-08-026; and (2) an amendment to its application consistent with its additional analyses of alternatives that may satisfy the needs of the Valley South System, including a corresponding amended PEA reflecting the additional analyses as appropriate. In accordance with ALJ Yacknin's email ruling, on May 11, 2020, SCE submitted a Second Amended Application and amendments to the PEA, which incorporate the additional alternative analyses.

After filing its motion, SCE discovered certain errors that affected the cost/benefit analysis. SCE subsequently launched an additional in-depth review of all the analyses mandated by the Decision. The SCE review team recommended certain clarifications and improvements and identified some additional, but inconsequential, errors. On February 1, 2021, SCE submitted the following documents for refiling:

- Item C-2 – Revised Planning Study originally submitted on May 6, 2020;
- Item F-1 – The forecasted impact of the proposed Project on service reliability performance;
- Item G-2 – Cost/benefit analysis of additional alternatives to the proposed Project; and
- Item I-1 – Detailed justification of the recommended solution as the best solution, including an explanation of how the proposed Project ranks in the SCE capital investment portfolio of infrastructure upgrades.

1.1 Purpose of the Supplemental Alternatives Screening Report

This supplemental alternatives screening report documents the alternatives screening process conducted for the proposed Project and supplements the information presented in the 2015 Valley–Ivyglen Subtransmission Line and Alberhill System Project Environmental Impact Report (EIR) Alternatives Screening Report and Addendum (as revised in 2017). Alternatives to the proposed Project were identified by the CPUC (the applicant) as part of the PEA and ensuing supplements and amendments to the PEA, and by the general public during the initial public scoping in 2015. The initial alternatives screening process identified and evaluated 30 potential alternatives to the proposed Project. This report supplements the 2017 revision of the Alternatives Screening Report (ASR) and provides:

- The range of alternatives identified and evaluated in the 2017 revision of the ASR;
- Screening for the alternatives identified by SCE in their 2020 Planning Study;[2]
- The approach and methods used for screening each alternative according to the California Environmental Quality Act (CEQA); and
- A description of the results of the screening evaluation for each alternative (i.e., the alternatives eliminated from further consideration or carried forward for further analysis in an appropriate CEQA document).

1.1.1 No Project Alternative

CEQA requires that all EIRs include a No Project Alternative (CEQA Guidelines Section 15126.6I). The purpose of describing and analyzing a No Project Alternative is to allow decision-makers to compare the effects of approving a proposed project with the effects of not approving it. Because CEQA requires full consideration of a No Project Alternative, the No Project Alternative cannot be screened from analysis in an EIR.[3] For the proposed Project it has been evaluated in the 2017 FEIR and is not included in this supplemental report.

1.2 Background Information`

This section discusses the applicant's electrical demand planning process and how it applies to the proposed Project. The purpose of the proposed Project relates to electrical demand planning for the Valley South 115 kV System (Figure 1).

1.2.1 Electrical Demand Planning

The applicant's electrical demand planning processes helps ensure that necessary system facilities are developed in time to meet projected electrical demand. The planning process begins with the development of a peak electrical demand forecast for each substation. This forecast incorporates historical and forecast population, urbanization, meteorological, and economic data.

[2] Data Request Item C – Planning Study, ED-Alberhill-SCE-JWS-4: Item C. Revised Amended Motion to Supplement February 1, 2021. https://www.cpuc.ca.gov/environment/info/ene/alberhill/Alberhill.html

The applicant's forecasts are based on annual forecasts prepared by the California Energy Commission. Peak electrical demand forecasts account for residential, commercial, and industrial developments that are planned or under construction, as well as historical growth trends in the area.

The forecast data are compared against electrical system *operating limits*—the amount of electrical load that can be served by equipment. The applicant establishes operating limits to ensure that capacity and system operational flexibility are maintained to safely and reliably meet projected peak electrical demands during periods of extreme heat, under both normal and abnormal conditions.

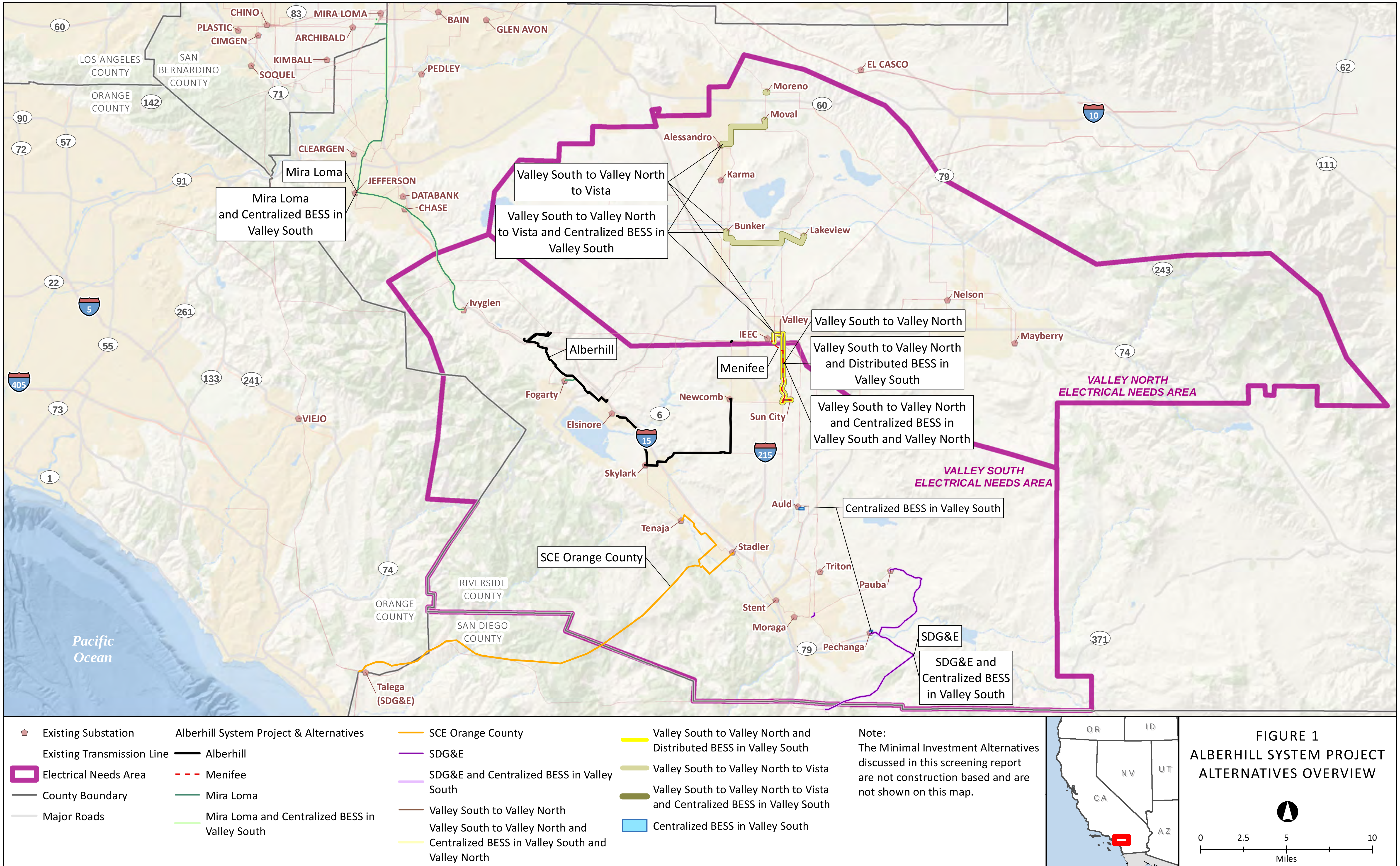


FIGURE 1
ALBERHILL SYSTEM PROJECT ALTERNATIVES OVERVIEW

1.2.2 About Valley Substation and the Valley South 115 kV System

Valley Substation, located in Romoland, California, is the only 500/115 kV substation serving electrical demand in the San Jacinto Region of southwestern Riverside County, an area encompassing roughly 1,260 square miles and serving over 187,000 metered customers, representing approximately 560,000 individuals, nearly 6,000 of which are critical care customers. Valley Substation transforms voltage from 500 to 115 kV using four 560-megavolt-ampere (MVA) transformers. In 2004, the Valley 115 kV System was split into two separate systems, the Valley North 115 kV System and the Valley South 115 kV System. Each system is served by two 560-MVA transformers. The two 115 kV systems are served from the same 500 kV source but are not connected at the 115 kV level. The maximum amount of electrical load that can be served by the Valley South 115 kV System is limited to the amount of electrical power that the two Valley South 115 kV System transformers can serve before exceeding their operating limits. The Valley North 115 kV System consists of 11 distribution-level substations, and the Valley South 115 kV System consists of 14 distribution-level (115 kV) substations.

1.2.3 Applicability of Transmission Planning Standards

The 500 kV transmission components of Valley Substation are subject to North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) planning standards. The 500 kV components connect the substation to the region's bulk electrical grid, which is managed by the California Independent System Operator (California ISO). The California ISO adheres to WECC planning standards, and WECC is one of the eight regional electric reliability councils under NERC. The 500 kV components of the proposed Alberhill Substation would also be subject to NERC and WECC planning standards.

The 115 kV components of Valley Substation and the Valley South 115 kV System are not subject to NERC or WECC planning standards because they are not managed by the California ISO or deemed part of the region's bulk electric grid. Therefore, these components are subject only to the applicant's *Transmission Planning Criteria and Guidelines*, which are based on the NERC and WECC planning standards. Similarly, the California ISO would not manage the 115 kV components of the proposed projects because they are not designed to be part of the region's bulk electric grid. Therefore, it is expected that these components would only be subject to the applicant's *Transmission Planning Criteria and Guidelines*.

1.2.4 Projected Valley South 115 kV System Demand

During its planning processes for Valley Substation, the applicant noted that the Valley South 115 kV System service area experienced growth in electrical demand from 2009 through 2018. Despite a decrease in 2009 and 2013, the applicant forecasts that demand will continue to grow through 2024 (Table 1).

Table 1 Historical Adjusted and Forecasted Peak Demand in Megavolt Amperes for the Valley South 115 kV System (2009 to 2028)

Historical Adjusted Peak Demand (MVA)	**2009**	**2010**	**2011**	**2012**	**2013**
Operating Limit	1,119	1,119	1,119	1,119	1,119
Adjusted Peak Demand, Normal Conditions	867	921	934	923	960
Historical Adjusted Peak Demand (MVA)	**2014**	**2015**	**2016**	**2017**	**2018**
Operating Limit	1,119	1,119	1,119	1,119	1,119
Adjusted Peak Demand, Normal Conditions	951	940	995	1,006	1,039
Forecasted Peak Demand (2019 to 2023) (MVA)	**2019**	**2020**	**2021**	**2022**	**2023**
Operating Limit	1,119	1,119	1,119	1,119	1,119
Forecasted Peak Demand Normal Conditions	1,025	1,026	1,037	1,046	1,061
Forecasted Peak Demand 1-in-5 Year Heat Storm	1,103	1,104	1,116	1,125	1,142
Forecasted Peak Demand (2024 to 2028) (MVA)	**2024**	**2025**	**2026**	**2027**	**2028**
Operating Limit	1,119	1,119	1,119	1,119	1,119
Forecasted Peak Demand Normal Conditions	1,071	1,079	1,087	1,096	1,104
Forecasted Peak Demand 1-in-5 Year Heat Storm	1,153	1,161	1,170	1,179	1,187

Source: SCE 2020
Key:
kV = kilovolt
MVA = megavolt amperes

The adjusted peak demand in 2012 was 923 MVA. The city of Lake Elsinore grew by 30 percent from 2010 through 2019 (USCB 2021). Population projections for 2010 through 2035 indicate that the city of Lake Elsinore's population will increase by approximately 80 percent, and the population of unincorporated Riverside County will more than double (SCAG 2012; USCB 2021).

Based on the increase in electrical demand from 2009 through 2018, and data that indicate continued growth in the county of Riverside, the applicant determined that electrical demand will continue to increase through 2028. The applicant forecasts that peak electrical demand for a 1-in-

5-year heat storm could increase to 1,187 MVA by 2028, exceeding the operating limit of the two Valley South 500/115 kV transformers (Table 1). The applicant's forecast for peak electrical demand indicates that there will be a need to reduce demand on the two transformers that serve the Valley South 115 kV System by 2022.

1.2.5 Operational Flexibility

To avoid exceeding the operating limit of the two Valley South 500/115 kV transformers, the applicant considered whether electrical load from the Valley South 115 kV System could be transferred but could not identify a system to accept the load. Because the Valley South 115 kV System is not tied to another 115 kV system, electrical load cannot be transferred between Valley South and a comparable system. The availability of other electrical systems in proximity to the Valley South 115 kV System is limited because of geographic boundaries and the applicant's service boundaries. The applicant found that its inability to transfer load from the Valley South 115 kV System to another 115 kV system limits the operational flexibility of the Valley South 115 kV System, which increases the potential for electrical service interruptions if a component of the Valley South 115 kV System malfunctions (e.g., the operating limit of a 500/115 kV transformer is exceeded).

1.3 Overview of the Proposed Project

The proposed Project would transfer load away from SCE's existing Valley South 500/kV System to the new 500/115 kV Alberhill System via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. The proposed Project would include 115 kV subtransmission line scope to transfer five 115/12 kV distribution substations (Fogarty, Ivyglen, Newcomb, Skylark and Elsinore) currently served by the Valley South System to the new Alberhill System. Subtransmission line construction and modifications in the Valley South System would also create three system ties between the Valley South System and the newly formed Alberhill System. The system-tie lines would allow for the transfer of load from the new Alberhill System back to the Valley South System (i.e., to one or all of the Fogarty, Newcomb, Skylark, and Elsinore Substations), as well as additional load transfer from the Valley South System to the new Alberhill System (Tenaja Substation) as needed.

The proposed Project would include the following components:

- Construction of a new 500/115 (kV) substation (approximately 44-acre footprint);
- Construction of two new 500 kV transmission line segments between the existing Serrano-Valley 500 kV transmission line and the new 500/115 kV substation (approximately 3 miles); and
- Construction of a new double-circuit 115 kV subtransmission line and modifications to existing lines between the new 500/115 kV substation and SCE's existing five 115/12 kV distribution substations: Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb (approximately 20 miles).

The proposed Project would require the construction of approximately 23 miles of new or modified 500 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided below.

1.3.1 New 500/115 kV Substation

The proposed Project would include the construction of a new 500/115 kV substation on approximately 44 acres of a privately owned, 124-acre property. The parcel is located north of Interstate 15 (I-15) and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County.

1.3.2 New 500 kV Transmission Lines

Two new 500 kV transmission lines would be constructed, connecting the new 500/115 kV substation to the existing Serrano-Valley 500 kV transmission line. This new 500 kV transmission line would begin at the new 500/115 kV substation approximately 0.2 miles northeast of the corner of the intersection of Temescal Canyon Road and Concordia Ranch Road. The lines would leave the substation on new structures extending to the northeast for approximately 1.6 miles. Both lines would connect and be configured into the existing Serrano-Valley 500 kV transmission line.

1.3.3 New 115 kV Subtransmission Lines

New 115 kV subtransmission lines would be constructed, connecting the new 500/115 kV substation to SCE's existing five 115/12 kV substations (Ivyglen, Fogarty, Elsinore, Skylark, and

Newcomb Substations). The 115 kV subtransmission line and ancillary project components, as described in SCE's third amendment to its application and PEA, would include:

- Double circuit approximately 10.6 miles of existing single-circuit, 115 kV subtransmission lines with structure replacement primarily in the existing right-of-way (ROW).
- Construct approximately 3 miles of single-circuit, 115 kV subtransmission line with distribution line underbuilt on the subtransmission line structures and remove about 3 miles of electrical distribution lines within the existing ROW.
- Install a second 115 kV circuit on approximately 6.2 miles of existing 115 kV subtransmission lines (constructed as part of the Valley–Ivyglen Project).
- Install approximately 550 feet of new 115 kV underground subtransmission circuit within new duct banks, and install approximately 4,000 feet of new 115 kV subtransmission circuit within existing duct banks.
- Install fiber optic lines overhead (approximately 9 miles) on sections of the new or modified subtransmission lines and underground (approximately 1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12 kV substations.
- Install a 120-foot microwave antenna tower at the proposed Alberhill Substation site. Install microwave telecommunications dish antennas at the proposed Alberhill Substation, the existing Santiago Peak communications site, and the Serrano Substation. Install telecommunications equipment at other existing and proposed substations.
- Install a new position inside Newcomb Substation to accommodate the new Newcomb-Skylark 115 kV line, and modify an existing position at Valley Substation to isolate the existing Valley-Newcomb 115 kV line, which will be taken out of service as part of the proposed Alberhill Project.

1.4 Location of the Proposed Project

As stated above, the proposed Alberhill Substation would be built on 44 acres of a 124-acre property located north of I-15 and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County (Figure 1). The two new 500 kV transmission lines would each extend about approximately1.6 miles northeast to connect the proposed Alberhill Substation to the existing Serrano-Valley 500 kV Transmission Line. The two 500 kV transmission lines would be constructed primarily in unincorporated Riverside County, although they would pass through the city of Lake Elsinore.

The 115 kV subtransmission line modifications and construction would occur southeast from the proposed Alberhill Substation to Skylark Substation (about 11.5 miles) and from Skylark Substation to Newcomb Substation (about 9 miles). The subtransmission lines would be modified or constructed in unincorporated Riverside County and in the cities of Lake Elsinore, Wildomar, and Menifee. Fiber optic lines would be installed overhead on the structures modified or constructed as part of the proposed Project. In a few locations, fiber optic lines would also be installed in new or existing underground conduit.

1.5 Purpose of the Proposed Project

The purpose of the proposed Project is to relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers by constructing a new 500/115 kV substation (e.g., Alberhill Substation) within the Electrical Needs Area[3] (ENA). The proposed Alberhill Substation would allow for the provision of safe and reliable electrical service pursuant to NERC and WECC standards. System ties between a new 115 kV system (e.g., the proposed Alberhill 115 kV System) served by the proposed Alberhill Substation) and the Valley South 115 kV System would be maintained such that either system could be used to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

1.6 CPUC Objectives for the Proposed Alberhill System Project

The CPUC developed the following objectives, as presented in the certified FEIR, to reflect the purpose of the proposed Project as described in the PEA and the applicant's responses to the CPUC's requests for further information (SCE 2011). The following three objectives were developed with consideration of the objectives presented in the PEA (see Section 1.7, below).

[3] The applicant defines the term "Electrical Needs Area" (ENA) as an area in which an electrical inadequacy exists or is forecast. The ENA for the proposed Project is the service area of the Valley South 115 kV System encompassing portions of southwestern Riverside County, including the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Murrieta Hot Springs, Temecula, and Wildomar, as well as the surrounding unincorporated portions of Riverside County.

The three objectives, as defined by the CPUC, were used as a basis for the development of a reasonable range of alternatives as required by CEQA. The basic objectives of the proposed Project are to:

1. Relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers;
2. Construct a new 500/115 kV substation within the ENA that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

The operating limit and projected electrical demand for the Valley South 115 kV System is shown in Table 1, above.

1.7 Applicant's Stated Objectives of the Proposed Alberhill System Project

The applicant's stated objectives were considered when the CPUC developed the three proposed Project objectives described in Section 1.6, above. The applicant identified the following seven objectives for the proposed Project in the 2009 PEA and reiterated them in the revised 2020 PEA:

1. Serve current and long-term projected electrical demand requirements in the ENA;
2. Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer substations from the current Valley South 115 kV System;
3. Transfer a sufficient amount of electrical demand from the Valley South 115 kV System to maintain a positive reserve capacity on the Valley South 115 kV System through the 10-year planning horizon;
4. Provide safe and reliable electrical service consistent with SCE's *Transmission Planning Criteria and Guidelines;*

5. Increase electrical system reliability by constructing a Project in a location suitable to serve the ENA;
6. Meet project need while minimizing environmental impacts; and
7. Meet project need in a cost-effective manner.

1.8 Organization of the Alternatives Screening Report

The remainder of this report provides an overview of the alternatives evaluation process (Section 2); descriptions, analyses, and determinations for each potential alternative (Section 3); and a summary of alternatives screening results (Section 4).

2 Overview of the Alternatives Screening Process

2.1 CEQA Requirements for the Consideration of Alternatives

An important aspect of EIR preparation is the identification and assessment of alternatives with the potential to avoid or lessen potentially significant effects of a proposed project. In addition to mandating consideration of the No Project Alternative, CEQA Guidelines (Section 15126.6(e)) emphasize the selection of a reasonable range of feasible alternatives and adequate assessment, which allows decision-makers to use a comparative analysis. CEQA Guidelines (Section 15126.6(a)) state:

> *An EIR shall describe a reasonable range of alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives. An EIR need not consider every conceivable alternative to a project. Rather it must consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation.*

To comply with CEQA requirements for the evaluation of alternatives, each alternative identified was evaluated according to three criteria:

1. Would the alternative accomplish all or most of the project objectives?
2. Would the alternative be feasible (from an economic, legal, and technological perspective)?

3. Would the alternative avoid or substantially lessen any significant effects of the proposed Project (including consideration of whether an alternative itself could create significant effects potentially greater than those of the proposed Project)?

The CEQA Guidelines require the consideration of alternatives capable of eliminating or reducing significant environmental effects even though they may "impede to some degree the attainment of project objectives or would be more costly" (Section 15126.6(b)). Under CEQA, it is not required that each alternative meet all of the project objectives or be cost efficient.

2.1.1 Considerations for Previously Certified CEQA Documents

In the case where an EIR has already been certified for a project, a public agency is only allowed to issue a Supplemental or Subsequent EIR if specific conditions are met. One or more of the specific conditions, as detailed in California Public Resources Code (PRC) § 21166, need to occur in order for a lead agency to issue a Supplemental or Subsequent EIR. The specific conditions are as follows:

1. Substantial changes are proposed in the project which will require major revisions of the EIR.

2. Substantial changes occur with respect to the circumstances under which the project is being undertaken which will require major revisions in the EIR.

3. New information, which was not known and could not have been known at the time the EIR was certified as complete, becomes available.

Title 14 of the California Code of Regulations (CCR) establishes three types of EIRs when changes to a project occur after an EIR is certified: a Subsequent EIR (Section 15162), Supplemental EIR (Section 15163), and Addendum EIR (Section 15164). As stated in CEQA Section 15164, an addendum to a previously certified EIR is appropriate if "some changes or additions are necessary but none of the conditions described in Section 15162 calling for preparation of a subsequent EIR have occurred." Section 15162 criteria are as follows:

(a) When an EIR has been certified or a negative declaration adopted for a project, no subsequent EIR shall be prepared for that project unless the lead agency determines, on the basis of substantial evidence in the light of the whole record, one or more of the following:

> (1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or negative declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;
>
> (2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
>
> (3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the Negative Declaration was adopted, shows any of the following:
>
>> (A) The project will have one or more significant effects not discussed in the previous EIR or negative declaration;
>>
>> (B) Significant effects previously examined will be substantially more severe than shown in the previous EIR;
>>
>> (C) Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or
>>
>> (D) Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.

(b) If changes to a project or its circumstances occur or new information becomes available after adoption of a negative declaration, the lead agency shall prepare a subsequent EIR if required under subdivision (a). Otherwise the lead agency shall determine whether to prepare a subsequent negative declaration, an addendum, or no further documentation.

(c) Once a project has been approved, the lead agency's role in project approval is completed, unless further discretionary approval on that project is required. Information appearing after an approval does not require reopening of that approval. If after the project is approved, any of the conditions described in subdivision (a) occurs, a subsequent EIR or negative declaration shall only be prepared by the public agency which grants the next discretionary approval for the project, if any. In this situation no other responsible agency shall grant an approval for the project until the subsequent EIR has been certified or subsequent negative declaration adopted.

(d) A subsequent EIR or subsequent negative declaration shall be given the same notice and public review as required under Section 15087 or Section 15072. A subsequent EIR or negative declaration shall state where the previous document is available and can be reviewed.

Decision (D.) 18-08-026 directed SCE to "supplement the Alberhill Project's record with additional analyses of alternatives which may satisfy the needs of the Valley South System." This new information may meet the third condition of PRC § 21166, as stated above. SCE's Second Amended Application and amendments to the PEA incorporate additional alternative analyses and present new alternatives. The new alternatives presented in the SCE Second Amended Application and amendments to the PEA may substantially reduce one or more significant effects on the environment, which is a criterion under 14 CCR 15162 (a) (3) (D). As a first step, the new alternatives are evaluated in this Alternative Screening Report as part of the typical CPUC screening process.

For alternatives presented in SCE's Second Amended Application and amendments to the PEA that were considered in the 2017 FEIR and ASR, the criteria under 14 CCR 15162 (a) (3) (C) must also be assessed to determine whether an alternative warrants consideration due to unforeseen changed circumstances or substantial new information.

2.2 Alternatives Screening Methodology

Each potential alternative identified by SCE in its 2020 Planning Study was assessed using a three-step process:

> **Step 1:** Clarify the description of the alternative to allow for comparative evaluation.
>
> **Step 2:** For alternatives considered in the 2017 FEIR and ASR, identify if any new information that was not known and reasonably could not have been known in 2017 or substantial changes in circumstances warrant further analysis of an alternative, consistent with 14 CCR 15162–15164. For alternatives not previously considered in the FEIR or previously considered alternatives that meet the above criteria, evaluate the alternative by comparing it with the proposed Project and with respect to the CEQA criteria for alternatives (Sections 2.2.1–2.2.3 below).
>
> **Step 3:** Determine the suitability of each alternative for full analysis under CEQA based on the results of Step 2. If the alternative is unsuitable, eliminate it from further consideration.

2.2.1 Consistency with the Objectives of the Proposed Project

A project's statement of objectives describes the underlying purpose of the project and the reasons for undertaking the project. To fulfill this requirement, the lead agency defined the objectives for the proposed project and provided a description of its purpose (Section 1.5).

The CPUC considered details of the expected functionality of each alternative when assessing the fulfillment of the CPUC project objectives. These considerations were informed by the supplemental information filed by SCE in the Amended Application and PEA, subsequent revisions, and in response to data requests made in 2020 and 2021. As part of the CPUC ED assessment process, a series of engineering and economic analyses was conducted on SCE-provided data responses and materials. CPUC also held a series of technical forums with SCE in the spring and summer of 2022. The findings are documented in the Final Alberhill System Project Energy Division Staff Report (Energy Division Staff Report), which is included as Appendix A.

CPUC project objectives and detailed considerations of those objectives:

1. **Relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115-kV System 500/115-kV transformers.** Fulfillment of this objective requires that the overall SCE system has sufficient capacity to serve the current and forecasted load of those customers currently served by the Valley South System under normal and reasonably expected operating conditions. Normal operations include when all existing components of the system are in operation, including subtransmission lines and transformers (i.e., N-0 conditions).[4] Reasonably expected operating conditions also include the temporary loss of a single transformer for maintenance (i.e., N-1 contingency where a single transformer is out of service and the Valley South System being served with one transformer until the spare transformer could be switched in). SCE Subtransmission Planning Criteria and Guidelines requires that there is no unserved load during normal (N-0) conditions of subtransmission lines and transformers and (N-1) conditions of transformers (SCE 2023). The current operating limit and projected electrical demand for the Valley South 115 kV System is shown in Table 1, in Section 1.2.4, above. SCE clarified that with effective tie-lines, the Valley South System is planned for the 1,120 MVA operating limit under N-0 transformer conditions and 896 MVA limit under a transformer N-1 contingency (SCE 2023).
2. **Construct a new 500/115-kV substation within the ENA that provides safe and reliable electrical service pursuant to NERC and WECC standards.** Fulfillment of this objective requires construction of a new 500/115 kV substation within the ENA. As discussed in the Energy Division Staff Report, SCE's planning criteria largely align with the NERC reliability standards.
3. **Maintain system-ties between a new 115-kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.** Fulfillment of this objective requires system-ties between a new 115-kV System and the Valley South 115 kV System. The temporary loss of a single

[4] N designates the number of pieces of equipment.

subtransmission line is a reasonably expected contingency or maintenance condition (i.e., N-1 subtransmission line contingency). SCE Subtransmission Planning Criteria and Guidelines requires that there is no unserved load during N-1 conditions of subtransmission lines.

A substantial component of meeting Objective 3 is the ability of the proposed project and/or alternative to manage and maintain service during more severe emergency events. Such emergency events can include high impact (i.e., severely impacting a significant number of customers), low probability contingency events that are credible threats. As part of its amended application, SCE examined several unlikely but credible contingencies that could result of loss of load. SCE expressed these contingency events in the Flex-1, Flex 2-1, and Flex 2-2 metrics documented in the supplemental information filed in the amended application and PEA, subsequent revisions, and in response to data requests. Descriptions of these contingency events are below:

- **Flex-1:** Includes simultaneous loss of two subtransmission lines that share common structures (i.e., N-2 contingency).
- **Flex 2-1:** Includes a complete Valley Substation outage condition (loss of all transformers at Valley Substation) due to a high impact, low probability event. These high impact, low probability substation events have occurred previously in the SCE system and more broadly in the industry. This type of event could include a single catastrophic transformer failure that results in damage to adjacent transformers and other facilities. A similar consequence could occur from an external event such as an earthquake, wildfire, sabotage, or electromagnetic pulse. The two-week recovery period is the minimum expected time to deliver, install, and in-service a remotely stored spare Valley System transformer and to repair associated bus work and other damage.
- **Flex 2-2:** Includes a scenario in which the two normally load-serving Valley South transformers are unavailable due to a fire or explosion of one of the transformers that causes collateral damage to the other. The bus work and other substation auxiliary equipment are assumed to remain unaffected, so the Valley Substation spare transformer is assumed to be available to serve load in the Valley South System. The

coincident transformer outages are assumed to have a two-week duration—the estimated minimum time to deliver, install, and in-service the remotely stored spare Valley transformer to restore full transformation capacity to Valley South (SCE 2021a).

Each of the Flex metrics can be expressed through the accumulation of Load at Risk (LAR). LAR is the total load required to be reduced during periods of time in which subtransmission operating criteria are not met such as thermal overload (power flows on lines or equipment that exceeds capacity limits) and voltage violation periods. LAR is expressed by the number of megawatt-hours (MWh) at risk which translates to the amount of electricity that would not be available to customers.

The SCE 2020 Planning Study, the series of technical forums CPUC held with SCE in the spring and summer of 2022, and associated data requests provided visibility of the impacts of the various contingency events including high impact, low probability contingency events. Impacts are documented in further detail in the Energy Division Staff Report, which is included as Appendix A.

2.2.2 Feasibility

According to the CEQA Guidelines (Section 15126.6(f)(1)), among the factors that may be taken into account when addressing the potential feasibility of alternatives are site suitability, economic viability, availability of infrastructure, general plan consistency, other plans or other regulatory limitations, jurisdictional boundaries, and proponent control over alternative sites in determining the range of alternatives to be evaluated in an EIR. The screening analysis for the proposed Project assessed the potential feasibility of alternatives using the following considerations:

- **Technical Feasibility.** Is the alternative feasible from a technological perspective, considering available technology? Are there any construction, operation, or maintenance constraints that cannot be overcome?
- **Legal Feasibility**. Do legal protections on lands preclude or substantially limit the feasibility of permitting high-voltage transmission lines and substations? Do regulatory

restrictions substantially limit the feasibility or successful permitting of high-voltage transmission lines and substations? Is the alternative consistent with regulatory standards for transmission system design, operation, and maintenance?

- **Economic Feasibility.** Is the alternative so costly that its implementation would be prohibitive?

2.2.3 Potential to Avoid or Lessen Significant Environmental Effects

A key CEQA requirement for an alternative is its potential to "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)). At the screening stage, it is not possible to evaluate all of the effects of alternatives in comparison to the proposed Project with absolute certainty, and it may not be possible to quantify the effects. However, it is possible to identify elements of an alternative that are likely to create an impact and relate them, to the extent possible, to general conditions in the proposed project area. Table 2 summarizes the potentially significant effects of the proposed Project as stated in the FEIR. Table 3 summarizes the effects of the proposed Project that were found to be less than significant or to have no impact. These tables were prepared following the completion of the FEIR and contain the findings of the detailed effects analysis.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
Aesthetics	Impact AES -2: Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a State Scenic Highway.	Significant with mitigation	Construction activities would be visible from I-15 and SR-74 for the duration of the construction, causing significant impacts to scenic resources within a State Scenic Highway. The operational impacts would be significant on I-15 because portions of the 500 kV transmission lines, and portions of 115 kV, would be visible from I-15. Visual impacts in proximity of the proposed Project would be significant.
	Impact AES -3: Substantially degrade the existing visual character or quality of the site and its surroundings.	Less than significant with mitigation	See details for Impact AES-2.
	Impact AES -4: Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area.	Less than significant with mitigation	There is a possibility that some construction activities for the proposed Project would occur at night, requiring temporary lighting. Night lighting could adversely affect nighttime views in the area, which would be a significant impact. Safety and security lighting at staging areas and other areas established for long-duration construction activities, such as laydown areas, may introduce new sources of substantial nighttime lighting, which would adversely affect nighttime views in their vicinity. In locations where this lighting would be visible to sensitive viewers, this impact would be significant.
Air Quality	Impact AQ-2: Violate any air quality standard or contribute substantially to an existing or projected air quality violation.	Significant with mitigation	During construction, uncontrolled maximum daily project emissions would exceed significance thresholds for VOC, NO_X, PM_{10}, and $PM_{2.5}$. Project Commitments would reduce PM_{10} and $PM_{2.5}$ emissions but not below the SCAQMD significance thresholds.
	Impact AQ-3: Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is nonattainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors).	Significant with mitigation	The project area is in nonattainment for O_3, PM10, and PM2.5. The proposed Project would result in a cumulatively considerable net increase of these pollutants if it would conflict with an air quality management plan or exceed regional significance thresholds. Construction emissions would exceed significance thresholds for NO_X and VOC (ozone precursors), PM_{10}, and $PM_{2.5}$ for all possible combinations of construction approaches. Implementation of Project Commitment J would not reduce emissions for any of these criteria pollutants to below significance thresholds.
	Impact AQ-4: Expose sensitive receptors to substantial pollutant concentrations.	Significant with mitigation	Emissions generated from construction activities are anticipated to cause temporary increases in ambient air pollutant concentrations in the vicinity of the proposed Project construction sites and along the access and spur roads used by project vehicles. Uncontrolled NO_X, $PM_{2.5}$, and PM_{10} emissions from construction activities would exceed SCAQMD LSTs, resulting in a significant impact.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
Biological Resources	Impact BR-1: Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by the CDFW or USFWS.	Less than significant with mitigation	Construction and operation of the proposed Project could negatively impact individuals of the following special-status wildlife species and their habitats: Quino checkerspot butterfly, vernal pool fairy shrimp, Riverside fairy shrimp, Belding's orange-throated whiptail, western spadefoot, coastal California gnatcatcher, least Bell's vireo, southwestern willow flycatcher, western burrowing owl, golden eagle, San Bernardino kangaroo rat, and SKR. Dulzura kangaroo rat, a species protected under the MSHCP, may also be impacted. Construction and operation of the proposed Project could also result in adverse impacts on the following special-status plants: long-spined spineflower, Munz's onion, paniculate tarplant, Coulter's matilija poppy, Parry's spineflower, Robinson's pepper grass, San Diego ambrosia, and smooth tarplant. These species were have a moderate to high potential to occur within the proposed project area, their elevated conservation status (i.e., listed as threatened or endangered), or the necessity to obtain a permit or provide compensation for impacts on the species or its habitat. Construction and operation of the proposed Project could also result in adverse impacts on migratory bird species and special-status vegetation communities. Permanent impacts on the critical habitat for the California gnatcatcher, San Diego ambrosia, and Munz's onion are associated with permanent project features that would remain throughout the life of the proposed Project, as well as the potential for direct, incidental take of individuals during project construction. The proposed Project would require the permanent removal of these species' critical habitat for the construction and operation. Construction-related activities such as site preparation, vegetation removal, installation of poles or towers, and the use of construction equipment could cause permanent and temporary direct and indirect impacts through the loss of special-status plants or their habitat, root or seed damage, or changes in soil chemistry or composition. Permanent direct impacts would result from new access roads, clearing of vegetation at tower footing locations, or the application of herbicides for fire prevention and weed control. Indirect impacts on special-status plants may be caused by soil disturbance, sedimentation or runoff, and increased dust levels during construction.
	Impact BR-2: Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the CDFW or USFWS.	Less than significant with mitigation	Direct, permanent impacts on special-status natural communities would result from the removal of vegetation for substation construction, pole and tower installation, helicopter pads, and access road construction. Impacts may also result from the use of temporary staging yards and wire-stringing sites. In addition, trees or native vegetation may require trimming, crushing, or removal to accommodate construction of the proposed Project. Special-status natural communities may be disturbed or removed during construction. Populations of special-status plants could be disturbed or removed by construction. Impacts from the construction and operation of the proposed Project would be significant.
	Impact BR-3: Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means.	Less than significant with mitigation	Numerous wetlands, drainages, or riparian areas, including many known to be subject to federal jurisdiction, have been identified in proximity to components of the proposed Project. Numerous vernal pools were also identified and surveyed as potential habitat for vernal pool branchiopods. Construction of new access roads; clearing vegetation, which exposes topsoil to weathering and erosion; and installing facilities within wetland or upland drainage areas would result in direct, permanent impacts on federally protected wetlands. Construction of the proposed Project may directly impact wetlands through soil disturbance, crossing by vehicles, topographic changes that affect wetland hydrology, removal of wetland vegetation, erosion, sedimentation, and input of pollutants.
	Impact BR-6: Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan.	Less than significant with mitigation	Each component of the proposed Project would be constructed within the plan areas of the MSHCP and SKR HCP. The SKR HCP area would be impacted through the direct removal of suitable SKR habitat during the construction of project components. Additionally, should the applicant injure or kill SKR within the core reserve, this action would violate the terms of the HCP and the ESA and CESA.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
Cultural Resources	Impact CR-1: Substantial adverse change in the significance of a historical resource or an archaeological resource.	Less than significant with mitigation	Resource P2233-15428, a house built in 1920, has not been evaluated for California or National Register eligibility. Adverse effects to the resource could result in a significant impact, given that the resource has not been evaluated for eligibility. Construction impacts could also potentially include physical damage or alteration, change in visual elements of a resource, and destruction of a resource. Impacts to previously unknown cultural resources, including historic resources and unique archaeological resources, would be significant if the resources are considered historic resources and if the impacts are substantial and adverse. CWA60-3, P33-021067/CA-RIV-10912, and P-33-021069/CA-RIV-10914, none of which have been evaluated for NRHP eligibility, are found within 0.1 miles of the proposed 500 kV transmission line routes. P33-17016 (eligible) and CWA60-2 (not evaluated) lie within 0.1 miles of the 500 kV transmission line. Substantial adverse effects to the resources could result in a significant impact, given that the resources have not been evaluated for eligibility or have been determined to be eligible.
	Impact CR-2: Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature.	Less than significant with mitigation	The proposed Project would include ground disturbance and excavation that could destroy undiscovered paleontological resources and result in a significant impact.
	Impact CR-3: Disturb any human remains, including those interred outside of formal cemeteries.	Less than significant with mitigation	Given the rich Native American history of the general area and the potential for human burial sites in the vicinity of the project components, there is a possibility that previously unknown human remains may be encountered during construction activities and may result in a significant impact.
Geology, Soils, and Mineral Resources	Impact GE-2: Result in substantial soil erosion or the loss of topsoil.	Less than significant with mitigation	During construction, erosion would occur from soil disturbance during grading and excavation associated with construction activities.
Hazards and Hazardous Materials	Impact HZ-1: Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials.	Less than significant with mitigation	Construction and operation of the proposed Project would include the use, transport, and disposal of hazardous materials, including fuel, lubricants, and antifreeze associated with construction and maintenance equipment and vehicles, as well as paints, solvents, adhesives, and cleaning chemicals. Additionally, during construction at the proposed site, subsurface structures such as pipelines or unknown/undetected storage tanks, or materials resulting in a release of contaminants such as lead, asbestos, pesticides, or fuel that may be associated with past uses may be encountered. Undocumented hazardous materials sites may also be encountered. Routine transport, use, or disposal of hazardous materials and petroleum products could result in accidental releases or spills, representing a potentially significant hazard to the public and environment during construction and operations.
	Impact HZ-2: Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment.	Less than significant with mitigation	Construction and operation of the proposed Project would require the transport of large quantities of new and used transformer oil to and from the proposed Alberhill Substation site. In addition, low-sulfur diesel would be stored at the proposed substation site. The transportation of oil, fuel, and hazardous materials would have the potential to leak along roadways and enter nearby sensitive areas. Additionally, the construction activities have the potential to encounter underground hazards, such as pipelines, which could release hazardous materials if punctured. Upset and accident conditions involving release of these materials would be a significant impact.
	Impact HZ-3: Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within 0.25 miles of an existing or proposed school.	Less than significant with mitigation	Twelve schools are located within 0.25 miles of the proposed Project. Hazardous materials could be released during construction or operation of the proposed Project, which could result in significant impacts.
	Impact HZ-4: Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a significant hazard to the public or the environment.	Less than significant with mitigation	The LUFT sites are located less than 100 feet from the proposed Project on the properties of operational gas stations. Excavation during construction of the proposed Project could expose contaminated soils if the fuel leaks have spread underground from the LUFT sites into the ROW or if undocumented sites or releases are discovered. Encountering contamination may lead to a significant impact.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
	Impact HZ-8: Expose people or structures to a significant risk of loss, injury, or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands.	Less than significant with mitigation	Construction, operation, and maintenance activities associated with the proposed Project would increase fire risk during refueling, vehicle and equipment use, welding, vegetation clearing, worker cigarette smoking, and other activities. Fires could ignite if objects contact the proposed power lines or other energized equipment, if a live-phase conductor falls to the ground, due to conductor-to conductor contact, or due to power surges.
Hydrology and Water Quality	Impact WQ-1: Violate any water quality standards or waste discharge requirements.	Less than significant with mitigation	The proposed Project would cross many drainages as well as the San Jacinto River. Construction activities associated with the proposed Project would include activities that could result in release of hazardous materials or sediment to waterbodies and drainages which could result in significant impacts.
	Impact WQ-3: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on or off site.	Less than significant with mitigation	Grading across the proposed Project site could substantially change drainage patterns and potentially result in substantial erosion and sedimentation on or off site resulting in potentially significant impacts.
	Impact WQ-4: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on or off site.	Less than significant with mitigation	See details for Impact WQ-3.
	Impact WQ-5: Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.	Less than significant with mitigation	The proposed Project would result in excess drainage flow off site to Temescal Wash. There would be a significant impact if the detention basin and outflow to Temescal Wash were insufficient to handle runoff water from the site.
	Impact WQ-8: Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam.	Less than significant with mitigation	Sections of the proposed Project would be installed within a FEMA designated 100-year flood hazard zone or dam failure inundation hazard area. The Project site is located in a dam inundation area; construction would last 21 months. Given that construction is temporary, workers would be in these areas for a limited amount of time. If flooding occurred during construction activities, the workers in the area at that time may be exposed to significant risk of loss, injury or death. Additionally, though dam failure is unlikely to occur, a dam failure would be a significant impact.
Land Use	Impact LU-2: Conflict with any applicable habitat conservation plan or natural community conservation plan.	Less than significant with mitigation	See details for Impact BR-6.
Noise and Vibration	Impact NV-1: Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies.	Less than significant with mitigation	The proposed Project's construction activities would cause noise on a temporary basis at every proposed location, primarily from on-road heavy construction equipment, grading and foundation installation, helicopter use for wire-stringing operations in the 500 kV transmission line, vehicles for worker commute, trucks needed to bring materials to the construction sites, and wire-stringing operations and telecommunication installation. The overhead telecommunication line construction would also require the use of bucket truck and several crew trucks. Operation of the proposed Alberhill Substation would create noise due to equipment running at the substation. Continuous operation of the proposed Alberhill Substation would also increase ambient noise levels as a result of transformer "hum" and cooling fan noise. The transmission and subtransmission lines would emit corona noise during operation. Impacts on noise standards would be significant due to the proposed Project's proximity to sensitive receptors.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
	Impact NV-4: Substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.	Significant and unavoidable	Noise generated from construction equipment and vehicle and helicopter use would result in temporary contributions to the ambient noise levels in the project vicinity during the overall 28-month construction period. Significant unavoidable impacts would occur from the noise associated with construction of the proposed Project.
Public Services and Utilities	Impact PS-1: Result in substantial adverse physical impacts on governmental facilities or from the need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times, or other performance objectives for any of the following: (1) fire protection, (2) police protection, (3) schools, (4) parks, or (5) other public facilities.	Less than significant with mitigation	Construction could increase the risk of fire caused by vehicle, helicopter, or construction equipment use or electrical discharge. Fires could be started during refueling, vehicle and equipment use, welding, vegetation clearing, worker cigarette smoking, contact between electrical lines and the ground, and power surges. There is also the potential for vandalism of components of the proposed Project during construction when equipment is left at staging areas overnight. Increased demand on emergency service providers could occur in the event of traffic- or equipment-related accidents, vandalism, or fires. Potential impacts from fire and other hazard risks would be significant.
	Impact PS-3: Require or result in the construction of new storm water drainage facilities or expansion of existing facilities.	Less than significant with mitigation	A detention basin within the proposed Alberhill Substation site and a drainage channel external to the proposed Alberhill Substation would be constructed. If the applicant excavates areas to provide imported soil, then additional drainage detention basins would be constructed. Drainage facilities would be installed along access roads.
Transportation and Traffic	Impact TT-1: Conflict with an applicable plan, ordinance or policy establishing a measure of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit.	Less than significant with mitigation	Installation of portions of the proposed Project would require temporary lane closures between two and four days. These activities would reduce the traffic capacity of the roadways by 17 to 50 percent and could temporarily disrupt automobile traffic patterns. This could result in a significant impact.
	Impact TT-2: Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways.	Less than significant with mitigation	Installation of the proposed Project would require roadway crossings during installation of the proposed overhead lines and temporary structure installation and wire-stringing activities along I-15 and SR-74. These activities could temporarily disrupt automobile traffic patterns and increase delays for vehicles. Closure of one lane of SR-74 would reduce the road's capacity by 50 percent. This could result in a significant impact.
	Impact TT-3: Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks.	Less than significant with mitigation	Helicopters would be used for construction work associated with footings, assembly, and erection of structures that are inaccessible from access roads and for wire-stringing activities along all sections of the transmission line routes and one section of subtransmission lines. Flights in proximity to residences or congested areas may result in significant safety impacts. Construction equipment and project components greater than 20 feet tall located approximately 1,000 feet from the Skylark Field 45 Airport runway would overlap with the Skylark Field Airport's imaginary slope; the slope increases an additional vertical foot for every additional 50 horizontal feet from the runway (up to 10,000 feet from the runway). Equipment exceeding this imaginary slope may pose a safety hazard to air traffic, which would be a significant impact.

Table 2 Summary of the Final Environmental Impact Report Findings of Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding	Details
	Impact TT-4: Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment).	Less than significant with mitigation	Safety issues may occur as large, slow trucks enter and exit the substation site into faster traffic on Temescal Canyon Road. In addition, trucks accessing staging areas could result in similar safety issues. Construction of the proposed project would require the use of overweight or oversized vehicles for the delivery of construction equipment and materials. The use of oversized vehicles may shorten the life of the pavement and eventually lead to rutting and cracking. Installation of the proposed Project lines would require roadway crossings during installation of the proposed overhead lines and temporary structure installation and wire-stringing activities would occur along roadways. Each of the discussed impacts would be significant if not mitigated.
	Impact TT-5: Result in inadequate emergency access.	Less than significant with mitigation	Places where the components of the proposed Project span a road or require a lane closure may result in impeded emergency access along those roadways. This would be a significant impact.
	Impact TT-6: Conflict with adopted policies, plans, or programs regarding public transit, bikeways, or pedestrian facilities, or otherwise substantially decrease the performance or safety of such facilities.	Less than significant with mitigation	Work near roadways could result in a safety hazard for bicyclists and pedestrians, which is a significant impact.

Key:

CDFW	California Department of Fish and Wildlife
CESA	California Endangered Species Act
ESA	federal Endangered Species Act
FEMA	Federal Emergency Management Agency
FMMP	Farmland Mapping and Monitoring Program
GHG	greenhouse gas
HCP	habitat conservation plan
I-15	Interstate 15
kV	kilovolts
LST	Localized significance thresholds
LUFT	Leaking Underground Fuel Tank
MSHCP	Multiple Species Habitat Conservation Plan
NO_X	oxides of nitrogen
NRHP	National Register of Historic Places
O_3	ozone
PM_{10}	particulate matter 10 micrometers or less
$PM_{2.5}$	particulate matter 2.5 micrometers or less
ROW	right-of-way
SCAQMD	South Coast Air Quality Management District
SKR	Stephen’s kangaroo rat
SR-74	State Route 74
USFWS	U.S. Fish and Wildlife Service
VOC	volatile organic compound

Table 3 Summary of the Final Environmental Impact Report Findings of No Impact or Less than Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding
Aesthetics	Impact AES -1: Substantial adverse effect on a scenic vista.	Less than significant
Agriculture and Forestry Resources	Impact AG-1: Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the FMMP of the California Resources Agency, to non-agricultural use.	Less than significant
	Impact AG-2: Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural use or conversion of Forest Land to non-forest use.	Less than significant
Air Quality	Impact AQ-1: Conflict with or obstruct implementation of the applicable air quality plan.	No impact
	Impact AQ-5: Create objectionable odors affecting a substantial number of people.	Less than significant
Biological Resources	Impact BR-4: Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites.	Less than significant
	Impact BR-5: Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance.	Less than significant
Geology, Soils, and Mineral Resources	Impact GE-1: Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving rupture of a known earthquake fault as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault (refer to Division of Mines and Geology Special Publication 42); strong seismic ground shaking; seismic-related ground failure including liquefaction; or landslides.	Less than significant
	Impact GE-3: Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or offsite landslide, lateral spreading, subsidence, liquefaction or collapse.	Less than significant

Table 3 Summary of the Final Environmental Impact Report Findings of No Impact or Less than Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding
	Impact GE-4: Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property.	Less than significant
	Impact GE-5: Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water.	Less than significant
	Impact GE-6: Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.	Less than significant
	Impact GE-7: Result in the loss of availability of a locally important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.	Less than significant
Greenhouse Gasses	Impact GHG-1: Generate GHG emissions, either directly or indirectly, that may have a significant impact on the environment	Less than significant
	Impact GHG-2: Conflict with any applicable plan, policy or regulation adopted for the purpose of reducing the emission of GHGs.	No impact
Hazards and Hazardous Materials	Impact HZ-5: For a project located within an airport land use plan or, where such a plan has not been adopted, within 2 miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area.	No impact
	Impact HZ-6: For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area.	Less than significant
	Impact HZ-7: Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan.	Less than significant
	Impact HZ-9: Result in substantial safety risks to hang gliders.	No impact

Table 3 Summary of the Final Environmental Impact Report Findings of No Impact or Less than Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding
Hydrology and Water Quality	Impact WQ-2: Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted).	Less than significant
	Impact WQ-6: Otherwise substantially degrade water quality.	Less than significant
	Impact WQ-7: Place within a 100-year flood hazard area structures which would impede or redirect flood flows.	Less than significant
	Impact WQ-9: Expose people or structures to a significant risk of loss, injury, or death involving inundation by seiche, tsunami, or mudflow.	Less than significant
Land Use	Impact LU-1: Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect.	No impact
Noise and Vibration	Impact NV-2: Exposure of persons to or generation of excessive ground-borne vibration or ground-borne noise levels.	Less than significant
	Impact NV-3: Substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project.	Less than significant
	Impact NV-5: Exposure of people residing or working in the project area to excessive noise levels within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport.	Less than significant
	Impact NV-6: Exposure of people residing or working in the project area to excessive noise levels within the vicinity of a private airstrip.	Less than significant

Table 3 Summary of the Final Environmental Impact Report Findings of No Impact or Less than Significant Effects to Resource Areas of the Alberhill System Project

Resource Area	Impact	Final EIR Significance Finding
Population and Housing	Impact PH-1: Induce substantial population growth in an area, either directly (for example, by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure).	Less than significant
	Impact PH-2: Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere.	No impact
Public Services and Utilities	Impact PS-2: Require or result in the construction of new water treatment facilities or expansion of existing facilities.	Less than significant
	Impact PS-4: Insufficient water supplies available to serve the project from existing entitlements and resources or new or expanded entitlements required.	Less than significant
	Impact PS-5: Served by a landfill without sufficient permitted capacity to accommodate the project’s solid waste disposal needs.	Less than significant
	Impact PS-6: Noncompliance with federal, state, or local statutes and regulations related to solid waste.	Less than significant
Recreation	Impact RE-1: Increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated.	Less than significant
Transportation and Traffic	Impact TT-7: Result in inadequate parking that would result in a significant impact on the environment.	Less than significant

3 Alternatives Descriptions and Determinations

3.1 Summary of Alternatives to the Proposed Project Presented in the 2015 ASR (Revised 2017) and 2017 FEIR

The Valley–Ivyglen Subtransmission Line and Alberhill System Project EIR ASR (2015, revised 2017) and the April 2017 FEIR identified and evaluated a number of potential alternatives to the proposed Project. Table 4 summarizes each of the alternatives identified for the proposed Project in either the 2017 revised ASR or the 2017 FEIR and explains why they were eliminated or retained for further consideration in the FEIR.

Table 4 Previously Analyzed Alternative Summary for the Proposed Alberhill System Project

Alternative	Analysis Document	Meets CPUC Objectives*			Potential Feasibility			Avoid or Lessen and Significant Effects of the Proposed Project	Finding
		CPUC Objective 1	CPUC Objective 2	CPUC Objective 3	Economic	Legal	Techno-logical		
ASP Alternative A – Lee Lake Substation Site (All Gas-Insulated Switchgear)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative may reduce effects on air quality and reduce cumulative air quality and aesthetic effects.	2015 ASR (revised 2017) Finding: Retained for analysis in the 2017 FEIR.
	2017 FEIR	Yes	Yes	Yes	Yes	Yes	Yes	2017 FEIR: This alternative would not reduce a potentially significant effect of the proposed Project.	2017 FEIR Finding: This alternative was found to be no longer be suitable for analysis in the 2017 FEIR because it would not substantially reduce impacts to air quality.
ASP Alternative B – All Gas-Insulated Switchgear at Proposed Alberhill Substation Site	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative may reduce effects on air quality and may reduce effects on aesthetics. May also reduce cumulative air quality and aesthetic effects.	2015 ASR (revised 2017) Finding: Retained for analysis in the 2017 FEIR.
	2017 FEIR	Yes	Yes	Yes	Yes	Yes	Yes	2017 FEIR: It was found in the 2017 FEIR that this alternative resulted in similar impacts in all resource categories analyzed with the exception of greenhouse gasses which was found to be greater than the proposed Project.	2017 FEIR Finding: This alternative would not reduce significant effects of the proposed Project and was not selected.
ASP Alternative C – Reduced Capacity Alberhill Substation (One Fewer Transformer)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative may reduce effects to air quality and aesthetics and from the risk of accident conditions involving the release of hazardous materials. May also reduce cumulative air quality and aesthetic effects.	2015 ASR (revised 2017) Finding: Retained for analysis in the 2017 FEIR.
	2017 FEIR	Yes	Yes	Yes	Yes	Yes	Yes	2017 FEIR: This alternative would not substantially reduce a potentially significant effect of the proposed Project.	2017 FEIR Finding: This alternative was found to be no longer be suitable for analysis in the 2017 FEIR because it would not substantially reduce impacts by reducing the project footprint by 1 acre.
ASP Alternative D – All Open-Air Insulated Switchgear at the Proposed Substation Site	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	No	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative E – Valley Substation Upgrade	2015 ASR (revised 2017)	Yes	No	No	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative may reduce potentially significant effects on aesthetics and from fugitive dust and the risk of accident conditions involving the release of hazardous materials.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative F – Transfer Demand to Valley North System	2015 ASR (revised 2017)	No	No	No	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative G – Auld System Project	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	No	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.

Table 4 Previously Analyzed Alternative Summary for the Proposed Alberhill System Project

Alternative	Analysis Document	Meets CPUC Objectives*			Potential Feasibility			Avoid or Lessen and Significant Effects of the Proposed Project	Finding
		CPUC Objective 1	CPUC Objective 2	CPUC Objective 3	Economic	Legal	Techno-logical		
ASP Alternative H – Lee Lake Substation Site (Proposed Alberhill Substation Design)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	No	2015 ASR (revised 2017): This alternative may reduce effects on air quality and reduce cumulative air quality and aesthetic effects.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative I – Gavilan Hills Site (Northwest of Proposed Alberhill Substation Site)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative J – East of the Proposed Alberhill Substation Site	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative K – 115 kV Segment ASP 8 Substation Site	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would reduce effects on aesthetics, air quality, and noise. The alternative may also reduce cumulative effects on aesthetics.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative L – Adjacent to Fogarty Substation Site, Alternative M – Substation Site Near Lake Street	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative N – 500 kV Line N1	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative O – 500 kV Line N2	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative P – 500 kV Line N3	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative Q – 500 kV Line C1	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative R – 500 kV Line C2	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative S – 500 kV Line C3	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.

Table 4 Previously Analyzed Alternative Summary for the Proposed Alberhill System Project

Alternative	Analysis Document	Meets CPUC Objectives*			Potential Feasibility			Avoid or Lessen and Significant Effects of the Proposed Project	Finding
		CPUC Objective 1	CPUC Objective 2	CPUC Objective 3	Economic	Legal	Techno-logical		
ASP Alternative T – 500 kV Line C4	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative U – One Double-Circuit Transmission Line (500 kV Line VA)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	No	2015 ASR (revised 2017): This alternative would reduce effects on air quality, biological resources, and hydrology.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative V – 500 kV Monopoles	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	No	Yes	2015 ASR (revised 2017): This alternative would reduce effects on aesthetics.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative W – Byers Road 115 kV Routing (Holland Road)	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative X – Underground 115 kV Segment ASP6 between Craig Avenue and Beth Drive	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative may reduce potentially significant effects on aesthetics.	2015 ASR (revised 2017) Finding: Retained for analysis in the 2017 FEIR.
ASP Alternative X1 – Underground 115 kV Segment ASP6	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative X2 – Span 115 kV Segment ASP6 Between Craig Avenue and Beth Drive	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
	2017 FEIR	Yes	Yes	Yes	Yes	Yes	Yes	2017 FEIR: This alternative would not substantially reduce a potentially significant effects of the proposed Project with mitigation.	2017 FEIR Finding: This alternative was incorporated into the proposed Project.
ASP Alternative Y – Collier Avenue 115 kV Subtransmission Line Route	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative Z – Access Road from 500 kV Tower SA-4 to Tower SA-5	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative Z1 – Southern Access Road to 500 kV Tower SA-5	2015 ASR (revised 2017)	Yes	Yes	Yes	Yes	Yes	Yes	2015 ASR (revised 2017): This alternative would not reduce a potentially significant effect of the proposed Project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.

Table 4 Previously Analyzed Alternative Summary for the Proposed Alberhill System Project

Alternative	Analysis Document	Meets CPUC Objectives*			Potential Feasibility			Avoid or Lessen and Significant Effects of the Proposed Project	Finding
		CPUC Objective 1	CPUC Objective 2	CPUC Objective 3	Economic	Legal	Techno-logical		
ASP Alternative AA – Demand Management and Energy Conservation Programs	2015 ASR (revised 2017)	Yes	No	No	Yes	Yes	No	2015 ASR (revised 2017): This alternative would eliminate all environmental effects of the proposed project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative BB – Distributed, Local, and Renewable Generation	2015 ASR (revised 2017)	Yes	No	No	Yes	Yes	No	2015 ASR (revised 2017): This alternative would eliminate all environmental effects of the proposed project.	2015 ASR (revised 2017) Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative CC – Chino-Viejo 220 kV Transmission Line	2016 ASR Addendum	Yes	No	Yes	Yes	No	Yes	2016 ASR Addendum: This alternative would not reduce a potentially significant effect of the proposed Project.	2016 ASR Addendum Finding: Eliminated from analysis from the 2017 FEIR.
ASP Alternative DD – Serrano Commerce Center Substation Site	2016 ASR Addendum	Yes	Yes	Yes	Yes	Yes	Yes	2016 ASR Addendum: This alternative may reduce potentially significant effects on biological resources.	2016 ASR Addendum Finding: Retained for analysis in the 2017 FEIR.
	2017 FEIR	Yes	Yes	Yes	Yes	Yes	Yes	2017 FEIR: It was found in the 2017 FEIR that this alternative resulted in similar impacts aesthetics, agriculture and forestry, biological resources, cultural resources, greenhouse gasses, hazards and hazardous materials, land use and planning, noise and vibration, population and housing, and recreation. It was determined that this Alternative would increase significant effects to air quality, geology, soils, and minerals, hydrology and water quality, public services and utilities, and cumulative effects. This alternative was found to only reduce impacts to and transportation and traffic.	2017 FEIR Finding: This alternative was found to only reduce impacts to and transportation and traffic. The alternative would result in increased impacts to several resources so this alternative was not chosen.

Notes:

*CPUC Objectives:

1. Relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers;
2. Construct a new 500/115 kV substation within the ENA that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

Key:

CPUC	California Public Utilities Commission
ASR	Alternatives Screening Report
FEIR	Final Environmental Impact Report
kV	kilovolts
NERC	North American Electric Reliability Corporation
WECC	Western Electricity Coordinating Council
ENA	Electrical Needs Area

3.2 Alternatives to the Proposed Project

In Decision (D.) 18-08-026 for the proposed Project proceeding, the CPUC took no action on the proposed Project and directed SCE to supplement the existing record with additional analyses (described in Section 1.0). These additional analyses included a Planning Study that supports the project need, describes the applicable planning criteria and reliability standards, provides a project alternatives evaluation, and provides cost/benefit analysis of additional alternatives for enhancing reliability and providing additional capacity. SCE used these analyses to evaluate how the alternatives meet the project need as compared with the proposed Project. In the process of preparing the alternatives analysis included in the Second Amendment to the PEA, SCE engaged with the ED and the public on the scope of the analysis and the alternatives considered.

This section describes each of the alternatives identified in the SCE's supplemental analyses, including the 2020 Planning Study and Second Amendment to the PEA and explains why they were eliminated or retained for further consideration in the supplemental to the EIR. After screening, if it was determined that a potential alternative to one of the proposed projects would be unable to meet most of that project's objectives, would be infeasible, or would not avoid or substantially lessen a potentially significant effect of the proposed projects, it was eliminated from further consideration. Alternatives determined to meet each of the CEQA criteria for alternatives (see Section 2.1) and at least one criterion for subsequent CEQA analysis would be retained for further consideration under CEQA. A summary of the screening analysis is provided in Tables 5 and 6, in Section 4.

3.2.1 Minimal Investment Alternatives

Utilizing Spare Transformer for the Valley South System and Installing a Sixth Transformer

This alternative was considered and eliminated from further consideration in the FEIR as Alternative E. Under this alternative, the existing spare 500/115 kV transformer would be placed into permanent service at the Valley Substation to provide an additional level of service to the Valley South System under peak loading conditions or as needed. This alternative would also require installation of a new spare 500/115 kV transformer (for a total of six transformers within Valley Substation).

Consideration of CEQA Criteria

This alternative was considered as part of the certified FEIR as Alternative E and eliminated.

No new information of substantial importance, which was not known nor could have been known at the time of the certification of the FEIR in 2017, showing that the alternative would not be feasible and/or considerably different from that analyzed in the FEIR was identified in the amended application and subsequent data requests. A discussion of the analysis of the alternative's ability to meet project objectives and overall feasibility is provided below and is consistent with the discussion provided in the 2017 FEIR.

Project Objectives

This alternative would not meet CPUC objectives (Section 1.6). It is not expected to relieve projected electrical demand through the applicant's planning period (Table 1), include construction of a new 500/115 kV substation, or maintain system ties between a new system and the Valley South 115 kV System. These findings are consistent with the FEIR analysis and no new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusions.

Feasibility

SCE is currently using this alternative to meet demand during peak loading conditions. Sufficient physical space exists for the spare transformer at the existing Valley Substation. This alternative uses standard equipment and technologies. There are no additional laws, regulations, or policies that could preclude implementation of this alternative. As such, the alternative is potentially feasible from a technical and legal standpoint.

Due to the minimal investment requirements of this alternative, the CPUC has no reason to believe it to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives, which is consistent with the FEIR findings and no new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusions.

Potential to Reduce Significant Environmental Impacts

Placing the existing spare transformer into permanent service at the Valley South Substation to provide an additional level of service to the Valley South System would eliminate all potential environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

This alternative would eliminate the environmental impacts of the proposed Project (summarized in Table 2, above) because it would not include a construction component outside of an already disturbed area.

Environmental Disadvantages

No environmental disadvantages to this alternative were identified during the screening process.

Conclusion

ELIMINATED. Though this alternative is currently being utilized to meet peak electrical demand, this alternative does not meet the CPUC's objectives for the proposed Project. Additionally, this alternative currently acts as a short-term solution to the current electrical demand but would not likely be able to meet future projected electrical demand. As discussed above, this alternative was considered as part of the certified FEIR as Alternative E and eliminated. No new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusion and this alternative remains eliminated from further consideration.

Operating Existing Valley South System Transformers above Normal Ratings

SCE's Subtransmission Planning Criteria and Guidelines allow operation of A-bank transformers above nameplate for periods of limited duration. This alternative would utilize the Valley South System transformers above normal ratings (i.e., intentionally operate them above the manufacturer nameplate ratings) to serve load in the Valley South System under peak loading conditions.

Consideration of CEQA Criteria

Project Objectives

This alternative would not meet the three Project objectives (Section 1.6). It would not relieve projected electrical demand through the applicant's planning period (Table 1), include construction of a new 500/115 kV substation, or maintain system ties between a new system and the Valley South 115 kV System.

Feasibility

This alternative uses standard equipment and technologies and would not require construction of any components. There are no additional laws, regulations, or policies that could preclude implementation of this alternative; however, industry standards indicate it is not a recommended practice and will accelerate equipment deterioration.[5] Repeated implementation would increase the risk of catastrophic transformer failure. Therefore, the alternative is potentially feasible from a technical and legal standpoint.

Due to the minimal investment requirements of this alternative, the CPUC has no reason to believe it to be economically infeasible, though it will require more frequent repair and replacement of the transformers due to accelerated deterioration.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would eliminate all potential environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

[5] The SCE transformer loading limits are established consistent with the intent and methodology in industry standards (IEEE Standard C57.91-2011 and IEC 60076-7-2017) to protect the transformers from accelerated degradation and catastrophic failure.

Environmental Advantages

This alternative would eliminate the environmental impacts of the proposed Project (summarized in Table 2, above) because it would not include a construction component outside of an already disturbed area.

Environmental Disadvantages

No environmental disadvantages to this alternative were identified during the screening process.

Conclusion

ELIMINATED. This alternative does not meet the CPUC's project objectives for the proposed Project.

Loading-Shedding Relays

This alternative would utilize load shedding[6] to maintain system reliability during stressed system conditions that result from peak load conditions that may exceed the ratings of the Valley South System transformers. To facilitate controlled load shedding remotely under this alternative, SCE would install additional equipment within existing equipment rooms at the substations of the Valley South System.

Consideration of CEQA Criteria

Project Objectives

This alternative would not meet the CPUC's objectives for the proposed Project (Section 1.6). It would not relieve projected electrical demand through the applicant's planning period (Table 1), include construction of a new 500/115 kV substation, or maintain system ties between a new system and the Valley South 115 kV System.

Feasibility

The alternative uses standard equipment and technologies and would not require construction of any components. Therefore, the alternative is potentially feasible from a technical standpoint. However, this alternative would result in rolling blackouts during times of peak electrical

[6] "Load shedding occurs when the demand for electricity approaches supply and we [the utility] are forced to reduce power demand by removing some customers to prevent longer, larger outages. The reduction of power ensures adequate reserve margin and helps prevent a failure of the larger electrical grid" (Entergy Storm Center 2021).

demand and, therefore, this alternative concedes to have a less reliable system and is not compatible with SCE's operating permit and the general obligation to reliably serve customers per Public Utilities Code 451. There are no additional laws, regulations, or policies that could preclude implementation of this alternative. Therefore, the alternative is potentially feasible from a legal standpoint.

Due to the minimal investment requirements for this alternative, the CPUC has no reason to believe it to be economically infeasible in terms of direct costs; however, indirect downstream economic consequences of rolling blackouts are outside the scope of this screening analysis.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would eliminate all potential environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

This alternative would reduce the environmental impacts of the proposed Project (summarized in Table 2, above) because it would not include a construction component.

Environmental Disadvantages

No environmental disadvantages to this alternative were identified during the screening process.

Conclusion

ELIMINATED. This alternative does not meet the CPUC's objectives for the proposed Project. The alternative may involve blackouts in areas of the Valley South System as load is shed during times of peak demand.

3.2.2 Conventional Alternatives

SDG&E Alternative: New 230/115 kV System Looped to SDG&E's Talega-Escondido 230 kV Transmission Line

The San Diego Gas and Electric (SDG&E) Alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system constructed at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would receive power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system, allowing for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations), as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed.

This alternative would include the following components:

- Construction of a new 230/115 kV substation (approximately 15-acre footprint);
- Construction of a new 230 kV double-circuit transmission line segment between SDG&E's existing Escondido-Talega 230 kV transmission line and SCE's new 230/115 kV substation (approximately 7.2 miles);
- Construction of a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles);
- Demolition of SCE's existing 115 kV switchrack at Pechanga Substation and reconstruction on an adjacent parcel (approximately 3.2-acre footprint);
- Construction of a double-circuit SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles); and
- Construction of a double-circuit a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 mile).

This alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.8 miles of existing 115 kV subtransmission line. This alternative totals approximately 17 miles of line construction. A detailed description of each of these components is provided below.

Alternative Components

New 230/115 kV Substation

The SDG&E Alternative would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in southwestern Riverside County. The parcel is bound by residences and equestrian facilities to the north, east, and west and Highway 79 and vacant land to the south. SCE would establish vehicular access to the site from Los Corralitos Road or Highway 79.

New 230 kV Double-Circuit Transmission Line

A new 7.2-mile, 230 kV double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 miles. At this point, the new line would enter Riverside County and the Pechanga Indian Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 mile before exiting the Pechanga Indian Reservation and continue until intersecting Highway 79. At the intersection with Highway 79, the new transmission line would extend northwest and parallel to Highway 79 for approximately 1 mile until reaching the new 230/115 kV substation.

New 115 kV Double-Circuit Subtransmission Line

A new 2-mile, 115 kV double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115/12 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in southwestern Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south along Rancho California Road and terminates at SCE's existing 115 kV Pauba Substation. This segment of the alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Auld Substation in the city of Murrieta and SCE's existing 115 kV Moraga Substation in the city of Temecula. An approximately 0.3-mile segment of this line within the city of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

Consideration of CEQA Criteria

<u>Project Objectives</u>

The SDG&E Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The SDG&E Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event) and an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in). As a result, the SDG&E Alternative would meet CPUC Objective 1.

Objective # 2

Although the SDG&E Alternative includes the construction of a new 230/115 kV substation within the ENA, this substation does not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective # 3

The SDG&E Alternative includes the construction of two 115 kV system ties between the Valley South System and new SDG&E system. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 52,762 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 466,537 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 90,095 customers and average of approximately 45,997 customers would likely be impacted (i.e., without power), with at least some customers impacted in every hour throughout the duration of the contingency. [7] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 149,209 customers (approximately 80 percent of customers in the Valley South System) and an average of approximately 96,186 customers (approximately 51 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted in every hour throughout the duration of the contingency event.[8] This alternative has a calculated annual LAR of 16,573 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the SDG&E Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of a Flex 2-1 contingency, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the SDG&E Alternative identified no fatal flaws or conflicts that would suggest the alternative is infeasible; however, it would require cooperation with SDG&E. Sufficient physical space exists for the new 15-acre 230/115 kV substation to be constructed on a vacant lot to the north of Highway 79. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

---

[7] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

[8] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, or airports. However, components of this alternative would cross the Pechanga Reservation, which could complicate implementation of the alternative possibly to the point of infeasibility, making this alternative potentially difficult to implement from a legal feasibility standpoint. Consultation with the Pechanga Tribe would be necessary to further assess the legal feasibility of this alternative crossing prior to further consideration. For the purposes of this preliminary screening analysis, a route crossing the Pechanga Reservation or an alternative route avoiding the Pechanga Reservation is assumed identifiable.

According to SCE's cost/benefit analysis, the estimated cost of the SDG&E Alternative is similar to the cost identified for the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the SDG&E Alternative economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2. This alternative would reduce linear component requirements by approximately 4 miles, shortening them to approximately 17 miles. The footprint of the substation would also be reduced from 40 acres associated with the proposed Project to approximately 15 acres. Construction and operation methodologies are expected to be similar to those proposed for the proposed Project.

The SDG&E Alternative would potentially reduce significant impacts to aesthetics, particularity to scenic resources within eyesight of State Route (SR-74), a designated State Scenic Highway, and within eyesight of I-15, an eligible scenic highway. This alternative's rural siting would also reduce additional non-significant impacts to aesthetic resources because it would affect a fewer number of receptors (e.g., motorists traveling on adjacent roadways). The existing infrastructure along the SDG&E alternatives corridor includes transmission lines directly adjacent to the proposed alternative. As such, the additional transmission components would not dramatically change the area's existing visual character.

This alternative would potentially reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The rural siting of the alternative would also reduce impacts to noise standards and sensitive receptors during construction and operation of the proposed Project. Finally, the reduction of length under this alternative may result in reduced construction time, further reducing the duration of noise and vibration impacts to sensitive receptors.

The SDG&E alternative may reduce temporary traffic impacts due to its rural siting and reduced number of road crossings. Additionally, due to its rural siting, installation of alternative components along public roadways would reduce the number of motorists impacted by temporary lane closures produced by stringing activities.

This alternative would result in impact findings similar to those identified in the 2017 FEIR for the proposed Project associated with air quality, biological resources, geology, soils, mineral resources, and hydrology and water quality. The alternative siting and use of similar construction methodologies would result in impact findings similar to those of the proposed Project but on a reduced scale. Though the scale is reduced, these findings would likely remain categorized as "significant" or "less than significant with mitigation." For example, the SDG&E Alternative could potentially decrease biological resource impacts compared to the proposed Project. The CPUC's preliminary desktop environmental analysis determined that there are no known occurrences of special-status species within the SDG&E Alternative footprint, and the alternative also does not cross habitat designated critical by the U.S. Fish and Wildlife Service (USFWS). The SDG&E Alternative and proposed Project have similar potential to disturb nesting habitat for migratory passerine birds and raptors protected by the Migratory Bird Treaty Act and California Fish and Game Code, including trees, shrubs, and grasslands, which are present throughout the alternative's potential route. The SDG&E Alternative would likely reduce the number of construction-related crossings of wetlands that would likely be considered jurisdictional by applicable regulatory agencies.

Environmental Disadvantages

The SDG&E Alternative would cross the Pechenga Reservation, which the proposed Project would not. It is unknown what additional impacts may be associated with the crossing of the reservation. This alternative would cross the Wildomar Fault Line associated with the Elsinore Fault Zone, potentially increasing exposure to geologic hazards and increasing the number of fault lines crossed. The construction of this alternative would increase potential fire hazards because of increased construction lengths across areas designated to be in Moderate, High, or Very High Fire Hazard Severity Zones.

This alternative's route crosses Rancho California, an active agricultural preserve (Williamson Act lands) and lands designated as Farmland of Local Importance, Farmland of Statewide Importance, Prime Farmland, and Unique Farmland at a greater rate than the proposed Project. Unique/Prime Farmlands and Farmland of Statewide/Local Importance are generally considered superior agricultural lands and are determined to be important to the local economy. The alternative would increase impacts to these agriculturally important lands.

Conclusion

ELIMINATED: The SDG&E Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The SDG&E Alternative would not meet CPUC Objective 2 because SCE's proposed substation associated with the alternative would not meet the objective's 500/115 kV requirement. The SDG&E Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the majority of CPUC's objectives for the proposed Project, the SDG&E Alternative is eliminated from further analysis under CEQA.

SCE Orange County Alternative: New 230/115 kV System Looped to Existing SONGS-Viejo 220 kV Transmission Line

The SCE Orange County Alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system by constructing a new 220/115 kV substation and looping in the SONGS-Viejo 220 kV line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Stadler and Tenaja 115/12 kV distribution substations to the newly formed 220/115 system. The existing 115 kV subtransmission lines serving Stadler and Tenaja Substations would become two system ties between the new 220/115 kV system and the Valley South System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Stadler and Tenaja Substations), as well as additional load transfer from the Valley South System to the new system (Skylark or Moraga Substation) as needed.

This alternative would include the following components:

- Construction of a new 220/115 kV substation (approximately 15-acre footprint);
- Construction of a new 220 kV double-circuit transmission line segment between SCE's existing San Onofre-Viejo 220 kV transmission line and SCE's new 220/115 kV substation (approximately 22.6 miles);
- Construction of a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Tenaja Substation (approximately 5 miles); and
- Construction of a new 115 kV single-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Stadler Substation (approximately 2.6 miles).

In total, this alternative would require the construction of approximately 30.2 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided below.

Alternative Components

New 220/115 kV Substation

The SCE Orange County Alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 67.3-acre, vacant parcel. The parcel is located southeast of Tenaja Road in the city of Murrieta. The parcel is generally trapezoidal in shape and surrounded by hilly, undeveloped land to the south and generally flat, undeveloped land to the north. SCE may establish vehicular access to this site from Tenaja Road, which is currently an unpaved road.

New 220 kV Double-Circuit Transmission Line

A new 22.6-mile 220 kV double-circuit transmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing San Onofre-Viejo 220 kV transmission line. This new 220 kV transmission line would begin at the existing San Onofre-Viejo 220 kV transmission line approximately 0.2 miles southwest of the intersection of East Avenida Pico and Camino la Pedriza in the city of San Clemente in Orange County. The line would leave the interconnection with the San Onofre-Viejo 220 kV transmission line on new structures to the east for approximately 3.2 miles. At this point, the new line would enter San Diego County, generally paralleling Talega Road and SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 3.1 miles, reaching the intersection of Talega Road and Indian Potrero Truck Trail. The line would then extend southeast, briefly crossing Cleveland National Forest, then extending east generally parallel to SDG&E's existing Escondido-Talega 220 kV transmission line for approximately 2.2 miles. The line would continue east, crossing Cleveland National Forest for approximately 5.5 miles, then turn to the northeast for approximately 1.9 miles before entering Riverside County. At this point, the line would extend generally northeast until reaching the new 220/115 kV substation site.

New 115 kV Single-Circuit Subtransmission Lines

New Subtransmission Line to Tenaja Substation

A new, approximately 5-mile, 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation to SCE's existing 115 kV Tenaja Substation. The line would begin at the proposed new substation site in the city of Murrieta and extend generally north on new structures until intersecting Tenaja Road. At this point, the line would extend northeast along Tenaja Road, Vineyard Parkway, and Lemon Street until intersecting SCE's existing Stadler-Tenaja 115 kV subtransmission line at Adams Avenue. At this point, the new 115 kV subtransmission line and Stadler-Tenaja 115 kV subtransmission line would be co-located on a single set of structures until reaching SCE's existing 115 kV Tenaja Substation. The existing line travels generally northwest along Adams Avenue, then southwest on Nutmeg Street, and then continues in a northwest direction along Washington Avenue. At the end of Washington Avenue, the route enters the city of Wildomar and continues northwest along Palomar Street until reaching Clinton Keith Road. At the intersection with Clinton Keith Road, the route travels south until terminating at SCE's existing 115 kV Tenaja Substation.

New Subtransmission Line to Stadler Substation

A new, approximately 2.6-mile, 115 kV single-circuit subtransmission line would be constructed, connecting the new 220/115 kV substation site to SCE's existing 115 kV Stadler Substation. The line would begin at the proposed new substation site in the city of Murrieta and extend northeast for approximately 0.1 miles on new structures. At this point, the line would extend southeast, crossing the Santa Rosa Plateau Ecological Reserve for approximately 0.6 miles. The line would extend northeast, leaving the Santa Rosa Plateau Ecological Reserve, and paralleling Ivy Street until the intersection with Jefferson Avenue. At this intersection, the new 115 kV subtransmission line would be co-located on a single set of structures with SCE's existing Stadler-Tenaja 115 kV subtransmission line for approximately 0.2 miles along Los Alamos Road until terminating at SCE's existing 115 kV Stadler Substation.

Consideration of CEQA Criteria

Project Objectives

The SCE Orange County Alternative would meet only one of CPUC's three project objectives (Section 1.6).

Objective #1

The SCE Orange County Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event) and an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in). As a result, the SCE Orange County Alternative would meet CPUC Objective 1.

Objective # 2

Although the SCE Orange County Alternative includes the construction of a new 220/115 kV substation within the ENA, this substation does not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective # 3

The SCE Orange County Alternative includes two system ties between the new 220/115 kV system and the Valley South System. SCE calculates that this alternative would not successfully manage an N-1 subtransmission line contingency, resulting in a calculated annual LAR of 23 MWh. This alternative has a calculated annual LAR of 142,815 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 437,757 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 15,490 customers and average of approximately 7,758 customers would likely be impacted (i.e., without power), with at least some customers impacted for approximately 24 hours throughout the duration of the contingency.[9] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 120,115 customers (approximately 64 percent of customers in the Valley South System) and an average of approximately 63,535 customers (approximately 34 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted the majority of the time during the contingency

[9] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

event.[10] This alternative has a calculated annual LAR of 13,523 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the SCE Orange County Alternative includes system ties, it does not successfully manage an N-1 subtransmission line contingency and it has a substantial calculated annual LAR for more severe emergency events, including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative does not successfully manage an N-1 subtransmission line contingency, which is a reasonably expected contingency or maintenance condition, and may also result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of Flex-1 and Flex 2-1 contingencies, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the SCE Orange County Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the new 15-acre 220/115 kV substation to be constructed on a new 67.3-acre lot southeast of Tenaja Road in the city of Murrieta. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, airports, or reservations. However, approximately 4.7 miles of this portion of the route would cross the Santa Rosa Plateau Ecological Reserve, 4.1 miles would cross the Cleveland National Forest, and 5.7 miles would cross Marine Corps Base Camp Pendleton, which could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially difficult to implement from a legal feasibility standpoint but not infeasible.

According to SCE's cost/benefit analysis, the estimated cost of the SCE Orange County Alternative is approximately 37 percent more than the proposed Project (SCE 2021b). Though

[10] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

there is a noteworthy cost increase associated with the SCE Orange County Alternative, the CPUC does not consider such an increase prohibitive to the point of potential infeasibility at the alternatives screening phase.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially “avoid or substantially lessen any of the significant effects of the project” (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2. This alternative would increase linear component construction requirements by approximately 6 miles compared to the proposed Project, for a total length of 30.2 miles. The footprint of the substation would also be reduced from the 40 acres of the proposed Project to approximately 15 acres. Construction and operation methodologies are expected to be similar to those proposed to be used for the proposed Project.

The SCE Orange County Alternative would potentially reduce significant impacts to aesthetics that would be caused by the proposed Project, particularity to scenic resources within eyesight of SR-74, a designated State Scenic Highway, and within eyesight of I-15, an eligible State Scenic Highway. Though construction of a portion of this alternative would also occur within eyesight of I-15, the total length of the alternative within eyesight of the I-15 corridor would be reduced compared to the proposed Project. Visual impacts to the SR-74 corridor would likely be eliminated because of this alternative’s distance from the corridor. As such, this alternative would cross the Santa Rosa Plateau Ecological Reserve, a 9,000-acre, relatively undisturbed area of oak woodland, chaparral, and native grassland habitat, where it would introduce new significant aesthetic impacts to the reserve’s visitors utilizing its hiking trails or other recreational opportunities. Impacts would occur during both construction and operation due to construction equipment and installation of permanent 220 kV double-circuit overhead lines. Additionally, the 15-acre substation site proposed for this alternative abuts the east side of the ecological reserve and would be within eyesight of several scenic viewpoints located within the reserve's boundaries.

The proposed Project would reduce all impacts to geology, soils, and mineral resources to less than significant with mitigation. The SCE Orange County Alternative would reduce potential impacts to lands classified by the California Mineral Land Classification System as MRZ-3, which are areas of unknown mineral resource significance.

The SCE Orange County Alternative would reduce the number of waterbody crossings, reducing the likelihood of an unexpected hazardous materials spill affecting the waterbody or excess drainage into the waterbody. The proposed Project would reduce all impacts to hydrology and water quality to less than significant with mitigation; therefore, this alternative would not likely reduce the potential impacts categorization from that of the proposed Project. Additionally, the construction of this alternative would decrease the number of miles constructed through FEMA designated Flood Hazard Zones (Low, Medium, and High).

This alternative would potentially reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The rural siting of the alternative would also reduce impacts to noise standards and sensitive receptors during construction and operation of the proposed Project.

The SCE Orange County Alternative may reduce temporary traffic impacts due to its rural siting and reduced number of road crossings. Additionally, due to its rural siting, installation of alternative components along public roadways would reduce the number of motorists impacted by temporary lane closures produced by stringing activities. The rural setting would also include construction across open lands that are not collocated with public roadways.

The SCE Orange County Alternative could potentially decrease biological resource impacts compared to the proposed Project. The CPUC's preliminary desktop environmental analysis determined that there are reduced known occurrences of special-status species within the SCE Orange County Alternative footprint. Though there are decreased special-status species documented within the footprint of this alternative, the alternative would increase the impacts to USFWS-designated critical habitat for the arroyo toad (*Anaxyrus californicus)* and thread-leaved brodiaea (*Brodiaea filifolia*) because of its siting. The SCE Orange County Alternative and proposed Project have similar potential to disturb nesting habitat for migratory passerine birds and raptors protected by the Migratory Bird Treaty Act and California Fish and Game Code, including trees, shrubs, and grasslands, which is present throughout the alternative's potential route. The SCE Orange County Alternative would likely reduce the number of construction-related crossings of wetlands that would likely be considered jurisdictional by applicable regulatory agencies.

Environmental Disadvantages

The proposed Project's air quality impacts were determined to be significant in the 2017 FEIR. The construction of this alternative would likely increase impacts to air quality because it would require more overland construction, resulting in greater quantities of fugitive dust being emitted during construction processes. Additionally, the alternative is longer, requiring an increase to the construction period and increased construction material movement. The impacts to air quality would not be reduced by this alternative and would remain significant.

It was determined in the 2017 FEIR that the proposed Project would reduce impacts to biological resources to less than significant with mitigation. This alternative has the potential to increase impacts to biological resources from those associated with the proposed Project, though the determination would remain the same. The alternative would disturb an ecological reserve that has maintained relatively undisturbed areas of oak woodland, chaparral, and native grassland habitat for wildlife species. Because of the lands crossed by the alternative (ecological reserve and Cleveland National Forest), an increased number of oak trees may need to be removed to accommodate the alternative. The alternative would eliminate impacts to critical habitat designated for the San Diego ambrosia; however, the alternative would impact designated critical habitats associated with the arroyo toad and thread-leaved brodiaea. Similar construction methodologies would result in similar types of impacts to threatened and endangered species (TES), riparian areas, wetlands, and habitat conservation plans (HCPs) and natural community conservation plan (NCCP)s; however, the increase in length of the alternative would increase these impacts to biological resources. Therefore, overall impacts to biological resources are expected to be similar to those of the proposed Project.

Impacts to geology and soils under this alternative would likely increase due to the length of this alternative. Specifically, erosion of soils newly exposed by construction would be increased because of the alternative's length and because of the increased wind erodibility traits of the impacted soils. Finally, this alternative would increase fault line crossings. It would cross the Wildomar Fault Line in the Elsinore Fault Zone twice along its routing.

The SCE Orange County Alternative would increase the potential of exposing people or structures to wildland fires because it would cross more lands designated as High and Very High Fire Hazard Severity Zones than does the proposed Project. These risks of wildland fire would be increased during the construction and operation phases of this alternative. Additionally, though not directly addressed in Appendix G of the 2021 CEQA guidelines, this alternative would increase the risk of exposure of construction crews to hazards—specifically, unexploded ordnance—during construction and operational maintenance activities occurring on lands managed by Marine Corps Base Camp Pendleton. Other impacts associated with hazards or hazardous materials would be similar to those associated with the proposed Project.

As discussed above, this alternative is routed across the Santa Rosa Ecological Reserve, which is managed under the County of Riverside General Plan Southwest Area Plan. The development of the SCE Orange County Alternative may conflict with Policy SWAP 5.2, which requires the preservation of lands within the reserve for habitat and open space uses. Further, the alternative would have the potential to cause damage to existing vegetation and oak trees in Riverside County, particularly across the reserve, which would be against the goal of Riverside County's General Plan Multipurpose Open Space Element Policy's OS 9.3 and OS 9.4, which require conservation of maintenance of superior examples of native trees, natural vegetation, stands of established trees, and other features for ecosystem, aesthetic, and water conservation purposes and to conserve the oak tree resources in the county.

The alternative also would cross the Marine Corps Base Camp Pendleton, which used the area for military training exercises. According to the Joint Integrated Natural Resources Management

Plan for Marine Corps Base and Marine Corps Air Station Camp Pendleton, easements for public utilities, including supporting structures for power lines, telephone lines, cellular towers, radio repeaters, fiber optic cables, and pipelines exist throughout the base. These structures, in aggregate, restrict or restrain training opportunities and inland maneuvers (DOD 2018). Other impacts to land use or HCP/NCCPs would also be increased because the alternative would cross the Orange County Transportation Authority NCCP/HCP, San Diego County Water Authority NCCP/HCP, SDG&E Subregional NCCP/HCP, San Diego North County Multiple Species Conservation Plan, and Western Riverside County Multiple Species NCCP/HCP.

Conclusion

ELIMINATED: The SCE Orange County Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The SCE Orange County Alternative would not meet CPUC Objective 2 because SCE's proposed substation associated with the alternative would not meet the 500/115 kV requirement. The SCE Orange County Alternative would not meet CPUC Objective 3 because this alternative does not successfully manage an N-1 subtransmission line contingency, which is a reasonably expected contingency or maintenance condition, and may also result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative may be feasible; however, it would likely be difficult to implement from a legal standpoint because the route crosses the Santa Rosa Plateau Ecological Reserve and Marine Corps Base Camp Pendleton. The alternative would potentially reduce significant impacts of the proposed Project. However, since this alternative does not meet the majority of CPUC's objectives for the proposed Project, the SCE Orange County Alternative is eliminated from further analysis under CEQA.

Menifee Alternative: New 115 kV System Looped to SCE's Existing Serrano-Valley 500 kV Transmission Line

The Menifee Alternative would transfer load away from SCE's existing Valley South 500/115 kV System to a new 500/115 kV system via construction of a new 500/115 kV substation and looping in the Serrano-Valley 500 kV transmission line. This alternative includes 115 kV subtransmission line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the newly formed 500/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two system ties between the Valley South System and the newly formed 500/115 kV Menifee System. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the new system (Auld Substation) as needed.

This alternative would include the following components:

- Construction of a new 500/115 kV substation (approximately 15-acre footprint);
- Construction of a new 500 kV double-circuit transmission line to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation (0.1 mile);
- Construction of a new 115 kV single-circuit subtransmission line between the new 500/115 kV substation and SCE's existing 115 kV Sun City Substation (approximately 4.6 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation (approximately 0.1 mile);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 mile); and
- Reconductoring of SCE's existing, single-circuit Auld–Sun City 115 kV subtransmission line (approximately 7.7 miles).

This alternative would require the construction of approximately 5.5 miles of new 500 kV transmission and 115 kV subtransmission lines and the modification of approximately 7.7 miles of existing 115 kV subtransmission line. This alternative totals approximately 13.2 miles. A detailed description of each of these components is provided below.

Alternative Components

New 500/115 kV Substation

The Menifee Alternative would involve the construction of a new, approximately 15-acre, 500/115 kV substation on six privately owned vacant parcels, totaling approximately 23.7 acres. The parcels are located south of Matthews Road, north of McLaughlin Road, west of Palomar Road, and east of San Jacinto Road in the city of Menifee. The parcels are also located directly east of the Inland Empire Energy Center (IEEC). When combined, the parcels form a trapezoid shape and are surrounded by industrial uses and vacant lands to the north and east, SCE's existing transmission line corridor to the south, and the IEEC to the west. SCE may establish vehicular access to this site from Matthews Road, Palomar Road, and/or San Jacinto Road.

New 500 kV Double-Circuit Transmission Line

A new 0.1-mile overhead 500 kV double-circuit transmission line segment would be constructed to loop SCE's existing Serrano-Valley 500 kV transmission line into the new 500/115 kV substation in the city of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road and approximately 0.1 miles west of the intersection of McLaughlin Road and Palomar Road before extending north until reaching the new 500/115 kV substation.

New 115 kV Single-Circuit Subtransmission Lines

New Substation to Sun City Substation

A new 4.6-mile 115 kV single-circuit subtransmission line would be constructed, connecting the new 500/115 kV substation to SCE's existing 115 kV Sun City Substation in the city of Menifee. The line would exit the new 500/115 kV substation's southeast corner and extend south along Palomar Road, crossing under SCE's existing transmission line corridor for approximately 0.3 miles. At this point, the route would extend generally southeast until reaching Rouse Road. The line would extend east along Rouse Road until the intersection with Menifee Road, then transition to an underground configuration and extend south along Menifee Road for approximately 3 miles until reaching SCE's existing Auld–Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east for approximately 0.5 miles, parallel to the Auld–Sun City 115 kV subtransmission line, until terminating at SCE's existing 115 kV Sun City Substation.

Valley-Newcomb to New Substation

Under this alternative, a new 0.1-mile underground 115 kV subtransmission line segment would be constructed to re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to the new 500/115 kV substation in the city of Menifee. This route would begin within SCE's existing transmission corridor along McLaughlin Road, which is approximately 0.1 miles west of the intersection of McLaughlin Road and Palomar Road, and extend north until reaching the new 500/115 kV substation.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new, approximately 0.7-mile, underground, 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld–Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, it would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet until reaching an existing subtransmission pole.

Reconductor Existing 115 kV Subtransmission Line

SCE's existing Auld–Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the city of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the city of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the alternative would be approximately 7.7 miles in length.

Consideration of CEQA Criteria

<u>Project Objectives</u>

The Menifee Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The Menifee Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 2,137 MWh. As a result, the Menifee Alternative would not meet CPUC Objective 1.

Objective # 2

The Menifee Alternative includes the construction of a new 500/115 kV substation, which would meet CPUC Objective 2.

Objective # 3

The Menifee Alternative includes the construction of two system ties between the Valley South System and the newly formed 500/115 kV Menifee System. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 54,051 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 742,386 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 101,853 customers and average of approximately 63,106 customers would likely be impacted (i.e., without power), with at least some customers impacted in every hour throughout the duration of the contingency.[11] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 153,795 customers (approximately 82 percent of customers in the Valley South System) and an average of approximately 107,206customers (approximately 57 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted in every hour throughout the duration of the contingency event.[12] This alternative has a calculated annual LAR of 21,975 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the Menifee Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of a Flex 2-1 contingency, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the Menifee Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the new 15-acre 500/115 kV substation to be constructed on several privately owned parcels totaling 23.7 available acres south of Matthews Road, north of McLaughlin Road, west of Palomar Road, and east of San Jacinto Road in the city of Menifee. The alternative would use standard

[11] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

[12] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations, which could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the Menifee Alternative is approximately 30 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC considers the Menifee Alternative to be potentially economically feasible in terms of cost.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2, above. This alternative would decrease the linear component construction requirements by approximately 10.5 miles compared to the proposed Project. The alternative would include 5.5 miles of new construction for the subtransmission lines and reconductor approximately 7.7 miles of existing lines, for a total construction disturbance length of 13.2-miles. The footprint of the substation would also be reduced from 40 acres under the proposed Project to approximately 15 acres. Construction and operation methodologies are expected to be similar to those used for the proposed Project.

The Menifee Alternative would potentially reduce significant impacts to aesthetics that would be caused by the proposed Project, particularity to scenic resources within eyesight of SR-74, a designated State Scenic Highway, and within eyesight of I-15, an eligible State Scenic Highway. Though construction of a portion of this alternative would also occur within eyesight of SR-74, the total length of the alternative within eyesight of the SR-74 corridor would be reduced from that associated with the proposed Project. Visual impacts to the I-15 corridor would likely be eliminated because of this alternative's distance from the I-15 corridor and topographic features separating the I-15 corridor and the alternative's routing. The alternative is routed within eyesight of residential neighborhoods but would not be expected to change the existing visual setting of the areas because of existing transmission infrastructure.

This alternative would likely reduce impacts to air quality because of its reduced size and construction requirements. Though this alternative would reduce the amount of construction emissions and time needed for construction, these impacts—though reduced—would remain significant for the area.

The proposed Project would reduce all impacts to biological resources to less than significant with mitigation. The Menifee Alternative would likely reduce all biological impacts associated with the proposed Project because of its reduced footprint and siting in previously developed areas. Similar construction methodologies would result in similar impacts to TES, riparian areas, wetlands, and HCPs and NCCPs, but on a reduced scale. The CPUC's preliminary desktop environmental analysis determined that there are limited occurrences of special-status species within the Menifee Alternative footprint. This alternative would reduce all impacts to USFWS-designated critical habitat. The Menifee Alternative would reduce the disturbance to nesting habitat for migratory passerine birds and raptors protected by the Migratory Bird Treaty Act and California Fish and Game Code, including trees, shrubs, and grasslands, which is present throughout the Alternative's potential route. It also appears that Menifee Alternative would likely reduce the number of construction-related crossings of wetlands that would likely be considered jurisdictional by applicable regulatory agencies.

This alternative's potential impacts to cultural resources are unknown at this time. Undocumented cultural resources may be present within the alternative's route. Therefore, due to the reduced size of the alternative's footprint and the routing through previously developed areas, it is expected that the probability of impacting significant cultural resources would be reduced from that associated with the proposed Project.

This alternative would potentially reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The urban setting of this alternative would likely affect sensitive receptors in proximity to the construction area; however, the reduction of length under this alternative may result in reduced construction time, thus reducing the duration of noise and vibration impacts to sensitive receptors.

The Menifee Alternative may reduce temporary traffic impacts due to its reduced length and number of road crossings, requiring fewer lane closures or intersection shutdowns during construction activities.

This alternative would result in reduced impacts associated with geology, soils, and mineral resources, specifically because it would not cause the same level of erosion due the reduced construction footprint. Hazards and hazardous materials impacts would be reduced because it would not require the same amount of hazardous materials for construction and it would greatly reduce the construction requirements in areas designated as Moderate, High, and Very High Fire Severity Zones which would also eliminate impacts to public services and utilities posed by the proposed Project. The proposed Project's hydrology and water quality impacts would be reduced because it does not cross any waterbodies, drainages, or lie in FEMA Flood Zones reducing its probability of violating water quality standards or waste discharge requirements. Finally, the alternative would reduce impacts to land use because it reduces the impacts to the Western Riverside County Multiple Species NCCP/HCP.

Environmental Disadvantages

No environmental disadvantages were identified during the limited screening process for this alternative.

Conclusion

ELIMINATED: The Menifee Alternative would not meet CPUC Objective 1 because the alternative would not successfully manage an N-1 transformer contingency. The Menifee

Alternative includes the construction of a new 500/115 kV substation, which would meet CPUC Objective 2. The Menifee Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, since this alternative does not meet the majority of CPUC's objectives for the proposed Project, the Menifee Alternative is eliminated from further analysis under CEQA.

Mira Loma Alternative: New 220/115 kV System Looped into Existing 220 kV Transmission Lines Serving Mira Loma Substation

The Mira Loma Alternative proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system by constructing a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty Substations would become two system ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations), as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed. This alternative would include the following components:

- Construction of a new 220/115 kV substation (approximately 15-acre footprint);
- Construction of a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet);
- Construction of a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles); and

- Construction of a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley–Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 miles).

In total, this alternative would require the construction of approximately 22.2 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided below.

Alternative Components

New 220/115 kV Substation

The Mira Loma Alternative would involve the construction of a new, approximately 15- acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the city of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor and approximately 2,000 feet east of Haven Avenue and would extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 21.6-mile 115 kV double-circuit subtransmission line would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southern portion of the property and travel east in an underground configuration along Ontario Ranch Road for approximately 0.2 miles. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-mile portion of the route, the line would exit the city of Ontario and enter the city of Eastvale at the intersection with Bellegrave Avenue. Within the city of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the city of Norco. Within the city of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the city of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue to parallel SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue to extend along West Ontario Avenue for approximately 0.2 miles, then parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and I-15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the city of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast along East Ontario Avenue within Riverside County for approximately 1.8 miles until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the city of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles, crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation.

New 115 kV Single-Circuit Subtransmission Line

A new, 0.6-mile, 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley–Ivyglen 115 kV subtransmission line into SCE's existing 115 kV Fogarty Substation. The new line segment would begin along the future Valley–Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce

Street and Baker Street in the city of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation.

Consideration of CEQA Criteria

<u>*Project Objectives*</u>

The Mira Loma Alternative would not meet the three CPUC project objectives (Section 1.6).

Objective #1

The Mira Loma Alternative would not relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would not successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers resulting in a calculated annual LAR of 13 MWh. SCE also calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 46 MWh. As a result, the Mira Loma Alternative would not meet CPUC Objective 1.

Objective # 2

Although the Mira Loma Alternative includes the construction of a new 220/115 kV substation within the ENA, this substation does not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective # 3

The Mira Loma Alternative includes two system ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. SCE calculates that this alternative would not successfully manage an N-1 subtransmission line contingency resulting in a calculated annual LAR of 2 MWh. This alternative has a calculated annual LAR of 99,638 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 2,283,812 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 76,715 customers and average of approximately 31,076 customers would likely be impacted (i.e., without power), with at least some customers impacted the majority of the time during the contingency event.[13] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 143,991 customers (approximately 77 percent of customers in the Valley South System) and an average of approximately 83,647 customers (approximately 45 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted in every hour throughout the duration of the contingency event.[14] This alternative has a calculated annual LAR of 24,608 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the Mira Loma Alternative includes system ties, it does not successfully manage an N-1 subtransmission line contingency (resulting in some calculated LAR) and it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative does not successfully manage an N-1 subtransmission line contingency, which is a reasonably expected contingency or maintenance condition, and may also result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of a Flex 2-1 contingency, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the Mira Loma Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the new 15-acre 220/115 kV substation to be constructed on a privately owned parcel totaling

[13] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

[14] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

approximately 27 acres. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

This alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the Menifee Alternative is approximately 35 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the Mira Loma Alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2, above. This alternative would decrease linear component construction requirements by approximately 2 miles, for a total length of 22.2 miles. The footprint of the substation would also be reduced from 40 acres under the proposed Project to approximately 15 acres. Construction and operation methodologies are expected to be similar to those proposed for the proposed Project.

The Mira Loma Alternative would potentially reduce significant impacts to aesthetics that would be caused by the proposed Project, particularity to scenic resources within eyesight of SR-74, a designated State Scenic Highway. Further, the alternative is sited largely in urban areas and would fit with the existing visual character of the urban areas where there are existing utility transmission lines. A large portion of the alternative would be within eyesight of I-15, an eligible State Scenic Highway, which would cause significant impacts in this area due to visual character degradation along the I-15 corridor.

This alternative would not create additional impacts to air quality resources but would not significantly reduce the impact findings of the 2017 FEIR because the alternative's construction length is similar to that of the proposed Project and construction methodologies would remain the same as those for the proposed Project.

According to the findings of the 2017 EIR, the proposed Project would reduce impacts to biological resources to less than significant with mitigation. Implementation of this alternative would avoid one significant impact associated with the proposed Project by eliminating impacts to critical habitat designated for the San Diego ambrosia. Similar lengths of the linear components of the alternative and the proposed Project, and similar construction methodologies, would result in similar impacts to TES, riparian areas, and designated wetlands. As such, because the alternative is slightly shorter in length, it would slightly decrease impacts across the Western Riverside County Multiple Species NCCP/HCP. Because it would involve a similar amount of construction disturbance as the proposed Project, the Mira Loma Alternative would have similar impacts to nesting habitat for migratory passerine birds and raptors protected by the Migratory Bird Treaty Act and California Fish and Game Code; this habitat includes trees, shrubs, and grasslands and is present throughout the alternative's route. The Mira Loma Alternative would reduce the number of construction-related crossings of wetlands likely to be considered jurisdictional by applicable regulatory agencies. While implementation of this alternative would avoid one significant impact, other impacts to biological resources are not expected to be significantly decreased or eliminated by the Mira Loma Alternative.

This alternative's potential impacts to cultural resources are unknown at this time. Undocumented cultural resources may be present within the Mira Loma Alternative's route. Therefore, due to the slightly reduced footprint of the alternative and the routing through previously developed areas, the probability of impacting significant cultural resources would be low.

The proposed Project would reduce all impacts to geology, soils, and mineral resources to less than significant with mitigation. The Mira Loma Alternative would slightly reduce impacts to highly erodible soils. As such, the impacts to soils due to erosion would remain similar to those of the proposed Project. Impacts to lands classified as MRZ-3 would be similar to those of the proposed Project.

This alternative would reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The siting of the alternative is similar to that of the proposed Project, so it would have similar impacts to noise standards and sensitive receptors during the construction and operation phases.

This alternative would result in impact findings similar to those identified in the 2017 FEIR for the proposed Project associated with hazards and hazardous materials, hydrology and water quality, and land use. The alternative's siting and use of construction methodologies similar to those of the proposed Project would result in similar impact findings to the proposed Project but on a minutely reduced scale. These findings would likely remain categorized as "less than significant with mitigation."

Environmental Disadvantages

Construction of the Mira Loma Alternative has the potential to introduce new significant impacts to lands classified by the California Mineral Land Classification System as MRZ-2, which are areas of known mineral resource significance. Further, this alternative would increase fault line crossings because it would cross the Glen Ivy North Fault in the Elsinore Fault Zone twice along its routing.

The Mira Loma Alternative would increase temporary traffic impacts because of its urban siting and increased number of road crossings. Installation of the alternative's components along public roadways would increase the number of motorists impacted by temporary lane and intersection closures produced by stringing activities.

The Mira Loma Alternative may impact designated critical habitats associated with the least Bell's vireo (*Vireo bellii pusillus)* and Santa Ana sucker.

Construction of this alternative would pose a similar level of risk as the proposed Project regarding fire caused by vehicle and construction equipment use or electrical discharge. Fires could be started during refueling, vehicle and equipment use, welding, vegetation clearing, worker cigarette smoking, contact between electrical lines and the ground, and power surges. Increased demand on emergency service providers could occur in the event of traffic- or equipment-related accidents, vandalism, or fires. Potential impacts from fire and other hazard risks would remain significant with this alternative's implementation.

Conclusion

ELIMINATED: The Mira Loma Alternative would not meet CPUC Objective 1 because the alternative would not successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The Mira Loma Alternative would not meet CPUC Objective 2 because SCE's proposed substation associated with this alternative would not meet the objective's 500/115 kV requirement. In addition, the alternative would not meet CPUC Objective 3 because it does not successfully manage an N-1 subtransmission line contingency, which is a reasonably expected contingency or maintenance condition, and may also result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the three CPUC objectives for the proposed Project, the Mira Loma Alternative is eliminated from further analysis under CEQA.

Valley South to Valley North Alternative: New 115 kV Line and Transfer Newcomb and Sun City Substations to the VN System

This alternative was considered and eliminated from further consideration in the FEIR (as Alternative F). The Valley South to Valley North Alternative would transfer load away from SCE's existing Valley South 500/115 kV System to SCE's existing Valley North 500/115 kV System by constructing new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North System back to the Valley South

System (one or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

This alternative would include the following components:

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles)
- Construction of a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 mile)
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley- Skylark 115 kV subtransmission lines (approximately 0.7 mile)
- Reconductoring of SCE's existing, single-circuit Auld–Sun City 115 kV subtransmission line (approximately 7.7 miles)

This alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line and the modification of approximately 7.7 miles of existing 115 kV subtransmission line. This alternative totals approximately 13.6 miles. A detailed description of each of these components is provided below.

Alternative Components

<u>*New 115 kV Single-Circuit Subtransmission Lines*</u>

Valley Substation to Sun City Substation

A new, approximately 4.4-mile, underground 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the city of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld–Sun City

115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld–Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new, approximately 0.8-mile, underground, 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the city of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new, approximately 0.7-mile, underground, 115 kV, subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld–Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, it would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure.

Reconductor Existing 115 kV Subtransmission Line

SCE's existing Auld–Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the city of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the city of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the alternative would be approximately 7.7 miles in length.

Consideration of CEQA Criteria

This alternative of was considered as part of the certified FEIR as Alternative F and eliminated. No new information of substantial importance, which was not known nor could have been known at the time of the certification of the FEIR in 2017, showing that the alternative would not be feasible and/or considerably different from that analyzed in the FEIR was identified in the amended application and subsequent data requests. A discussion of the analysis of the alternative's ability to meet project objectives and overall feasibility is provided below and is consistent with the discussion provided in the 2017 FEIR.

Project Objectives

The Valley South to Valley North Alternative would not meet the three CPUC project objectives (Section 1.6).

Objective #1

The Valley South to Valley North Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 2,137 MWh. As a result, the Valley South to Valley North Alternative would not meet CPUC Objective 1.

Objective #2

The Valley South to Valley North Alternative does not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation.

Objective #3

While this alternative includes system ties between two existing systems it does not maintain system ties between a new system and the Valley South 115 kV System and, therefore, would not meet CPUC Objective 3. These findings are consistent with the FEIR analysis and no new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusions.

Feasibility

The CPUC's preliminary analysis of the Valley South to Valley North Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the construction of new tie lines. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the Valley South to Valley North Alternative is approximately 60 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the Valley South to Valley North Alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives which is consistent with the FEIR findings and no new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusions.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially “avoid or substantially lessen any of the significant effects of the project” (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2, above. This alternative would decrease the linear component construction requirements by approximately 10.4 miles. The alternative would include 5.9 miles of new construction for the subtransmission lines and modification of approximately 7.7 miles of existing lines, for a total construction length of 13.6 miles. The footprint of the proposed Project’s 40-acre substation would be eliminated because this alternative does not include a substation. Construction and operation methodologies are expected to be similar to those proposed for the proposed Project. The Valley South to Valley North Alternative’s siting is similar to the Menifee Alternative’s siting; therefore, the Valley South to Valley North Alternative’s ability to reduce potentially significant impacts would be similar to that of the Menifee Alternative.

The Valley South to Valley North Alternative would potentially reduce significant impacts to aesthetics that would be caused by the proposed Project particularity to scenic resources within eyesight of SR-74, a designated State Scenic Highway, and within eyesight of I-15, an eligible State Scenic Highway. Though construction of a portion of this alternative would also occur within eyesight of SR-74, the total length of the alternative within eyesight of the SR-74 corridor would be reduced compared to the proposed Project. Visual impacts to the I-15 corridor would likely be eliminated because of this alternatives distance from the I-15 corridor and topographic features separating the I-15 corridor and the alternative’s routing. The alternative is routed within eyesight of residential neighborhoods but would not be expected not change the existing visual setting of the areas because of existing transmission infrastructure.

This alternative would likely reduce impacts to air quality because of its reduced length, no construction of a substation, and construction requirements. Though this alternative would reduce the amount of construction emissions and times, these impacts - though reduced - would remain significant for the area.

The proposed Project would reduce all impacts to biological resources to less than significant with mitigation. This alternative would likely reduce all biological impacts associated with the propose Project because of its reduced footprint and siting in previously developed areas. Similar construction methodologies would result in similar impacts to TES, riparian areas, wetlands, and HCPs and NCCPs but on a reduced scale. The alternative would reduce all impacts to critical habitat.

This alternative’s potential impacts to cultural resources are unknown at this time. Undocumented cultural resources may be present within the alternative’s route. As such, due to the reduced size of the alternative’s footprint and the routing through previously developed areas, it is expected that the probability of impacting significant cultural resources will be reduced.

This alternative would potentially reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The urban setting of this alternative would likely affect sensitive receptors in proximity to the construction area; however, the reduction of length of the alternative may result in reduced construction time reducing the duration of noise and vibration impacts to sensitive receptors.

The Valley South to Valley North Alternative’s alternative may reduce temporary traffic impacts due to its reduced length and number of road crossings requiring fewer lane closures or intersection shutdowns during construction activities.

This alternative would reduce impacts associated with geology, soils, and mineral resources, specifically because it would not cause the same level of erosion due the reduced construction footprint. Hazards and hazardous materials impacts would be reduced because it would not require the same amount of hazardous materials for construction and it would greatly reduce the construction requirements in areas designated as Moderate, High, and Very High Fire Severity

Zones which would also eliminate impacts to public services and utilities posed by the proposed Project. The proposed Project's hydrology and water quality impacts would be reduced because it does not cross any waterbodies, drainages, or lie in FEMA Flood Zones reducing its probability of violating water quality standards or waste discharge requirements. Finally, the alternative would reduce impacts to land use because it would reduce the impacts to the Western Riverside County Multiple Species NCCP/HCP.

However, as disclosed in the FEIR under the screening of Alternative F, because this alternative would not relieve projected electrical demand through the applicant's planning period the proposed Project or a similar project would need to be constructed, which could eliminate the environmental advantages described above.

<u>*Environmental Disadvantages*</u>

No environmental disadvantages were identified during the limited screening process for this alternative.

Conclusion

ELIMINATED: The Valley South to Valley North Alternative would not meet the CPUC Objective 1 because the alternative would not successfully manage an N-1 transformer contingency or CPUC Objective 3 because it does not include system ties between a new 115 kV system and the Valley South System. It would not meet Objective 2 because it does not include the construction of a new 500/115 kV substation. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative would not relieve projected electrical demand through the applicant's planning period the proposed Project or a similar project would need to be constructed which could eliminate the identified environmental advantages. As discussed above, this alternative was considered as part of the certified FEIR (as Alternative F) and eliminated. No new information has been presented in the amended application or subsequent data requests that would change the FEIR conclusion and this alternative remains eliminated from further consideration.

Valley South to Valley North to Vista Alternative: New 115 kV Line, Transfer Newcomb and Sun City Substations to the VN System, Transfer Moreno Substation to Vista 115 kV System

The Valley South to Valley North to Vista Alternative would transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System by constructing new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South would create two system ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North System back to the Valley South System (one or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista System back to the Valley North System (Moreno Substation), as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed.

This alternative would include the following components:

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 miles);

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Bunker and Lakeview Substations (approximately 6 miles);
- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Alessandro and Moval Substations (approximately 4 miles);
- Reconductoring of SCE's existing, single-circuit Auld–Sun City 115 kV subtransmission line(approximately 7.7 miles); and
- Double-circuiting of a segment of SCE's existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 miles).

This alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission lines and modification of approximately 7.8 miles of existing 115 kV subtransmission line. This alternative totals approximately 23.7 miles. A detailed description of each of these components is provided below.

Alternative Components

New 115 kV Single-Circuit Subtransmission Lines

Valley Substation to Sun City Substation

A new, approximately 4.4-mile, underground, 115 kV single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the city of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south for approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld–Sun City 115 kV subtransmission line, which is approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld–Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new, approximately 0.8-mile, underground, 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the city of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north, under SCE's existing transmission corridor, and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new, approximately 0.7-mile, underground, 115 kV, subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld–Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure.

Bunker Substation to Lakeview Substation

A new, approximately 6-mile, 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the city of Perris and SCE's existing 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 miles, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with Water Avenue, the line would leave the city of Perris, extending east for approximately 0.8 miles until the intersection with Bradley Road. It would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview

115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, extending north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation.

Alessandro Substation to Moval Substation

A new, approximately 4-mile, 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the city of Moreno Valley. The new line would exit SCE's existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 mile until the intersection with Alessandro Boulevard, where it would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE's existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE's existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE's existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue.

Reconductor Existing 115 kV Subtransmission Line

SCE's existing Auld–Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the city of Murrieta near the intersection of Liberty Road and Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, the line extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the city of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation.

Double-Circuit Existing 115 kV Subtransmission Lines

SCE currently operates the single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE's existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-mile segment of this line within the city of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE's existing 115 kV Moreno Substation.

Consideration of CEQA Criteria

Project Objectives

The Valley South to Valley North to Vista Alternative would not meet the three CPUC project objectives (Section 1.6).

Objective #1

The Valley South to Valley North to Vista Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 2,137 MWh. As a result, the Valley South to Valley North to Vista Alternative would not meet CPUC Objective 1.

Objective #2

The Valley South to Valley North to Vista Alternative does not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation.

Objective #3

The Valley South to Valley North to Vista Alternative includes the construction of multiple system ties connecting the Valley South System to the Valley North System and the Valley North and Vista Systems. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 54,051 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 3,485,449 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during the year (either during off-peak or peak months), all customers in the Valley South System would be impacted (i.e., without power) for the entire duration of the contingency.[15] This alternative has a calculated annual LAR of 21,975 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the Valley South to Valley North to Vista Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events—particularly in the event of a Flex 2-1 contingency, which would cause blackouts affecting all customers within the Valley South System—it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the Valley South to Valley North to Vista Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the construction of new tie lines. The alternative would use standard

[15] Off-peak months include, roughly, October through May. Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

equipment and technologies that have been used successfully in other locations. As such, it is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the Valley South to Valley North to Vista Alternative is approximately 56 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the Valley South to Valley North to Vista Alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The potential impacts associated with this alternative were compared to the environmental impacts identified to be significant for the proposed Project in the 2017 FEIR and summarized in Section 2.2.3, Table 2. This alternative would decrease the linear component construction requirements by approximately 0.3 miles. The alternative would include 15.9 miles of new construction for the subtransmission lines and modification of approximately 7.8 miles of existing lines, for a total construction length of 23.7 miles. The footprint of the proposed Project's 40-acre substation would be eliminated because this alternative does not include a substation. Construction and operation methodologies are expected to be similar to those proposed for the proposed Project. The Valley South to Valley North to Vista Alternative's siting is similar to the Menifee Alternative's siting. Additionally, a portion of this alternative is the same as the Valley South to Valley North Alternative; therefore, a portion of the Valley South to Valley North to Vista Alternative's impacts would be similar to those of the Menifee and Valley South to Valley North Alternatives.

The Valley South to Valley North to Vista Alternative would potentially reduce significant impacts to aesthetics that would be caused by the proposed Project, particularity to scenic resources within eyesight of SR-74, a designated State Scenic Highway, and within eyesight of I-15, an eligible State Scenic Highway. Though construction of a portion of this alternative would also occur within eyesight of SR-74, the total length of the alternative within eyesight of the SR-74 corridor would be reduced compared to the proposed Project. Visual impacts to the I-15 corridor would be eliminated because of this alternative's distance from the I-15 corridor and topographic features separating the I-15 corridor and the alternative's routing. The alternative is routed within eyesight of several residential neighborhoods but would not be expected to change the existing visual setting of the areas because of existing transmission infrastructure. The additional components include ties between the Bunker and Lakeview Substations and Alessandro and Moval Substations. These alternative components would not be expected to change the existing visual setting of the areas because of existing transmission infrastructure.

The proposed Project would reduce all impacts to biological resources to less than significant with mitigation. The Valley South to Valley North to Vista Alternative would eliminate impacts to critical habitat designated for the San Diego ambrosia; however, the alternative may impact designated critical habitats associated with the spreading navarretia. The similar lengths of the linear components of the alternative and the proposed Project, and similar construction methodologies, would result in similar impacts to TES, riparian areas, and designated wetlands. The alternative is shorter in length, however, and would slightly decrease impacts across the Western Riverside County Multiple Species NCCP/HCP. Therefore, overall impacts to biological resources are not expected to be significantly decreased or eliminated by Valley South to Valley North to Vista Alternative.

This alternative's potential impacts to cultural resources are unknown at this time. Undocumented cultural resources may be present within the alternative's route. Therefore, the probability of impacting significant cultural resources would be similar to those of the proposed Project.

This alternative would potentially reduce impacts attributed to noise and vibration because it would not involve the construction of 500 kV transmission line towers, which would require the use of a helicopter. The urban setting of this alternative would likely affect sensitive receptors in proximity to the construction area. Other noise and vibration impacts associated with construction and operation of this alternative would be similar to those of the proposed Project.

The Valley South to Valley North to Vista Alternative may reduce temporary traffic impacts due to its rural siting and reduced number of road crossings. Additionally, due to its rural siting, installation of alternative components along public roadways would reduce the number of motorists impacted by temporary lane closures produced by stringing activities.

This alternative would reduce impacts associated with geology, soils, and mineral resources, specifically because it would not cause the same level of erosion nor cross the same number of miles of Surface Mining and Reclamation Act designated MRZ-3 lands due the reduced construction footprint. Hazards and hazardous materials impacts would be reduced under this alternative because it would not require the same amount of hazardous materials for construction and it would greatly reduce the construction requirements in areas designated as Very High Fire Severity Zones, which would also eliminate impacts to public services and utilities posed by the proposed Project. The proposed Project's hydrology and water quality impacts would be reduced because its route does not cross any waterbodies, drainages, or lie in FEMA Flood Zones, reducing its probability of violating water quality standards or waste discharge requirements. Finally, the alternative would reduce impacts to land use because it would reduce the impacts to the Western Riverside County Multiple Species NCCP/HCP.

Environmental Disadvantages

This alternative's route crosses lands designated as Farmland of Local Importance, Farmland of Statewide Importance, Prime Farmland, and Unique Farmland at a greater rate than the proposed Project. Unique/Prime Farmlands and Farmland of Statewide/Local Importance are generally considered superior agricultural lands and are determined to be important to the local economy. The alternative would increase impacts to these agriculturally important lands.

Conclusion

ELIMINATED: The Valley South to Valley North to Vista Alternative would not meet CPUC Objective 1 because the alternative would not successfully manage an N-1 transformer contingency. The alternative would not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation. The Valley South to Valley North to Vista Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the three CPUC objectives for the proposed Project, the Valley South to Valley North to Vista Alternative is eliminated from further analysis under CEQA.

Non-Wire Alternatives

Centralized Battery Energy Storage System in Valley South

The Centralized Battery Energy Storage System (BESS) in Valley South Alternative would reduce peak demand in the Valley South 500/115 kV System via construction of two new 115/12 kV substations with BESSs near Pechanga and Auld Substations, which would loop in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

This alternative would include the following components:

- Construction of two new 115/12 kV substations with BESSs (approximately 9-acre footprint each); and
- Construction of two new 115 kV subtransmission segments to loop the new BESSs into the Valley South 115 kV System.

A detailed description of each of these components is provided below.

Alternative Components

<u>*BESS and 115 kV Loop-ins*</u>

Pechanga BESS and Loop-in

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the city of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line, which is directly adjacent to the site, would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-in

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 26.4-acre, privately owned parcel in the city of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped in to the 115 kV Auld BESS.

Consideration of CEQA Criteria

<u>*Project Objectives*</u>

The Centralized BESS in Valley South Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The Centralized BESS in Valley South Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in), resulting in a calculated annual LAR of 8,757 MWh. The potential for battery storage to resolve this contingency was not included in this calculation of LAR for N-1 transformer contingencies, as the operation of a dispatchable battery could result in reduced battery capacity or unavailability should an event occur. For the purposes of this analysis, while LAR is noted, the ED assumes the battery capacity will be held in standby and be fully available to address an N-1 transformer contingency, and therefore assumes, for the purposes of this alternative screening, the Centralized BESS in Valley South Alternative would be capable of addressing the N-1 transformer contingency. As a result, the Centralized BESS in Valley South Alternative would meet CPUC Objective 1.

Objective #2

Although the Centralized BESS in Valley South Alternative includes the construction of two new 115/12 kV substations within the ENA, these substations do not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective #3

The Centralized BESS in Valley South Alternative does not create or maintain system ties between a new 115 kV system and the Valley South 115 kV System. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 81,951 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 3,485,449 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during the year (either during off-peak or peak months), all customers in the Valley South System would be impacted (i.e., without power) for the entire duration of the contingency.[16] This alternative has a calculated annual LAR of 72,077 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the Centralized BESS in Valley South Alternative successfully manages an N-1 subtransmission line contingency, it does not include system ties and it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative does not include system ties and may result in impacts to a large proportion of Valley South System customers during some credible contingency events—particularly in the event of a Flex 2-1 contingency, which would cause blackouts affecting all customers within the Valley South System—it does not meet Objective 3.

Feasibility

The alternative uses standard equipment and technologies and has been modeled to indicate that it could mitigate Valley South transformer overload under normal conditions. There are no laws, regulations, or policies that could preclude implementation of this alternative. Therefore, the alternative is potentially feasible from a technical and legal standpoint.

Due to the minimal investment requirements of this alternative, the CPUC has no reason to believe it to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

[16] Off-peak months include, roughly, October through May. Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

Environmental Advantages

This alternative would reduce or eliminate most or all of the significant environmental impacts of the proposed Project because of the reduced footprint of this alternative and would require minimal construction of new components. Construction of new components under this alternative would involve approximately 18 acres of new disturbance, resulting in a reduction of construction-related impacts when compared to the proposed Project.

Environmental Disadvantages

No environmental disadvantages were identified during the screening process.

Conclusion

ELIMINATED. The Centralized BESS in Valley South Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The Centralized BESS in Valley South Alternative would not meet CPUC Objective 2 because SCE's proposed substations associated with the alternative would not meet the objective's 500/115 kV requirement. The Centralized BESS in Valley South Alternative would not meet CPUC Objective 3 because this alternative does not include system ties and may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The Centralized BESS in Valley South Alternative is feasible from a technical, legal, and economic standpoint, and it would eliminate all significant impacts associated with the proposed Project.

However, because this alternative does not meet the majority of CPUC's objectives for the proposed Project, the Centralized BESS in Valley South Alternative is eliminated from further analysis under CEQA.

3.2.3 Hybrid Alternatives

Hybrid alternatives were developed by combining the conventional alternatives and non-wire alternatives, discussed above. The conventional solutions were chosen based on their ability to meet the 10-year load forecast and then paired with BESS to satisfy incremental capacity needs that develop over time.

Capacity margin above and beyond the capacity provided by new transformation or the transfer of load in each of the hybrid alternatives is initially achieved through the construction of system tie lines, as tie lines can be engaged to alleviate a potential thermal or voltage violation on a subtransmission line. Then, consistent with planning criteria under normal (i.e., N-0) conditions, the BESSs were sized to mitigate capacity shortfalls in the Valley South and Valley North Systems over the 30-year load forecast. The initial battery installation therefore occurs when there is a projected capacity shortfall under normal conditions. This initial installation varies among the alternatives and is driven by the amount of margin that is provided by the corresponding conventional scope.

Unlike the conventional alternatives, the BESS alternatives include both a power (megawatt; MW) and energy (megawatt-hour) sizing component to meet capacity shortfalls. The power component corresponds to the amount of peak demand in excess of the transformer capacity in the systems, and the energy component corresponds to the total energy that would otherwise go unserved during times when the transformer capacity is exceeded. The power component of the BESS was augmented for N-1 conditions (consistent with the Subtransmission Planning Criteria) by including an additional 10 MW of capacity. Similarly, the energy component of the BESS was augmented for battery degradation (2 percent per year), and for N-1 conditions.

The initial, and each subsequent, BESS installation is sized to meet the projected capacity need in the system for five years. For example, a BESS installed in 2037 would mitigate the projected capacity shortfall through 2042, at which point additional BESS capacity would be added.

Valley South to Valley North and Distributed BESS in Valley South

The Valley South to Valley North and Distributed BESS in Valley South (VS to VN and Distributed BESS in VS) Alternative proposes to reduce peak demand in the Valley South 500/115 kV System via distributed BESSs at existing 115/12 kV distribution substations. This alternative would include 115 kV line scope to transfer SCE’s Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North System back to the Valley South System (one or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed.

This alternative would include the following components:

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation (approximately 4.4 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 miles);
- Reconductoring of SCE's existing, single-circuit Auld–Sun City 115 kV subtransmission line (approximately 7.7 miles); and
- Construction of new energy storage components within the existing fence lines at three existing SCE 115 kV substations.

This alternative would require construction of approximately 5.9 miles of new 115 kV subtransmission line and modification of approximately 7.7 miles of existing 115 kV subtransmission line. This alternative totals approximately 13.6 miles. A detailed description of each of these components is provided below.

Alternative Components

<u>*New 115 kV Single-Circuit Subtransmission Lines*</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line approximately 4.4 miles in length would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the city of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld–Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld–Sun City 115 kV subtransmission line, for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment approximately 0.8 miles in length would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the city of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment approximately 0.7 miles in length would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld–Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, it would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure.

Reconductor Existing 115 kV Subtransmission Line

SCE's existing Auld–Sun City 115 kV subtransmission line would be reconductored between SCE's existing 115 kV Auld and Sun City Substations. This component would begin at SCE's existing 115 kV Auld Substation in the city of Murrieta near the intersection of Liberty Road and

Los Alamos Road. The existing line exits the substation to the west and continues along unpaved access roads for approximately 1 mile until reaching the intersection of Clinton Keith Road and Menifee Road. At this point, it extends north for approximately 3 miles along Menifee Road and unpaved access roads until reaching Scott Road. At this intersection, the line enters the city of Menifee and continues north along Menifee Road, Bell Mountain Road, and unpaved access roads for approximately 3.2 miles. Approximately 0.1 miles north of the intersection of Newport Road and Menifee Road, the line extends approximately 0.5 miles east until terminating at SCE's existing 115 kV Sun City Substation. This segment of the alternative would be approximately 7.7 miles in length.

Energy Storage Components

This alternative would require the installation of energy storage components within the existing fence line at three existing SCE 115 kV substations. A description of each of these substation locations is provided below.

Auld Substation

SCE's existing 115 kV Auld Substation is located on approximately 4.1 acres of SCE-owned land southwest of the intersection of Los Alamos Road and Liberty Road in the city of Murrieta. This site is bounded by residential development to the south and west, and vacant land to the north and the east.

Elsinore Substation

SCE's existing 115 kV Elsinore Substation is located on approximately 2.1 acres of SCE-owned land south of the intersection of West Flint Street and North Spring Street in the city of Lake Elsinore. This site is bounded by vacant land to the west, commercial and residential uses to the north, residential uses to the east, and commercial uses to the south.

Moraga Substation

SCE's existing 115 kV Moraga Substation is located on approximately 4 acres of SCE-owned land, approximately 0.1 miles southwest of the intersection of Mira Loma Drive and Calle Violetta in the city of Temecula. This site is bounded on all sides by residential uses.

Consideration of CEQA Criteria

<u>*Project Objectives*</u>

The VS to VN and Distributed BESS in VS Alternative would meet only one of the CPUC's three objectives (Section 1.6).

Objective #1

The VS to VN and Distributed BESS in VS Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in), resulting in a calculated annual LAR of 2,137 MWh. The potential for battery storage to resolve this contingency was not included in this calculation of LAR for N-1 transformer contingencies, as the operation of a dispatchable battery may result in reduced battery capacity or unavailablity should an event occur. For the purposes of this analysis, while LAR is noted, the ED assumes the battery capacity will be held in standby and be fully available to address an N-1 transformer contingency; therefore, the ED assumes, for the purposes of this alternative screening, the VS to VN and Distributed BESS in VS Alternative would be capable of addressing the N-1 transformer contingency. As a result, the VS to VN and Distributed BESS in VS Alternative would meet CPUC Objective 1.

Objective #2

The VS to VN and Distributed BESS in VS Alternative does not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation.

Objective #3

The VS to VN and Distributed BESS in VS Alternative includes the construction of two system ties between the Valley South and Valley North Systems. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 44,298 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 3,485,449 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during the year (either during off-peak or peak months), all customers in the Valley South System would be impacted (i.e., without power) for the entire duration of the contingency.[17] This alternative has a calculated annual LAR of 21,975 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the VS to VN and Distributed BESS in VS Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events, including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events—particularly in the event of a Flex 2-1 contingency, which would cause blackouts affecting all customers within the Valley South System—it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the VS to VN and Distributed BESS in VS Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the construction of new tie lines. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

[17] Off-peak months include, roughly, October through May. Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

According to SCE's cost/benefit analysis, the estimated cost of the VS to VN and Distributed BESS in VS Alternative is approximately 41 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the VS to VN and Distributed BESS in VS Alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The environmental advantages of this alternative would be the same as those for the Valley South to Valley North Alternative, discussed above. The addition of a BESS within previously disturbed areas would not discernably alter impacts associated with this alternative. The VS to VN and Distributed BESS in VS Alternative would likely reduce environmental impacts compared to the proposed Project.

Environmental Disadvantages

The environmental disadvantages of this alternative would be the same as those for the Valley South to Valley North Alternative, discussed above.

Conclusion

ELIMINATED: The VS to VN and Distributed BESS in VS Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The VS to VN and Distributed BESS in VS Alternative would not meet CPUC Objective 2 because this alternative does not include the construction of a new 500/115 kV substation. The VS to VN and Distributed BESS in VS Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events.

The alternative is feasible from a technical, legal, and economic standpoint, and it would likely reduce significant impacts associated with the proposed Project. However, because this alternative does not meet the majority of CPUC's objectives for the proposed Project, the VS to VN and Distributed BESS in VS Alternative is eliminated from further analysis under CEQA.

SDG&E and Centralized BESS in Valley South (SDG&E and Centralized BESS in VS) Alternative

The SDG&E Alternative, described in Section 3.2.2, proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 230/115 kV system created at the southern boundary of the SCE service territory and adjacent to SDG&E's service territory. The new system would be provided power from the existing SDG&E 230 kV system via construction of a new 230/115 kV substation and looping in the SDG&E Escondido-Talega 230 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Pauba and Pechanga 115/12 kV distribution substations to the newly formed 230/115 kV system. Subtransmission line construction and modifications in the Valley South System would also create two 115 kV system ties between the Valley South System and the newly formed 230/115 kV SDG&E-sourced system. The system-tie lines would allow for the transfer of load from the new system back to the Valley South System (either or both Pauba and Pechanga Substations), as well as additional load transfer from the Valley South System to the new system (Triton Substation) as needed. To further reduce load in the Valley South System, the SDG&E and Centralized BESS in VS Alternative would involve a new 115/12 kV substation with BESS constructed near Auld Substation with a loop-in of the Auld-Moraga #1 line.

This alternative would include the following components:

- Construction of a new 230/115 kV substation (approximately 15-acre footprint);
- Construction of a new 230 kV double-circuit transmission line between SDG&E's existing Escondido-Talega 230 kV transmission line and SCE's new 230/115 kV substation (approximately 7.2 miles);
- Construction of a new 115 kV double-circuit subtransmission line between SCE's new 230/115 kV substation and SCE's existing Pechanga Substation (approximately 2 miles);

- Demolition of SCE's existing 115 kV switchrack at Pechanga Substation and reconstruction on an adjacent parcel (approximately 3.2-acre footprint);
- Double-circuiting of SCE's existing Pauba-Pechanga 115 kV subtransmission line (approximately 7.5 miles);
- Double-circuiting of a segment of SCE's existing Auld-Moraga #2 115 kV subtransmission line (approximately 0.3 miles); and
- Construction of one new 115/12 kV substation with BESS (approximately 9-acre footprint) Construct one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE's existing 115 kV subtransmission system.

This alternative would require the construction of approximately 9.2 miles of new 230 kV transmission and 115 kV subtransmission lines and modification of approximately 7.8 miles of existing 115 kV subtransmission line. This alternative totals approximately 17 miles. A detailed description of each of these components is provided below.

Alternative Components

<u>*New 230/115 kV Substation*</u>

SDG&E would include the construction of a new, approximately 15-acre, 230/115 kV substation on a privately owned, approximately 56.4-acre, vacant parcel. The parcel is located north of Highway 79, between the intersections with Los Caballos Road and Pauba Road, in Riverside County. The parcel is trapezoidal in shape and is bounded by residences and equestrian facilities to the north, east, and west; and Highway 79 and vacant land to the south. SCE may establish vehicular access to the site from Los Corralitos Road or Highway 79.

<u>*New 230 kV Double-Circuit Transmission Line*</u>

A new, approximately 7.2-mile, 230 kV, double-circuit transmission line would be constructed, connecting the new 230/115 kV substation to SDG&E's existing Escondido-Talega 230 kV transmission line. This new 230 kV transmission line would begin at SDG&E's existing 230 kV Escondido-Talega 230 kV transmission line approximately 0.6 miles northeast of the intersection of Rainbow Heights Road and Anderson Road in the community of Rainbow in San Diego County. The line would leave the interconnection with SDG&E's existing Escondido-Talega 230 kV transmission line on new structures extending to the northeast for approximately 0.8 miles. At this point, the new line would enter Riverside County and the Pechanga Reservation for approximately 4 miles. The line would continue in a generally northeast direction for approximately 1 mile before exiting the Pechanga Reservation and continue until intersecting Highway 79. At the intersection with Highway 79, the line would extend northwest and parallel to Highway 79 for approximately 1 mile until reaching the new 230/115 kV substation.

New 115 kV Double-Circuit Subtransmission Line

A new, approximately 2-mile, 115 kV, double-circuit subtransmission line would be constructed to connect the new 230/115 kV substation to SCE's existing 115 kV Pechanga Substation. The line would depart the new 230/115 kV substation to the northwest on new structures for approximately 1.5 miles while traveling parallel to Highway 79. Near the intersection of Highway 79 and Anza Road, the line would transition to an underground configuration and continue along Highway 79 for approximately 0.5 miles until reaching SCE's existing 115 kV Pechanga Substation.

Demolish and Reconstruct an Existing 115 kV Switchrack

SCE currently operates the existing 115 kV Pechanga Substation, located on an approximately 3.2-acre, SCE-owned parcel approximately 0.2 miles northeast of the intersection of Highway 79 and Horizon View Street. This site is bounded by vacant land to the east and west and residential uses to the north and south. SCE would demolish this existing 115 kV switchrack and reconstruct it on an approximately 16.9-acre, privately owned parcel directly east of the existing substation. The new 115 kV switchrack would occupy approximately 3.2 acres within the parcel.

Double-Circuit Existing 115 kV Subtransmission Lines

Pauba-Pechanga

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Pauba and Pechanga Substations in Riverside County. This existing line would be converted to a double-circuit configuration, adding a new 115 kV circuit between SCE's existing 115 kV Pauba and Pechanga Substations. The existing line departs SCE's existing 115 kV Pechanga Substation and extends east along Highway 79 until reaching Anza Road. At the intersection of Highway 79 and Anza Road, the line extends northeast along Anza Road until reaching De Portola Road. At this intersection, the line extends generally northeast along De Portola Road until intersecting Monte de Oro Road, then extends west along Monte de Oro Road until reaching Rancho California Road. At this point, the line extends south along Rancho California Road and terminates at SCE's existing 115 kV Pauba Substation. This segment of the alternative is approximately 7.5 miles in length.

Auld-Moraga #2

SCE currently operates an existing 115 kV single-circuit subtransmission line between SCE's 115 kV Auld Substation in the city of Murrieta and SCE's existing 115 kV Moraga Substation in the city of Temecula. An approximately 0.3-mile segment of this line within the city of Temecula would be converted from a single-circuit to double-circuit configuration. This segment would begin near the intersection of Rancho California Road and Calle Aragon. The existing line then extends south before turning west and intersecting Margarita Road, approximately 0.2 miles northwest of Rancho Vista Road.

BESS and 115kV Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the city of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld-Moraga 115 kV subtransmission line, which is directly adjacent to the site, would be looped in to the 115 kV Auld BESS.

Consideration of CEQA Criteria

Project Objectives

The SDG&E and Centralized BESS in VS Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The SDG&E and Centralized BESS in VS Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event) and an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in). As a result, the SDG&E and Centralized BESS in VS Alternative would meet CPUC Objective 1.

Objective # 2

Although the SDG&E and Centralized BESS in VS Alternative includes the construction of a new 230/115 kV substation within the ENA, this substation does not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective # 3

The SDG&E and Centralized BESS in VS Alternative includes the construction of two 115 kV system ties between the Valley South System and new SDG&E system. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 42,455MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 466,537 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 90,095 customers and average of approximately 45,997 customers would be impacted (i.e., without power), with at least some customers impacted in every hour throughout the duration of the contingency.[18] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 149,209 customers (approximately 80 percent of customers in the

[18] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

Valley South System) and an average of approximately 96,186 customers (approximately 51 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted in every hour throughout the duration of the contingency event.[19] This alternative has a calculated annual LAR of 16,573 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System.) While the SDG&E and Centralized BESS in VS Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of a Flex 2-1 contingency, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the SDG&E and Centralized BESS in VS Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the new 15-acre 230/115 kV substation to be constructed on a vacant lot to the north of Highway 79. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, or airports. However, components of this alternative would cross the Pechanga Reservation, which could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially difficult to implement from a legal feasibility standpoint.

[19] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

According to the SCE's cost/benefit analysis, the estimated cost of the SDG&E and Centralized BESS in VS Alternative is approximately 69 percent higher than the cost identified for the proposed Project (SCE 2021b). Though this alternative is estimated to cost more than the proposed Project, the CPUC does not consider the alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The environmental advantages of this alternative would be the same as those for the SDG&E Alternative, discussed above. The addition of a 9-acre centralized BESS site in the vicinity of the existing Auld Substation would not discernably alter impacts associated with this alternative.

Environmental Disadvantages

The environmental disadvantages of this alternative would be the same as those for the SDG&E Alternative, discussed above.

Conclusion

ELIMINATED: The SDG&E and Centralized BESS in VS Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The SDG&E and Centralized BESS in VS Alternative would not meet CPUC Objective 2 because SCE's proposed substation associated with the alternative would not meet the objective's 500/115 kV requirement. The SDG&E and Centralized BESS in VS Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the majority of CPUC's objectives for the proposed Project, the SDG&E and Centralized BESS in VS Alternative is eliminated from further analysis under CEQA.

Mira Loma and Centralized BESS in Valley South (Mira Loma and Centralized BESS in VS) Alternative

The Mira Loma Alternative, described in Section 3.2.2, proposes to transfer load away from SCE's existing Valley South 500/115 kV System to a new 220/115 kV system via construction of a new 220/115 kV substation and looping in the Mira Loma-Chino 220 kV transmission line. This alternative would include 115 kV subtransmission line scope to transfer SCE's Ivyglen and Fogarty 115/12 kV distribution substations to the new 220/115 kV system. The existing 115 kV subtransmission lines serving Ivyglen and Fogarty Substations would become two system ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. The system ties would allow for the transfer of load from the new system back to the Valley South System (either or both Ivyglen and Fogarty Substations), as well as additional load transfer from the Valley South System to the new system (Elsinore Substation) as needed. To further reduce load in the Valley South System, the Mira Loma and Centralized BESS in VS would involve two new 115/12 kV substations with BESSs constructed near Pechanga and Auld Substations, which loop-in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.

This alternative would include the following components:

- Construction of a new 220/115 kV substation (approximately 15-acre footprint);
- Construction of a new 220 kV double-circuit transmission line segment to loop SCE's existing Chino-Mira Loma 220 kV transmission line into SCE's new 220/115 kV substation (approximately 130 feet);
- Construction of a new 115 kV double-circuit subtransmission line between SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation (approximately 21.6 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap SCE's future Valley–Ivyglen 115 kV subtransmission line to SCE's existing 115 kV Fogarty Substation (approximately 0.6 miles);

- Construction of two new 115/12 kV substations with BESSs (each with an approximately 9-acre footprint); and
- Construction of two new 115 kV subtransmission segments to loop the new 115 kV BESS locations into SCE's existing 115 kV subtransmission system.

In total, this alternative would require the construction of approximately 22.2 miles of new 220 kV transmission and 115 kV subtransmission lines. A detailed description of each of these components is provided below.

Alternative Components

New 220/115 kV Substation

The Mira Loma and Centralized BESS in VS Alternative would involve the construction of a new, approximately 15-acre, 220/115 kV substation on a privately owned, approximately 27-acre, vacant parcel. The parcel is located north of Ontario Ranch Road, east of Haven Avenue, and west of Hamner Avenue in the city of Ontario. The parcel is rectangular in shape and is bounded by vacant land to the north, SCE's existing 220 kV Mira Loma Substation and vacant land to the east, vacant land to the south, and vacant land and industrial uses to the west. The vacant parcel has a residential land use designation, and an existing SCE transmission corridor crosses the southeast portion of the site. Vehicular access would likely be established from Ontario Ranch Road.

New 220 kV Double-Circuit Transmission Line

A new 220 kV double-circuit transmission line segment would be constructed between the existing Chino-Mira Loma 220 kV transmission line and SCE's new 220/115 kV substation. This approximately 130-foot segment would begin within SCE's existing transmission corridor, approximately 2,000 feet east of Haven Avenue, and extend south until reaching SCE's new 220/115 kV substation site.

New 115 kV Double-Circuit Subtransmission Line

A new 115 kV double-circuit subtransmission line approximately 21.6 miles in length would be constructed, connecting SCE's new 220/115 kV substation and SCE's existing 115 kV Ivyglen Substation. This line would exit the new 220/115 kV substation site from the southern portion of the property and travel east in an underground configuration for approximately 0.2 miles along Ontario Ranch Road. The line would pass under SCE's existing transmission line corridor and then transition to an overhead configuration, continuing on new structures along Ontario Ranch Road for approximately 0.5 miles until intersecting Hamner Road. The line would then extend south along Hamner Road and parallel to SCE's existing Mira Loma-Corona 66 kV subtransmission line for approximately 6.8 miles. Within this approximately 6.8-mile portion of the route, the line would exit the city of Ontario and enter the city of Eastvale at the intersection with Bellegrave Avenue. Within the city of Eastvale, the line would continue along Hamner Avenue, cross the Santa Ana River, and enter the city of Norco. Within the city of Norco, the line would continue south along Hamner Avenue until intersecting 1st Street. At this point, the line would extend west along 1st Street for approximately 0.5 miles until West Parkridge Avenue. At this intersection, the line would enter the city of Corona and continue generally south along North Lincoln Avenue for approximately 3.2 miles, paralleling the Chase-Corona-Databank 66 kV subtransmission line between Railroad Street and West Ontario Avenue. At the intersection with West Ontario Avenue, the line would extend east and continue paralleling SCE's existing Chase-Corona-Databank 66 kV subtransmission line for approximately 1.4 miles until the intersection with Magnolia Avenue. The line would continue along West Ontario Avenue for approximately 0.2 miles, then parallel SCE's existing Chase-Jefferson 66 kV subtransmission line between Kellogg Avenue and I-15 for approximately 1.7 miles. The line would continue along East Ontario Avenue, pass under I-15, and exit the city of Corona after approximately 0.2 miles at the intersection of East Ontario Avenue and State Street. The line would extend southeast for approximately 1.8 miles along East Ontario Avenue within Riverside County until the intersection of Cajalco Road. At this intersection, the line would extend southeast along Temescal Canyon Road, crossing the city of Corona for approximately 1.2 miles between Cajalco Road and Dos Lagos Drive. The line would then continue within Riverside County along Temescal Canyon Road for approximately 3.9 miles before crossing under I-15 and terminating at SCE's existing 115 kV Ivyglen Substation.

New 115 kV Single-Circuit Subtransmission Line

A new, approximately 0.6-mile, 115 kV single-circuit subtransmission line segment would be constructed to tap SCE's future Valley–Ivyglen 115 kV subtransmission line into SCE's existing

115 kV Fogarty Substation. The new line segment would begin along the future Valley–Ivyglen 115 kV subtransmission line's alignment, approximately 680 feet southeast of the intersection of Pierce Street and Baker Street in the city of Lake Elsinore. The new line segment would extend generally southwest and parallel to SCE's existing Valley-Elsinore-Fogarty 115 kV subtransmission line until terminating at SCE's existing 115 kV Fogarty Substation.

<u>*BESS and 115 kV Loop-Ins*</u>

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the city of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Auld BESS and Loop-In

The approximately 9-acre, 115 kV Auld BESS would be constructed on an approximately 24.6-acre, privately owned parcel in the city of Murrieta. The parcel is rectangular in shape and bounded by Liberty Road to the west, residential uses and vacant land to the north, vacant land to the east, and Porth Road and vacant land to the south. SCE would establish vehicle access to the 115 kV Auld BESS from Liberty Road or Porth Road. In addition, the existing Auld -Moraga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Auld BESS.

Consideration of CEQA Criteria

<u>*Project Objectives*</u>

The Mira Loma and Centralized BESS in VS Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The Mira Loma and Centralized BESS in VS Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event) and an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in). As a result, the Mira Loma and Centralized BESS in VS Alternative would meet CPUC Objective 1.

Objective # 2

Although the Mira Loma and Centralized BESS in VS Alternative includes the construction of a new 220/115 kV substation within the ENA, this substation does not meet CPUC Objective 2's stated requirement to construct a 500/115 kV substation within the ENA.

Objective # 3

The Mira Loma and Centralized BESS in VS Alternative includes two system ties between the newly formed 220/115 kV Mira Loma System and the Valley South System. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 87,130 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 2,283,812 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during off-peak months, a maximum of approximately 76,715 customers and average of approximately 31,076 customers would likely be impacted (i.e., without power), with at least some customers impacted most of the time during the contingency event.[20] If the Flex 2-1 contingency were to occur during a peak demand period, a maximum of approximately 143,991 customers (approximately 77 percent of customers in the Valley South

[20] Off-peak months include, roughly, October through May. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

System) and an average of approximately 83,647 customers (approximately 45 percent of customers in the Valley South System) would likely be impacted, with at least some customers impacted in every hour throughout the duration of the contingency event.[21] This alternative has a calculated annual LAR of 24,608 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the Mira Loma and Centralized BESS in VS Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events, particularly in the event of a Flex 2-1 contingency, it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the Mira Loma and Centralized BESS in VS Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the new 15-acre 220/115 kV substation to be constructed on a privately owned parcel totaling approximately 27 acres. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the Mira Loma Alternative is approximately 150 percent more than the proposed Project (SCE 2021b). Because this alternative

[21] Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

is estimated to cost more than the proposed Project, the CPUC does not consider the alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed Project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The environmental advantages of the Mira Loma and Centralized BESS in VS Alternative would be the same as those for the Mira Loma Alternative, discussed above. The addition of two 9-acre centralized BESS sites in the vicinity of the existing Auld and Pechenga Substations would not discernably alter impacts associated with this alternative.

Environmental Disadvantages

The environmental disadvantages of this alternative would be the same as those for the Mira Loma Alternative, discussed above.

Conclusion

ELIMINATED: The Mira Loma and Centralized BESS in VS Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The Mira Loma and Centralized BESS in VS Alternative would not meet CPUC Objective 2 because SCE's proposed substation associated with this alternative would not meet the objective's 500/115 kV requirement. The Mira Loma and Centralized BESS in VS Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the majority of CPUC's objectives for the proposed Project, the Mira Loma and Centralized BESS in VS Alternative is eliminated from further analysis under CEQA.

Valley South to Valley North and Centralized BESS in Valley South and Valley North (VS to VN and Centralized BESS in VS and VN) Alternative

The Valley South to Valley North Alternative, described in Section 3.2.2, proposes to transfer load away from SCE's existing Valley South 500/115 kV System to SCE's existing Valley North 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations to the Valley North System. Subtransmission line modifications in the Valley South System would also create two system ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North System back to the Valley South System (one or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. To further reduce load in the Valley South System, the VS to VN and Centralized BESS in VS and VN would involve a new 115/12 kV substation with BESS that would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line, and a second BESS installed at Alessandro Substation, to offset a portion of the load that is transferred from the Valley South to Valley North System.

This alternative would include the following components:

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 miles);

- Construction of one new 115/12 kV substation with BESS and add BESSs to an existing SCE substation; and
- Construction of one new 115 kV subtransmission segment to loop the new BESS into SCE's existing subtransmission system.

This alternative would require the construction of approximately 5.9 miles of new 115 kV subtransmission line. A detailed description of each of these components is provided below.

Alternative Components

<u>*New 115 kV Single-Circuit Subtransmission Lines*</u>

Valley Substation to Sun City Substation

A new, approximately 4.4-mile, underground 115 kV, single-circuit subtransmission line would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the city of Menifee. The new line would exit Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend south approximately 3.9 miles along Menifee Road until reaching SCE's existing Auld–Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east, parallel to the Auld–Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new, approximately 0.8-mile, underground, 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and SCE's existing 500 kV Valley Substation in the city of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road, then east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west, parallel to SCE's existing Auld–Sun City 115 kV subtransmission line, until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, it would extend west along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line for approximately 350 feet to an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the alternative would be approximately 0.7 miles in length.

BESS and 115 kV Loop-Ins

Pechanga BESS and Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the city of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Alessandro BESS

The 115 kV Alessandro BESS would be constructed within SCE's existing 115 kV Alessandro Substation in the city of Moreno Valley. The existing substation is located on an approximately 24.2-acre parcel at the intersection of John F Kennedy Drive and Kitching Street. This site is bounded by residential development to the north, east, and south, and residential development and a school to the west.

Consideration of CEQA Criteria

Project Objectives

The VS to VN and Centralized BESS in VS and VN Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The VS to VN and Centralized BESS in VS and VN Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 2,137 MWh. The potential for battery storage to resolve this contingency was not included in this calculation of LAR for N-1 transformer contingencies, as the operation of a dispatchable battery may result in reduced battery capacity or unavailability should an event occur. For the purposes of this analysis, while LAR is noted, the ED assumes the battery capacity will be held in standby and be fully available to address an N-1 transformer contingency; therefore, the ED assumes, for the purposes of this alternative screening, the VS to VN and Centralized BESS in VS and VN Alternative would be capable of addressing the N-1 transformer contingency. As a result, the VS to VN and Centralized BESS in VS and VN Alternative would meet CPUC Objective 1.

Objective #2

The VS to VN and Centralized BESS in VS and VN Alternative does not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation.

Objective #3

The VS to VN and Centralized BESS in VS and VN Alternative includes the construction of two system ties between the Valley South and Valley North Systems. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 64,547 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 3,485,449 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during the year (either during off-peak or peak months), all customers in the Valley South System would be impacted (i.e., without power) for the entire duration of the contingency.[22] This alternative has a calculated annual LAR of 21,975 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the VS to VN and Centralized BESS in VS and VN Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events—particularly in the event of a Flex 2-1 contingency, which would cause blackouts affecting all customers within the Valley South System—it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the VS to VN and Centralized BESS in VS and VN Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the construction of new tie lines. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

[22] Off-peak months include, roughly, October through May. Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

According to SCE's cost/benefit analysis, the estimated cost of the VS to VN and Centralized BESS in VS and VN Alternative is approximately 116 percent more than the proposed Project (SCE 2021b). Though this alternative is estimated to cost more than the proposed Project, the CPUC does not consider the alternative to be economically infeasible.

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The environmental advantages of the VS to VN and Centralized BESS in VS and VN Alternative would be the same as those for the Valley South to Valley North Alternative, discussed above. The addition of a 9-acre centralized BESS sites in the vicinity of the existing Pechenga substation and installation of a BESS at the existing Alessandro Substation would not discernably alter impacts associated with this alternative. The VS to VN and Centralized BESS in VS and VN Alternative would likely reduce environmental resource impacts compared to the proposed Project.

Environmental Disadvantages

The environmental disadvantages of this alternative would be the same as those for the Valley South to Valley North Alternative, discussed above.

Conclusion

ELIMINATED: The VS to VN and Centralized BESS in VS and VN Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The VS to VN and Centralized BESS in VS and VN Alternative would not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation. The VS to VN and Centralized BESS in VS and

VN Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is feasible from a technical, legal, and economic standpoint, and it would likely reduce significant impacts associated with the proposed Project. However, since this alternative does not meet the majority of CPUC's objectives for the proposed Project, the VS to VN and Centralized BESS in VS and VN Alternative is eliminated from further analysis under CEQA.

Valley South to Valley North to Vista and Centralized BESS in Valley South (VS to VN to Vista Centralized BESS in VS)

The Valley South to Valley North to Vista Alternative, described in Section 3.2.2, proposes to transfer load away from SCE's existing Valley South 500/115 kV System to the Valley North 500/115 kV System, and away from the Valley North 500/115 kV System to the Vista 500/115 kV System via construction of new 115 kV subtransmission lines. This alternative would include 115 kV line scope to transfer SCE's Sun City and Newcomb 115/12 kV distribution substations from the Valley South to the Valley North System, and the Moreno 115/12 kV distribution substation to the Vista System. Subtransmission line construction and modifications in Valley South create two system ties between the Valley South and Valley North Systems. The system-tie lines would allow for the transfer of load from the Valley North System back to the Valley South System (one or both Sun City and Newcomb Substations), as well as additional load transfer from the Valley South System to the Valley North System (Auld Substation) as needed. Subtransmission line construction and modifications in Valley North create two system ties between the Valley North and Vista Systems. These system-tie lines would allow for the transfer of load from the Vista System back to the Valley North System (Moreno Substation), as well as additional load transfer from the Valley North System to the Vista System (Mayberry Substation) as needed. To further reduce load in the Valley South System, the VS to VN to Vista Centralized BESS in VS Alternative would involve a new 115/12 kV substation with BESS installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line.

This alternative would include the following components:

- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 500 kV Valley and 115 kV Sun City Substations (approximately 4.4 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to connect and re-terminate SCE's existing Valley-Newcomb 115 kV subtransmission line to SCE's existing 500 kV Valley Substation (approximately 0.8 miles);
- Construction of a new 115 kV single-circuit subtransmission line segment to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines (approximately 0.7 miles);
- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Bunker and Lakeview Substations (approximately 6 miles);
- Construction of a new 115 kV single-circuit subtransmission line between SCE's existing 115 kV Alessandro and Moval Substations (approximately 4 miles);
- Double-circuit a segment of SCE's existing 115 kV Moreno-Moval-Vista subtransmission line (approximately 0.1 miles);
- Construction of one new 115/12 kV substation with BESS (approximately 9-acre footprint); and
- Construction of one new 115 kV subtransmission segment to loop the new 115 kV BESS into SCE's existing 115 kV subtransmission system.

This alternative would require the construction of approximately 15.9 miles of new 115 kV subtransmission line and the modification of approximately 0.1 miles of existing 115 kV subtransmission line. This alternative totals approximately 16 miles. A detailed description of each of these components is provided below.

Alternative Components

<u>*New 115 kV Single-Circuit Subtransmission Lines*</u>

Valley Substation to Sun City Substation

A new underground 115 kV single-circuit subtransmission line approximately 4.4 miles in length would be constructed between SCE's existing 500 kV Valley Substation and 115 kV Sun City Substation in the city of Menifee. The new line would exit SCE's existing 500 kV Valley Substation near the intersection of Pinacate Road and Menifee Road. The route would extend approximately 3.9 miles south along Menifee Road until reaching SCE's existing Auld–Sun City 115 kV subtransmission line, approximately 0.1 miles north of the intersection of Menifee Road and Newport Road. At this point, the route would extend east and parallel to the Auld–Sun City 115 kV subtransmission line for approximately 0.5 miles until reaching SCE's existing 115 kV Sun City Substation.

Tap and Re-Terminate Valley-Newcomb to Valley Substation

A new underground 115 kV single-circuit subtransmission line segment would be constructed between SCE's existing Valley-Newcomb 115 kV subtransmission line and 500 kV Valley Substation in the city of Menifee. This line segment would begin near the intersection of SCE's existing Valley-Newcomb 115 kV subtransmission line and Palomar Road. The line would then extend north under SCE's existing transmission corridor and along Palomar Road until intersecting Pinacate Road. The line would then extend east along Pinacate Road until terminating at SCE's existing 500 kV Valley Substation. This segment of the alternative would be approximately 0.8 miles in length.

Tap and Reconfigure Valley-Newcomb-Skylark to Sun City Substation

A new underground 115 kV subtransmission line segment would be constructed to tap and reconfigure SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line to SCE's existing 115 kV Sun City Substation, creating the Newcomb-Sun City and Valley-Skylark 115 kV subtransmission lines. This new segment would begin at the southeast corner of SCE's existing 115 kV Sun City Substation and would extend west and parallel to SCE's existing Auld–Sun City 115 kV subtransmission line until reaching Menifee Road. The line would then extend south along Menifee Road until intersecting Newport Road. At this point, the line would extend west for approximately 350 feet along Newport Road and parallel to SCE's existing Valley-Newcomb-Skylark 115 kV subtransmission line until terminating at an existing subtransmission pole. The tap would be completed in the vicinity of this structure. This segment of the alternative would be approximately 0.7 miles in length.

Bunker Substation to Lakeview Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Bunker Substation in the city of Perris and 115 kV Lakeview Substation in Riverside County. From SCE's existing 115 kV Bunker Substation, the line would extend south on Wilson Avenue on new structures for approximately 0.4 miles until the intersection with Placentia Avenue. At this intersection, the line would extend east on Placentia Avenue for approximately 0.4 miles, then turn south for approximately 0.3 miles and travel parallel to a dry creek bed until the intersection with Water Avenue. At the intersection with water Avenue, the line would leave the city of Perris and extend east for approximately 0.8 miles until the intersection with Bradley Road. The line would then continue east across vacant and agricultural lands for approximately 2.1 miles until intersecting SCE's existing Valley-Lakeview 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Valley-Lakeview 115 kV subtransmission line for approximately 2 miles, then extend north until terminating at SCE's existing 115 kV Lakeview Substation. The current route extends north, southeast along 11th Street, and northeast along an unpaved access road before arriving at SCE's existing 115 kV Lakeview Substation. This segment of the alternative would be approximately 6 miles in length.

Alessandro Substation to Moval Substation

A new 115 kV single-circuit subtransmission line would be constructed between SCE's existing 115 kV Alessandro and Moval Substations in the city of Moreno Valley. The new line would exit SCE's existing 115 kV Alessandro Substation in an underground configuration and extend north for approximately 350 feet along Kitching Street until intersecting John F Kennedy Drive. At this intersection, the line would transition to an overhead configuration on new structures and extend east along John F Kennedy Drive for approximately 0.5 miles until the intersection with Lasselle Street. The line would then extend north on Lasselle Street for approximately 1 mile until the intersection with Alessandro Boulevard, where it would extend east for approximately 2 miles until intersecting Moreno Beach Drive and SCE's existing Lakeview-Moval 115 kV subtransmission line. The new 115 kV subtransmission line would be co-located with the existing Lakeview-Moval 115 kV subtransmission line for approximately 0.5 miles until terminating at SCE's existing 115 kV Moval Substation. The current route extends north along Moreno Beach Drive until reaching SCE's existing 115 kV Moval Substation, approximately 0.1 miles south of the intersection of Moreno Beach Drive and Cottonwood Avenue. This segment of the alternative would be approximately 4 miles in length.

Double-Circuit Existing 115 kV Subtransmission Line

SCE currently operates an existing, single-circuit Moreno-Moval-Vista 115 kV subtransmission line between SCE's existing 115 kV Moreno, Moval, and Vista Substations. An approximately 0.1-mile segment of this line within the city of Moreno Valley would be converted from a single-circuit to double-circuit configuration. This segment would begin at the intersection of Ironwood Avenue and Pettit Street and extend east before turning north and entering SCE's existing 115 kV Moreno Substation.

BESS and 115 kV Loop-In

The approximately 9-acre, 115 kV Pechanga BESS would be constructed on an approximately 16.9-acre, privately owned parcel adjacent to SCE's existing 115 kV Pechanga Substation in the city of Temecula. The parcel is a generally rectangular shape and is bounded by equestrian facilities and residences to the north, vacant land and residences to the east, Highway 79 and residential uses to the south, and SCE's existing 115 kV Pechanga Substation and vacant land to the west. SCE would establish vehicle access to the 115 kV Pechanga BESS from Highway 79 or through SCE's existing 115 kV Pechanga Substation. In addition, the existing Pauba-Pechanga 115 kV subtransmission line is directly adjacent to the site and would be looped into the 115 kV Pechanga BESS.

Consideration of CEQA Criteria

Project Objectives

The VS to VN to Vista Centralized BESS in VS Alternative would meet only one of the CPUC's three project objectives (Section 1.6).

Objective #1

The VS to VN to Vista Centralized BESS in VS Alternative would relieve electrical demand exceeding the operating limit of the two Valley South System transformers. SCE calculates that this alternative would also successfully manage the normal (N-0) operating conditions of subtransmission lines and transformers (i.e., no contingency event). However, SCE calculates that this alternative would not successfully manage an N-1 transformer contingency (i.e., a single transformer out of service and the Valley South System being served with one transformer until the spare transformer could be switched in) resulting in a calculated annual LAR of 2,137 MWh. The potential for battery storage to resolve this contingency was not included in this calculation of LAR for N-1 transformer contingencies, as the operation of a dispatchable battery may result in reduced battery capacity or unavailability should an event occur. For the purposes of this analysis, while LAR is noted, the ED assumes the battery capacity will be held in standby and be fully available to address an N-1 transformer contingency; therefore the ED assumes, for the purposes of this alternative screening, the VS to VN to Vista Centralized BESS in VS Alternative would be capable of addressing the N-1 transformer contingency. As a result, the VS to VN to Vista Centralized BESS in VS Alternative would meet CPUC Objective 1.

Objective #2

The VS to VN to Vista Centralized BESS in VS Alternative does not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation.

Objective #3

The VS to VN to Vista Centralized BESS in VS Alternative includes the construction of multiple system ties connecting the Valley South System to the Valley North System and the Valley North and Vista Systems. SCE calculates that this alternative would successfully manage an N-1 subtransmission line contingency. This alternative has a calculated annual LAR of 64,547 MWh for a Flex-1 contingency (i.e., simultaneous loss of two subtransmission lines that share common structures). This alternative also has a calculated annual LAR of 3,485,449 MWh for a Flex 2-1 contingency (i.e., a complete Valley Substation outage condition with an estimated minimum two-week recovery period). If a Flex 2-1 contingency event were to occur during the year (either during off-peak or peak months), all customers in the Valley South System would be impacted (i.e., without power) for the entire duration of the contingency.[23] This alternative has a calculated annual LAR of 21,975 MWh for a Flex 2-2 contingency (i.e., two normally load-serving Valley South transformers are unavailable, but the spare transformer is available to serve load to the Valley South System). While the VS to VN to Vista Centralized BESS in VS Alternative includes system ties and successfully manages an N-1 subtransmission line contingency, it has a substantial calculated annual LAR for more severe emergency events, including Flex-1, Flex 2-1, and Flex 2-2 contingencies. Because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events—particularly in the event of a Flex 2-1 contingency, which would cause blackouts affecting all customers within the Valley South System—it does not meet Objective 3.

Feasibility

The CPUC's preliminary analysis of the VS to VN to Vista Centralized BESS in VS Alternative identified no fatal faults or conflicts that would suggest the alternative is infeasible. Sufficient physical space exists for the construction of new tie lines. The alternative would use standard equipment and technologies that have been used successfully in other locations. As such, the alternative is considered to be potentially feasible from a technical standpoint.

The alternative would not be located on or within any wilderness areas, wilderness study areas, restricted military bases, airports, or reservations that could preclude implementation of the alternative due to regulatory restrictions, making this alternative potentially feasible from a legal standpoint.

According to SCE's cost/benefit analysis, the estimated cost of the VS to VN to Vista Centralized BESS in VS Alternative is approximately 8 percent less than the proposed Project (SCE 2021b). Therefore, the CPUC does not consider the VS to VN to Vista Centralized BESS in VS Alternative to be economically infeasible.

[23] Off-peak months include, roughly, October through May. Peak months include, roughly, June through September of each year. Impacted customer estimates were developed using LAR data from Table 6-1 contained in SCE's Revised Planning Study (Exhibit C-2) (submitted with SCE's Second Amended Motion on 06/22/2021), load forecast data from SCE's response to Cal Advocates Data Request A909022-SCE-010-Question-02 (submitted 08/19/2021), and data from SCE's response to Energy Division Data Request A.09-09-022 CPUC-Supplemental Data Request-013 Q. DG-MISC-82_FollowUp_2 (submitted on 07/26/2022).

Overall, this alternative is potentially feasible from technical, legal, and economic perspectives.

Potential to Reduce Significant Environmental Impacts

This alternative would potentially reduce environmental impacts compared to the proposed project. Therefore, this alternative meets the CEQA criterion that alternatives fully analyzed in an EIR potentially "avoid or substantially lessen any of the significant effects of the project" (CEQA Guidelines Section 15126.6(a)).

Environmental Advantages

The environmental advantages of the VS to VN to Vista Centralized BESS in VS Alternative would similar to those for the Valley South to Valley North to Vista Alternative, discussed above. The addition of a 9-acre 115/12 kV substation and BESS site in the vicinity of the existing Pechenga substation would not discernably alter impacts associated with this alternative. The VS to VN to Vista Centralized BESS in VS Alternative would likely reduce environmental resource impacts compared to the proposed Project.

Environmental Disadvantages

The environmental disadvantages of this alternative would be the same as those for the Valley South to Valley North to Vista Alternative, discussed above.

Conclusion

ELIMINATED: The VS to VN to Vista Centralized BESS in VS Alternative would meet CPUC Objective 1 by relieving projected electrical demand on the Valley South System and successfully managing the normal (N-0) operating conditions of subtransmission lines and transformers and an N-1 transformer contingency. The alternative would not meet CPUC Objective 2 because it does not include the construction of a new 500/115 kV substation. The VS to VN to Vista Centralized BESS in VS Alternative would not meet CPUC Objective 3 because this alternative may result in impacts to a large proportion of Valley South System customers during some credible contingency events. The alternative is considered potentially feasible and would potentially reduce significant impacts of the proposed Project. However, because this alternative does not meet the majority of CPUC objectives for the proposed Project, the VS to

VN to Vista Centralized BESS in VS Alternative is eliminated from further analysis under CEQA.

4 Summary of Alternative Screening Results

This section summarizes the conclusions from Section 3. Table 5 documents the LAR (MWh) for the N-0, N-1 transformer, and N-1 subtransmission line conditions and Flex metrics for each conventional, non-wire, and hybrid project alternative analyzed in Section 3. Each alternative identified in this report is listed in Table 6, below, along with a summary of the screening results for each alternative.

4.1 Alternatives Carried Forward for Analysis under CEQA

Based on the analysis presented in this report, none of the new alternatives identified in this report will be carried forward for full analysis under CEQA.: No changes to the previous alternatives screening analysis included in the 2017 Final EIR are necessary.

Table 5 Project Objectives and Load at Risk Summary Table

Alternative	CPUC Objective #1				CPUC Objective #2		CPUC Objective #3[24]					
	Relieve Projected Electrical Demand	N-0 [25] LAR (MWh)	N-1 Transformer LAR (MWh)	Meets CPUC Objective #1	New 500/115 kV Substation	Meets CPUC Objective #2	Includes System Ties	N-1 Sub-transmission Lines[26] LAR (MWh)	Flex-1 LAR (MWh)	Flex-2-1 LAR (MWh)	Flex 2-2 LAR (MWh)	Meets CPUC Objective #3
Conventional Alternatives												
SDG&E	Yes	0	0	Yes	No[27]	No	Yes	0	52,762	466,537	16,573	No
SCE Orange County	Yes	0	0	Yes	No[28]	No	Yes	23	142,815	437,757	13,523	No
Menifee	Yes	0	2,137	No	Yes	Yes	Yes	0	54,051	742,386	21,975	No
Mira Loma	Yes	13.1	46	No	No[29]	No	Yes	2	99,638	2,283,812	24,608	No
Valley South to Valley North	Yes	0	2,137	No	No	No	Yes	0	54,051	3,485,449	21,975	No
Valley South to Valley North to Vista	Yes	0	2,137	No	No	No	Yes	0	54,051	3,485,449	21,975	No
Non-Wires Alternatives												
Centralized BESS in Valley South	Yes	0	8,757	Yes[30]	No[31]	No	No	0	81,951	3,485,449	72,077	No
Hybrid Alternatives												
Valley South to Valley North and Distributed BESS in Valley South	Yes	0	2,137	Yes[32]	No	No	Yes	0	44,298	3,485,449	21,975	No
SDG&E and Centralized BESS in Valley South	Yes	0	0	Yes	No[33]	No	Yes	0	42,455	466,537	16,573	No
Mira Loma and Centralized BESS in Valley South	Yes	0	0	Yes	No[34]	No	Yes	0	87,130	2,283,812	24,608	No

24 Year 2028, Source: Exhibit C-2, Table 6-1 in SCE 2021a
25 Year 2031, Source: SCE 2023
26 Year 2031, Source: SCE 2023
27 The SDG&E Alternative includes the construction of a new 230/115 kV substation.
28 The SCE Orange County Alternative includes the construction of a new 220/115 kV substation.
29 The Mira Loma Alternative includes the construction of a new 220/115 kV substation.
30 A right-sized BESS could address the N-1 Transformer contingency.
31 The Centralized BESS in Valley South includes the construction of two new 115/12 kV substations.
32 A right-sized BESS could address the N-1 Transformer contingency.
33 The SDG&E and Centralized BESS in VS Alternative includes the construction of a new 230/115 kV substation.
34 The Mira Loma and Centralized BESS in VS Alternative includes the construction of a new 220/115 kV substation.

Alternative	CPUC Objective #1				CPUC Objective #2		CPUC Objective #3[24]					
	Relieve Projected Electrical Demand	N-0 [25] LAR (MWh)	N-1 Transformer LAR (MWh)	Meets CPUC Objective #1	New 500/115 kV Substation	Meets CPUC Objective #2	Includes System Ties	N-1 Sub-transmission Lines[26] LAR (MWh)	Flex-1 LAR (MWh)	Flex-2-1 LAR (MWh)	Flex 2-2 LAR (MWh)	Meets CPUC Objective #3
Valley South to Valley North and Centralized BESS in Valley South and Valley North	Yes	0	2,137	Yes[35]	No	No	Yes	0	64,547	3,485,449	21,975	No
Valley South to Valley North to Vista and Centralized BESS in Valley South	Yes	0	2,137	Yes[36]	No	No	Yes	0	64,547	3,485,449	21,975	No

[35] A right-sized BESS could address the N-1 Transformer contingency.
[36] A right-sized BESS could address the N-1 Transformer contingency.

Table 6 2024 Alternative Screening Summary

Alternative	Analysis Document	Meets 14 CCR 15162	Meets CPUC Objectives*			Potential Feasibility (Technological, Legal, Economic)	Potential to Reduce Significant Environmental Effects, As Compared to Proposed Project											ASR Determination
			CPUC Objective 1	CPUC Objective 2	CPUC Objective 3		Aesthetics	Air Quality	Biological Resources	Cultural Resources	Geology, Soils, and Mineral Resources	Hazards and Hazardous Materials	Hydrology and Water Quality	Land Use	Noise and Vibration	Public Services and Utilities	Transportation and Traffic	
Minimal Investment Alternatives																		
Utilizing spare transformer for the Valley South System	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	Eliminated (this alternative was considered as part of the certified FEIR as Alternative E)
Operating existing Valley South System transformers above normal ratings	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	Eliminated
Loading-Shedding Relays	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	Eliminated
Conventional Alternatives																		
SDG&E	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Likely – Pending land use restrictions across the Pechenga Reservation	(-)	(-)	(o)	(o)	(+)	(o)	(o)	(o)	(o)	(o)	(-)	Eliminated
SCE Orange County	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Likely – Pending land use restrictions across Camp Pendleton	(+)	(o)	(+)	(o)	(+)	(+)	(o)	(+)	(-)	(o)	(-)	Eliminated

Table 6 2024 Alternative Screening Summary

Alternative	Analysis Document	Meets 14 CCR 15162	Meets CPUC Objectives*			Potential Feasibility (Technological, Legal, Economic)	Potential to Reduce Significant Environmental Effects, As Compared to Proposed Project											ASR Determination
			CPUC Objective 1	CPUC Objective 2	CPUC Objective 3		Aesthetics	Air Quality	Biological Resources	Cultural Resources	Geology, Soils, and Mineral Resources	Hazards and Hazardous Materials	Hydrology and Water Quality	Land Use	Noise and Vibration	Public Services and Utilities	Transportation and Traffic	
Menifee	2019 Planning Study; 2020 Amended PEA	No	No	Yes	No	Yes	(-)	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(-)	(o)	(-)	Eliminated
Mira Loma	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(o)	(-)	(o)	(+)	(o)	(o)	(o)	(o)	(o)	(+)	Eliminated
Valley South to Valley North (VS to VN)	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(-)	(o)	(-)	Eliminated (this alternative was considered as part of the certified FEIR as Alternative F)
Valley South to Valley North to Vista (VS to VN to Vista)	2019 Planning Study; 2020 Amended PEA	No	No	No	No	Yes	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	(-)	Eliminated
Non-Wires Alternatives																		
Centralized BESS in VS	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	Eliminated
Hybrid Alternatives																		

Table 6 2024 Alternative Screening Summary

Alternative	Analysis Document	Meets 14 CCR 15162	Meets CPUC Objectives*			Potential Feasibility (Technological, Legal, Economic)	Potential to Reduce Significant Environmental Effects, As Compared to Proposed Project											ASR Determination
			CPUC Objective 1	CPUC Objective 2	CPUC Objective 3		Aesthetics	Air Quality	Biological Resources	Cultural Resources	Geology, Soils, and Mineral Resources	Hazards and Hazardous Materials	Hydrology and Water Quality	Land Use	Noise and Vibration	Public Services and Utilities	Transportation and Traffic	
Valley South to Valley North and Distributed BESS in VS	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(-)	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(-)	(o)	(-)	Eliminated
SDG&E and Centralized BESS in VS	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(-)	(-)	(o)	(o)	(+)	(o)	(o)	(o)	(o)	(o)	(-)	Eliminated
Mira Loma and Centralized BESS in VS	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(o)	(o)	(o)	(o)	(+)	(o)	(o)	(o)	(o)	(o)	(+)	Eliminated
VS to VN and Centralized BESS in VS and VN	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(-)	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(-)	(o)	(-)	Eliminated
VS to VN to Vista and Centralized BESS in VS	2019 Planning Study; 2020 Amended PEA	No	Yes	No	No	Yes	(-)	(-)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	(-)	Eliminated

Notes:

***CPUC Objectives:**

1. Relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers;

2. Construct a new 500/115 kV substation within the ENA that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system-ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

Key:

(-) = Significance (reduced compared to the significant impacts of the Alberhill System Project identified in the 2017 FEIR)
(o) = Significance (equal to the significant impacts of the Alberhill System Project identified in the 2017 FEIR)
(+) = Significance (increased compared to the significant impact of the Alberhill System Project identified in the 2017 FEIR)

ASR	Alternatives Screening Report
BESS	battery energy storage system
CPUC	California Public Utilities Commission
ENA	Electrical Needs Area
kV	kilovolt
NERC	North American Electric Reliability Corporation
PEA	Proponent's Environmental Assessment
SCE	Southern California Edison
SG&E	San Diego Gas & Electric
VN	Valley North
VS	Valley South
WECC	Western Electricity Coordinating Council

5 References

Entergy Storm Center. 2021. The Balancing of Electric Supply and Demand. https://www.entergynewsroom.com/storm-center/restoration/loadshed/ Accessed July 21, 2021.

Southern California Edison (SCE). 2011. Proponent's Environmental Assessment: Alberhill System Project (April 11), as amended by responses from SCE to CPUC requests for additional information.

______. 2012. Compliance Filing of Southern California Edison Company (U 338-E) Pursuant to Decision 08-09-039 (Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols.). Rosemead, CA. April 30.

______. 2020. Second Amendment to the PEA. Filed May 11, 2020.

______. 2021a. Southern California Edison Company's (U338-E) Second Amended Motion to Correct Clerical Error in Amended Motion to Supplement the Record. June 22, 2021. Exhibit C-2.

______. 2021b. Exhibit G-2 Cost/Benefit Analysis of Additional Alternatives to ASP. ED-Alberhill-SCE-JWS-4: Item G.

______. 2023. Response to CPUC Data Request 017, Question DG-MISC-80 Follow_Up 1. Email to CPUC. January 20, 2023.

Southern California Association of Governments (SCAG). 2012. Adopted 2012 TTP Growth Forecast. http://www.scag.ca.gov/forecast/index.htm. Accessed October 15,

United States Census Bureau (USCB). 2021. State and County QuickFacts. City of Lake Elsinore, California. https://www.census.gov/quickfacts/fact/table/lakeelsinorecitycalifornia/PST045219.

United States Department of Defense (DOD). 2018. Final Joint Integrated Natural Resources Management Plan for Marine Corps Base and Marine Corps Air Station Camp Pendleton, California. https://www.pendleton.marines.mil/Portals/98/Docs/Environmental/Natural%20Resources/Integrated_Natural_Resources_Management_Plan_2018.pdf. Accessed July 21, 2021.

Appendix A: Final Alberhill System Project Energy Division Staff Report

Alberhill System Project

ENERGY DIVISION STAFF REPORT

September 15, 2023

Final

The purpose of this Energy Division Staff Report is to detail the review and analyses the California Public Utilities Commission Energy Division has conducted to date related to Southern California Edison's supplemental information filed in response to CPUC Decision 18-08-026.

California Public Utilities Commission

Contents

Tables & Figures

Tables

Figures

Acronyms & Abbreviations

AMI	Advanced metering infrastructure
ASR	Alternative Screening Report
BCA	benefit-cost analysis
BESS	battery energy storage systems
BTM	behind-the-meter
C&I	commercial and industrial
CBESS	centralized battery energy storage system(s)
CEQA	California Environmental Quality Act
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DER	distributed energy resources
Draft Staff Report	Alberhill System Project Draft Staff Report
EENS	Expected Energy Not Served
EIR	Environmental Impact Report
Kevala	Kevala, Inc.
kV	kilovolt
LAR	Load at Risk
LCCA	life cycle cost analysis
LOLE	Loss of Load Expectation
MW	megawatt
MWh	megawatt hours
NERC	North American Electric Reliability Corporation
O&M	operations and maintenance
PEA	Proponent's Environmental Assessment
PG&E	Pacific Gas and Electric

Proposed Alberhill Project	Alberhill System Project
PSLF	positive sequence load flow
PV	photovoltaic
PVRR	Present Value Revenue Requirement
ROW	right-of-way
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SPS	special protection scheme
STATCOM	STATic synchronous COMpensator
VOLL	value of loss load
VOS	value of service
WECC	Western Electricity Coordinating Council
WSP	WSP USA Inc.

Executive Summary

California Public Utilities Commission Energy Division Conclusion

The California Public Utilities Commission (CPUC) Energy Division Staff (Energy Division) conducted a series of engineering and economic analyses on Southern California Edison (SCE)-provided data responses and materials. The initial analyses indicated the potential that installation of two smaller-scaled system improvements, an alternative that uses distributed battery energy storage systems (BESS) and a fewer number of tie-lines, might provide a reliable short-term energy solution and be more cost-effective. After considering the additional supplemental analysis performed through a series of technical forums with SCE to evaluate the Valley South to Valley North with Centralized BESS (both with and without a static synchronous compensator [STATCOM]), the Energy Division has determined that the potential alternative does not adequately address the effect on system performance of a high impact, low probability contingency event such as a total loss of the Valley Substation.

Data since the Draft Energy Division Staff Report

The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with SCE in the spring and summer of 2022. The main findings, decisions, and actions in 2022 are highlighted and then described in more detail in the sections below.

Overall, while some of SCE's analyses focused on metrics that incorporate data lacking consensus (i.e., the probability weighting for Expected Energy Not Served [EENS]), many of the SCE supplemental analysis conclusions remain qualitatively sound. Significantly, the Energy Division finds that though unlikely to occur, the high-impact total loss of the Valley Substation contingency considered by SCE in its planning criteria is compelling when weighing the resiliency needs for the proposed Alberhill System Project. Determining the probability of such a high impact but unlikely event to monetize EENS is a challenging endeavor because there is little SCE and industry operational data. Commission Decision D.18-08-026 did not prescribe the method of compliance, and Commission permitting processes typically use least-cost best-fit analysis, not cost-benefit analyses for Certificate of Public Convenience and Necessity (CPCN) projects.

Energy Division has evaded the challenge by exploring the Load At Risk (LAR) of normal conditions and contingency events separately. Energy Division elected to compare the LAR predicted for project alternatives under normal conditions with all facilities in service, likely contingencies, and unlikely contingencies. SCE has convincingly shown that many of the reliability and resiliency challenges potentially faced by the Valley South System may not be fully addressed by addition of BESS and limited tie-lines to the Valley North System, particularly when evaluating mitigations for high-impact contingency events.

However, by instructing SCE to analyze the 13 project alternatives in comparison to basic planning criteria for normal conditions with all facilities in service and likely contingency conditions upon single loss of transformer, Energy Division learned during the technical forums and from data request responses that the five lowest cost alternatives based on SCE Present Value Revenue Requirement (PVRR) costs, and at least two of the substation project alternatives, do not meet basic planning criteria. The Menifee Alternative does not meet basic planning criteria under loss of single transformer (N-1) in 2031 because Menifee experiences LAR. The Mira Loma Alternative does not meet basic planning criteria for normal conditions with all facilities in service (N-0) nor likely contingency conditions for loss of single transformer (N-1) for 2031.[1]

Consequently, at this time, Energy Division does not conclude that two smaller-scaled systems or a different project alternative involving distributed battery energy storage would provide a reliable, short-term energy solution that is more cost-effective than other project alternatives, saving millions of dollars in upfront costs. The Energy Division Staff concludes that the additional supplemental analysis performed through the technical forums to evaluate Valley South to Valley North with Centralized BESS with and without STATCOM accomplished the expected analysis of the potential alternative suggested by Kevala that uses distributed BESS and a fewer number of tie-lines. The analysis did not support the hypothesis that a different project alternative would provide a short-term energy solution that would save millions of dollars in upfront costs, which Energy Division Staff posited in its draft staff report.

Purpose

As directed in the September 30, 2020, Assigned Commissioner's Ruling Amending Scoping Memo, the Energy Division, with support from WSP USA Inc., formerly Ecology and Environment, Inc. (WSP), and Kevala, undertook a review of SCE's amended Proponent's Environmental Assessment (PEA) and other relevant matters pursuant to the California Environmental Quality Act as the procedural next step in the proceeding. The Energy Division analyzed data provided by SCE in the supplemental information filed in the amended application and PEA, subsequent revisions, and in response to data requests made in 2020 and 2021. As part of the Energy Division assessment process, a series of engineering and economic analyses was conducted on SCE-provided data responses and materials.

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Each of the parties to the proceeding, including the applicant, were invited to give a presentation at the workshop on their review of the Draft Energy Division Staff Report and the alternatives and justifications in SCE's modified application at the workshop. Following the workshop, the CPUC invited the parties to the proceeding, including the applicant, to submit written comments by January 27, 2022.

[1] SCE Response to Energy Division Data Request No. 11, question DG-MISC-80.

Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with SCE in the spring and summer 2022 to gain additional understanding and potential alignment around several topics. The CPUC also issued a series of data requests to support and document the technical forum findings.

The 2022 technical forums also explored additional context regarding SCE's operation of the radial subtransmission Valley South System. As stated in SCE's Comments to the Draft Energy Division Staff Report for the proposed Alberhill Project, the Valley Substation is the sole source of 115 kV power for both the Valley South and Valley North Systems. The radial Valley South System is isolated, both physically and electrically, and does not have system tie-lines to serve as electrical connections to other SCE systems. SCE explained the importance of having system tie-lines to provide the ability to transfer load between adjacent systems bidirectionally. System tie-lines would enable system operators to use the available capacity of an adjacent system to provide load relief in the event of an unplanned outage of a subtransmission line or a subtransmission transformer. The SCE Planning Study and the service reliability performance of the proposed Alberhill Project, provide additional information about the Valley South System (SCE 2021, Items C and F).

Engineering Analyses

Since the Draft Staff Report, Kevala has learned that the 115kV portion of SCE's system included in the proposed Alberhill Project is not required to be planned to meet North American Electric Reliability Corporation (NERC) reliability standards. As discussed further in Section 2.3, while SCE's planning criteria align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which are analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios," (SCE 2023a, 6), including Flex-1, Flex-2-1, and Flex-2-2. It is reasonable to expect SCE to craft specific system performance metrics that are rooted in transmission system planning event analysis.

In the absence of the CPUC ordering a specific standardized evaluation approach, the Energy Division finds it reasonable for SCE to define performance metrics and scenarios to use in evaluating unlikely contingencies that may result in loss of load. This form of reliability/resilience assessment is nascent in the electric utility industry and Energy Division has seen examples of this form of assessment under development by Department of Energy National Laboratories, other utilities examining investment plans for extreme events, in white papers or journal articles from the Institute of Electrical and Electronics Engineers, and others. The Federal Energy Regulatory Commission, NERC, and Western Electricity Coordinating Council (WECC) have opened proceedings or opined in annual reports on the need for alternative planning based on high-impact, low-frequency events.

Although SCE is not mandated to follow NERC standards, SCE has provided an evaluation method that is rooted in transmission system planning event analysis. In NERC regulation, the regulatory agency expects the transmission operator to exercise its engineering judgment and operating experience to choose relevant events to study and to provide rationale justifying the events studied. NERC does not specify the duration of study periods in its regulation. Similarly, the CPUC expects SCE to use its engineering judgment and operating experience to evaluate unlikely contingencies at the subtransmission/distribution level even if CPUC has not dictated a standardized evaluation approach by regulation, rule, or order.

Energy Division finds that it is reasonable for SCE to use these evaluation methods involving novel reliability/resilience metrics and modeling as an additional screening method for resilience because high-impact, low-frequency events impacts to this subtransmission system could severely affect a significant number of customers.

SCE presented further background on how and why they chose certain performance metrics. They considered LAR, EENS, and metrics commonly used in resource adequacy studies, such as loss of load expectation. SCE wanted a metric that could compare cost effectiveness of solutions and that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration. These criteria led to SCE's selected use of LAR and EENS.

In response to an Energy Division recommendation in the Draft Staff Report, SCE provided additional analysis on the feasibility of developing distributed BESS in the Valley South system and the capability of the recommended tie-lines to transfer load. SCE expressed concerns that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a centralized battery energy storage system (CBESS) was a more realistic consideration. SCE prepared and presented additional analysis that looked at an alternative (with needed system sizing) that included CBESS paired with a STATCOM.

The Energy Division and its consultants extensively discussed the probabilities SCE used for an extreme event that results in loss of service at the Valley Substation, which was incorporated in calculations of the EENS metric. Due to lack of industry standard and lack of consensus on the appropriate probabilities for such contingency events, the additional analysis of Valley South to Valley North with a CBESS and a STATCOM were shown with LAR values calculated but not EENS values to avoid use of probabilities in comparative metrics.

As shown by the calculated LAR values, BESS cannot defer the proposed Alberhill Project's need alone to meet the Flex-2-1 planning case because the Valley System is a radially operated subtransmission system that would need to be operated as an islanded microgrid (i.e., a stand-alone electrical system disconnected from the main grid). The facilities and approach for operating Valley System like an islanded microgrid has not been tested nor operated at scale for a system this size. The Valley System would remain vulnerable to loss of its source of supply under a high impact, low probability event—which is undesirable for a high-density urban load area subject to extreme heat events.

Economic Analysis

WSP conducted a series of economic analyses finding that SCE's proposed Alberhill Project's Benefit-Cost Analysis (BCA) of alternatives does not display an equitable comparison of alternatives or calculation of each benefit-cost ratio since the benefits and costs for each alternative were not correctly timed in terms of when they would realistically occur. SCE's BCA accrues project benefits before the proposed Alberhill Project has been constructed or placed in service (instead, it is based on a project need date). It is also unclear how operation and maintenance costs were incorporated into the timeline or analysis, as they are not linked with the analysis, and the calculation of costs is not traceable.

Through technical forums with CPUC and SCE in May 2022, the Energy Division concluded that SCE conducted a life cycle cost analysis (LCCA) while preparing their economic analysis, instead of a BCA. An LCCA is a subset of a BCA. In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Although the SCE economic analysis appears to adhere to the criteria for comparing alternatives within an LCCA (determining the most cost-effective option among alternatives with identical in-service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA (Kneifel and Webb 2020; OMB n.d.; USDOT 2002, 2012, 2022).

WSP, on behalf of the Energy Division, conducted economic analysis to re-time the benefits to align with BCA methodologies. Based on the retiming of benefits beginning to accrue on the appropriate project in-service date, the most purely economically attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by San Diego Gas and Electric (seventh place) and Mira Loma (eighth place). Importantly, these rankings necessarily retain the probability weighting SCE used in its original EENS calculations for the contingency events and is agnostic as to whether the alternatives analyzed may be potentially infeasible or undesirable for noneconomic reasons, such as those discussed in the engineering analyses.

Project History

SCE filed an application (A.09-09-022) for a CPCN with the CPUC on September 30, 2009, to construct the proposed Alberhill Project. On August 31, 2018, CPUC Decision 18-08-026 granted SCE's petition to modify the permit to construct the Valley–Ivyglen 115-kV Subtransmission Line Project, deconsolidated Application 09-09-022 from Applications 07-01-031 and 07-04-028, and held Application 09-09-022 open to further review SCE's application for a CPCN for the proposed Alberhill Project. Ordering Paragraph 4 of Decision 18-08-026 directed SCE to supplement the record with additional analyses of alternatives that may satisfy the needs of the Valley South System. In response, SCE filed an amendment to its application on May 11, 2020, and included a corresponding amended PEA (Application A.09-09-022, second amendment).

1 Introduction

1.1 Project Background

1.1.1 Project History

Southern California Edison (SCE) filed an application (A.09-09-022) for a Certificate of Public Convenience and Necessity (CPCN) with the California Public Utilities Commission (CPUC) on September 30, 2009, to construct the Alberhill System Project (proposed Alberhill Project). SCE filed an amendment to the application on March 15, 2010 (Application A.09-09-022, amended), and filed amended sections of the Proponent's Environmental Assessment (PEA) on April 11, 2011. The proposed Alberhill Project would include a new 500/115-kilovolt (kV) substation (Alberhill Substation), new 500-kV transmission lines, new and modified 115-kV subtransmission lines, and telecommunications system installations. Appendix A provides a full project description of the proposed Alberhill Project, including project location and components.

The CPUC determined that it would be in the public's best interest to consolidate the California Environmental Quality Act (CEQA) analyses for the SCE Valley–Ivyglen Subtransmission Project Petition for Modification application (A. 07-01-031; proposed Valley–Ivyglen Project) and the proposed Alberhill Project CPCN application into a single CEQA document. As the lead agency, the CPUC prepared one Draft and one Final Environmental Impact Report (EIR) to evaluate the environmental impacts of both projects in accordance with the criteria, standards, and procedures of CEQA (Public Resources Code Sections 21000 et seq. and California Code of Regulations Title 14, Sections 15000 et seq.). The Final EIR, including responses to comments, was released in April 2017.

On August 31, 2018, CPUC Decision 18-08-026 granted SCE's petition to modify the permit to construct the Valley–Ivyglen 115-kV Subtransmission Line Project, deconsolidated Application 09-09-022 from Applications 07-01-031 and 07-04-028, and held Application 09-09-022 open to further review SCE's application for a CPCN for the proposed Alberhill Project. Ordering Paragraph 4 of Decision 18-08-026 directed SCE to supplement the record with additional analyses of alternatives that may satisfy the needs of the Valley South System. Table 1 details the supplemental analyses identified in Decision 18-08-026. On April 10, 2020, the CPUC issued an email ruling directing SCE to file: (1) a compliance filing for its additional analyses of alternatives that may satisfy the needs of the Valley South System to supplement the record Application (A.) 09-09-022, pursuant to D.18-08-026; and (2) an amendment to its application consistent with its additional analyses of alternatives that may satisfy the needs of the Valley South System, including a corresponding amended PEA reflecting the additional analyses as appropriate. In response, SCE filed an amendment to its application on May 11, 2020, including a corresponding amended PEA (Application A.09-09-022, second amendment).

Table 1: SCE Proposed Alberhill Project Supplemental Analysis	
Item	Supplemental Information Requested
A	Load forecast including industry accepted methods for estimating load growth and incorporating load reduction programs due to energy efficiency, demand response, and behind-the-meter generation.
B	Identification of all subtransmission planning areas in the SCE system with similar reliability issues.
C	A planning study that supports the project need and includes applicable planning criteria and reliability standards.
D	An analysis of several years of electric reliability performance for the Valley systems to demonstrate existing customer service level.
E	An analysis of outages over the past five years by root cause for the Valley South Systems in comparison to SCE system average and to other subtransmission radial systems.
F	The forecasted impact of the proposed Alberhill Project on service reliability performance, using electric service reliability metrics where applicable.
G	Cost/benefit analysis of several alternatives for enhancing reliability and providing additional capacity, including evaluation of energy storage, distributed energy resources, demand response, or smart grid solutions.
H	Identify capital investments or operational changes effectuated to address reliability issues in the absence of construction of the Alberhill Substation and the associated costs for such actions.
I	Detailed justification of the recommended solution as the best solution, including an explanation of how the proposed Alberhill Project ranks in the SCE capital investment portfolio of infrastructure upgrades.

On September 30, 2020, the assigned CPUC commissioner to the proposed Alberhill Project issued a ruling amending the scoping memo after considering SCE's amended application and PEA, amended protests, and the discussion at the second prehearing conference held on August 18, 2020. In the September 2020 ruling, the assigned CPUC commissioner confirmed the scope of issues identified in the June 19, 2017, scoping memo remained unchanged and determined the CPUC Energy Division (Energy Division) would undertake a review of SCE's amended PEA and any other relevant matters pursuant to CEQA as the procedural next step in the proceeding.

After SCE filed an amendment to its application on May 11, 2020, SCE discovered certain errors that affected the cost-benefit analysis. In an amended motion filed on February 1, 2021 (Application A.09-09-022, Amended Motion), SCE provided updated analyses and corrected information previously submitted into the record on May 11, 2020. Corrected documents included the Planning Study, Forecasted Impact of the proposed Alberhill Project, Cost-Benefit Analysis, and Detailed Justification of the Recommended Solution as the Best Solution (see Table 1 for descriptions of the required supplemental information) (SCE 2021, Items C, F, G, and I). SCE filed a second amended motion (Application A.09-09-022, Second Amended Motion) on June 22, 2021, to correct clerical errors in spreadsheet tabular data in SCE's February 2021 Amended Motion. Corrected documents included the Planning Study, Forecasted Impact of proposed Alberhill Project, and Cost-Benefit Analysis (SCE 2021, Items C, F, and G).

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Each of the parties to the proceeding, including the applicant, were invited to give a presentation at the workshop on their review of the Draft Energy Division Staff Report and the alternatives and justifications in SCE's modified application at the workshop. Following the workshop, the CPUC invited the parties to the proceeding, including the applicant, to submit written comments by January 27, 2022.

Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including:

- The SCE Benefit-Cost Analysis methodology and the metrics and treatment of batteries in the assessment of performance;
- SCE's additional analysis of Valley South to Valley North Plus Centralized Battery Energy Storage project alternatives including BESS sizing;
- The SCE Subtransmission Planning Criteria and Guidelines and the identification of project alternatives that satisfy the basic planning criteria (Capacity N-0, N-1 subtransmission lines, and N-1 transformer outage conditions); and
- The resilience need for the proposed Alberhill Project.

The CPUC also issued a series of data requests (CPUC Supplemental Data Requests 11-17) to support and document the technical forum findings.

The 2022 technical forums also explored additional context regarding SCE's operation of the radial subtransmission Valley South System. As stated in SCE's Comments to the Draft Energy Division Staff

Report for the proposed Alberhill Project, the Valley Substation is the sole source of 115 kV power for both the Valley South and Valley North Systems. The radial Valley South System is isolated, both physically and electrically, and does not have system tie-lines to serve as electrical connections to other SCE systems. SCE explained the importance of having system tie-lines to provide the ability to transfer load between adjacent systems bidirectionally. System tie-lines would enable system operators to use the available capacity of an adjacent system to provide load relief in the event of an unplanned outage of a subtransmission line or a subtransmission transformer. The SCE Planning Study and the service reliability performance of the proposed Alberhill Project, provide additional information about the Valley South System (SCE 2021, Items C and F).

Key milestones of the proposed Alberhill Project process are summarized in Table 2.

Table 2: Proposed Alberhill Project Milestones

Milestone	Date
Application A.09-09-022 Submitted to CPUC	September 30, 2009
Final EIR	April 2017
Oral Argument	May 2018
Decision 18-08-026 Issued - Final EIR Certified. Directed SCE to Supplement the Record with Additional Analyses of Alternatives	August 31, 2018
SCE Filed Amended Application and PEA	May 11, 2020
Receipt of Protests	June 2020
Alberhill CPCN Prehearing Conference	August 18, 2020
Assigned Commissioner's Ruling Amending Scoping Memo	September 30, 2020
SCE Filed Amended Motion to Supplement the Record	February 1, 2021
SCE Filed Second Amended Motion to Supplement the Record	June 22, 2021
Draft Energy Division Staff Report Published	December 3, 2021
CPUC Virtual Workshop on Draft Energy Division Staff Report Findings	January 20, 2022

Receipt of Comments on the Draft Energy Division Staff Report from SCE and Parties to the Proceeding	January 27, 2022
CPUC/SCE Technical Forums	Spring/summer 2022

Key:

CPCN = Certificate of Public Convenience and Necessity

CPUC = California Public Utilities Commission

EIR = Environmental Impact Report

PEA = Proponent's Environmental Assessment

SCE = Southern California Edison

1.2 Project Description

As described in the 2017 Final EIR, the proposed Alberhill Project would include construction of the Alberhill Substation, which would be expandable to a maximum of 1,680 megavolt amperes depending on future need. In addition to construction of a new Alberhill Substation, the proposed Alberhill Project would include the following (see Appendix A for a full project description of the proposed Alberhill Project):

- Construction of two new 500-kV transmission lines (approximately 3.3 miles combined) within a new right-of-way (ROW) to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line;
- Double circuit of approximately 11.75 miles of existing single-circuit 115-kV subtransmission lines with structure replacement primarily in the existing ROW;
- Construction of about 3 miles of single-circuit 115-kV subtransmission lines with distribution lines underbuilt on the subtransmission line structures and the removal of about 3 miles of electrical distribution lines within the existing ROW;
- Installation of a second 115-kV circuit on approximately 6.5 miles of single-circuit 115-kV subtransmission lines (the single-circuit line is to be constructed as part of the proposed Valley–Ivyglen Project);
- Installation of fiber-optic lines overhead (9 miles) on sections of the new or modified subtransmission lines and underground (1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12-kV substations;
- Construction of an approximately 120-foot microwave antenna tower at the proposed Alberhill Substation site; installation of microwave telecommunications dish antennae at the proposed

Alberhill Substation, the existing Santiago Peak Communications Site, and Serrano Substation; and other telecommunications equipment installations at existing and proposed substations; and

- Transfer of five of the 14 Valley South 115-kV System Substations to the proposed Alberhill Project: the Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb 115/12-kV Substations.

1.3 Alternatives Identified in SCE's Supplemental Analysis

Table 3 describes each of the alternatives identified in SCE's supplemental analyses, including the SCE 2020 Planning Study and Second Amendment to the PEA and subsequent revisions to the Planning Study in the February 2021 Amended Motion and June 2021 Second Amended Motion (SCE 2021, Item C). As described in the SCE Planning Study, SCE developed the project alternatives based on inputs from the CPUC in Decision (D.) 18-08-026, previous assessments in the proposed Alberhill Project Final EIR, and public and stakeholder engagement. The project alternatives include the following categories:

- Minimal Investment Alternatives: Alternatives in this category utilize existing equipment and make modest capital investments of <$25 million.
- Conventional Alternatives: Alternatives in this category include substation and wires-based solutions with tie-lines.
- Non-Wires Alternatives: Alternatives in this category include battery energy storage systems (BESS) and the consideration of demand side management and other distributed energy resources (DERs).
- Hybrid Alternatives: Alternatives in this category include a combination of conventional alternatives and non-wires alternatives. The conventional solutions were chosen based on their ability to meet the 10-year load forecast and then paired with BESS to satisfy incremental capacity needs that develop over time.

Table 3: Alternatives Identified in SCE's Supplemental Analysis	
Alternative	Description
Minimal Investment Alternatives	
Utilizing spare transformer for the Valley South System	SCE has temporarily placed a spare 500/115-kV transformer in service at the Valley Substation to provide an additional level of service to the Valley South System under peak loading conditions or as needed. This alternative would continue the current practice of the mitigation plan.[a] This alternative would also require installation of a new spare 500/115-kV transformer (for a total of six transformers within Valley Substation).
Operating existing Valley South System transformers above normal ratings	SCE's Subtransmission Planning Criteria and Guidelines allow operation of A-bank transformers above nameplate for periods of limited duration. This alternative would utilize the Valley South System transformers above normal ratings (i.e., intentionally operate them above the manufacturer nameplate ratings) to serve load in the Valley South System under peak loading conditions.
Loading-Shedding Relays	This alternative would utilize load shedding to maintain system reliability during stressed system conditions that result from peak load conditions that may exceed the ratings of the Valley South System transformers.
Conventional Alternatives	
SDG&E	This alternative includes a new 230/115-kV system looped to the San Diego Gas and Electric (SDG&E) Talega-Escondido 230-kV transmission line. Project components include construction of a new 230/115-kV substation, approximately 9.2 miles of new 230-kV transmission and 115-kV subtransmission lines, and the modification of approximately 7.8 miles of existing 115-kV subtransmission line (17 miles total).
SCE Orange County	This alternative includes a new 220/115-kV system looped to existing San Onofre Nuclear Generating Station-Viejo 220-kV transmission line. Project components include construction

	of a new 220/115-kV substation and approximately 30 miles of new 220-kV transmission and 115-kV subtransmission lines.
Menifee	This alternative includes a new 115-kV system looped to SCE's existing Serrano–Valley 500-kV transmission line. Project components include construction of a new 500/115-kV substation, approximately 5.5 miles of new 500-kV transmission and 115-kV subtransmission lines, and the modification of approximately 7.7 miles of existing 115-kV subtransmission line (13.2 miles total).
Mira Loma	This alternative includes a new 220/115-kV system looped to existing 220-kV transmission lines serving the Mira Loma Substation. Project components include construction of a new 220/115-kV substation and approximately 22.2 miles of new 220-kV transmission and 115-kV subtransmission lines.
Valley South to Valley North	This alternative includes a new 115-kV line and transfers Newcomb and Sun City Substations to the Valley North System. Project components include construction of approximately 5.9 miles of new 115-kV subtransmission line and the modification of approximately 7.7 miles of existing 115-kV subtransmission line (13.6 miles total).
Valley South to Valley North to Vista	This alternative includes a new 115-kV line, transfer Newcomb and Sun City Substations to the Valley North System, and transfer Moreno Substation to Vista 115-kV System. Project components include the construction of approximately 15.9 miles of new 115-kV subtransmission lines and modification of approximately 7.8 miles of existing 115-kV subtransmission line (23.7 miles total).
Non-Wires Alternatives	
Centralized BESS in Valley South	This alternative would reduce peak demand in the Valley South 500/115-kV System via construction of two new 115/12-kV substations with BESS near Pechanga and Auld Substations, which would loop in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.
Hybrid Alternatives	

Valley South to Valley North and Distributed BESS in Valley South	This alternative includes a combination of the Valley South to Valley North Alternative as described under *Conventional Alternatives* and construction of new energy storage components (distributed BESS) within the existing fence lines at three existing SCE 115-kV substations.
SDG&E and Centralized BESS in Valley South	This alternative includes a combination of the SDG&E alternative as described under *Conventional Alternatives* and construction of one new 115/12-kV substation with BESS near Auld Substation with a loop-in of the Auld-Moraga #1 line.
Mira Loma and Centralized BESS in Valley South	This alternative includes a combination of the Mira Loma alternative as described under *Conventional Alternatives* and construction of two new 115/12-kV substations with BESS near Pechanga and Auld Substations, which loop in to the Pauba-Pechanga and Auld-Moraga #1 lines, respectively.
Valley South to Valley North and Centralized BESS in Valley South and Valley North	This alternative includes a combination of the Valley South to Valley North Alternative as described under *Conventional Alternatives* and construction of a new 115/12-kV substation with BESS that would be installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line, and a second BESS installed at Alessandro Substation, to offset a portion of the load that is transferred from the Valley South to Valley North System.
Valley South to Valley North to Vista and Centralized BESS in Valley South	This alternative includes a combination of the Valley South to Valley North to Vista Alternative as described under *Conventional Alternatives* and construction of a new 115/12-kV substation with BESS installed near Pechanga Substation with a loop-in of the Pauba-Pechanga line.

Note:

(a) A standby spare 500/115-kV transformer was installed at the Valley Substation in 2011; the spare transformer provides backup transformer capacity in the event of transformer failure at Valley Substation. The spare transformer was installed to comply with SCE's internal *Transmission Planning Criteria and Guidelines*. These guidelines state that all 500/115-kV substations have an on-site three-phase spare transformer available for use in the event of transformer failure. If electrical demand exceeds the operating limits of the existing equipment of the Valley South 115-kV System before the proposed Alberhill Project is operational, the spare transformer will be temporarily put into service as a contingency plan (Valley–Ivyglen 115-kV Subtransmission Line and Alberhill System Projects FEIR 2017).

1.4 SCE's Proposed Alberhill Project Supplemental Analysis Findings

In the Detailed Justification of the Recommended Solution, SCE recommends the proposed Alberhill Project as the best solution to meet the needs of the Valley South System (SCE 2021, Item I). SCE states that the supplemental information filed in the amended application and PEA and subsequent revisions show that the proposed Alberhill Project is superior to all other alternatives in meeting the Project Objectives detailed in SCE's proposed Alberhill Project application. This conclusion is based on:

1. The proposed Alberhill Project's superior performance in meeting identified capacity, reliability, and resiliency needs over both near-term and long-term horizons, as measured by a set of objective system performance metrics;
2. The cost effectiveness of the proposed Alberhill Project as demonstrated in a cost-benefit analysis;
3. Consideration of option value and risk by evaluating the sensitivity of results to uncertainty and volatility in future load growth and alternative DER development and cost scenarios; and
4. Challenges with implementation of alternatives other than the proposed Alberhill Project to meet imminent near-term needs.

Overall, SCE contends that the proposed Alberhill Project is a cost-effective, robust solution that limits the risk of service disruptions to SCE customers during normal and abnormal electrical system events or conditions and minimizes risk of potential delays in implementing an adequate system solution (SCE 2021, Item I, Exhibit I-1).

1.5 Purpose of the Energy Division Staff Report

As directed in the September 2020 Assigned Commissioner's Ruling Amending Scoping Memo, the Energy Division, with support from WSP USA Inc., formerly Ecology and Environment, Inc. (WSP), and Kevala, Inc. (Kevala), undertook a review of SCE's amended PEA and any other relevant matters pursuant to CEQA as the procedural next step in the proceeding. The Energy Division analyzed data provided by SCE in the supplemental information filed in the amended application and PEA, subsequent revisions, and in response to data requests made in 2020 and 2021. The purpose of this Energy Division Staff Report is to provide an independent evaluation of the SCE supplemental analysis and materials provided to the CPUC as part of their response to Decision (D.) 18-08-026. This report details the review and analyses the Energy Division has conducted to date and staff recommendations derived from that review. Table 4 summarizes the analyses conducted and presented in this Energy Division Staff Report. A summary of each report's methodologies and findings are included in Sections 2 through 7 of this Energy Division Staff Report, and the reports in their entirety are included in the appendices for reference.

Table 4: Energy Division Staff Report Analyses		
Energy Division Staff Report Section	Report	Description
2	Preliminary Results: Tie-Line Power Flow Analysis	Analyzes the necessity of the Valley South tie-lines proposed by SCE.
3	Evaluation of SCE's Load Forecast Methodologies and Performance Metrics	Evaluates SCE's methodology and performance metrics used to evaluate the proposed Alberhill Project and its alternatives.
4	Behind-the-Meter Adoption Propensity Analysis for the Valley South System	Applies technological and economic parameters to SCE data to assess the potential likely adopters of behind-the-meter resources.
5	Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System	Expands on findings from the Behind-the-Meter Adoption Propensity Analysis to evaluate impact of distributed energy resources adoption on the load forecast.
6	Review of SCE's Electrical Engineering Analysis for the Alberhill System Project	Electrical engineering analysis on system reliability and expansion on the tie-lines assessment.
7	Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project	Results of an integrated time-series benefit-cost analysis for the proposed Alberhill Project.

A separate proposed Alberhill Project Supplement to the Alternative Screening Report (ASR) is being developed by the Energy Division. Pursuant to CEQA, the Supplement to the ASR supplements the 2017 revision of the ASR by evaluating the alternatives identified by SCE in the supplemental information filed in the amended application and PEA and subsequent revisions. The development of the Supplement to the ASR is ongoing and will be released separately to this Energy Division Staff Report.

2 Preliminary Results: Tie-Line Power Flow Analysis

2.1 Methods of Investigation

As part of the proposed Alberhill Project, SCE stated that tie-lines are a necessary requirement for the project (see Figure 1). Kevala's tie-line analysis considered whether the Valley South tie-lines proposed by SCE as part of the proposed Alberhill Project were necessary to achieve system capacity, reliability, and resiliency in the Valley South service area.

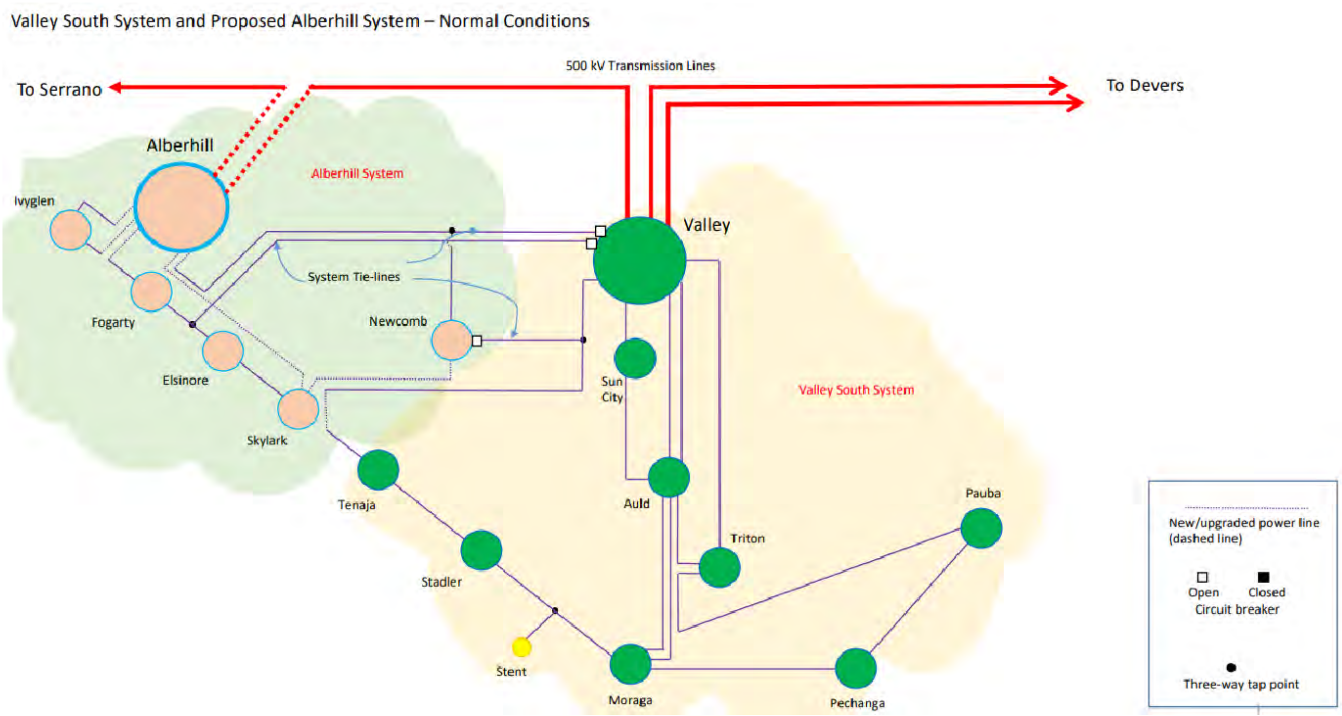


Figure 1: Proposed Alberhill Project Tie-Lines (Proposed Alberhill Project Energy Division Briefing Deck 2018)

To assess how the tie-lines that are proposed as part of the proposed Alberhill Project perform with respect to capacity, reliability, and resiliency, several base cases representing scenarios were studied. These scenario cases represented alternatives that include tie-lines in the Valley South System, distributed battery energy resources, and centralized BESS. This approach enabled comparison of the base case, which represents the Valley South System as it exists today without any new projects or tie-lines, with the following scenarios:

- System performance with the installation of additional tie-lines.
- System performance with the installation of battery energy storage.
- System performance with combination installation of tie-lines and energy storage.

Power flow studies were conducted for each of these scenario cases and the results were compared under normal conditions and contingency conditions based on North American Electric Corporation (NERC) reliability standards.[2]

Using the General Electric Positive Sequence Load Flow software and base cases, power flow studies were conducted under normal and contingency conditions. Single contingencies[3] and double contingencies,[4] where the circuits were on the same tower or in the same ROW, were used to study contingency conditions. The contingencies were obtained from the *Quanta Technical Cost Benefit Analysis of Alternatives* report. The results were assessed based on NERC reliability standards and SCE planning criteria. Power flow results under each of the base cases were compared to assess what impacts the tie-lines have on reliability and resiliency at Valley South Substation. Power flow results obtained for the Valley South (Base) scenario were used as a basis for comparing impacts.

2.2 Results of Report

The findings of this assessment were as follows:

- Tie-lines that transfer substation service from the Valley South to Valley North are effective in mitigating the overload on the Valley South transformers and meet reliability and resiliency requirements. SCE has concluded that the tie-lines in the Valley South to Valley North Alternative are ineffective under double contingencies or a catastrophic event that results in a loss of both transformers in the Valley South System. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted, and the power flow results indicated that this alternative performed effectively.

[2] While SCE's Valley 115-kV system is part of SCE's distribution network and not under the California Independent System Operator (CAISO) control, its reliability performance must still be consistent with general accepted utility practices which are based on NERC Reliability standards. Parts of the NERC reliability Standards are adopted in SCE's Subtransmission Planning Criteria which require that all facilities operate within their continuous ratings under normal system conditions and under emergency ratings under contingency conditions.

[3] Single Contingency (N-1): considers the loss of a single element (a generator or transmission component) in a power system.

[4] Double Contingency (N-1-1): considers the sequential loss of a single element (a generator or transmission component) in a power system, followed by system adjustments, then followed by another loss of an element in a power system.

- It appears that SCE applied a mitigation strategy or special protection scheme (SPS)[5] to the proposed Alberhill Project to demonstrate the effectiveness of the tie-lines included as part of the proposed Alberhill Project. Use of this mitigation strategy alleviates the overload on the Auld-Moraga 115-kV #1 line, which experiences an overload under all configurations, including the current configuration, proposed Alberhill Project, and the alternatives.
- Transferring service for two substations (Newcomb and Sun City) via 115-kV tie-lines to the Valley North System and installing 50 megawatts (MW) of distributed BESS in the Valley South System could also mitigate this overload as effectively as the proposed Alberhill Project while meeting capacity, reliability, and resiliency requirements. This alternative satisfies part of the CPUC's objective to enable electrical service redundancy between the Valley South and a new 115-kV system. The difference is that these tie-lines enable electricity service from the existing Valley North System or from the Valley South System and would achieve the same performance.

As discussed above, it is unclear from the record of SCE's analysis whether SCE applied mitigation strategies and to which alternatives. Selectively applying mitigation strategies to certain alternatives without substantiation of the rationale for doing so can create an unequal comparison between alternatives. Understanding, on the record, SCE's basis for applying a mitigation strategy to the proposed Alberhill Project as opposed to some of the alternatives is important to evaluate how each of the alternatives supports the reliability, resiliency, and capacity needs described by SCE.

See Appendix B, Preliminary Results: Tie-Line Power Flow Analysis (Kevala 2021a), for the complete report.

2.3 Expanded Discussion

Section 2.1 and 2.2 provided a summary of Kevala's tie-line power flow analysis in the Alberhill System Project Draft Staff Report of November 2021 (Draft Staff Report). This section expands on information noted in Sections 2.1 and 2.2 to clarify and incorporate additional information from SCE.

Section 2.1 notes that the results of Kevala's tie-line analysis results were assessed based on NERC reliability standards and SCE planning criteria. The radially operated 115-kV subtransmission component of the Valley South System is not part of the bulk electric system subject to California Independent System Operator (CAISO) authority because it is "used in local distribution of electric energy" pursuant to section 215 of the (153 Federal Energy Regulatory Commission ¶ 61,384). Therefore, SCE is not required to comply to NERC reliability standards and (WECC) criteria for operation of the Valley South 115-kV system. SCE is required to adhere to the SCE Subtransmission Planning Criteria and Guidelines (SCE 2015) and fulfill its obligations of Public Utility Code 451.

[5] NERC defines SPS as an automatic protection system designed to detect abnormal or predetermined system conditions and take corrective actions other than or in addition to the isolation of faulted components to maintain system reliability.

SCE Subtransmission Planning Criteria and Guidelines require examination of unlikely contingencies that could result of loss of load. SCE's planning criteria largely align with the NERC reliability standards. The NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structures), local area events and wide-area events (NERC n.d.), which is analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios" (SCE 2023a) including Flex-1, Flex-2-1, and Flex-2-2. The NERC standards expect system operators and planners, such as SCE, to craft specific system performance metrics that are rooted in transmission system planning event analysis, such as those presented by SCE.[6] Their meaning, use, and purpose are covered in detail in SCE presentations and data request responses provided to CPUC staff since their originally-filed reports (NERC n.d.). Kevala's assessment of SCE's system performance metrics is shown in Section 3, and Kevala specifically explained this further in the March 2022 workshop (SCE 2022a, 18). In this workshop, Kevala noted that "because of the heavy weighting of tie-lines by the metrics, the tie-line power flow analysis was conducted based on NERC reliability standards and WECC criteria to understand how much the metrics weight the prioritization of [the Alberhill System Project]and its alternatives." Energy Division's learnings on this topic since the release of the Draft Staff Report are documented in Section 2.4 below.

SCE did not specify in their original Planning Study the way the transfer of load from Valley South to the proposed Alberhill Project would occur in the event of an Auld-Moraga #1 overload. Based on the review of SCE's studies, Kevala considered the ability of the proposed Alberhill Project to reconfigure its system under outage conditions to be an SPS, at that time. To provide an equal basis for comparison between other projects that did not include, what at that time was believed to be, the benefit of an SPS, that transfer was excluded from Kevala's study.

The Kevala system tie-line analysis (Appendix B) evaluated tie-line function for forecasted load in 2025. SCE conducted additional loads at risk evaluations for the forecasted load in 2028 (i.e., the 10-year project horizon) and for the period ending in 2048.

As detailed in Section 2.2, the primary result of the approach of excluding the tie-line transfer is that Valley South to Valley North Alternative with 50 MW of DBESS[7] (SCE Project I) produced very similar results to the proposed Alberhill Project (see Appendix A in SCE 2021, Item G). Kevala concluded that in relation to the proposed Alberhill Project, Project I satisfies the guideline for all facilities in service (N-0) as well as likely contingency (i.e., one subtransmission line out of service [N-1]) and unlikely contingency for two subtransmission lines out of service on common structure (N-2). This conclusion is based on information and assumptions as presented by SCE in its original proposed project and subtransmission power flow data provided to Energy Division by SCE (SCE 2020a, 2020b). Energy Division studied General Electric's

[6] Multiple CPUC proceedings, such as R.19-09-009, are exploring defining appropriate resiliency scenarios and definitions that may apply to distribution planning in the future, however none have been formally established by the CPUC at this time.

[7] For this report, distributed BESS refer to utility-scale BESS sited at multiple locations around a given region as opposed to one larger and centralized utility-scale BESS being sited at one location.

Positive Sequence Load Flow (PSLF) base cases that were modeled on the data Energy Division requested from SCE in CPUC Supplemental Data Request 6, dated September 16, 2020 (SCE 2020c). Following the release of the Draft Staff Report, further discussions on this topic in 2022 resulted in updated conclusions that are described in Section 2.4.

2.4 Subsequent Findings

Following the release of this Draft Staff Report, SCE provided follow-up on key points in the report via written comments and technical forums[8] that provided SCE with the opportunity to clarify certain elements of its original proposed Alberhill Project, as follows:

- SCE has clarified that the portion of the Valley South radial 115-kV subtransmission is not required to meet NERC reliability standards because these facilities are not part of the CAISO controlled bulk electric transmission system. As noted above in Section 2.3, while SCE's planning criteria largely align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which are analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios" including Flex-1, Flex-2-1, and Flex-2-2 (SCE 2023a, 6).
- Since the Draft Staff Report, SCE clarified that it did not explicitly perform N-1 loss of single transformer contingencies in their Planning Study. SCE commented that the N-1 transformer study was integrated within the Flex 2-2 case. Because of this finding that the SCE Planning Study did not explicitly perform these contingencies, Energy Division and SCE agreed to perform the following actions:
    - In Response to CPUC Supplemental Data Request 011, Question DG-MISC-80, SCE provided data on the impact of N-1 transformer outages on each project alternative and further clarified the method for this determination in the January 2023 Follow-up to this data request (SCE 2023b). Kevala reviewed this data request and follow-up and independently verified the data provided and method of calculation. It should be noted that the quantification of Load at Risk (LAR) in this data request followed a different methodology than the Flex Case 2-2, which means that the LAR values produced cannot be directly compared to the Planning Study results.
    - In June 2022, SCE presented a study (documented in SCE 2022b) to CPUC staff and subconsultants that discussed estimated battery sizes for a Valley South to Valley North Alternative centralized BESS configuration that would be sized to address transformer N-1 contingencies. This additional study indicates that a BESS size of 168 MW without static synchronous compensator (STATCOM) or 158 MW with STATCOM was required to

[8] Technical forums (SCE 2022a, 2023a, and 2022b) were held during 2022 and attended by SCE, CPUC, and CPUC subconsultants (including Kevala). The materials presented in these forums are entered into the record via subsequent data requests.

address the transformer N-1 contingencies, which were previously not studied in SCE's planning studies. BESS sizing was performed for the year 2031, as this is the final year of SCE's current 10-year planning horizon (covering the years 2022 to 2031) (SCE 2022b). Kevala found that the PSLF modeling and the associated results demonstrated in SCE's August 30, 2022, presentation were qualitatively reasonable and in alignment with the results previously shared via data requests and prior presentations for each case and variation.

- Section 2.2 noted that the Valley South to Valley North Alternative line and installation of 50 MW of distributed BESS in the Valley South System could mitigate the Auld-Moraga #1 line overload as effectively as the proposed Alberhill Project while meeting capacity, reliability, and resiliency requirements. The Quanta study from June 2022 demonstrates that the required BESS size should be 168 MW without STATCOM or 158 MW with STATCOM, when transformer N-1 contingencies are considered. The necessary BESS sizing is much greater than the 50 MW considered in the Draft Staff Report.
    - Kevala agrees that this BESS (168 MW without STATCOM or 158 MW with STATCOM) alternative solution does not achieve the same performance as the proposed Alberhill Project. For example, the Valley System is islanded and served from a single point of delivery to the bulk power system, a vulnerability which addition of BESS would not alleviate. In a contingency where Valley Substation loses its source of supply, both Valley South and Valley North would lose power. The battery energy storage system would have no way to recharge after it discharges during such a contingency event.
- In the Planning Study, SCE does not specify the way the transfer of load from Valley South to proposed Alberhill Project would occur to remedy an Auld-Moraga #1 overload in the event of a contingency. SCE clarified in the Draft Staff Report comments that this transfer of load would be a manual action, as opposed to an automated scheme (SCE 2022c). Because of this learning that this transfer of load would be a manual action, the following conclusions were determined in 2022:
    - Based on the NERC definition of an SPS (NERC 2013), this transfer of load from Valley South to the proposed Alberhill Project is not an SPS because it is performed manually. Kevala interprets this manual transfer specification for the proposed Alberhill Project as being common practice for SCE when a tie-line transfers load.
    - In the Draft Staff Report comments, SCE states that addressing the Auld-Moraga #1 overload "is not a project objective of the ASP and in the near term, the Auld-Moraga #1 overload can be addressed by simply reallocating distribution load with load transfers using circuit ties between existing distribution circuits and substations" (SCE 2020a, 2020b). This distinction from SCE clarifies the original filing: that the proposed project and alternatives handled this overload either by tie-line transfer or reconductoring of the Auld-Moraga #1 line, rather than reallocation of distribution load with load transfers.
    - The Appendix B power flow study, completed by Kevala in April 2021, concluded that that tie-lines were effective at resolving double-line contingencies, which differed from the results

of SCE's Planning Study. SCE's Planning Study concluded that tie-lines would not be effective in resolving double contingencies or a catastrophic loss of both transformers in the Valley South System. As previously discussed in Section 2.3, Kevala assumed that tie-line transfers occurring were an SPS and so excluded those transfers from the power flow study. This exclusion and evaluation for different forecast years fundamentally altered the results of the power flow study, creating the difference between the Kevala and SCE conclusions.

- As supplemental analysis to the April 2021 power flow study (Appendix B), SCE and Energy Division validated load transfer capability of several alternatives during an N-1 loss of single transformer through a shared power flow model demonstration. This analysis confirmed that the Valley South to Valley North project alternatives, such as the alternatives defined in the Response to CPUC Supplemental Data Request 013, Question DG-MISC-82 (SCE 2022d), could not transfer meaningful amounts of load during such a contingency to avoid a substantial outage (SCE 2022b).
- SCE demonstrated that the Valley South to Valley North project alternatives are less effective in their ability to transfer load via system tie-lines compared to proposed Alberhill Project. Staff noted that some project alternatives accumulated more LAR due to N-1 loss of subtransmission line compared to the proposed Alberhill Project during years 2028 to 2048. The basis for the differences in LAR accumulations at year 2048 are attributable to the designs of the solutions. Every derivative of the Valley South to Valley North alternatives may experience a future Subtransmission line overload after 2028. Under those conditions, each of those Valley South to Valley North project alternatives is only able to transfer load that was being served in the northern part of the Valley System. Most of the N-1 subtransmission line overloads occurred farther downstream in the system. Under the same conditions, the proposed Alberhill Project can transfer loads of three additional distribution substations (i.e., Tenaja, Stadler, and Stent) to avoid loss of load and experience less LAR than all Valley South to Valley North alternatives (SCE 2022e).[9] These results reflect the performance of the project alternatives based on their design.[10]
- In consideration of the changed understanding of the nature of the load transfer, discussed above, Energy Division staff concludes that Valley South to Valley North and Centralized BESS (CBESS) in Valley South and Valley North) would not be effective at resolving double contingencies nor catastrophic events that results in a loss of both transformers in the Valley South System.

[9] See slide 66.

[10] In Response to CPUC Supplemental Data Request 014, Question DG-MISC-84, SCE states on page 4: "On slides 57 and 58 of SCE's August 30, 2022 presentation, the intent was only to demonstrate that the overload on the Auld-Moraga #1 line during an outage of the Auld-Moraga #2 line would not be solved by using the system tie-line capacity of the Valley South to Valley North alternatives and that the overload could be remedied by upgrading the conductor of the Auld-Moraga #1 line."

3 Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

3.1 Methods of Investigation

Kevala assessed SCE's load forecasting methodology and performance metrics for the proposed Alberhill Project and alternatives. To conduct this evaluation, Kevala reviewed SCE's Revised Planning Study (SCE 2021, Item C) and the Quanta Technology (Quanta) reports released by SCE in their February 1, 2021, Amended Motion to Supplement the Record as well as researched and analyzed the load forecasting methodologies used by the California Energy Commission, Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E). These methodologies were then compared to those utilized by SCE for evaluation.

3.2 Results of Report

The findings of this assessment were as follows:

- The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and SDG&E. Some metrics used by SCE, such as LAR, were not being practiced by other utilities in the industry. The Loss of Load Expectation (LOLE) metric is a commonly used metric in the industry. Both LOLE and LAR are comparable in that they account for loss of load. The LOLE metric calculates the expected average number of days per year during which the load exceeds available generating capacity due to outages or other system conditions. In contrast, the LAR metric calculates the energy in megawatt hours (MWh) potentially at risk of not being served due to a variety of system conditions under normal and contingency conditions.
- Although some of the metrics were uncommon, the overall performance metrics developed by SCE have sufficient basis in other metrics commonly used by utilities, such as LOLE. Research of typical performance metrics by comparable utilities revealed no examples of utilities using LAR as a performance metric nor was it discussed in research papers as a performance metric. Additionally, a survey of other projects under CEQA review did not uncover projects using these metrics. It was not clear why SCE used less common metrics. Overall, however, the metrics and methodologies SCE used were reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.
- Prior to choosing LAR as the primary performance metric, SCE used Expected Energy Not Served (EENS). Only one utility had used the EENS metric (British Columbia Hydro in Vancouver, British

Columbia). All other publications that used EENS as a performance metric were research and academic publications.

See Appendix C, Evaluation of SCE's Load Forecast Methodologies and Performance Metrics (Kevala 2021b), for the complete report.

3.3 Subsequent Findings

Following the release of this Alberhill System Project Draft Staff Report in November 2021, SCE followed up on key points in the report via written comments and technical forums that presented follow-on studies and clarifications. The findings of these documents and presentations were as follows:

- Section 3.2 in the Draft Staff Report assessed the performance metrics used by SCE, including LAR. Since the release of the Draft Staff Report in November 2021, SCE provided further context around their selection and use of LAR in technical discussions throughout 2022. During a technical session that occurred on May 4, 2022, SCE detailed and explained the selection of LAR criteria, citing the need for a metric that compared cost effectiveness of projects (SCE 2023a). These comparison criteria included a metric that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration (SCE 2023a, 7).
- SCE considered LAR, EENS, and metrics commonly used in resource adequacy studies such as LOLE (SCE 2023a, 8–10). Of these metrics, SCE preferred LAR, which they defined as "total load required to be curtailed during periods of time in which subtransmission operating criteria were not met," and EENS, which they defined as "LAR that is probability-weighted for specific events and scenarios" (SCE 2023a, 8).
- The probabilities SCE used for an extreme event that results in loss of service at the Valley Substation for the EENS metric calculation were also discussed extensively (SCE 2022b). Due to lack of an industry standard for appropriate probabilities for contingency events to occur, the additional analysis of Valley South to Valley North with a CBESS and a STATCOM were shown with LAR values calculated but not EENS values.

4 Behind-the-Meter Adoption Propensity Analysis for the Valley South System

4.1 Methods of Investigation

Kevala conducted a behind-the-meter (BTM) adoption propensity analysis to identify the likely levels of adoption of BTM storage and photovoltaic (PV) systems in the Valley South area given economic and technological parameters. Using its Network Assessor platform, Kevala analyzed BTM DERs adoption propensity in support of the CPUC with the goal of determining whether DERs, beyond those included in the base assessment by SCE, might reduce the magnitude and duration (i.e., shape of the need) or the viability of certain proposals.

This analysis is a techno-economic approach to identify economically feasible adoption of BTM resources at the customer-sited level (i.e., at existing residential and commercial and industrial parcels). BTM resources include solar plus storage and storage-only systems. The propensity for adoption of BTM resources is based on an individual customer's load profile, the payback period for the investment in BTM resources, Value of Lost Load, and other factors. The analysis included evaluation of full 8,760 time-series hourly load profiles (i.e., 365 days times 24 hours per day) for approximately 102,000 customer meters.

Kevala used its proprietary Network Assessor platform to ingest data provided by SCE and run analytics related to grid infrastructure, load, generation, and price. Specifically, the advanced metering infrastructure (AMI) data was used for the rates analytics and the storage algorithm within the Network Assessor platform. These ultimately identified economically efficient BTM adoption customers under five different scenarios for residential customers and three different scenarios for commercial and industrial customers.

4.2 Results of Report

There is considerable potential for BTM resource adoption across the Valley South area. The findings indicate that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the Scenario 4 (four outages at 1 hour duration) adoption propensity for residential customers as shown in Table 5 below. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery as shown in Table 6 below. These scenarios model different levels of adoption and indicate that with incentivization, it would be economically efficient for this amount of DERs to be interconnected.

See Appendix D, Behind-the-Meter Adoption Propensity Analysis for the Valley South System (Kevala 2021c), for the complete report.

Table 5: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers	4%	8%	21%	49%	82%
Sum of Total Photovoltaic (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610

Key:

BESS = distributed battery energy storage system

BTM = behind-the-meter

MW = megawatts

MWh = megawatt hours

4.3 Expanded Discussion

Sections 4.1 and 4.2 of the Draft Staff Report provide background and summary of Kevala's BTM adoption propensity analysis. The CPUC's Independent Professional Engineer prepared clarifying questions about this portion of the work and reviewed them with Kevala on February 16, 2022. The responses to those questions are summarized below and include further detail on Kevala's initial study. This discussion includes input on how to contextualize Kevala's BTM adoption propensity analysis, further detail on Kevala's Network Assessor platform and associated analytical tools, the outage scenarios considered, and further detail on how SCE rates were considered in the analysis.

4.3.1 Contextualizing Analysis Results

Kevala's BTM adoption propensity analysis was a sensitivity analysis and was not meant to provide alternate solutions. The total number of customers and resulting solar and storage sizes indicated does not mean that each customer would purchase a system in a real setting. The study provided a sensitivity analysis around the *potential* for commercial and industrial (C&I) and residential customers to adopt PV and BTM storage under specific economic incentives.

This study defined economically efficient BTM adoption as the value yielded by a PV and storage system (or storage only) supported by current policies and incentive structures. This definition is consistent with those used by the CPUC in the 2019 to 2020 integrated resource planning process within a defined payback period. The size of the system was optimized based on this payback period and 2019 historical AMI data providing the customer demand profile at the customer level (i.e., shape of need). This translates to the study providing a defined number of customers economic benefit to adopt one of these systems if SCE were to offer an annual incentive depending on the outage use case. Section 4.2 summarizes the amount of residential solar, residential storage, and C&I storage that Kevala's BTM adoption propensity analysis indicated would be economically efficient.

- Given that Kevala's analysis was a sensitivity analysis meant to determine economically efficient BTM adoption, the amount of solar and storage summarized in Section 4.2 is not meant to represent alternative solutions to be compared directly to alternatives in SCE's studies (SCE 2023a). Two limitations of this portion of the study and its results are noted below: Kevala's analysis only considered passive systems, which means that the batteries were not assumed to be dispatchable. Operational performance requirements satisfying the need to schedule BESS operation with the ability to meet charging and discharging needs based on the full historic 2019 customer AMI profile were out of scope of the assessment. While the amount of solar and storage in Kevala's analysis is estimated to be economically efficient, these sensitivity scenarios were not evaluated for their ability to be dispatched to meet a system need.
- On page 18 of the "Comments to the Draft Energy Division Staff Report for the Alberhill System Project" (January 27, 2022), SCE provides their perspectives on the challenges related to BESS operation (SCE 2022c). SCE points out concerns around implementing a large-scale BTM DER Alternative as it would require the utility to obtain additional monitoring, control, and cybersecurity infrastructure. They highlight that the industry has never implemented a BTM BESS solution at the scale that Kevala's analysis indicates would be economically efficient. This reaffirms the status of Kevala's study as a sensitivity analysis rather than an alternative for comparison to project alternatives presented in SCE's studies (SCE 2023a).

4.3.2 Kevala Network Assessor Platform and Associated Analytical Tools

To complete the BTM adoption propensity analysis, Kevala used its Network Assessor platform to ingest data provided by SCE and run advanced analytics related to grid infrastructure, load, generation, and price. At a high level, Kevala's Network Assessor platform ingests and employs data across three key areas: load, generation, and infrastructure. Additional details about this analysis method are provided in Kevala's Behind-the-Meter Adoption Propensity Analysis for the Valley South System report (Kevala 2021c).

- **Load:** Kevala ingested SCE-provided meter data for the year 2019 to create an 8760 time-series load profile for each premise in SCE territory.
- **Generation:** Kevala used generation data for SCE at both the bulk-power level and for DERs, including generator nameplate capacity and associated feeder. These data were used to estimate local energy supply and forecasted production profiles.
- **Infrastructure:** Kevala used SCE-provided geospatial files on electric infrastructure.

To detect existing residential PV system locations and estimate installed capacity, Kevala used an internal proprietary tool called "Sun Spot." Parcel data were used to determine primary usage by identifying the customer type, building footprint, and load, but the tool did not calculate roof space, roof direction, or individual location shading. A standard direction, tilt, and azimuth was used for adoption propensity across all systems.

4.3.3 Outage Scenarios and Approach

The outage scenarios considered for the residential and C&I studies were based on SCE's value of service study where values of service associated with specific outage definitions are provided (referenced specifically according to the use case below). This study then incremented the number of outages corresponding to the specific definition being studied to maintain the use of the value provided. The result is a sensitivity that provides an adoption forecast based on the number of outages. This study with results including a sensitivity that provides an adoption forecast based on the number of outages can facilitate additional study based on this further detail about outages in the region. Note that these are short duration outages of 1 hour and not the extended outages that SCE considered for other project alternatives, such as through the Flex-2-1 and Flex-2-2 metrics (SCE 2021, Item C.)

For residential customers, Kevala mimicked SCE's approach to monetizing outages. The document states that use of a 1-hour outage stems from "SCE's practice to minimize the impact of an extended outage to any single customer by periodically rolling the outages within the system" (SCE 2021, Item C, 65). This meant applying the Value of Service (VOS) of $9.47/kWh for residential customers based on a 1-hour outage (SCE 2021, Item C, Table 8-4). VOS represents the overall impact to customers on the system, or the estimated monetary value to unserved customer load. Mimicking SCE's approach here captures the potential for new customers to adopt solar plus storage systems and the potential for existing residential solar owners to adopt an incremental BTM storage system. Five scenarios of quantity and duration of annual outages were considered, including:

1. No outages
2. 1 outage, 1 hour duration
3. 2 outages, 1 hour duration
4. 3 outages, 1 hour duration
5. 4 outages, 1 hour duration

Kevala examined the potential for C&I customers without existing DER to adopt new BTM storage systems with the incentive to reduce demand charges. This part of the analysis aimed to align the value of loss load (VOLL) outage scenarios with SCE's own outage scenarios. VOLL is the estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service, or the value to the individual customer adopting a BESS system. A value of $46.95/kWh was used for C&I customers based on a 4-hour outage. Kevala adopted the scenarios presented in SCE's VOS Study (SCE 2021, Item C, Figure 8-1). The scenarios studied for VOLL were:

- **Low Scenario:** Four outages, 4-hour duration each
- **Medium Scenario:** Six outages, 4-hour duration each
- **High Scenario:** Eight outages, 4-hour duration each

Kevala found that, for both residential and C&I customers, as the number of outages increased, the likelihood that a customer would adopt went up. In the case of C&I customers, the number of customers adopting remained constant across the scenarios, but the average payback period did decrease.

4.3.4 Rates

Kevala's Adoption Propensity analysis looked at the likelihood of adopting a resource given a certain set of rates, the CPUC's Self-Generation Incentive Program incentives, and outage scenarios. It did not consider the time it takes for the systems to get installed. The battery costs were fixed in this analysis, approximately $12,600 for total storage system cost with hardware and installation, and did not consider decreasing BESS costs, which made this analysis a conservative assessment of BESS adoption. The analysis also used the lifespan associated with current BESS warranties to inform the lifespan used in the analysis. These lifespans range from 10 to 20 years and the conservative value of 10 years was used. Readoption of BESS end-of-life was not considered. This could provide value (i.e., be facilitated) through the continued utilization of system parts, excluding the battery, to make a subsequent readoption less costly. The selling of these system parts was also not considered.

The assessment considered time-of-use rates for C&I and residential adoption, which assumes customers will shift load to maximize bill savings. In a similar fashion, the outage cases in the study corresponded to maximizing the VOLL with the outage occurring during peak value timing. The same 2019 demand profiles used by SCE for the substations within the Valley South System were used to define the specific shape and magnitude of the demand profiles associated with the outage scenario. These approaches were performed to align with SCE's approach that also used the peak values when assessing the viability of the proposed Alberhill Project and the alternatives.

Table 6: Commercial and Industrial BTM Adoption Propensity

4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	Medium	High
Total Commercial and Industrial Customers	869	869	869
Commercial Customers	869	869	869
Industrial Customers	-	-	-
Total Power (MW)	5.03	5.03	5.03
Total Capacity (MWh)	18.10	18.10	18.10

Key:

BTM = behind-the-meter

MW = megawatts

MWh = megawatt hours

5 Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System

5.1 Methods of Investigation

This report builds on Kevala's prior analysis of potential adoption of BTM solar plus storage in the *Behind-the-Meter Adoption Propensity Analysis for the Valley South System* (Kevala 2021c) report and quantifies the impacts of BTM DER on the load forecasts used by SCE in its support of the proposed Alberhill Project application.

Kevala analyzed how peak loads in this area will change with targeted DER procurement efforts beyond the DER adoption propensity forecasted in the proposed Alberhill Project and its alternatives. The Valley South System load forecast was modified based on the DER capacities determined through the BTM DER propensity analysis. Because SCE peak load coincides with PV system peak production, BESS were utilized for their dispatchability, which enables effective peak load reduction. After determining the new peak loads from the BTM adoption propensity results, power flow analyses were performed to determine the new system impacts, quantifying the peak load reduction based on capacity of DER as modeled in each of the scenarios.

5.2 Results of Report

When power flow analyses were run on the residential BTM adoption propensity scenarios, Kevala noted that the initial load forecasts resulted in a significant number of network violations.[11] The network violations were observed in power flow analyses when the load forecast was reduced by 316 MW (DER adoption levels under Scenario 4). Power flow analyses also indicated that reducing the peak load by 188 MW instead, as modeled under Scenario 3 (see Table 5 above), resulted in a reduction of overloads on the Valley South transformers without high voltage violations. With the addition of voltage regulation equipment, higher penetration levels of DERs could potentially be incorporated into the Valley North and Valley South Systems, further reducing the load beyond 188 MW to 316 MW of DER-driven load reduction.

See Appendix E, Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System (Kevala 2021d), for the complete report.

[11] Capacity and voltage violations based on equipment ratings of the network.

6 Review of SCE's Electrical Engineering Analysis for the Alberhill System Project

6.1 Methods of Investigation

Kevala compared SCE's electrical engineering analysis of the proposed Alberhill Project to power flow study approaches used at similar electric utilities such as PG&E and SDG&E. In addition, Kevala further expanded on the preliminary tie-line analysis documented in the *Preliminary Results: Tie-Line Power Flow Analysis* (Kevala 2021a) report to identify the right sizing of BESS. Power flow studies consist of a numerical analysis of the flow of electric power in the interconnected electrical system, in this case the Valley South System.

To assess how the tie-lines that are proposed as part of the proposed Alberhill Project perform with respect to capacity, reliability, and resiliency, several scenarios (i.e., base cases) were studied using General Electric's PSLF software. These scenario cases represented alternatives that include tie-lines in the Valley South System, distributed battery energy resources, and centralized BESS. This approach enabled comparison to the Valley South System as it exists today without any new projects or tie-lines (i.e., the base case), with the following scenarios:

- Tie-line performance.
- Battery energy storage performance.
- Combination of tie-lines and energy storage.

6.2 Results of Report

Kevala's review found SCE's power flow analysis to be consistent with widely used study approaches. Once SCE obtained results from their analysis, performance metrics developed by SCE were applied to assess and rank the proposed Alberhill Project and its alternatives. Although the SCE-developed metrics were a variation on common industry metrics as described in Section 3, they were found to be reasonable. Consequently, alternatives that included tie-lines were ranked more favorably than alternatives without tie-lines. Moreover, among the projects with tie-lines, SCE favors larger projects (i.e., proposed Alberhill Project) over the smaller projects (i.e., Valley South to Valley North Alternative). Kevala found tie-lines to be beneficial; however, the smaller projects with tie-lines are just as effective as the large projects with tie-lines.

Kevala's power flow analyses found that the Auld-Moraga 115-kV #1 line in the Valley South System experiences overloads following the worst single contingency and the worst double contingency in the Valley South System. This overload is observed with all the power flow cases, including the current configuration of the do-nothing case, the proposed Alberhill Project, and the alternatives. This overload appears unrelated to the proposed Alberhill Project, indicating that a mitigation project or an SPS should be studied to address this overload. As discussed above, selectively applying a mitigation strategy to certain alternatives and not to others without substantiation of the rationale for doing so can lead to an unequal comparison between alternatives. Therefore, understanding SCE's basis for applying an SPS to the proposed Alberhill project as opposed to some of the alternatives is important within the scope of this proceeding and application to evaluate how each of the alternatives supports the reliability, resiliency, and capacity needs described by SCE.

With respect to the expansion on the preliminary tie-line analysis to identify the right sizing of BESS, consistent with the scenario cases discussed above, a 143-MWh centralized BESS that is capable of operating for up to 6.5 hours is the appropriate size to cover the forecasted load peaks at the Valley South Substation over the course of the year under single and double contingencies.

See Appendix F, Review of SCE's Electrical Engineering Analysis for the Alberhill System Project (Kevala 2021e), for the complete report.

6.3 Subsequent Findings

Following the release of the Draft Staff Report, SCE followed up on key points in the report via written comments and technical forums that presented follow-on studies and clarifications. The findings of these documents and presentations were as follows:

- Sections 6.1 and 6.2 discuss sizing of BESS. Through discussions in 2022, SCE shared that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a CBESS was a more realistic consideration. SCE prepared and presented additional analysis that reviewed an alternative that included CBESS paired with a STATCOM. This additional analysis estimated that to satisfy the N-0 and N-1 minimum planning criteria, including the loss of a Valley South transformer, a 168 MW BESS without STATCOM or 158 MW BESS with STATCOM power rating would be required (SCE 2022b).
- Section 6.2 of the Draft Staff Report raised a question about whether an SPS is applied to the proposed Alberhill System Project. As described above in Section 2.4, SCE does not specify the manner in which the transfer of load from Valley South to proposed Alberhill Project would occur to remedy an Auld-Moraga #1 overload in the event of a contingency in their planning study. SCE clarified in the Draft Staff Report comments that this transfer of load would be a manual action, as opposed to an automated scheme (SCE 2022c). Based on the NERC definition of an SPS (NERC 2013), this means that this transfer is not an SPS.

7 Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project

7.1 Methods of Investigation

WSP reviewed SCE's *Benefit-Cost Analysis of Alternatives for SCE's Alberhill System Project* (SCE 2021, Item G) to validate whether the benefit-cost analysis (BCA) for each alternative had been properly conducted, documented, and completed and to document any other findings that would warrant a more detailed review.

Step 1. Review of SCE's BCA(s): Upon review, WSP found the SCE BCA(s) (both the May 2020 SCE Amended Application and PEA and February 2021 SCE Amended Motion to Supplement the Record BCAs and the supporting spreadsheets, *Effective PV Forecast*, *PV Watts Forecast*, and *Spatial Base Forecast*) were not appropriately developed over the actual project timeline and the calculations of the Present Value Revenue Requirement (PVRR) total costs were not shown. While project benefits were treated appropriately in terms of traditional capital analysis ("net present valuation procedures,") project costs were derived through the use of an external program-based ("present value revenue requirement") process. Using this method to compute project costs externally made it unclear whether the total project costs and annual project costs were calculated appropriately. Further, there were no linkages to annual operations and maintenance (O&M) costs included in the Project cost stream (O&M was found in the separate Excel project cost sheet, but not linked to the analysis). In addition, the year the project construction was expected to start and the year benefits would begin accruing were not placed into the timeline correctly. For all alternatives, the project benefits and O&M costs designated within the model were accruing in years before the project was constructed (prior to the facility operational in-service date), thus yielding an erroneous BCA comparison among the alternatives under review.

Accordingly, the tasks described below were undertaken to gain a clear understanding of actual benefits and costs associated with the various alternatives.

Step 2. Implementation of Independent BCA: Using data from the SCE February 2021 BCA and the associated spreadsheets, three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. Each analysis employed integrated appropriately timed benefit streams extending over the respective operational period(s). Total project costs were either based on SCE's PVRR cost or on an appropriately timed Net Present Value of cost streams with and without uncertainty and battery revenues. To evaluate the different cost effects (PVRR or Net Present Value), the resulting net benefits and benefit-cost ratios were compared to those of the SCE February 2021 BCA and associated spreadsheets submission.

All BCAs involved an integrated time series (wherein the time series of the costs and benefits of each alternative were appropriately integrated with their construction and O&M timeline). This procedure adhered to a traditional capital improvement BCA (OMB n.d.; USDOT 2012, 2022).

Step 3: Review of SCE's June 2021 SCE Second Amended Motion to Supplement the Record: WSP examined updates to the SCE BCA spreadsheets submitted as part of the June 2021 SCE Second Amended Motion to Supplement the Record. Specific figures had received some minor SCE edits; these were mostly clerical or in the form of linkages to a database.

7.2 Results of Report

Three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. The analysis also used the revised O&M costs, PVRR construction costs, and benefits (e.g., the four main benefit categories used for monetization are EENS under N-0 normal conditions (i.e., N-0); EENS under single contingency conditions; Flex-1; and Flex-2) of each proposed Alberhill Project alternative (as provided by SCE). WSP then aligned the costs and benefits within a traditional BCA capital analysis in terms of when they would realistically occur (based on the construction schedule and the facility's expected operational in-service date). WSP's analysis continued to use the unaltered SCE annual PVRR cost and benefit streams (these were simply applied to the realistic implementation timeframe described above). The objective was to examine how realigning the data in the time series would affect the final benefit-cost ratios of each alternative and the relative ranking of each alternative in terms of overall net benefits and benefit-cost ratios. In comparing the result with SCE's models, this analysis resulted in a substantial reduction in benefits, cutting benefits by about half. Figure 2 displays a summary of the differences. The differences are mainly due to the timing of benefits in SCE's model (occurring prior to completion of the project facility); however, there is still uncertainty with the PVRR computations, given the calculations were not disclosed by SCE. Also, there is uncertainty in exactly how the O&M costs were incorporated into the total project cost for the same time-series computational reasoning by SCE.

Based on the retiming of benefits beginning to accrue on the appropriate Project in-service date, the most attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by SDG&E (seventh place) and Mira Loma (eighth place).

MIXED BENEFIT COST ANALYSIS - USING "SCE" PVRR COSTS AND CAPITAL ANALYSIS BENEFITS Includes Uncertainty and Battery Revenues *Millions of ($2019 dollars)*									
	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	**SCE PVRR COSTS**	**Capital Analysis Benefits NPV**	**Net Benefits**	**BCR**	**BCR RANK**	**PVRR COSTS**	**Net Benefits**	**BCR**	**BCR Rank**
Valley South to Valley North	$207	$1,106	$899	5.3	1	$207	$2,156	10.4	2
Menifee	$331	$1,702	$1,371	5.1	2	$331	$3,648	11.0	1
VS to VN & Distributed BESS VS	$232	$1,111	$879	4.8	3	$232	$2,165	9.3	3
VS to VN to VST & Cen BESS VS	$289	$1,266	$977	4.4	4	$289	$2,468	**8.5**	6
Valley S to Valley N to Vista	$290	$1,268	$978	4.4	5	$290	$2,470	8.5	7
Alberhill System Project	**$474**	**$1,996**	**$1,521**	**4.2**	**6**	**$474**	**$4,282**	**9.0**	**4**
SDG&E	$453	$1,867	$1,414	4.1	7	$453	$4,001	8.8	5
Mira Loma	$309	$1,214	$905	3.9	8	$309	$2,601	8.4	8
VS to VN & Central BESS VS VN	$367	$1,304	$937	3.6	9	$367	$2,542	**6.9**	10
SDG&E and Centralized BESS in VS	$531	$1,885	$1,354	3.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$560	$1,461	$901	2.6	11	$560	$3,132	5.6	11
Centralized BESS in VS	$525	$1,301	$776	2.5	12	$525	$2,535	4.8	13
SCE Orange County	$747	$1,705	$958	2.3	13	$747	$4,021	5.4	12

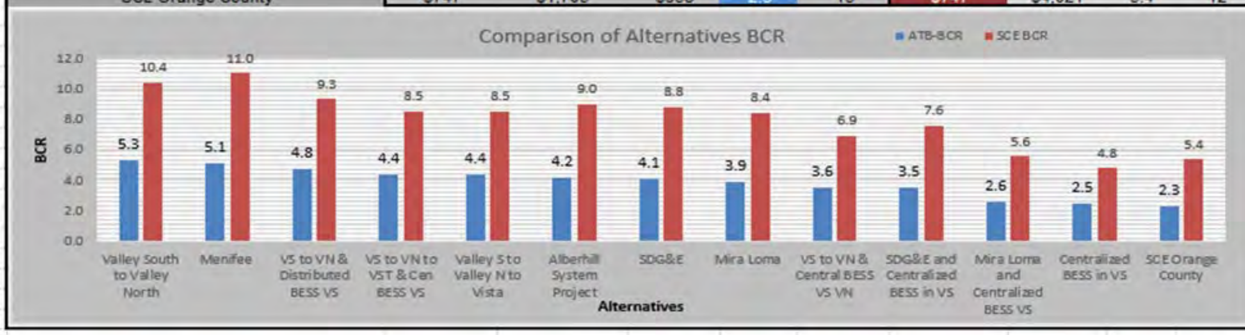


Figure 2: Differences in Independent Capital Analysis BCA and SCE's PVRR Analysis BCA

SCE documentation emphasizes that the proposed Alberhill Project supplies the best solution in meeting the energy needs of the future, based on its reliability performance. This is paramount to the proposed Alberhill Project's attractiveness and ultimately displaced all other alternatives as the preferred alternative. Although the reliability of energy capacity needs may justify the proposed Alberhill Project as the best solution, it is also a very costly solution, at $474 million. In comparison, Valley South to Valley North (first place in terms of WSP's BCA ranking) costs are only $207 million; however, it is unclear how this and other alternative systems would perform giving equal consideration to their cost effectiveness, reliability performance, and capacity over time.

From a purely economic perspective, other alternatives could be explored, possibly including incremental implementation. For instance, the equivalent monetary investment of two smaller-scaled systems (i.e., similar to the scale of the Valley South to Valley North Alternative) might be installed, providing a short-term energy solution (say over 5 to 10 years), saving $60 million dollars in upfront costs. CPUC held additional technical forums with SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including smaller-scaled systems such as the Valley South to Valley North Alternative. SCE performed preliminary analysis of the transformer N-1 contingency (SCE 2022b). SCE's study looked at various configurations of CBESS in combination with Valley South to

Valley North connections to calculate the CBESS size requirements. See Section 3 for additional information on the results of this analysis from a technical perspective.

The three primary metrics evaluated in the SCE economic analysis were the benefit-cost ratio, the reliability score, and the annual capacity (in megawatt hours) produced versus need. These three factors were used by SCE as the criteria by which all alternatives should be evaluated. This led SCE to identify the proposed Alberhill Project as the favored solution, primarily because it meets required future megawatt needs and was deemed the most reliable solution.

WSP examined updates to the SCE BCA spreadsheets submitted as part of the June 2021 SCE Second Amended Motion to Supplement the Record. Additionally, WSP requested and received tracked changes versions of the spreadsheets. Initially, the proposed Alberhill Project and the Valley South to Valley North Alternative were reviewed for impacts influencing the bottom-line benefit-cost ratios or net benefits (February 2021 SCE Amended Motion to Supplement the Record spreadsheets were compared to the June 2021 SCE Second Amended Motion to Supplement the Record spreadsheets).

WSP found for most alternatives, while certain underlying inputs (figures in interior cells) were slightly changed, they were not changed to an order of magnitude that would affect the integrated time-series BCA results documented above. Project costs for all alternatives remained unchanged. However, for the Menifee Alternative, the changes in the benefit cells resulted in a 6.4 percent increase in overall benefits. With this being the case, WSP input the new Menifee Alternative benefits into WSP's independent Capital Analysis BCA (where benefits start occurring once the project is in service) and found, in terms of benefit-cost ratio, the increased benefits resulted in the Menifee Alternative moving to first place (switching places with Valley South to Valley North Alternative, from that shown in the Figure 2). Importantly, these assessments were made from a purely benefit-cost ratio standpoint, but do not consider the engineering ability of alternatives to resolve planning criteria contingencies, such as an N-1 Loss of Transformer contingency. No other changes (from the June 2021, or third version spreadsheets) were applied to the integrated time-series BCA because the other changes were minor, and since SCE hadn't adjusted the timing of accruing benefits before the Project is in service, making the changes inconsequential.

During this review, WSP also observed that the data linking to computations of benefits was missing or not supplied. These cells were previously linked to supplied Excel spreadsheet data titled *Cost Assumptions*. However, in both the tracked and untracked latest versions of spreadsheets, the benefit cells were linked to *Cost Data & Assumptions* (as referred to in cells), but Excel spreadsheet data was missing or not supplied, meaning the computation of benefit cells could not be linked to their source. These cells were also password protected, limiting disclosure and the scope/tracking of review.

Based on discussions at the Energy Division virtual workshop on January 20, 2022, regarding the Draft Energy Division Staff Report findings and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer 2022 to gain additional understanding and potential alignment around a series of topics including the SCE BCA methodology. Through technical forums with

CPUC and SCE in May 2022, it appears that SCE conducted a life cycle cost analysis (LCCA) in the course of preparing their economic analysis, instead of a BCA.

An LCCA is a subset of a BCA. An LCCA may be used to determine the most cost-effective way to accomplish a project's objectives by comparing life cycle costs of alternatives that have the same study period, base date, and service date. Unlike LCCA, BCA considers variable benefits of project alternatives as well as its costs (USDOT 2002). BCA allows for the evaluation and comparison of alternatives with different in-service dates, and life cycles, depending on the timing of costs and benefits as they are realistically incurred. A BCA can be used to compare alternatives that do not yield identical benefits (e.g., energy utility alternatives that have varying levels of supply or alternatives that accrue benefits at different stages in the analysis). Table 7 provides a comparison of elements typically included in LCCA and BCA.

Table 7: Comparison of Analysis Elements: LCCA Versus BCA

Project Element	LCCA	BCA
Construction and maintenance expenditures	Yes	Yes
Costs during construction, rehabilitation, or maintenance	Yes	Yes
Costs during normal operations	Yes	Yes
Benefits resulting from project	No	Yes
Other external effects resulting from project	No	Yes

Source: USDOT 2022

In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Though the SCE economic analysis adheres to the criteria for comparing alternatives within an LCCA (finding the least cost option between alternatives that have the same service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA.

See Appendix G, Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project, for the WSP memoranda.

8 Conclusions

The CPUC released the Draft Energy Division Staff Report to the public on December 3, 2021. The Energy Division held a virtual workshop on January 20, 2022, for the parties to the proceeding regarding the Draft Energy Division Staff Report findings. Based on discussions at the January workshop and subsequent written comments, CPUC held a series of technical forums with the SCE in the spring and summer of 2022. The main findings, decisions, and actions in 2022 are described below.

SCE noted via letter (SCE 2022c, 13) that tie-lines in the proposed Alberhill Project that could be engaged following a contingency would be operated manually and therefore do not constitute an SPS. Kevala agrees that manual operation of a tie-line does not constitute an SPS or mitigation strategy.

Since the Draft Staff Report, Kevala has learned that the portion of SCE's 115 kV system included in the proposed Alberhill Project is not required to be planned to meet NERC reliability standards. As noted above in Section 2.3, while SCE's planning criteria align with the NERC reliability standards, the NERC standards do not explicitly define all contingencies, such as P-7 Multiple Contingency (common structure), local area events, and wide-area events (NERC n.d.), which is analogous to what SCE refers to in its planning criteria as the "Unlikely Contingency Scenarios," (SCE 2023a, 6), including Flex-1, Flex-2-1, and Flex-2-2. It is reasonable to expect SCE to craft specific system performance metrics that are rooted in transmission system planning event analysis.

In the absence of the CPUC defining a standardized evaluation approach, the Energy Division finds it reasonable for SCE to define performance metrics and scenarios to use in evaluating unlikely contingencies that may result in loss of load. This form of reliability/resilience assessment is nascent in the electric utility industry and Energy Division has seen examples of this form of assessment under development by Department of Energy National Laboratories, other utilities examining investment plans for extreme events, and in white papers or journal articles from the Institute of Electrical and Electronics Engineers and others. The Federal Energy Regulatory Commission, NERC, and WECC have opened proceedings or opined in annual reports on the need for alternative planning based on high-impact, low-frequency events.

Although SCE is not mandated to follow NERC standards, SCE has provided an evaluation method that is rooted in transmission system planning event analysis. In NERC regulation, the regulatory agency expects the transmission operator to exercise its engineering judgment and operating experience to choose relevant events to study and to provide rationale justifying the events studied. NERC does not specify the duration of study periods in its regulation. Similarly, the CPUC expects SCE to use its engineering judgment and operating experience to evaluate unlikely contingencies at the subtransmission/distribution level even if CPUC has not dictated a standardized evaluation approach by regulation, rule, or order.

Energy Division finds that it is reasonable for SCE to use these evaluation methods involving novel reliability/resilience metrics and modeling as an additional screening method for resilience because high-impact, low-frequency events impacts to this subtransmission system could severely affect a significant number of customers.

SCE expressed concerns that they have limited space at many substations to accommodate multiple distributed BESS units and that the cost for each individual instance of a distributed BESS would accumulate such that a CBESS was a more realistic consideration. SCE prepared and presented additional analysis that looked at an alternative (with needed system sizing) that included CBESS paired with a STATCOM.

Kevala found that the PSLF modeling and associated results demonstrated in SCE's August 30, 2022, presentation to the Energy Division were qualitatively reasonable and in alignment with the results previously shared via data requests and prior presentations for each case and variation, including analysis of placing CBESS both with and without a STATCOM within the Valley South System.

SCE presented further background on how and why they chose certain performance metrics. They considered LAR, EENS, and metrics commonly used in resource adequacy studies, such as LOLE. SCE wanted a metric that could compare cost effectiveness of solutions and that is monetizable, forward-looking, scenario-specific, and reflective of outage magnitude and duration. These criteria led to SCE's selected use of LAR and EENS.

The Energy Division and its consultants extensively discussed the probabilities SCE used for an extreme event that results in loss of service at the Valley Substation which was incorporated in calculations of the EENS metric. Due to lack of industry standard and lack of consensus on the appropriate probabilities for such contingency events, the Energy Division reported the additional analysis of Valley South to Valley North with a CBESS and a STATCOM using LAR values calculated but not EENS values to avoid use of probabilities in comparative metrics.

As shown by the calculated LAR values, BESS cannot defer the proposed Alberhill Project's need alone to meet the Flex-2-1 planning case because the Valley System is a radially operated subtransmission system that would need to be operated as an islanded microgrid (i.e., a stand-alone electrical system disconnected from the main grid). The facilities and approach for operating Valley System like an islanded microgrid has not been tested nor operated at scale for a system this size. The Valley System would remain vulnerable to loss of its source of supply under a high-impact, low-probability event—which is undesirable for a high-density urban load area subject to extreme heat events.

The WSP economic analyses found that SCE's proposed Alberhill Project's BCA of alternatives is not an equitable comparison of alternatives or calculation of each benefit-cost ratio because the benefits and costs for each alternative were not correctly timed in terms of when they would realistically occur. SCE's BCA incorrectly identifies accrual of project benefits before the proposed Alberhill Project has been constructed or placed in service (instead, it is based on a project need date). It is also not clear how O&M costs were incorporated into SCE's timeline or analysis as they are not linked, and the calculation of costs is not traceable.

Through technical forums with CPUC and SCE in May 2022, it appears that SCE conducted a lifecycle cost analysis in the course of preparing their economic analysis, instead of a BCA. An LCCA is a subtype of BCA. The LCCA is a cost comparison of competing project alternatives that is used to compare total life cycle costs across project alternatives that have equivalent benefits. In comparing alternatives, the SCE economic analysis uses the same study period, base date, and service date for all alternatives. Although the SCE economic analysis appears to adhere to the criteria for comparing alternatives within an LCCA (determining the most cost-effective option among alternatives with identical in-service dates), this is not strictly consistent with the methodology for conducting and comparing the variable costs and variable benefits of alternatives within a BCA (Kneifel and Webb 2020; OMB n.d.; USDOT 2002, 2012, 2022).

WSP, on behalf of the Energy Division, conducted economic analysis to re-time the benefits to align with BCA methodologies. Based on the re-timing of benefits beginning to accrue on the appropriate Project in-service date, the most purely economically attractive alternatives (in terms of the benefit-cost ratio) were Valley South to Valley North (ranked in first place), Menifee (second place), and Valley South to Valley North and Distributed BESS in Valley South (third place). The proposed Alberhill Project was ranked in sixth place, followed by SDG&E (seventh place) and Mira Loma (eighth place). Importantly, these rankings necessarily retain the probability-weighting SCE used in its original EENS calculations for the contingency events and is agnostic as to whether the alternatives analyzed may be potentially infeasible or undesirable.

Commission Decision D.18-08-026 did not prescribe the specific method for preparation of the BCA.

Overall, while some of SCE's analyses focused on metrics which incorporate data lacking consensus (i.e., the probability weighting for EENS), many of the SCE supplemental analysis conclusions are, in the professional opinion of the Energy Division, still qualitatively sound. Significantly, the Energy Division finds that though unlikely to occur, the high-impact total loss of the Valley Substation contingency considered by SCE in its planning criteria is compelling when weighing the resiliency needs the proposed Alberhill System Project seeks to address. Determining the probability of such a high impact but unlikely event to monetize EENS is a challenging endeavor because there is little SCE and industry operational data regarding such events. Energy Division elected to compare the LAR predicted for project alternatives under normal conditions with all facilities in service, likely contingencies, and unlikely contingencies. Energy Division did not rely upon a fully probability-weighted metric such as EENS for making a quantitative economic assessment of all benefits. Furthermore, SCE has convincingly shown that many of the reliability and resiliency challenges potentially faced by the Valley South System may not be fully addressed by addition of BESS and limited tie-lines to the Valley North System, particularly when looking at high-impact contingency events.

SCE's analysis of the thirteen project alternatives in comparison to basic planning criteria for normal conditions with all facilities in service and likely contingency conditions of single loss of transformer clarified to Energy Division, in concert with information shared with Energy Division during the technical forums and from data request responses, that the five lowest cost alternatives based on SCE PVRR costs, and at least two of the substation project alternatives, do not meet SCE's basic planning criteria. The Menifee Alternative does not meet SCE's basic planning criteria under loss of single transformer (N-1) contingency in 2031 because Menifee experiences LAR. The Mira Loma alternative does not meet basic planning criteria for normal conditions with all facilities in service (N-0) nor likely contingency conditions for loss of single transformer (N-1) in 2031. [12]

The Energy Division concludes that the additional supplemental analysis performed by SCE through the technical forums to evaluate Valley South to Valley North with Distributed BESS with and without STATCOM fulfilled the analytical needs suggested by Kevala for the uses distributed BESS and a fewer number of tie-lines.

After considering the additional supplemental analysis performed through a series of technical forums with SCE to evaluate the Valley South to Valley North with Centralized BESS (both with and without STATCOM), the Energy Division has determined that the potential alternative does not adequately address the effect on system performance of a high-impact, low-probability contingency event such as a total loss of the Valley Substation. Consequently, at this time, Energy Division does not conclude that two smaller-scaled systems or a different project alternative involving distributed battery energy storage would provide a reliable short-term energy solution that is more cost-effective than other project alternatives. The analysis did not support the hypothesis that two smaller-scaled systems a different project alternative involving distributed battery energy storage would provide a short-term energy solution that would save millions of dollars in upfront costs, which Energy Division posited in its Draft Staff Report.

[12] SCE Response to Energy Division Data Request No. 11, question DG-MISC-80.

9 References

Kevala, Inc. (Kevala). 2021a. *Preliminary Results: Tie-Line Power Flow Analysis*. Alberhill System Project. San Francisco: Kevala.

Kevala, Inc. (Kevala). 2021b. *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics*. San Francisco: Kevala.

Kevala, Inc. (Kevala). 2021c. *Behind-the-Meter Adoption Propensity Analysis for the Valley South System*. San Francisco: Kevala.

Kevala, Inc. (Kevala). 2021d. *Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System*. San Francisco: Kevala.

Kevala, Inc. (Kevala). 2021e. *Review of SCE's Electrical Engineering Analysis for the Alberhill System Project*. San Francisco: Kevala.

Kneifel, Joshua and David Webb. 2020. *Life Cycle Costing Manual for the Federal Energy Management Program*. National Institute of Standards and Technology, U.S. Department of Commerce. Handbook 135. Accessed August 16, 2023. https://doi.org/10.6028/NIST.HB.135-2020.

North American Electric Reliability Corporation (NERC). 2013. Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards. Revision 0.1. Atlanta: NERC. Accessed May 4, 2023. https://www.nerc.com/pa/Stand/Prjct201005_2SpclPrtctnSstmPhs2/System_Protection_and_Control_Subcommittee_SPCS_20_SAMS-SPCS_SPS_Technic_02182014.pdf.

North American Electric Reliability Corporation (NERC). Not dated. Transmission System Planning Performance Requirements. Accessed May 4, 2023. https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

Office of Management and Budget (OMB). Not dated. "OMB Circular A-94: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." Transmittal Memo No.64. Accessed August 16, 2023. https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A94/a094.pdf.

Southern California Edison (SCE). 2020a. Response to CPUC Data Request 003, Question DG-MISC-41. Email to CPUC. April 20, 2020.

Southern California Edison (SCE). 2020b. Response to CPUC Data Request 003, Question DG-MISC-42. Email to CPUC. May 7, 2020.

Southern California Edison (SCE). 2020c. Response to CPUC Data Request 006, Question DG-MISC-58. Email to CPUC. October 6, 2020.

Southern California Edison (SCE). 2021. Supplemental Data Items A-I submitted as part of May 2020 Amended Application, February 2021 Amended Motion to Supplement the Record, and June 2021 Second Amended Motion to Supplement the Record.

Southern California Edison (SCE). 2022a. SCE Alberhill Draft Report Discussion, Energy Division. March 16, 2022.

Southern California Edison (SCE). 2022b. Response to CPUC Data Request 012, Question DG-MISC-83. Email to CPUC. July 15, 2022.

Southern California Edison (SCE). 2022c. Southern California Edison's Comments to the Draft Energy Division Staff Report for the Alberhill System Project. Email to CPUC. January 27, 2022.

Southern California Edison (SCE). 2022d. Response to CPUC Data Request 013, Question DG-MISC-82. Email to CPUC. July 26, 2022.

Southern California Edison (SCE). 2022e. Response to CPUC Data Request 011, Question DG-MISC-82. Email to CPUC. July 1, 2022.

Southern California Edison (SCE). 2023a. Response to CPUC Data Request 016, DG-MISC-6. Alberhill System Project: Benefit-Cost Analysis Workshop, Energy Division (May 4, 2022). Email to CPUC. January 20, 2023.

Southern California Edison (SCE). 2023b. Response to CPUC Data Request 017, Question DG-MISC-80. Email to CPUC. January 20, 2023.

U.S. Department of Transportation (USDOT). 2002. *Life-Cycle Cost Analysis Primer*. Washington, D.C.: U.S. Department of Transportation Federal Highway Administration Office of Asset Management. https://www.fhwa.dot.gov/pavement/lcca/010621.pdf.

U.S. Department of Transportation (USDOT). 2012. *Operations Benefit/Cost Analysis Desk Reference: Providing Guidance to Practitioners in the Analysis of Benefits and Costs of Management and Operations Projects*. May 2012. Washington, D.C.: U.S. Department of Transportation, Federal Highway Administration. https://ops.fhwa.dot.gov/publications/fhwahop12028/fhwahop12028.pdf.

U.S. Department of Transportation (USDOT). 2022. Benefit-Cost Analysis Guidance for Discretionary Grant Programs. Washington, D.C. Office of the Secretary, U.S. Department of Transportation. March 2022 (Revised).

WSP USA Inc. (WSP). 2021. *Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project.*

Appendices

Appendix A – Project Description of the Proposed Alberhill Project

Appendix A

The following text is excerpted from the Final Environmental Impact Report (2017) for the Valley–Ivyglen 115-kV Subtransmission Line and Alberhill System Projects. Project description excerpts pertain to the proposed Alberhill Project.

1.0 Alberhill Project Overview

The proposed Alberhill Project would include construction of a new 1,120 megavolt ampere (MVA) 500/115-kV substation (Alberhill Substation), which would be expandable to a maximum of 1,680 MVA depending on future need. In addition to construction of a new Alberhill Substation, the proposed Alberhill Project would include the following:

- Construction of two new 500-kV transmission lines (approximately 3.3 miles, combined) within a new ROW to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line;
- Double-circuit approximately 11.75 miles of existing single-circuit 115-kV subtransmission lines with structure replacement primarily in the existing ROW;
- Construction of about 3 miles of single-circuit 115-kV subtransmission lines with distribution lines underbuilt on the subtransmission line structures and removal of about 3 miles of electrical distribution lines within the existing ROW;
- Installation of a second 115-kV circuit on approximately 6.5 miles of single-circuit 115-kV subtransmission lines (the single-circuit line is to be constructed as part of the proposed Valley–Ivyglen Project);
- Installation of fiber optic lines overhead (9 miles) on sections of the new or modified subtransmission lines and underground (1 mile) in proximity to the proposed Alberhill Substation and several of the existing 115/12-kV substations;
- Construction of an approximately 120-foot microwave antenna tower at the proposed Alberhill Substation site; installation of microwave telecommunications dish antennas at the proposed Alberhill Substation, the existing Santiago Peak Communications Site, and Serrano Substation; and other telecommunications equipment installations at existing and proposed substations; and

The applicant estimates that construction of the proposed Alberhill Project would take approximately 28 months.

2.0 Alberhill Project Location

The Alberhill Substation is proposed to be built on 34 to 40 acres of a 124-acre property located north of I-15 and the intersection of Temescal Canyon Road and Concordia Ranch Road in unincorporated western Riverside County. The two new 500-kV transmission lines would each extend approximately 1.5 miles northeast to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission

Line. The two 500-kV transmission lines would be constructed primarily in unincorporated Riverside County, although the transmission lines would pass through the City of Lake Elsinore.

The proposed 115-kV line modifications and construction would occur southeast from the proposed Alberhill Substation to Skylark Substation (approximately 11.5 miles) and from Skylark Substation to Newcomb Substation (approximately 9 miles). The subtransmission lines would be modified or constructed in unincorporated Riverside County and in the Cities of Lake Elsinore, Wildomar, and Menifee.

Fiber optic lines would be installed overhead on the structures modified or constructed as part of the proposed Alberhill Project. In a few locations, fiber optic lines would also be installed in a new underground conduit. Telecommunications equipment would be installed within the telecommunications rooms at the applicant's Barre, Fogarty, Ivyglen, Mira Loma, Newcomb, Serrano, Skylark, Tenaja, Valley, and Walnut Substations. Telecommunications systems would also be upgraded at the Box Springs Communications Site, which is located northwest of the City of Moreno Valley, California, and the applicant's Irvine Operations Center in southeastern Irvine, California.

One new approximately 120-foot microwave antenna tower would be installed at the proposed Alberhill Substation; one new microwave dish antenna would be installed at Serrano Substation in the City of Orange in Orange County; and two new dish antennas would be installed at the Santiago Peak Communications Site, which is located on land managed by the United States Forest Service within the Cleveland National Forest.

3.0 Components of the Proposed Alberhill Project

The components of the proposed Alberhill Project are summarized in Table 3-1.

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Alberhill Substation		
New 1,120 MVA 500/115-kV substation expandable to 1,680 MVA	• Up to three 500 MVA transformers in service and one spare transformer [(a)]	• 34 to 43 acres [(b)] • 33,550 gallons of oil per transformer • 37-foot-high transformers
500-kVA backup generator	1	• 960 gallons of diesel fuel
500-kV switchrack	• One gas-insulated switchrack • Space for second 500-kV switchrack and enclosure • Space for two future 500-kV capacitor banks	• One 350-foot-long, 49-foot-high steel enclosure • Up to 50,000 pounds of SF_6
115-kV switchrack and future 12-kV switchrack	• One open-air insulated switchrack	• One 60-foot-high dead-end structure

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
	• Space for additional positions on switchrack • Space for future 12-kV switchrack and 115/12-kV transformers • One 115-kV capacitor bank • Space for three future 115-kV capacitor banks	• One 43-foot-high dead-end structure • Space for additional dead-end structures • Up to 1,200 pounds of SF_6 (circuit breakers)
Control building	• Substation monitoring equipment	• 20-feet high, 7,040 square feet
Parking area and multiple driveways	n/a	• 7,600-square-foot parking area • 30-foot to 45-foot-wide driveways • 156,000 square feet of road surface [c]
Agricultural water pipe relocation	n/a	• 27-inch-diameter pipe • 1,700 feet long
Transmission Lines (Overhead)		
Line SA: New 500-kV transmission line to connect the proposed Alberhill Substation to existing Serrano–Valley 500-kV Transmission Line	• 6 LSTs (1 LST removed) [d]	• 1.6 miles long • 250-foot to 2,100-foot spans between LSTs • 200-foot-wide ROW (new) [e]
Line VA: New 500-kV transmission line to connect the proposed Alberhill Substation to existing Serrano–Valley 500-kV Transmission Line (overhead)	• 6 LSTs No structures removed	• 1.7 miles long • 250-foot to 2,100-foot spans between LSTs • 200-foot-wide ROW (new) [e]
New overhead ground wires installed on 500-kB Lines AS and VA	n/a n/a	• 3.3 miles
Subtransmission Line Segments (Overhead)		
Segment ASP1: New double-circuit 115-kV subtransmission line at proposed substation site	• 7 TSPs • 3 LWS poles No structures removed	• 0.22 miles • On proposed substation site
	• 4 LWS poles • 8 TSPs	• 0.5 miles

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Segment ASP1.5: New double-circuit 115-kV subtransmission line and removal of existing single-circuit section of Valley–Elsinore–Fogarty 115-kV line	• 2 existing TSPs to be modified (4 wood poles removed)	• 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP2: Double-circuit Valley–Ivyglen 115-kV line segment (g)	• 4 LWS • 2 TSP (4 LWS removed)	• 6.27 miles • 60-foot to 100-foot-wide ROW (existing). Existing distribution line underbuilt to be relocated to new 115-kV structures.
Segment ASP3: New double-circuit 115-kV line segment and removal of existing single-circuit section of Valley–Elsinore–Fogarty 115-kV line	• 13 LWS poles • 3 TSPs • 2 existing TSPs to be modified • 1 LWS guy stub (13 wood poles and 1 TSP)	• 0.48 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP4: New double-circuit 115-kV subtransmission line and removal of existing single-circuit sections of Elsinore–Skylark 115-kV lines	• 101 LWS poles • 12 TSPs • 12 LWS guy stubs • 3 Wood (modified) (112 wood poles, 1 LWS, and 1 TSP removed)	• 4.24 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
Segment ASP5: New double-circuit 115-kV subtransmission line segment and removal of existing single-circuit section of Valley–Newcomb–Skylark 115-kV line	• 109 LWS poles • 11 TSPs • 10 H-frame structures (h) • 1 TSP (modified) • 13 LWS guy stubs (119 wood, 2 LWS, 2 wood H-frame(h), 8 LWS H-frame(h))	• 5.5 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP6: New single-circuit 115-kV subtransmission line segment along existing distribution line route	• 100 LWS poles • 1 TSP (modified) • 7 LWS guy stubs (3 wood poles removed)	• 3 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line to be relocated to new 115-kV structures
Segment ASP7: New double-circuit 115-kV subtransmission line segment and removal of existing single-circuit section of Valley–Newcomb–Skylark 115-kV line	• 9 LWS poles • 4 TSPs • 3 LWS guy stubs (6 wood poles and 2 TSPs removed)	• 0.25 miles • 60-foot to 100-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Segment ASP8: Connect Valley–Ivyglen and Valley–Newcomb single-circuit 115-kV lines	• 3 LWS poles • 4 TSPs (3 wood poles removed)	• 0.06 miles or 300 feet • 260-foot to 390-foot-wide ROW (existing) • Existing distribution line underbuild to be relocated to new 115-kV structures (f)
Telecommunications Equipment and Fiber Optic Lines (Overhead and Underground)		
New microwave tower at Alberhill Substation	• 1 antenna tower	• 120 feet tall
New dishes at the proposed Alberhill Substation (one), Serrano Substation (one), and the Santiago Peak Communications Site (two)	• 4 microwave dish antennas	• 10 feet wide (each)
New fiber optic telecommunication line installed on two 115-kV line taps into the proposed Alberhill Substation	n/a	• 2,000 feet • 650 feet underground

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications
New fiber optic telecommunication line installed on 115-kV Segments ASP1, ASP 1.5, ASP5, ASP6, and ASP7	n/a	• 8.66 miles • 1.11 miles underground
New telecommunications equipment installed inside existing substations (e.g., microwave radios)	n/a	n/a
Totals		
New 500-kV transmission line	n/a	3.3 miles
New or modified 115-kV subtransmission line	n/a	20.42 miles
New fiber optic line	n/a	8.66 miles (1.11 miles in new underground conduit)
New 500-kV ROW to be acquired	n/a	3.3 miles (200 feet wide)
Number of transmission and subtransmission structures by structure type	• 12 LSTs installed • 3 Wood Poles (modified) • 346 LWS poles installed • 10 H-frame structures installed • 51 TSPs installed • 36 LWS guy stubs installed • 4 existing TSPs to be modified • 2 TSPs (modified) (1 LST, 260 wood poles, 7 LWS poles, 3 TSPs, 2 wood H-frames and 8 LWS H-frames removed)	• 95 feet to 190 feet tall, four concrete footings • 75 feet to 100 feet tall, 1.5 to 2.5 feet in diameter at ground level • 70 feet to 80 feet tall, two 1.5 to 2.5 feet diameter LWS poles at ground level • 70 feet to 115 feet tall, 5 to 8 feet in diameter at ground level (including foundation)

Source: SCE 2011

Key: kV = kilovolt, kVA = kilovolt ampere, LST = lattice steel tower, LWS = lightweight steel, MVA = megavolt ampere, n/a = not applicable, SF_6 = sulfur hexafluoride gas, ROW = right-of-way, TSP = tubular steel pole

Notes:

Table 3-1 Components of the Proposed Alberhill Project

Component	Quantity	Dimensions / Specifications

[a] The initial build would include the installation of two transformers, with one of the two a spare. Space would be available for the installation of two additional transformers, for a maximum of three in-service transformers and a spare, if needed in the future.
[b] Approximately 34 acres would be needed for construction of the Alberhill Substation, including landscaping and access roads. If the applicant elects to excavate 5.2 acres of land adjacent to the northeast corner of the proposed substation site to obtain fill under Import Soil Option 1, then the land required for construction of the proposed substation would increase from 34 acres to approximately 40 acres (Section 2.4.6.2).
[c] Road surfaces inside and surrounding the proposed Alberhill Substation would be asphalt, concrete, or gravel (Class II Aggregate).
[d] One 500-kV tower would be removed from the Serrano–Valley 500-kV Transmission Line.
[e] Refer to Tables 2-6 and 2-7 for disturbance area by project component.
[f] A number of the existing single-circuit 115-kV structures to be replaced with double-circuit 115-kV structures have existing distribution and telecommunications lines underbuilt on (installed on the lower position of) the single-circuit 115-kV circuit structures. The existing distribution and telecommunications lines would be relocated to and underbuilt on the proposed double-circuit 115-kV structures.
[g] Placing a second circuit on this proposed Alberhill Project 115-kV segment requires that proposed Valley–Ivyglen Project 115-kV Segments VIG4 and VIG5 are constructed.
[h] H-frame structures are constructed using two LWS poles. Existing H-frame structures to be removed consist of two wood poles or two LWS poles. See figure 2-8 for a diagram of the H-frame structure.
[i] Two parallel overhead ground wires would be installed on the top of each of the proposed 500-kV towers.

3.1 Alberhill Substation

The proposed 1,120 MVA 500/115-kV Alberhill Substation would be expandable to a maximum of 1,680 MVA, with space for three in-service 560 MVA 500/115-kV transformers and one spare, depending on future need. Up to five 500-kV transmission lines may connect to the final build of the substation, as needed. The substation would be unstaffed and automated. The initial build of the proposed Alberhill Substation would connect to an existing 500-kV transmission line via new segments and include the following:

- Two 560 MVA 500/115-kV transformers with one used as a spare;
- 500-kV switchrack with gas-insulated switchgear;
- 115-kV switchrack;
- 115-kV capacitor bank;
- Control building with basement;
- Electrical power sources including a backup generator;
- Lighting;
- Entrance, gates, driveways, parking, and a perimeter wall that is a minimum of 8 feet tall and a maximum of 14 feet tall; and
- Restroom, septic system, water supply, and landscaping irrigation.

Five 115-kV lines would extend from the initial build of the proposed Alberhill Substation. If the proposed substation is expanded in the future and two or up to three load-serving 500/115-kV transformers are installed, up to 10 115-kV lines may ultimately extend from the proposed substation. To allow for construction of the substation, a 27-inch agricultural water pipeline would be relocated to the perimeter of the proposed Alberhill Substation property.

TRANSFORMERS

The proposed Alberhill Substation would include the installation of two 560 MVA 500/115-kV transformers as part of the initial build. Because the total load that would be transferred initially from the Valley Substation to the proposed Alberhill Substation would be less than the capacity of one of the installed transformers (560 MVA), the second transformer would be energized and available for service as the spare for the purposes of the initial build.

The proposed Alberhill Substation would be constructed with enough space for two additional 560 MVA 500/115-kV transformers. When the electrical load exceeds 560 MVA, the first two transformers would serve the load and a third transformer would be installed as a spare. Based on the applicant's projections, the load may exceed 560 MVA between 2024 and 2029. A fourth transformer would be installed as a spare and the first three transformers would serve the load when the electrical load exceeds 1,120 MVA. The applicant projects that the load may exceed 1,120 MVA between 2037 and 2050, depending on annual growth in electrical demand. Each of the 560 MVA 500/115-kV transformers would be approximately 37 feet high and contain approximately 33,550 gallons of transformer oil (mineral oil). There would also be space reserved for the future installation of 115/12-kV transformers.

SWITCHRACKS

500-kV Switchrack (Gas Insulated)

The 500-kV switchgear would be housed in a steel enclosure that is approximately 350 feet long, 60 feet wide, and 49 feet high. There would be space reserved at the proposed Alberhill Substation for a future 500-kV switchrack. The 500-kV switchrack would consist of six positions with two operating buses arranged in a breaker-and-a-half configuration. The operating buses would have six 500-kV gas-insulated potential-transformers. Initially, four positions would be installed. Three positions would be equipped for two 500-kV line positions and two transformer bank positions. The two 500-kV line positions and two bank positions would be equipped with line/bank dead ends. The 500-kV transmission lines and transformer bank leads would have twelve 500-kV lightning arresters.

115-kV Switchrack and Future 12-kV Switchrack (Open-Air Insulated)

The 115-kV switchrack would use open-air-insulated switchgear. Five 115-kV lines would extend from the proposed 115-kV switchrack. There would be space reserved at the proposed Alberhill Substation for an extension of the 115-kV switchrack. If the proposed substation is expanded in the future and up to three load-serving 500/115-kV transformers are operational, it is estimated that up to 10 115-kV lines may ultimately extend from the 115-kV switchrack. The 115-kV operating buses would have eighteen 115-kV lightning arresters. The initial-build of the 115-kV switchrack would connect to two *dead-end structures*.[1] Space would be reserved at the proposed Alberhill Substation for a future 12-kV switchrack.

CAPACITOR BANKS

One 115-kV capacitor bank would be installed in the initial build of the proposed Alberhill Substation with a circuit breaker and a disconnect switch. The capacitor bank would be approximately 14 feet high. Space would be reserved for three additional 115-kV capacitor banks and two 500-kV capacitor banks.

CONTROL BUILDING

Monitoring equipment for the proposed Alberhill Substation would be located in a permanent control building that would be constructed of prefabricated metal and include a full basement. The control building (7,040 square feet) would be approximately 64 feet wide, 110 feet long, and 20 feet high.

3.2 500-kV Transmission Lines

The applicant proposes to construct two new 500-kV transmission lines (500-kV Line SA and 500-kV Line VA) to connect the proposed Alberhill Substation to the existing Serrano–Valley 500-kV Transmission Line . Line SA would be 1.6 miles long and Line VA would be 1.7 miles long. Construction of the 500-kV transmission lines would require the removal of one 500-kV lattice steel tower (M13-T4) and installation of 12 new lattice steel towers (500-kV towers SA1 to SA6 and VA1 to VA6).

The lattice steel tower footings would require four excavated holes 3 feet to 6 feet in diameter and 20 feet to 45 feet deep. On average, footings extend above the ground between 1 and 4 feet. The two lattice steel towers installed nearest to the proposed Alberhill Substation would be taller, double-circuit towers, but the conductor would be installed only on one side of the towers as part of the proposed Alberhill Project. The other 10 lattice steel towers installed would be single-circuit towers.

3.3 115-kV Subtransmission Lines (Segments ASP1 through ASP8)

The proposed Alberhill Project would involve the construction of new 115-kV subtransmission lines and modification of existing 115-kV subtransmission lines. LWS poles, TSPs, guy stubs and H-frames would be used for construction of the new 115-kV subtransmission lines. Each of the proposed 115-kV structures would support polymer insulators, 954-kcmil stranded aluminum conductor (SAC), and 4/0 ACSR for grounding. If needed, 954-kcmil ACSR would be used at locations requiring higher tension.[2] The normal

---

[1] *Dead-end structures* are higher-strength structures used at the termination point of powerlines that are designed to support the high-tension forces associated with the length of the line leading up to the termination point. Higher-strength structures are also installed where powerlines change direction.

[2] Stranded aluminum 954-kcmil conductor has a diameter of approximately 1.1 inches. The American Wire Gauge conductor size 4/0 is equivalent to 212-kcmil conductor, which is approximately 0.5 inches in diameter. Aluminum steel-reinforced 954-kcmil conductor, which is composed of strands of aluminum on the outer shell of the conductor cable and strands

rating (in clear atmospheric conditions, with an ambient temperature of 104 degrees Fahrenheit, at an elevation of 500 feet, and with a wind speed of 4 feet per second) of the proposed 954-kcmil SAC is 1,090 amps when in continuous operation. The emergency rating, assuming 4 hours of operation, is 1,470 amps. The 115-kV lines that would be replaced along 115-kV Segments ASP3, ASP4, ASP5, and ASP7 use 653-kcmil ACSR with a normal rating of 920 amps and emergency rating of 1,240 amps under the same conditions identified for the proposed 954-kcmil SAC previously described.

115-KV SEGMENT ASP1

115-kV Segment ASP1 would be a new double-circuit 115-kV subtransmission line at the proposed Alberhill Substation site that would connect the substation to 115-kV Segment ASP2. New TSPs and LWS poles would be installed (Table 3-1). The new double-circuit 115-kV line would connect to the 115-kV switchrack at the western end of the proposed Alberhill Substation. The line would exit the proposed substation near the main entry gate, turn south, and then parallel the substation perimeter south to Temescal Canyon Road. The line would continue southeast along Temescal Canyon Road to Concordia Ranch Road.

115-KV SEGMENT ASP1.5

The 115-kV Segment ASP1.5 would connect to the new 115-kV switchrack at the western end of the proposed Alberhill Substation. The segment would exit the proposed substation near the main entry gate, turn south/southwest, and then cross Temescal Canyon Road to a point along the existing Fogarty–Ivyglen 115-kV line alignment. The 115-kV Segment ASP1.5 would then extend southeast along Temescal Canyon Road and cross I-15. The 115-kV Segment ASP1.5 would be a double-circuit subtransmission line.

115-KV SEGMENT ASP2

The 115-kV Segment ASP2 would place a second circuit on an approximately 6.3-mile section of the proposed Valley–Ivyglen 115-kV line (115-kV Segments VIG4 and VIG5; Figures 2-2a and 2-2b). As part of the proposed Valley-Ivyglen Project, four LWS poles would be installed on the south side of Concordia Ranch Road to avoid conflicts that would occur during construction of the proposed Alberhill Substation. As part of the proposed Alberhill Project, three replacement LWS poles and two TSP would be installed on the north side of Concordia Ranch Road (Table 3-1). The final location of the five poles on the north side of Concordia Ranch Road would accommodate 115-kV circuits that would exit Alberhill Substation to the east on poles constructed as part of the Valley–Ivyglen Project. No other structure installation or replacement would be required along 115-kV Segment ASP2 as part of the proposed Alberhill Project. The proposed Valley–Ivyglen 115-kV line is designed to support two circuits. To add the second circuit along 115-kV Segment ASP2, the proposed Valley–Ivyglen 115-kV line structures would require the addition of crossarms, anchors, insulators and conductor.

---

of steel in the core, is generally a few millimeters in diameter wider than 954-kcmil stranded aluminum conductor, which does not contain a steel core (Grigsby 2001).

Double-circuiting would begin at the southeastern end of 115-kV Segment ASP1 and follow Concordia Ranch Road east to its terminus. From there it would cross I-15 south to Temescal Canyon Road and then continue east to Lake Street. From Lake Street, it would continue south to Nichols Road. The line would then follow Nichols Road to Pierce Street and then turn southeast on Baker Street and continue to Riverside Avenue (SR-74). The line would follow Riverside Avenue northeast and then pass southeast over land to Pasadena Avenue. It would continue along Pasadena Avenue and then turn northeast onto Third Street and continue to Collier Avenue.

115-KV SEGMENT ASP3

Along 115-kV Segment ASP3, a second circuit along a section of the Valley–Elsinore–Fogarty 115-kV line would be installed and the existing single-circuit section of the line would be removed. New structures capable of supporting two circuits would be installed. The new LWS poles and several TSPs would be installed to enable the crossing of I-15 (Table 3-1). Wood poles and the existing TSPs adjacent to I-15 would be replaced in the City of Lake Elsinore between the intersections of Third Street and Collier Avenue and Second Street and Camino del Norte.

115-KV SEGMENT ASP4

115-kV Segment ASP4 includes installation of new double-circuit LWS poles along a section of the Elsinore-Skylark 115-kV lines as well as removal of the existing single-circuit sections of the lines (Table 3-1). From East Hill Street southwest to East Pottery Street, structures would be constructed and removed along a section of the Elsinore–Skylark 115-kV line. From East Pottery Street east to East Franklin Street and then southeast to Skylark Substation, structures would be constructed and removed on the Elsinore–Skylark 115-kV line. The line would continue from East Franklin Street over land and then along Auto Center Drive, Casino Drive, Malaga Road, and Mission Trail to Skylark Substation.

115-KV SEGMENT ASP5

115-kV Segment ASP5 includes installation of new double-circuit LWS poles and H-frame structures along a section of the Valley–Newcomb–Skylark 115-kV line (Table 2-2). The existing 115-kV LWS poles, H-frame structures, and wood poles would be removed. This segment would pass through the cities of Wildomar and Menifee.

Starting at Skylark Substation, the double-circuit lines would continue east across Mission Trail Road to Waite Street. It would follow Waite Street and then turn north onto Almond Street and continue to Lemon Street. It would cross I-15 and continue east along Lemon Street to where the street turns into Lost Road. It would continue northeast on Lost Road and then turn east and cross open land and multiple roads to Beverly Street. It would follow Beverly Street and then continue east along Bundy Canyon Road to Scott Road.

115-KV SEGMENT ASP6

115-kV Segment ASP6 includes construction of LWS poles for a new single-circuit 115-kV subtransmission line north from the intersection of Scott Road and Murrieta Road to Newport Road. An existing distribution line with wood poles along Murrieta Road would be removed, and the distribution line conductor would be transferred to and underbuilt on the new 115-kV structures (installed below the new 115-kV circuit).

115-KV SEGMENT ASP7

115-kV Segment ASP7 includes installation of new double-circuit LWS poles and TSPs along a section of the Valley–Newcomb–Skylark 115-kV line north of the intersection of Newport Road and Murrieta Road to Newcomb Substation in Menifee. Existing 115-kV wood structures would be removed. In addition, the circuit breaker at Newcomb Substation that connects the substation to Valley Substation would be opened, which would disconnect Newcomb Substation from Valley Substation.

115-KV SEGMENT ASP8

115-kV Segment ASP8 includes installation of new LWS poles and TSPs along a 300-foot section at the intersection of Murrieta Road and McLaughlin Road in Menifee to connect the Valley–Newcomb 115-kV line to the proposed Valley–Ivyglen 115-kV line (Figure 2-2f). Existing 115-kV wood structures would be removed. The circuit breaker that connects the proposed Valley–Ivyglen 115-kV line to Valley Substation would be opened to ensure that the line is deenergized from Valley Substation.

3.3 Telecommunications

The proposed Alberhill Substation would require the installation of new telecommunication infrastructure to provide protective relaying, data transmission, and telephone services to the substations served by the proposed Alberhill System. These new facilities include modifications to the applicant's existing microwave system and the addition of new fiber optic cable. The proposed Alberhill Project would include the installation of new telecommunication infrastructure required for communication with the substations served by the proposed Alberhill 115-kV System. New microwave components, fiber optic cable, and other telecommunications equipment installations would be part of the proposed Alberhill Project.

3.4 Access Roads

Each of the proposed 500-kV transmission line tower sites could require 24-hour vehicular access during operation of the proposed Alberhill Project for emergency and maintenance activities. The applicant would install gates to restrict general and recreational vehicular access roads. The applicant would construct approximately 3 miles of new or modified access roads to access the proposed 500-kV transmission line structures if the conventional method of construction is used for the 500-kV transmission line. The proposed Alberhill 115-kV segments would not require new or modified access roads.

References

SCE (Southern California Edison). 2011. Proponent's Environmental Assessment: Alberhill System Project (April 11), as amended by responses from SCE to CPUC requests for additional information.

Appendix B – Preliminary Results: Tie-Line Power Flow Analysis

Portions of this report have been redacted based on Southern California Edison's claims of confidentiality based on critical infrastructure information and other legal privileges.

kevala

Alberhill System Project

Preliminary Results:
Tie-Line Power Flow Analysis

April 12th, 2021

kevala

Table of Contents

List of Tables

List of Figures

kevala

Executive Summary

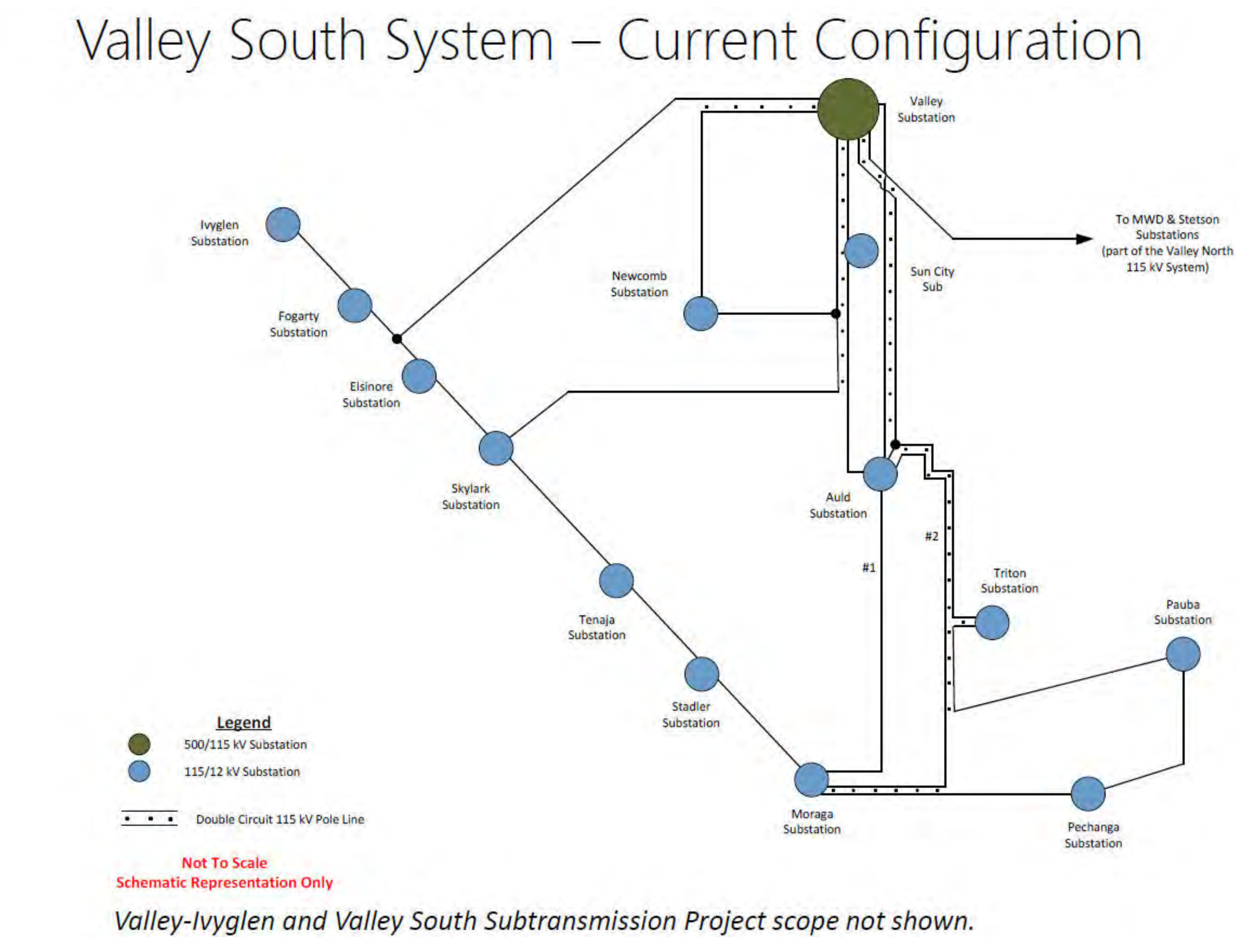
This report presents the results of the tie-line analysis conducted to understand whether the Valley South tie-lines proposed by SCE as part of the Alberhill System Project were necessary in order to achieve system capacity, reliability, and resiliency in the Valley South service area. Four power flow base cases that represent alternatives containing tie-lines and a base case were used for this analysis. Following a review of the preliminary results, additional scenario cases were developed to further study the effects that tie-lines alone, energy storage alone, or a combination thereof have on the Valley South system. The findings of this assessment were as follows:

- Tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers and meet reliability and resiliency requirements. SCE has concluded that the tie-lines in this alternative are ineffective under double contingencies or a catastrophic event that results in a loss of both Valley South transformers.
- Transferring service for two substations (Newcomb and Sun City substations) via 115 kV tie-lines to the Valley North system and installing 50 MW of distributed battery energy storage system (BESS) in the Valley South system could also mitigate this overload as effectively as the Alberhill System Project while meeting capacity, reliability, and resiliency requirements. This alternative satisfies part of the CPUC's objective to enable electricity service from Valley South or from a new 115 kV system. The difference is that these tie-lines enable electricity service from the existing Valley North system or from the Valley South system and would achieve the same performance.
- SCE concluded that the tie-lines in this alternative are ineffective in the event there is a double contingency or in the event that a catastrophic event occurs that results in the loss of both Valley South transformers. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted and the power flow results indicated that this alternative performed effectively.

Background

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the two 560 MVA Valley South 500 kV transformers to become overloaded in 2023. As part of supporting and informing the CEQA process, several technical analyses are being conducted. One of these is an analysis of the tie-lines proposed as part of ASP. This report discusses the analysis conducted and the results. Figure 1 depicts the current configuration of the Valley South system without tie-lines.

Figure 1: Current Valley South System Configuration.[1]



Valley South Service Area Socio-economic Profile

Valley South substation is located in Menifee, CA and its service area comprises approximately 380 square miles in the southwestern portion of Riverside County. SCE estimates that the Valley South substation serves approximately 560,000 people[2] in the unincorporated areas of Riverside County and in the cities of Elsinore, Menifee, and Wildomar. According to the 2019 Census data, the population that would be impacted by this project are relatively young families. The census data for this area indicates that the population on average are in their thirties and about a quarter have earned a bachelor's degree or higher. Home

[1] *Source: Quanta Technology Reliability Analysis of Alberhill System Project report*.

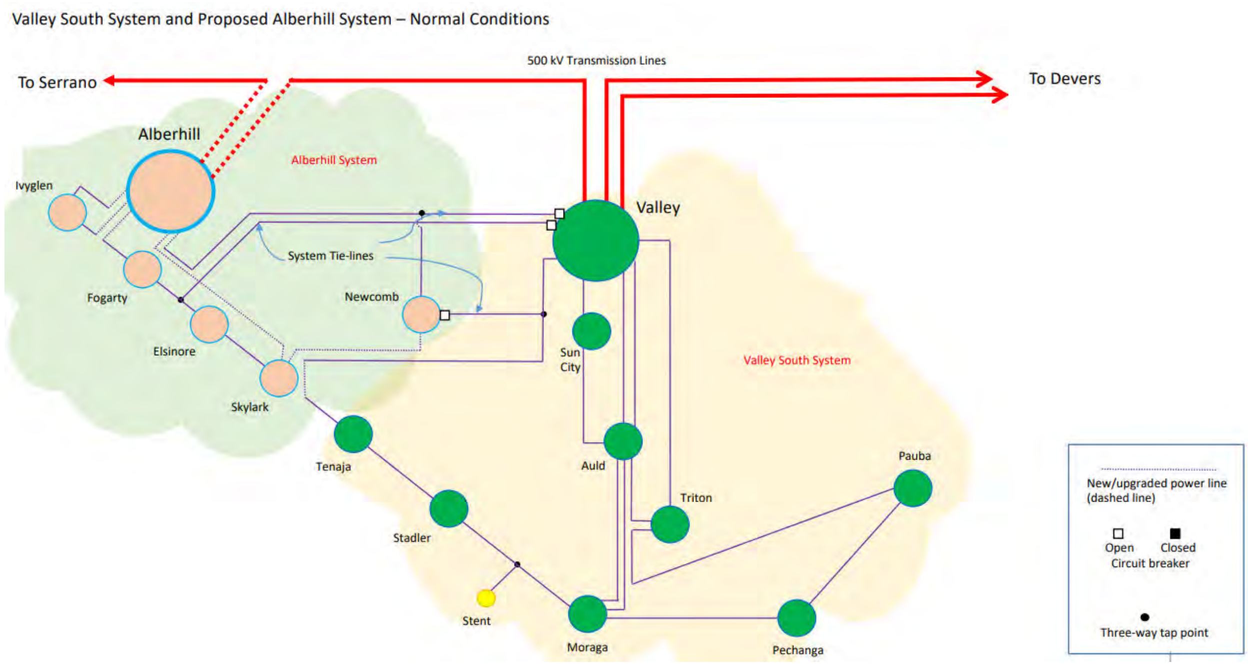
[2] *A0909022-SCE-ASP Amended Motion to Supplement – Exh C-2.pdf, page 8.*

ownership rates are about 70 percent with about a quarter having moved into their homes in the 2000s. In the cities within the Valley South service area, the median household income ranges from $73,000 to $77,000 and poverty rates range from 8 to 12 percent. For context, the statewide median household income is $80,440 and the poverty rate is 11.8 percent.

Proposed Alberhill System Project

The ASP consists of a new 500/115 kV substation and two new 500 kV lines to connect the Alberhill System to the Serrano 500 kV substation to the west and the Valley 500 kV substation to the east. On the 115 kV side of ASP, one new 115 kV line would be built, and four existing 115 kV lines would be modified to connect Ivyglen, Fogarty, Elsinore, Skylark, and Newcomb substations to ASP. As part of this project, some of the 115 kV line modifications would be for the purpose of creating system tie-lines in the Valley South 115 kV system to increase system flexibility and resiliency. Figure 2 depicts the Alberhill System Project.

Figure 2: ASP Tie-lines.[3]



Objective and Technical Approach

Objective

The objective of this analysis is to assess whether the Valley South tie-lines result in power flow impacts that affect Valley South substation's reliability and resiliency.

Technical Approach

To assess how the tie-lines that are proposed as part of ASP perform with respect to capacity, reliability, and resiliency, several base cases representing scenarios were studied. These scenario cases represented alternatives that include tie-lines in the Valley South system, distributed battery energy resources, and centralized battery energy storage systems. This approach enabled comparison of the base case, which represents the Valley South system as it exists today without any new projects or tie-lines, with the following scenarios:

- Tie-line performance
- Battery energy storage performance

[3] *Source: 20210218 ASP Energy Division Briefing Deck 0218 Final*

kevala

- Combination of tie-lines and energy storage.

Power flow studies were conducted for each of these scenario cases and the results were compared under normal conditions and contingency conditions based on NERC reliability standards[4].

CPUC and SCE Objectives of ASP

As part of this analysis, ASP objectives from SCE and from the CPUC were considered. The CPUC developed the following objectives for ASP to provide a basis for developing a reasonable range of alternatives pursuant to the CEQA process.[5]

1. Relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers;
2. Construct a new 500/115 kV substation within the Electrical Needs Area that provides safe and reliable electrical service pursuant to NERC and WECC standards; and
3. Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems.

The power flow analysis conducted as part of this tie-line analysis addressed the CPUC's first and third objectives.

SCE listed the following project objectives in their planning study report and chose ASP as the preferred project based on its performance relative to the other twelve alternatives:

1. Serve current and long-term projected demand requirements.
2. Increase system operational flexibility and maintain system reliability by creating system ties that establish the ability to transfer to substations from the current Valley South system.

[4] While SCE's Valley 115 kV system is part of SCE's distribution network and not under CAISO control, its reliability performance must still be consistent with general accepted utility practices which are based on NERC Reliability standards. Parts of the NERC reliability Standards are adopted in SCE's Subtransmission Planning Criteria which require that all facilities operate within their continuous ratings under normal system conditions and under emergency ratings under contingency conditions.

[5] https://www.cpuc.ca.gov/environment/info/ene/alberhill/Docs/1.0%20ASP-VIG%20Introduction.pdf

3. Transfer a sufficient amount of demand from the Valley South system to maintain reserve capacity through the ten-year planning horizon.
4. Provide reliable service consistent with SCE's Subtransmission Planning Criteria and Guidelines.
5. Increase system reliability by constructing a project in a location suitable to serve the existing Valley South service area.
6. Meet project needs while minimizing environmental impacts.
7. Meet project needs in a cost-effective manner.

While most of SCE's project objectives are typical and similar to objectives stated by other utilities proposing similar projects, objective number 2, the specification of tie-lines, appears prescriptive and could potentially result in alternatives without system ties being dropped from further consideration even if they meet the other six objectives.

SCE's Objective number 4 refers to the Subtransmission Planning Criteria which covers a range of operational conditions and exceptions to the criteria, some of which are not applicable to Valley South Substation. This is typical of utility planning criteria which are generally based on NERC Reliability Standards, but may take their unique system configurations into consideration when developing exceptions. The portions of this criteria that are applicable to the Valley South transformers are the requirements for component overloads under emergency conditions. The Subtransmission Guidelines contain several guidelines that are applicable to the Valley South system configuration and its performance under normal and contingency conditions. These include maintaining sufficient transformer capacity under normal and contingency conditions and tie-lines to facilitate load transfer to limit the durations of customer interruptions. In the context of the Valley South system, these are applicable guidelines as the Valley South transformer is expected to overload under normal conditions starting in 2023. Neither the SCE Subtransmission criteria nor the guidelines as presented by SCE are currently being violated.

The power flow analysis conducted as part of this tie-line analysis addressed SCE's first, second, third, and fourth objectives.

Power Flow Assessment

Methodology and Assumptions

Using the General Electric (GE) Positive Sequence Load Flow (PSLF) software and PSLF base cases, power flow studies were conducted under normal and contingency conditions. Single contingencies and double contingencies where the circuits were on the same tower or in the same right-of-way were used to study contingency conditions. The contingencies used are shown below, in Table 1, and were obtained from the Quanta Technical Cost Benefit Analysis of Alternatives report[6]. The results were assessed based on NERC reliability standards and SCE planning criteria. Power flow results under each of the base cases described below were compared to assess what impacts the tie-lines have on reliability and resiliency at Valley South substation. Power flow results obtained for the Valley South (Base) scenario were used as a basis for comparing impacts.

Table 1: Single and Double Contingencies

Single Contingencies (N-1)	Double Contingencies (N-2)
Auld-Moraga #1	Auld-Moraga #2 & Valley-Triton
Auld-Moraga #2	Valley EFG-Auld #1 & Valley EFG-Auld #2
Valley EFG-Newcomb-Skylark	Auld-Moraga #2 & Pauba-Triton
Skylark-Tenaja	Valley EFG-Auld #2 & Valley EFG-Triton
Valley EFG-Elsinore-Fogarty	Valley EFG-Sun City & Valley EFG-Newcomb-Skylark
Valley EFG-Auld #1	Auld-Sun City & Valley EFG-Newcomb-Skylark
Valley EFG-Auld #2	Auld-Moraga #2 & Moraga-Pechanga
Valley EFG-Sun City	Valley EFG-Triton & Pauba-Triton
Valley EFG-Newcomb	Valley EFG-Elsinore-Fogarty & Valley-Newcomb

[6] Quanta Technology (January 27, 2021) Reliability Analysis of Alberhill System Project Report (Version 2).

Moraga-Pechanga	Fogarty-Ivyglen & Valley EFG-Ivyglen
Valley EFG-Ivyglen	
Valley EFG-Triton	

Power Flow Case Descriptions

[redacted]

[redacted]

[7] *Source: SCE PSLF Load Allocation Percentages Spreadsheet*

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[8] *Source: Exh C-2 SCE Planning Report.*

[redacted]

[redacted]

kevala

[redacted]

[10] *Exh C-2 SCE Planning Report.*

[redacted]

[redacted]

[11] *Source: Exh C-2 SCE Planning Report.*

[redacted]

[12] *Exh C-2 SCE Planning Report.*

kevala

Results

Power flow studies were conducted to assess system performance with system load modelled at the forecasted load for 2025. The following sections discuss results under normal system conditions, single contingency conditions, and double contingency conditions.

Normal Conditions

[redacted]

[redacted]

kevala

[redacted]

[redacted]

Single Contingency Conditions

[redacted]

kevala

[redacted]

[redacted]

[redacted]

[redacted]

Double Contingency Conditions

[redacted]

[redacted]

kevala

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Conclusions

The power flow studies conducted for this assessment were conducted using PSLF base cases provided by SCE and the assumptions were based on information obtained from both the SCE Planning Report, the Quanta Technical Reliability Analysis of Alberhill System Project report, and the Quanta Technical Cost Benefit Analysis of Alternatives report. The base cases were modified to reflect the 2025 load forecasts and to differentiate between the results more precisely. Several scenario cases were developed for this tie-line analysis. The results of this analysis conclude that:

- An overload occurs on the Valley South transformers under normal system conditions. Tie-lines that transfer substation service from Valley South to Valley North are effective in mitigating this overload. Transferring service for Newcomb and Sun City substations to Valley North and installing 50 MW of distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements. This alternative also meets the CPUC's objectives of relieving demand that overloads the Valley South Transformers; and partially meets the objective of enabling electricity service from Valley South or from a new 115 kV system.
- An assessment using both the worst single contingency and the worst double contingency showed that the transformers do not experience overloads, and in fact, their flows are significantly reduced. Other 115 kV lines in the Valley South system do experience overloads under contingency conditions. However, those appear unrelated to the Valley South transformer overloads.
- BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is most effective when combined with tie-lines.
- SCE concluded that the tie-lines in this alternative are ineffective in the event there is a double contingency or in the event that a catastrophic event occurs that results in the loss of both Valley South transformers. While a catastrophic event was not studied as part of this analysis, double contingencies were conducted and the power flow results indicated that this alternative performed effectively.

Appendix C – Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

kevala

Alberhill System Project

Evaluation of SCE's Load Forecast Methodologies and Performance Metrics

June 11, 2021

Table of Contents

kevala

Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP).

In this analysis, SCE's load forecasting methodologies were assessed relative to typical load forecasting methodologies and were found to be comparable to those used by similar utilities, including Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E). Kevala determined the methodologies to be reasonable and will further assess the impact of the load forecast methodologies in the electrical engineering analysis[13].

The performance metrics used by SCE to evaluate and rank the proposed project and each alternative were also assessed relative to performance metrics used by PG&E and SDG&E. Kevala determined the performance metrics to be reasonable, though several were considered to be uncommon, including the Load at Risk (LAR), flexibility-1, and flexibility-2 metrics[14]. SCE's adaptation of loss of load expectation (LOLE) into the metrics that were developed for assessing the ASP and alternatives (such as LAR, flexibility-1, and flexibility-2) affected the relative ranking of the ASP proposal over some alternatives. While LOLE is commonly used in other analyses, the use of LAR over alternative metrics likely caused proposals with tie-lines to be ranked higher than alternatives without them. The metrics developed by SCE have sufficient basis in acceptable metrics to be reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.

---

[13]The electrical engineering analysis will be reported in *Review of SCE's Electrical Engineering Analysis for the Alberhill System Project* (June, 2021)
[14] Note that all of the Flexibility-1 and Flexibility-2 metrics also use LAR as part of their calculation.

kevala

Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the two 560 MVA Valley South 500 kV transformers to become overloaded in 2023.

This report documents a review of SCE's load forecasting methodology for the Alberhill System Project. Additionally, this analysis considered SCE's reported peak load, the implications of the load forecast trend, and the potential modifications to the forecasted load by the proposed project.

Additionally, the performance metrics defined by SCE were compared to metrics typically used in the industry to evaluate whether they are comparable and reasonable. Kevala reviewed the documents released by SCE in their refiling, including SCE's *Revised Planning Study* (February 1, 2021) and the Quanta Technology's (Quanta) report, *Reliability Analysis of Alberhill System Project* (February 1, 2021)[15]. SCE's load forecasting methodology was then compared to load forecasting methodologies used by the California Energy Commission (CEC), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E). Lastly, additional research was conducted to determine whether the performance metrics used by SCE are commonly used by other comparable utilities, such as Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E).

[15] SCE's *Revised Planning Study* (February 1, 2021) is available on the CPUC website.

SCE Load Forecasting Methodologies

Overview

Kevala reviewed SCE's *Revised Planning Study* (February 1, 2021), Quanta's *Reliability Analysis of Alberhill System Project* (February 1, 2021), CEC's load forecast methodology, PG&E's load forecasting methodology, and SDG&E's load forecasting methodology.

Three load forecast methodologies were presented by SCE:

- SCE's load forecasting methodology
- Quanta's conventional load forecasting methodology
- Quanta's spatial load forecasting methodology

Load Forecasting Methodology Summary

SCE develops a 10-year peak load forecast based on peak load values collected from historical data which is then normalized to a common temperature base to account for variations in peak temperatures from year to year. Customer load growth and Distributed Energy Resource (DER) forecasts were also utilized to develop the peak load forecast. The DER considered include:

- Energy efficiency (EE)
- Energy storage (ES)
- Demand response (DR)
- Electric vehicle (EV) charging
- Distributed generation (DG)

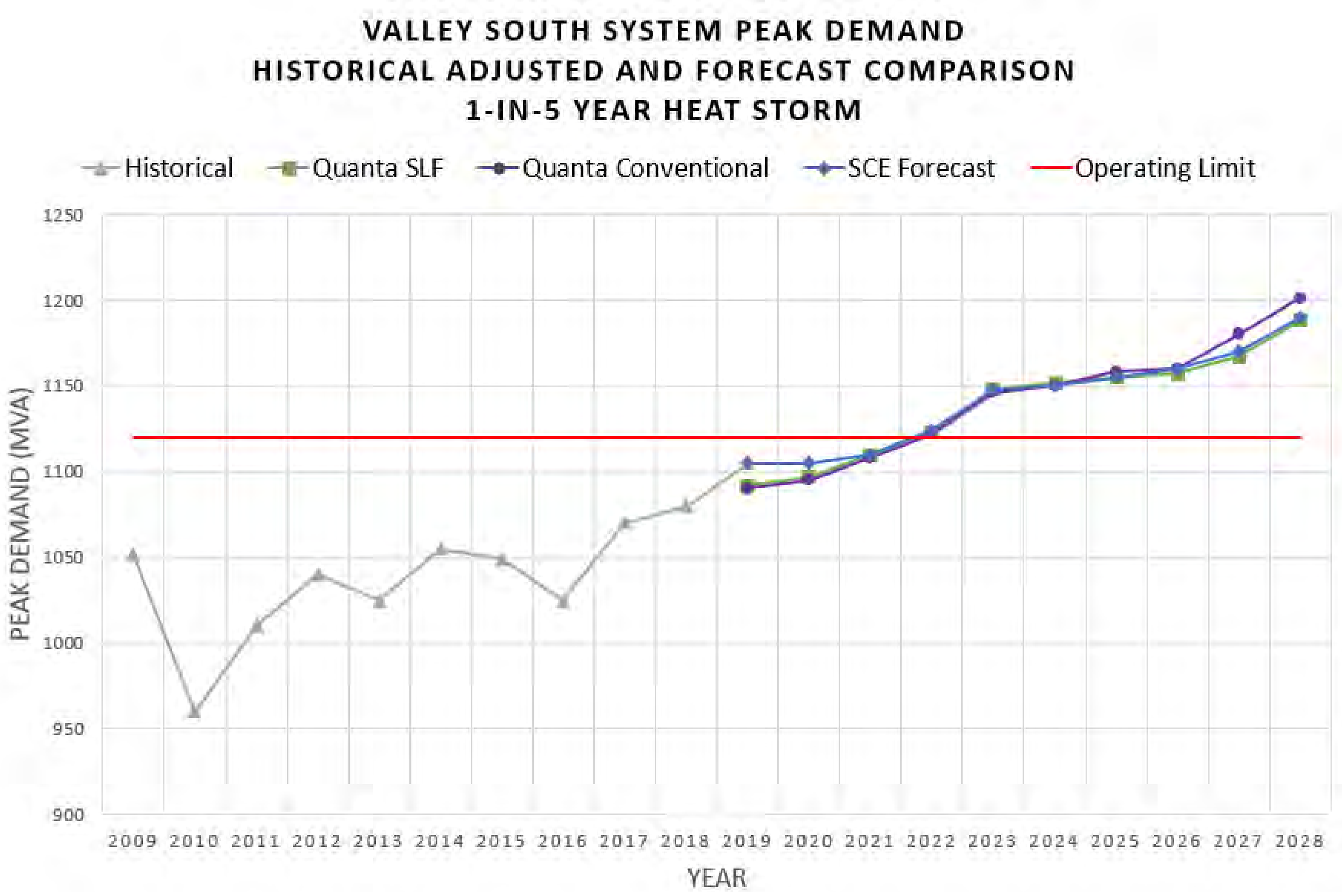
At the distribution level, SCE uses the CEC's Integrated Energy Policy Report (IEPR) that is derived from the California Energy Demand (CED) forecast to determine base load growth. SCE uses customer advanced metering infrastructure (AMI) data to inform load disaggregation of the CED forecast. This allows for DER and other load reducing programs to more accurately be considered when accounting for local and specific electrical needs. Moreover, as appropriate, any additional load growth that is not reflected in the CED forecast is appropriately incorporated into SCE's forecast.

For the second and third load forecasting methodologies that were reviewed, Quanta developed load forecasts based on other methodologies and sensitivities. These included:

- Extension of Conventional 10-year load forecast: A methodology in which the conventional 10-year load forecast was extended to produce a 30-year (2019-2048) 1-in-5 year peak load forecast based on historical substation load normalized to a common temperature.
- Spatial load forecast: A sensitivity that produced a 30-year (2019-2048) net peak system load. This involves the forecasting of peak load, customer count (based on zoning and land-use data), and customer energy consumption within a particular needs area. Non-traditional factors such as PV, EV adoption, and EE were incorporated by disaggregating CEC's CED forecast at the subdivision level.
- Spatial Base forecast: a sensitivity where DERs are assumed to continue historical trends, a Spatial Effective PV forecast where DERs are varied based on the California Energy Demand forecast developed at the CEC, and a spatial PV Watts sensitivity forecast which incorporates the unadjusted CED PV forecast.

The Spatial Effective PV load forecast methodology (a sensitivity as part of the Spatial Base forecast) was ultimately used by SCE to develop the forecast used to conduct the cost-benefit analysis for the ASP. Quanta selected the Spatial Effective PV load forecast as the likely future long-term load forecast scenario and used the extended 2019-2048 forecast to conduct analyses. A 10-year comparison of the SCE and Quanta load forecasts is depicted in the figure below.

Figure 1: SCE load forecasts and Quanta load forecasts



Assessment

The methodologies used by SCE in developing their load forecast for evaluating the ASP and its alternatives range from comparable to less commonly used. For example, SCE's 10-year peak load forecast uses a methodology that is comparable to that used by PG&E and SDG&E. All three utilities use historical loads, weather data, economic data, and demographic data as inputs. The difference is that where PG&E and SDG&E start with the CEC's CED forecast and then apply factors unique to their service territories to create a long-term forecast, SCE starts with historical load data and then uses the CED forecast to determine DER proportions in the long-term forecast. As a result, a direct comparison of SCE's load forecast methodology to the CED forecast methodology is not possible as SCE did not use the CED as the basis for its long-term forecast. Furthermore, the CED forecast produces a single forecast for SCE territory, whereas for the ASP, SCE developed a forecast specifically for the Valley South substation. SCE's load forecast incorporated the CEC's DER projections and this is consistent with the approach used by PG&E and SDG&E.

Kevala did not perform an assessment of the Quanta load forecasts as SCE retained Quanta to develop independent forecasts to validate the SCE forecast and to demonstrate that other independently developed methodologies arrived at forecasts that were similar to SCE's.

Performance Metrics

Overview

To assess the performance metrics used by SCE in evaluating the ASP and each of the alternatives, Quanta's report, *Reliability Analysis of Alberhill System Project* (February 1, 2021), was reviewed. Kevala conducted further research to find other instances where these performance metrics were used in evaluating and ranking projects and alternatives. This research included a review of the Expected Energy Not Served (EENS) Literature Search provided by SCE via email on July 13, 2020.

SCE used several different performance metrics as shown in Table 1. Some of these metrics are accepted industry standards while others are newer metrics that require evaluation.

Table 1: Definitions of SCE's performance metrics

System Performance Metric	Description
Load at Risk (LAR)	Calculated as MWh at risk during thermal overload and voltage violation periods under N-0 and N-1 conditions.
Expected Energy Not Served	This metric was formerly known as LAR. It was revised and renamed LAR in the reports included in the February 1, 2021 filing.
Maximum Interrupted Power (IP)	Calculated as maximum MW that would need to be curtailed during thermal overload and voltage violation periods under N-0 and N-1 conditions.
Flexibility 1 (Flex-1)	Calculated as the summation of LAR for all possible N-2 line contingencies. Results are probabilistically weighted to reflect the actual frequency of each N-2 contingency.
Flexibility 2 (Flex-2-1)	● Calculated as LAR resulting from loss of all transformers in the Valley South substation. ● Assumes a two-week period that randomly occurs throughout the year.
Flexibility 2 (Flex-2-2)	● Summation of LAR when the Valley South transformers are unavailable due to a fire. ● Assumes a two-week period that randomly occurs throughout the year.

Period of Flexibility Deficit (PFD)	Calculated as LAR resulting when the system tie-lines do not provide the required flexibility capacity under N-0 and N-1 conditions.

- **Normal overloads:** Defined as overloads that exceed 100% of normal ratings. The criteria require the loading of all transmission system facilities (transmission lines and transformers) to be within their normal ratings under normal operating conditions.
- **Emergency overloads:** Defined as overloads that exceed 100% of emergency ratings following single element contingencies and multiple element contingencies. The criteria require all transmission facilities to remain within their emergency ratings during single or multiple contingency conditions.
- **Voltage deviations:** Defined as deviations that should not exceed 5% from pre-contingency levels under single element contingencies, and 10% from pre-contingency levels under multiple element contingencies.

Assessment

Research of typical performance metrics by comparable utilities revealed no examples of utilities using LAR as a performance metric nor was it discussed in research papers as a performance metric. Additionally, a survey of other projects under CEQA review did not uncover projects using these metrics.

Prior to choosing LAR as the primary performance metric, SCE used EENS. Only one utility had used the EENS metric (British Columbia Hydro in Vancouver, British Columbia). All other publications that used EENS as a performance metric were research and academic publications.

The Flexibility 1 and Flexibility 2 metrics were developed by SCE to create a methodology that takes different contingency events and their probabilities into account while evaluating the performance of the alternative solutions relative to the ASP. These are not sufficiently comparable to other metrics used in industry such as loss of load and therefore do not provide clarity into the ranking and selection process. Although the metrics themselves are uncommon, the approach of using the metrics as a high-level comparison tool does enable a juxtaposition of the alternatives against each other based on a common metric.

The IP metric is a commonly used metric for calculating necessary curtailments to relieve overloads under normal or contingency conditions. Its use is appropriate as a metric for comparing the ASP and each of the alternatives.

The PFD metric is not a commonly used metric and appears to have been created for the purpose of giving more weight in the rankings to alternatives using tie-lines that provide more flexibility capacity based on their performance under normal and contingency conditions.

The Loss of load expectation (LOLE) metric is a commonly used metric in the industry, however, it appears that SCE may have adapted the LOLE metric into LAR in an effort to suit their particular system. Both LOLE and LAR are comparable in that they account for loss of load. The LOLE metric calculates the expected average number of days per year during which the load exceeds available generating capacity due to outages or other system conditions. In contrast, the LAR metric calculates the energy (MWh) potentially at risk of not being served due to a variety of system conditions, under normal and contingency conditions. The Flexibility-1 and Flexibility-2 metrics are also calculated based on the LAR resulting from the loss of the Valley South transformers. For this reason, the metrics developed by SCE appear to have been designed to give favorable weighting to alternatives with tie-lines relative to those without tie-lines.

SCE achieved this by assuming a two week duration for the loss of the Valley South transformers which results in higher levels of LAR. Although this contingency may be a low probability event, its duration contributes to the large magnitude of the LAR. This metric supports SCE's project objective to increase operational flexibility and maintain system reliability by creating system tie-lines that establish the ability to transfer substations from the current Valley South system.

It is possible that an application of LOLE without the SCE adaptation to favor tie-lines could have boosted the ranking of alternatives that create capacity on the Valley South transformers through the interconnection of PV and battery energy storage system (BESS) in the Valley South system or by transferring load away from Valley South substation. Namely, these are:

- The Centralized BESS in Valley South alternative
- The Valley South to Valley North and Distributed BESS in Valley South alternative

- The Valley South to Valley North and Centralized BESS in Valley South and Valley North alternative
- The Valley South to Valley North alternative
- The Valley South to Valley North to Vista alternative

The SCE alternatives and capacity improvements are available in Table 2, taken from SCE's *Revised Planning Study* (February 1, 2021), the alternatives listed show a 100% improvement under the Capacity Improvement column. However, they show an improvement of 1% or 3% under the Reliability/Resiliency Improvement column (compared to the ASP at 98%). This poor showing is due to the favorable weighting of tie-lines in the metrics developed by SCE. Kevala's report, *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021) provides an analysis of the reliability and resiliency of alternatives that consist of tie-lines. The tie-line power flow analysis was conducted based on North American Electric Reliability Corporation (NERC) reliability standards and Western Electricity Coordinating Council (WECC) criteria. The analysis demonstrated that alternatives that transferred load from two substations via tie-lines performed as well as alternatives with BESS under normal system conditions and slightly better under contingency conditions. The large difference in reliability/resiliency improvement results shown in the table below were not reflected in the power flow results.

Table 2: SCE alternatives and capacity improvement

Alternative	Results Through 2028		Results Through 2048	
	Capacity Improvement	Reliability/ Resiliency Improvement	Capacity Improvement	Reliability/ Resiliency Improvement
No Project	0%	0%	0%	0%
Alberhill System Project	100%	98%	99%	97%
SDG&E	100%	87%	99%	82%
SCE Orange County	99%	85%	93%	79%
Menifee	100%	67%	92%	62%
Mira Loma	100%	36%	77%	34%
Valley South to Valley North	100%	3%	78%	6%
Valley South to Valley North to Vista	100%	3%	89%	6%
Centralized BESS in Valley South	100%	1%	100%	3%
Valley South to Valley North and Distributed BESS in Valley South	100%	3%	81%	7%
SDG&E and Centralized BESS in Valley South	100%	87%	100%	83%
Mira Loma and Centralized BESS in Valley South	100%	36%	100%	35%
Valley South to Valley North and Centralized BESS in Valley South and Valley North	100%	3%	95%	6%
Valley South to Valley North to Vista and Centralized BESS in Valley South	100%	3%	92%	6%

Note: Performance improvements for each alternative represent the percentage of LAR reductions over the No Project Scenario. LAR N-0 and LAR N-1 are capacity metrics, while Flex-1, Flex 2-1, and Flex-2-2 are reliability/resiliency metrics.

The standards used in the power flow analyses by SCE are common and are in fact required as part of compliance with WECC and NERC regulations. All utilities in the WECC and NERC regions must comply with these criteria and standards.

Alberhill System Project Effect on the Load Forecast

Power flow studies conducted using SCE's load forecast confirmed that overloads on the Valley South transformers do occur in 2023. Similarly, simulations of the ASP in the power flow cases show a significant reduction in the flows through the Valley South transformers. All of the alternatives (except for the no-project alternative) also provide varying levels of reduction in power flows and bring the Valley South transformers within their normal ratings. This same forecast when projected long-term to thirty years becomes less certain as a thirty-year outlook is almost impossible to predict. Consequently, results showing when the Valley South transformers may become overloaded again under the ASP and each of the alternatives is highly speculative beyond the ten-year period. The normal practice is to use the 10-year forecast for planning projects and to use the 20-year forecast as an informative screening tool.

Conclusions

This report assesses SCE's load forecasting methodology and performance metrics for the ASP and proposed alternatives. Kevala reviewed SCE's Revised Planning Study and the Quanta Technology (Quanta) reports released by SCE in their February 1, 2021 refiling as well as researched and analyzed the load forecasting methodologies used by the CEC, PG&E, and SDG&E. These methodologies were then compared to those utilized by SCE for evaluation. Kevala determined that some metrics, such as LAR, were not being practiced elsewhere.

The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and at SDG&E. This assessment also ascertained that SCE may have used a common performance metric, LOLE, and adapted it to create a similar metric, LAR, in order to suit their system. Consequently, project alternatives with tie-lines were weighted more heavily than alternatives without. Although some performance metrics were uncommon due to this adaptation, the overall performance metrics developed by SCE have sufficient basis in other metrics commonly used by utilities. Kevala determined that the metrics and methodologies used by SCE to be reasonable as a high-level comparison tool for ranking the relative performances of the alternatives against each other.

Appendix D – Behind-the-Meter Adoption Propensity Analysis for the Valley South System

kevala

Alberhill System Project

Behind-the-Meter Adoption Propensity Analysis for the Valley South System

April 16th, 2021

kevala

Table of Contents

Executive Summary

The California Public Utilities Commission (CPUC), through the consultants Ecology and Environment (E&E, now WSP), is performing a California Environmental Quality Act ("CEQA") analysis of Southern California Edison's ("SCE") application for a Certificate of Public Convenience and Necessity ("CPCN") as part of the proposed Alberhill System Project (ASP). Kevala, Inc. (Kevala) prepared this report for the CPUC Energy Division to support the 2021 Draft Alternatives Screening Report (ASR) which WSP is preparing as part of the CPUC's CEQA review of the ASP.

As part of the proposed Alberhill System Project, SCE identified an initial list of 16 project alternatives: three minimal investment alternatives, seven conventional alternatives, one Non-Wire Alternatives (NWAs), and five hybrid alternatives. The purpose of this report is to provide additional data on the potential for behind-the-meter (BTM) solar + storage to serve as an alternative to components of the proposed project.

Kevala's analysis applied a bottom-up economic propensity for adoption modeling to identify customers in the Valley South System who would be likely adopters of BTM resources. This techno-economic analysis utilized technological parameters (e.g., BTM storage system size and performance) and economic inputs (e.g., installation cost) to consider how these factors impact a customer's utility bill and the likelihood of them interconnecting Distributed Energy Resources (DER).

This report provides details on the potential of DER throughout the Valley South system and identifies the amount of electric capacity that could be provided by BTM resources. Kevala's methodological approach, including economic and capacity implications for different scenarios of adoption levels of BTM alternatives, are detailed in this report. The range of adoption propensity scenarios was driven by SCE's value of service and outages, then utilized to model a potential BTM solar + storage adoption.

Introduction

Southern California Edison (SCE) submitted an application for the Alberhill System Project (ASP) on September 30, 2009 as part of Application A.09-09-022. An amended Proponent's Environmental Assessment (PEA) was later submitted by SCE on April 11, 2011.

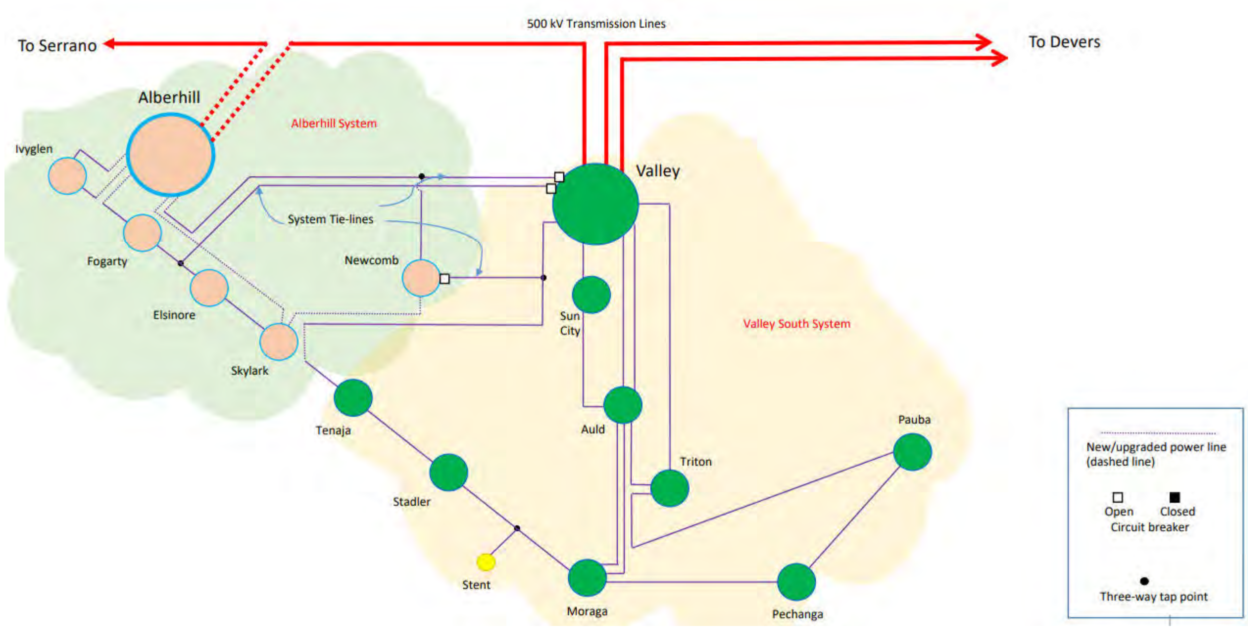
According to SCE's Planning Study, the Valley South system currently serves over 187,000 customers. The Planning Study also stated that forecasted load growth in the area will experience peak demand that exceeds the transformer capacity by the year 2022. The proposed Alberhill project is intended to alleviate capacity constraints in the Valley South system and will serve the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Hot Springs, Temecula, and Wildomar, and unincorporated Riverside County.

kevala

Project Overview

SCE's proposed Alberhill System Project is an upgrade to the Valley System located in the San Jacinto Region in Riverside, California. The Valley System consists of two distinct electrical systems: The Valley North and the Valley South. The ASP focuses on the Valley South system, which includes 14 substations (Ivyglen, Fogarty, Elsinore, Skylark, Tenaja, Stadler, Stent, Moraga, Newcomb, Sun City, Auld, Triton, Pauba, and Pechanga). The proposed ASP is illustrated in Figure 1 below.

Figure 1: Proposed Alberhill System Project



The ASP would consist of three main components. The first is construction of a new 500/115 kV electrical substation. The second is construction of two 500 kV transmission line segments, each about 1.7 miles long, that would connect the Alberhill substation to the existing Valley-Serrano 500 kV transmission line. The last component includes the addition of one new 115 kV transmission line and upgrades to four existing 115 kV transmission lines to transfer five existing substations from the Alberhill substation.

SCE identified and proposed the following project objectives in the Alberhill System Project Planning Study:

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

Alberhill System Proposed Alternatives

SCE developed the Alberhill System Project Planning Study[16], which identifies 13 project alternatives categorized as conventional alternatives, non-wire alternatives, and hybrid alternatives. The conventional alternatives are designed with transmission and/or subtransmission build-outs with system tie lines to neighboring systems. The non-wire alternatives utilize a centralized battery energy storage systems (BESS) design. Lastly, hybrid alternatives utilize non-wire alternatives to meet incremental capacity needs but also include conventional alternative approaches to meet the remaining capacity needs that develop.

The only proposed alternative incorporating distributed BESS is the Valley South to Valley North and Distributed BESS in Valley South hybrid solution. This alternative proposes transferring SCE's existing Newcomb and Sun City substations from the Valley South to the Valley North system and interconnecting three 12 kV BESS at the Auld, Elsinore, and Moraga substations. None of the proposed alternatives

[16] SCE's Exhibit C-2 Revised Alberhill System Project Planning Study, submitted on February 1, 2021

considered the impact of more granular adoption of BTM DERs, such as individual customers adopting solar + storage.

CPUC Objectives

As part of this analysis, ASP objectives from the CPUC were considered. The CPUC developed the following objectives for ASP to provide a basis for developing a reasonable range of alternatives pursuant to the CEQA process.[17]

- Relieve projected electrical demand that may exceed the operating limit of the two load-serving Valley South 115 kV System 500/115 kV transformers
- Construct a new 500/115 kV substation within the Electrical Needs Area that provides safe and reliable electrical service pursuant to NERC and WECC standards
- Maintain system ties between a new 115 kV System and the Valley South 115 kV System that enable either of these systems to provide electricity in place of the other during maintenance, during emergency events, or to relieve other operational issues on one of the systems

Kevala's Role

In its August 31, 2018 decision, the CPUC ordered SCE to revisit its application and consider Distributed Energy Resources ("DERs") including battery storage systems as part of the CEQA process. Kevala is further supporting the CEQA process by conducting an analysis of the amount of potential DERs that may produce an environmentally superior alternative under the SCE's application. The alternative considered in this report outlines likely DER adoption propensity based on economic and technological parameters.

Using its Network Assessor platform, Kevala analyzed BTM DER adoption propensity in support of the CPUC with the goal of determining if DERs, beyond those included in the base assessment by SCE, might reduce the magnitude and duration (i.e., shape of the need) or the viability of certain proposals.

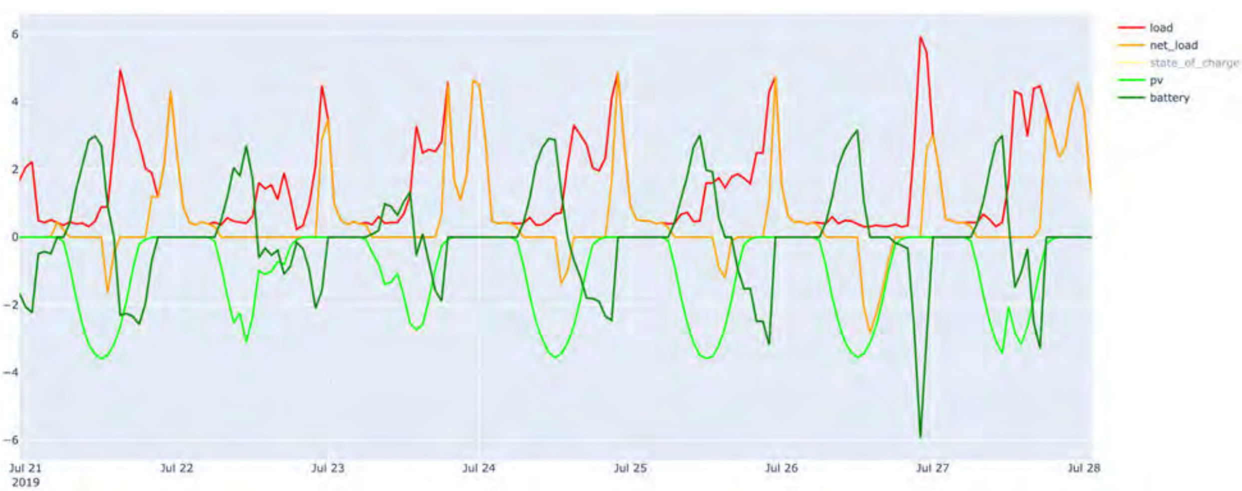
[17] https://www.cpuc.ca.gov/environment/info/ene/alberhill/Docs/1.0%20ASP-VIG%20Introduction.pdf

Methodology

This analysis is a techno-economic approach to identify economically feasible adoption of BTM resources at the customer-sited level (i.e., at existing residential and commercial and industrial (C&I) parcels). BTM resources include solar + storage and storage-only systems. The propensity for adoption of BTM resources is based on an individual customer's load profile, the payback period for the investment in BTM resources, Value of Lost Load (VOLL), and other factors. The analysis included evaluation of full 8760 time-series hourly load profiles (i.e., 365 days times 24 hours per day) for approximately 102,000 customer meters.

BTM storage systems function by either directly reducing the customer's own grid consumption (i.e., discharging to meet the customer's electrical demand, especially during peak demand periods), or sending excess stored power back to the grid, often in response to a price or event signal. When paired with solar, BTM storage can store excess generation to be used when solar goes offline (e.g. when the sun goes down). This allows solar + storage customers to further reduce consumption from the grid during times of peak demand, and likely save costs on their electricity bill through time-of-use rate arbitrage. DER behavior and impact on a residential customer's load profile is visualized in Figure 2 below.

Figure 2: Sample Load Profile for Residential Customer--July, 2019



As illustrated in Figure 2, the difference between load (red) and net load (orange) is the sum of the behavior of the PV system and the battery system. The payback period is calculated based on the tariff applied to each line to produce a monthly bill difference. The greater the bill savings, the shorter the payback period for the BTM resource.

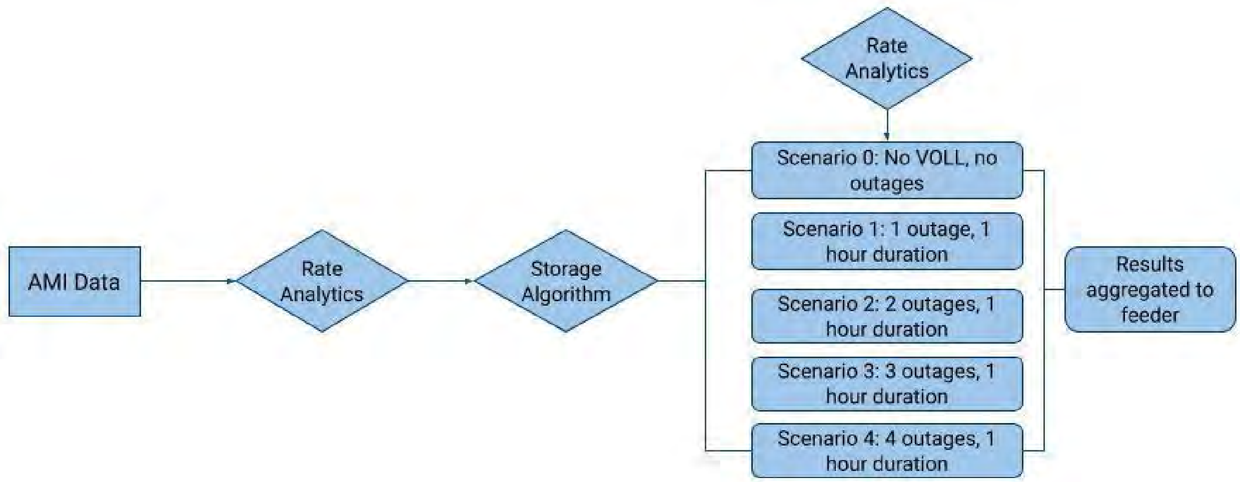
Approach

Kevala used its Network Assessor platform to ingest data provided by SCE and run advanced analytics related to grid infrastructure, load, generation, and price. At a high level, Kevala's Network Assessor platform ingests and employs data across the following three key areas:

- Load: In Kevala's Assessor platform load is typically provided as time series data (i.e. the magnitude of demand for electricity for every individual hour or 15 minute interval of a year). While time series data is generally incompatible with grid planning tools or geospatial (GIS) datasets, Kevala's platform is designed specifically to handle the volume of data associated with time series data. Kevala ingested SCE provided metered data to create an 8760 time series load profile for each building and, as needed, aggregated the data to the feeder level for analysis in power flow software.
- Generation: This includes both data at the bulk power level and DERs including, nameplate capacity and the associated feeder. Kevala uses this dataset to estimate local energy supply and forecasted production profiles.
- Infrastructure: For this project, Kevala used SCE-provided geospatial files on electric infrastructure.

Kevala's approach to the residential analysis is shown in Figure 3 below. The Advanced Metering Infrastructure (AMI) data was utilized for the rates analytics and the storage algorithm. These ultimately identified economically- efficient BTM adoption customers under five different scenarios, for residential customers, and three different scenarios for commercial and industrial customers.

Figure 3: Process of Kevala's BTM Analysis



These scenarios model the number and duration of outages annually. The number of outages was then assessed by determining where the sensitivity in likely DER adoption occurs. Because of this, the two analyses modeled different scenarios:

The residential scenarios modeled in the analysis are as follows:

- Scenario 0: No VOLL, no outages
- Scenario 1: 1 outage, 1 hour duration each
- Scenario 2: 2 outages, 1 hour duration each
- Scenario 3: 3 outages, 1 hour duration each
- Scenario 4: 4 outages, 1 hour duration each

The commercial and industrial analysis applied the following scenarios:

- Low Scenario: 4 outages, 4-hour duration each
- Medium Scenario: 6 outages, 4-hour duration each
- High Scenario: 8 outages, 4-hour duration each

Separate analyses of the types of resources adopted were also performed for residential customers and C&I customers. The residential analysis considered the potential for new customers to adopt solar + storage systems, as well as the potential for existing residential solar owners to adopt an incremental BTM storage system. In contrast, the C&I analysis looked solely at the potential for customers without existing DER to adopt new BTM storage systems, incentivized largely by a desire to reduce demand charges.

Inputs and Assumptions

To conduct the BTM analysis, Kevala modeled performance of BTM storage resources at the customer level, utilizing historical AMI data for the 2019 calendar year. The analysis was optimized for size to meet payback period requirements. Inputs used in the analysis (e.g., performance and cost of battery storage systems and current policies and incentive structures) are consistent with those used by the CPUC in the 2019 - 2020 Integrated Resource Planning (IRP) process. Table 1 summarizes the inputs and assumptions used in the residential and C&I analyses.

Table 1: Residential Analysis Inputs and Assumptions

Input	Residential Assumptions
Rate	Customers subject to SCE's 2020 time-of-use rate Peak: 4:00pm-9:00pm: **Summer:** June-September **Winter:** October-May
PV System Size, Performance, and Cost	Photovoltaic kilowatt (kW) size is optimized based on household energy consumption. A minimum threshold of 3 kW of PV system capacity was applied for the analysis. PV performance is modeled using National Renewable Energy Lab (NREL) PV Watts. PV system cost is aligned with the Integrated Resource Plan 90(IRP) assumptions on dollars per watt ($/W) for 2020.
Storage System Size, Performance, and Cost	7 kW/13.5 kWh lithium ion Adoption for number of batteries is optimized for each customer based on historic load and payback period Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is about $12,600

Policy Assumptions	Customers are eligible to benefit from the solar investment tax credit (ITC) and Self-Generation Incentive Program (SGIP) based on current program incentive levels and rules for enrollment.
Payback Period	10 years or fewer
Value of Loss Load	Scenarios are tested at a value of $9.47/kWh based on SCE's Value of Service Study assumptions for 1-hour outages. • Scenario 0: No VOLL, 0 outages • Scenario 1: 1 outage, 1 hour duration • Scenario 2: 2 outages, 1 hour duration • Scenario 3: 3 outages, 1 hour duration • Scenario 4: 4 outages, 1 hour duration

Table 2: Commercial and Industrial (C&I) Analysis Inputs and Assumptions

Input	C&I Assumptions
Rate	Customers are subject to appropriate SCE rates based on load and to demand charges.
PV System Size, Performance, and Cost	N/A
Storage System Size, Performance, and Cost	Adoption for number of batteries is optimized for each customer based on historic load and payback period. Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is about $12,600
Policy Assumptions	Customers are eligible to participate through SGIP, based on current incentive levels in SCE territory. Customers are not additionally incentivized through participation in other markets (i.e., demand response).
Payback Period	8 years or fewer

Value of Loss Load	• Low Scenario: 4 outages, 4-hour duration each • Medium Scenario: 6 outages, 4-hour duration each • High Scenario: 8 outages, 4-hour duration each

Results and Discussion

Detailed results for the BTM adoption propensity analysis (disaggregated by feeder) are provided in Appendix A.

Residential Results

The aggregated results for residential BTM Adoption Propensity are identified below in Table 3.

- Total Customers: the number of customers in which it would be economically efficient to adopt solar + storage under the respective scenarios.
- Total Customers (%): "Total Customers" as percentage of the total number of AMI records run in the analysis (i.e. Total Customers/ total number of AMI records)
- Sum of Total PV: Sum of expected PV capacity (MW) if all customers in "Total Customers" adopted DERs
- Storage (MW and MWh): Sum of expected storage if all customers in "Total Customers" adopted DERs
- Annual VOLL ($): annual dollar value for incentivizing customers to adopt DERs

The annual value of loss load (VOLL) can represent the annual dollar value for these customers to be incentivized to adopt BTM solar + storage. For example, Scenario 1 has an annual average VOLL of $127.85. If SCE offered every customer an incentive of $127.85 annually for the total payback period of the system, then it would be economically-efficient for 4,592 customers to adopt BTM resources. As the annual VOLL figure increases, it becomes more economically-efficient for more customers to adopt these resources.

The dollar value for VOLL in Table 3 was calculated using SCE's value of service. Per SCE's Value of Service Study[18], SCE assumed a cost of $9.47/kWh for a 1-hour outage for residential customers. This dollar value was applied to the different scenario calculations to produce the cost in which it would be economically viable for customers to adopt BTM solar + storage.

[18] This value of service is provided in Table 8-4 of the February 1, 2021SCE revised Planning Study.

Table 3: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

As shown in Table 3, there is considerable potential for BTM resource adoption across the Valley South area. Under Scenario 0, which models no outages and no VOLL, about 1,966 residential customers meet the criteria for economically efficient adoption and could potentially be incentivized to adopt BTM resources through an RFP process. If all of these customers adopted BTM solar and/or storage technology with the parameters outlined in this report, this would equate to approximately 4 MW of solar and 14 MW of storage.

This adoption rate increases very quickly as additional scenarios model an increasing number of outages. In contrast, Scenario 4 models a total of four hours of outages annually and has the greatest potential for adoption of BTM resources. Under this scenario, approximately 45,210 economically efficient customers were identified as potential adopters, equating to 350 MW of solar and 316 MW/610 MWh of storage.

Note that the dollar value for VOLL in Table 3 was calculated using SCE's value of service. Per table 5-6 of the SCE Value of Service Study, SCE assumed a cost of $9.47/kWh for a 1-hour outage for residential customers. This dollar value was applied to the different scenario calculations to produce the cost in which it would be economically viable for customers to adopt BTM solar + storage.

These economic values are broken down further by substation in Table 4 below. The proposed incentive identified is an aggregate cost of the VOLL for the entire payback period for each customer on a given feeder.

Table 4: Economic Outputs of Residential Records by Substation

Scenario 1														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	528	435	239	318	84	143	419	470	529	260	225	264	192	486
Avg. payback (yrs)	9.7	9.6	9.6	9.7	9.6	9.7	9.7	9.6	9.6	9.5	9.5	9.7	9.6	9.7
Total Incentive Cost ($)	652,187	32,988	294,030	393,347	104,084	175,714	519,089	576,709	653,437	319,260	276,693	327,184	236,023	599,883
Scenario 2														
Values	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	1398	953	596	898	235	280	1222	990	1323	633	573	787	417	1263
Avg. payback (yrs)	9.59	9.54	9.61	9.59	9.53	9.57	9.66	9.57	9.65	9.53	9.53	9.64	9.57	9.63
Total Incentive Cost ($)	1,257,139	1,032,213	567,779	756,952	201,093	340,493	999,829	1,117,248	1,260,173	617,851	534,022	630,555	455,799	1,157,449
Scenario 3														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	3264	2015	1383	2055	653	523	3222	2038	3056	1442	1503	1831	917	2902

Avg. payback (yrs)	9.50	9.49	9.51	9.47	9.56	9.36	9.53	9.48	9.50	9.37	9.54	9.51	9.38	9.52
Total Incentive Cost ($)	1,819,899	1,501,050	823,383	1,094,165	291,780	495,383	1,446,418	1,625,124	1,825,210	897,807	774,069	912,686	661,033	1,677,162

Scenario 4														
Substation	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton
Sum of Total AMI Records	5120	3200	2196	3507	1370	794	6117	3289	5043	2463	2917	2826	1415	4953
Avg. payback (yrs)	9.25	9.25	9.25	9.19	9.36	9.11	9.28	9.26	9.26	9.23	9.33	9.23	9.24	9.29
Total Incentive Cost ($)	2,345,508	1,942,835	1,062,945	1,408,259	376,894	641,444	1,863,069	2,103,792	2,353,456	1,161,172	998,869	1,176,172	853,394	2,163,447

A further breakdown of the adoption propensity by substation is presented in Table 5 below. As displayed in the table, the Newcomb and Auld substations are associated with the greatest BTM adoption potential. Under the Scenario 0 analysis, there is potential for adoption of 5 MW of PV and 1MW/2MWh of storage along the feeders connected to the Newcomb substation and 4 MW of PV and 1MW/3MW of storage along feeders connected to the Auld substation. This potential increases under Scenario 4 to 41 MW of PV and 43 MW/83 MWh of storage for the Newcomb substation and to 36MW of PV and 36 MW/69 MWh of storage for the Auld substation.

Table 5: Residential Adoption Propensity by Substation

Scenario 0															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 0 Total
Total Customers	206.0	223.0	109.0	109.0	27.0	72.0	141.0	253.0	212.0	128.0	102.0	95.0	85.0	204.0	1966.0
Total Customer (%)	4%	6%	4%	3%	2%	8%	2%	6%	4%	4%	3%	3%	5%	3%	4%
Total PV Installed (MW)	4.3	11.1	2.9	3.6	4.8	2.2	5.1	6.7	6.1	3.7	9.5	3.7	1.8	9.0	74.0
Sum of Total BESS (MW)	1.4	1.6	0.8	0.8	0.2	0.5	1.0	1.8	1.5	0.9	0.7	0.7	0.6	1.4	14.0
Sum of Total BESS (MWh)	2.8	3.0	1.5	1.5	0.4	1.0	1.9	3.4	2.9	1.7	1.4	1.3	1.2	2.8	27.0
Scenario 1															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 1 Total
Total Customers	528.0	435.0	239.0	318.0	84.0	143.0	419.0	470.0	529.0	260.0	225.0	264.0	192.0	486.0	4592.0
Total Customer (%)	9%	11%	9%	8%	5%	15%	5%	12%	9%	9%	6%	8%	12%	8%	8%
Sum of Total PV (MW)	7.7	13.5	4.3	5.7	5.4	3.1	8.1	9.2	9.4	5.2	10.8	5.4	2.9	12.0	103.0
Sum of Total BESS (MW)	3.7	3.1	1.7	2.2	0.6	1.0	2.9	3.3	3.7	1.8	1.6	1.9	1.3	3.4	32.0

Sum of Total BESS (MWh)	7.1	5.9	3.2	4.3	1.1	1.9	5.7	6.4	7.1	3.5	3.0	3.6	2.6	6.6	62.0

Scenario 2															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 2 Total
Total Customers	1398.0	953.0	596.0	898.0	235.0	280.0	1222.0	990.0	1323.0	633.0	573.0	787.0	417.0	1263.0	11568.0
Total Customer (%)	24%	24%	23%	21%	13%	30%	15%	25%	22%	21%	16%	24%	26%	21%	21%
Sum of Total PV (MW)	15.0	17.9	7.3	10.4	6.7	4.3	14.7	14.1	16.3	8.5	13.7	9.8	4.9	18.5	161.9
Sum of Total BESS (MW)	9.8	6.7	4.2	6.3	1.7	2.0	8.6	6.9	9.3	4.4	4.0	5.5	2.9	8.8	81.0
Sum of Total BESS (MWh)	18.9	12.9	8.1	12.1	3.2	3.8	16.5	13.4	17.9	8.6	7.7	10.6	5.6	17.1	156.2
Scenario 3															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 3 Total
Total Customers	3264.0	2015.0	1383.0	2055.0	653.0	523.0	3222.0	2038.0	3056.0	1442.0	1503.0	1831.0	917.0	2902.0	26804.0
Total Customer (%)	55%	51%	53%	49%	36%	56%	41%	52%	50%	47%	41%	56%	56%	48%	49%
Sum of Total PV (MW)	27.0	24.9	12.4	17.4	9.5	6.0	27.4	21.4	27.9	13.8	19.6	16.5	8.2	29.2	261.0

Sum of Total BESS (MW)	22.9	14.1	9.7	14.4	4.6	3.7	22.6	14.3	21.4	10.1	10.5	12.8	6.4	20.3	188.0
Sum of Total BESS (MWh)	44.1	27.2	18.7	27.7	8.8	7.1	43.5	27.5	41.3	19.5	20.3	24.7	12.4	39.2	362.0

Scenario 4															
Substations	Auld	Elsinore	Fogarty	Glen Ivy	Moraga	Murrieta	Newcomb	Pauba	Pechanga	Skylark	Stadler	Sun City	Tenaja	Triton	Scenario 4 Total
Total Customers	5120.0	3200.0	2196.0	3507.0	1370.0	794.0	6117.0	3289.0	5043.0	2463.0	2917.0	2826.0	1415.0	4953.0	45210.0
Total Customer (%)	86%	81%	85%	84%	75%	85%	77%	83%	83%	80%	79%	86%	87%	82%	82%
Sum of Total PV (MW)	36.2	30.7	16.3	24.1	12.9	7.4	40.9	27.7	37.8	18.8	26.3	21.2	10.7	39.2	350.0
Sum of Total BESS (MW)	35.8	22.4	15.4	24.5	9.6	5.6	42.8	23.0	35.3	17.2	20.4	19.8	9.9	34.7	316.0
Sum of Total BESS (MWh)	69.1	43.2	29.6	47.3	18.5	10.7	82.6	44.4	68.1	33.3	39.4	38.2	19.1	66.9	610.0

Figures 4 and 5 below depict the shape profiles of the PV system, storage system, customer demand before adopting DERs, and the customer net load after adopting DERs. These samples represent a residential customer for the months of July and March, respectively. Each line represents the following datasets:

- Red line: customer load before any DERs are interconnected
- Orange line: customer load after DERs are interconnected
- Light green line: State of PV (e.g., when it's generating energy).
- Dark green line: State of BESS (e.g., when the battery is charging and discharging)

The DERs behave so that the BESS is charging while the PV system is generating energy and discharging when demand peaks. With the adoption of DERs, the net load illustrates a reduction in the customer's energy demand as well as a shift in when the peak demand occurs.

Figure 4: Sample Load Profile for Residential Customer--July, 2019

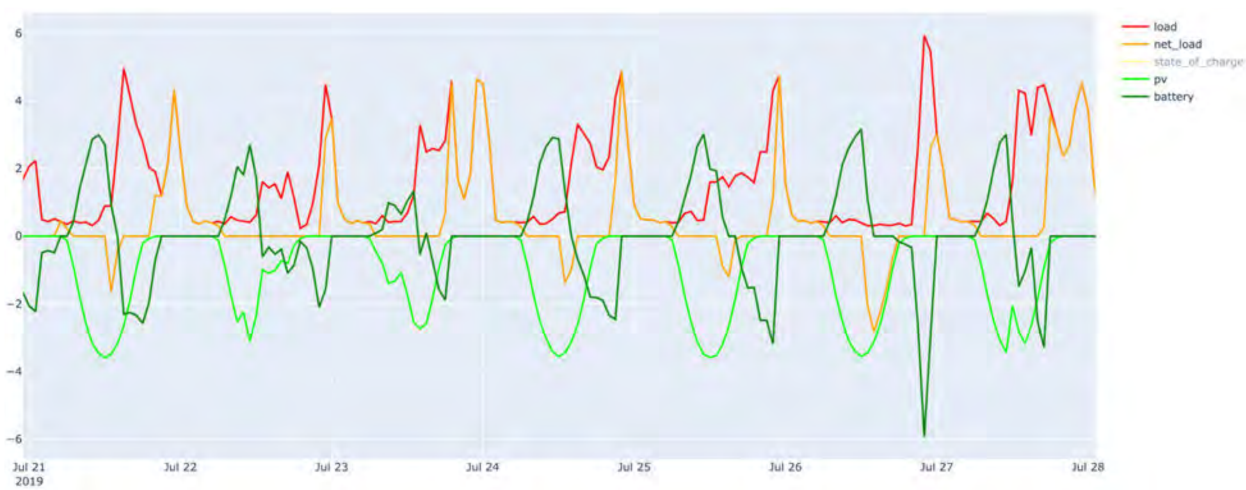
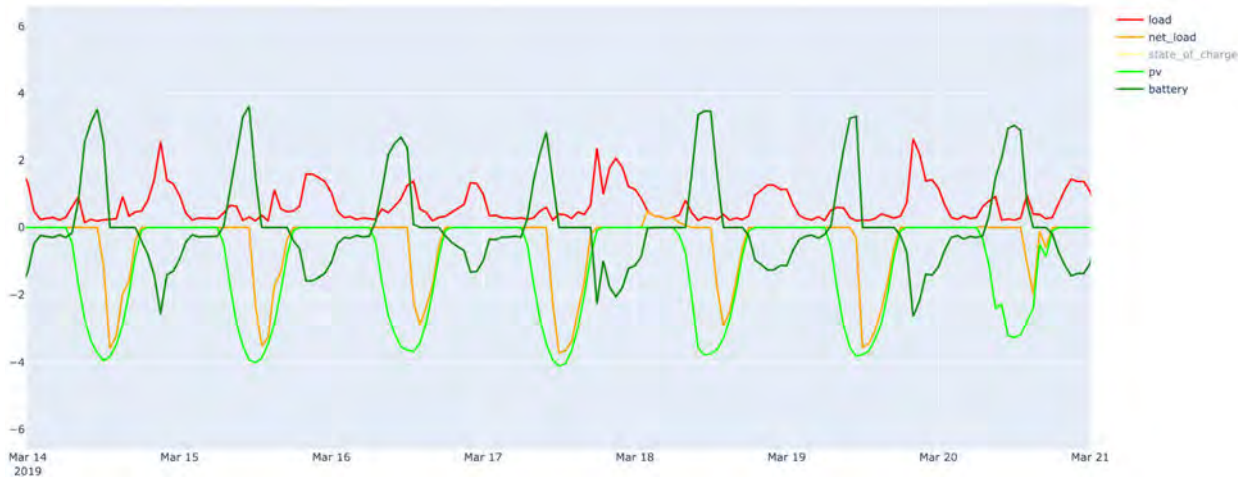


Figure 5: Sample Load Profile for Residential Customer--March, 2019



The interconnection of BTM solar + storage has considerable impact on a customer's load. The sample parcel in July shows significant reduction in demand during the highest peak times. In March, when there is generally lower demand on the grid, the sample parcel has a negative net load after interconnecting DERs.

Commercial & Industrial Results

Commercial and industrial customers represent a much smaller portion of the Valley South area and represent a much smaller portion of potential BTM adopters. The different scenarios run for C&I customers did not impact the number of customers to the point where it would be economically viable for additional customers to adopt BTM resources (i.e., the total number of customers in which it would be economically efficient to adopt BTM storage is a constant 520 customers for the low, medium, and high scenarios, as seen in Table 6 below). Modeling an increase in the number of outages annually had the greatest effect on the average payback period, which decreases gradually as the number of outages increases.

Table 6: C&I 2-Hour Battery Adoption Propensity

2-Hour Battery BTM Adoption Propensity	Scenario		
	Low	**Medium**	**High**
Total C&I customers	520	520	520
Commercial customers	520	520	520
Industrial customers	-	-	-
Total power (MW)	0.81	0.81	0.81
Total capacity (MWh)	1.45	1.45	1.45
Average payback period (yr)	1.41	0.93	0.70

Table 7: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	**Medium**	**High**
Total C&I customers	869	869	869
Commercial customers	869	869	869
Industrial customers	-	-	-
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

Overall, the results indicate that the greatest potential for DER adoption propensity is driven by residential customers adopting new solar + storage systems while C&I customers adoption storage is not as impactful. The C&I results disaggregated by feeder are provided in Appendix A.

Conclusions

This report uses Kevala's Network Assessor platform to analyze BTM solar + storage adoption propensity in the Valley system area of the San Jacinto region in support of the CPUC's CEQA analysis for the proposed Alberhill System Project. The findings indicate that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the Scenario 4 (4 outages, at 1 hour duration) adoption propensity for residential customers. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery.

Though the total number of customers economically advantaged by adopting BTM resources at different levels of incentive does not determine how many customers will definitively adopt them, it does indicate that there is a quantifiable increase in the number of economically beneficial adopters as the capacity payment or a perceived value of avoided loss load increases.

As stated previously, one of the objectives of the Alberhill System Project is to increase system operational flexibility and maintain system reliability by creating system tie lines that establish the ability to transfer to substations from the current Valley South System. Due to this objective, adoption of BTM resources on their own could not meet all the project objectives.

However, customers in the Valley South interconnecting solar + storage could alleviate capacity constraints on the Valley System. This is evident from Figures 4 and 5, in which a residential customer adding DERs observed reduced peak demands as well as a shift in the occurrence of peak demand.

Next Steps

The next phase of work will consist of a consideration of potential impacts of forecasted loads and DER adoption to the SCE ASP and proposed alternatives. Kevala will analyze how peak loads in the Valley South will shift with targeted DER procurement efforts beyond the DER adoption forecasted in the ASP and SCE proposed alternatives. Moreover, the effects that targeted procurements would have on the size and economics of the proposed alternatives will also be analyzed.

The results outlined in this report from the BTM Solar + Storage Adoption Propensity Analysis will be utilized to understand the impacts.

kevala

Appendix A: Commercial & Industrial Results

2 Hour C&I: Low						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average Payback (Years)
CARISO	191	191	-	153.34	276.02	1.44
CARMEL	2	2	-	204.44	368.00	1.38
KELLER	1	1	-	156.27	281.28	1.46
RIDGEMOOR	326	326	-	294.12	529.42	1.35

2 Hour C&I: Medium						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average Payback (Years)
CARISO	191	191	-	153.34	276.02	0.95
CARMEL	2	2	-	204.44	368.00	0.92
KELLER	1	1	-	156.27	281.28	0.96
RIDGEMOOR	326	326	-	294.12	529.42	0.89

2 Hour C&I: High						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average Payback (Years)
CARISO	191	191	-	153.34	276.02	0.71
CARMEL	2	2	-	204.44	368.00	0.69
KELLER	1	1	-	156.27	281.28	0.72
RIDGEMOOR	326	326	-	294.12	529.42	0.67

4 Hour C&I: LOW						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average payback period (yr)
ARGONAUT	1	1	-	71.47	257.28	1.37
BLITZ	13	13	-	135.22	486.80	1.32
CALLAWAY	1	1	-	155.56	560.00	1.30
CAPELIN	4	4	-	251.11	904.00	1.14
CARISO	195	195	-	329.10	1,184.76	1.30
CARMEL	2	2	-	327.11	1,177.60	1.05
CHAWA	1	1	-	111.00	399.60	1.33
COLLIER	4	4	-	323.52	1,164.66	1.34
CONESTOGA	13	13	-	419.14	1,508.92	1.38
DORMAN	13	13	-	383.94	1,382.20	1.31
GRIDIRON	1	1	-	81.33	292.80	1.38
GRUWELL	22	22	-	90.60	326.16	1.40
HORTON	89	89	-	99.20	357.14	1.37
KELLER	1	1	-	243.2	875.52	1.20
LAKELAND	131	131	-	192.87	694.32	1.35
LIMITED	1	1	-	134.22	483.20	1.41
MERLOT	1	1	-	69.60	250.56	1.39
POTTERY	1	1	-	120.00	432.00	1.29
REFEREE	1	1	-	85.33	307.20	1.37
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.89
ROCKRIDGE	3	3	-	80.79	290.84	1.36
SERNA	9	9	-	289.47	1,042.08	1.30
SUNDANCE	4	4	-	227.19	817.88	1.17
SUNGLASSES	1	1	-	89.07	320.64	1.37
VIA NORTE	30	30	-	127.70	459.72	1.31
VINE	1	1	-	143.33	516.00	1.30

4 Hour C&I: Medium						
Feeder	**Total C&I customers**	**Commercial customers**	**Industrial customers**	**Total power (kW)**	**Total capacity (kWh)**	**Average payback period (yr)**
ARGONAUT	1	1	-	71.47	257.28	0.92
BLITZ	13	13	-	135.22	486.80	0.88
CALLAWAY	1	1	-	155.56	560.00	0.86
CAPELIN	4	4	-	251.11	904.00	0.76
CARISO	195	195	-	329.10	1,184.76	0.86
CARMEL	2	2	-	327.11	1,177.60	0.70
CHAWA	1	1	-	111.00	399.60	0.89
COLLIER	4	4	-	323.52	1,164.66	0.90
CONESTOGA	13	13	-	419.14	1,508.92	0.91
DORMAN	13	13	-	383.94	1,382.20	0.88
GRIDIRON	1	1	-	81.33	292.80	0.92
GRUWELL	22	22	-	90.60	326.16	0.92
HORTON	89	89	-	99.20	357.14	0.91
KELLER	1	1	-	243.2	875.52	0.79
LAKELAND	131	131	-	192.87	694.32	0.90
LIMITED	1	1	-	134.22	483.20	0.92
MERLOT	1	1	-	69.60	250.56	0.93
POTTERY	1	1	-	120.00	432.00	0.87
REFEREE	1	1	-	85.33	307.20	0.92
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.59
ROCKRIDGE	3	3	-	80.79	290.84	0.91
SERNA	9	9	-	289.47	1,042.08	0.87
SUNDANCE	4	4	-	227.19	817.88	0.78

SUNGLASSES	1	1	-	89.07	320.64	0.91
VIA NORTE	30	30	-	127.70	459.72	0.87
VINE	1	1	-	143.33	516.00	0.86

kevala

4 Hour C&I: High						
Feeder	Total C&I customers	Commercial customers	Industrial customers	Total power (kW)	Total capacity (kWh)	Average payback period (yr)
ARGONAUT	1	1	-	71.47	257.28	0.92
BLITZ	13	13	-	135.22	486.80	0.88
CALLAWAY	1	1	-	155.56	560.00	0.86
CAPELIN	4	4	-	251.11	904.00	0.76
CARISO	195	195	-	329.10	1,184.76	0.86
CARMEL	2	2	-	327.11	1,177.60	0.70
CHAWA	1	1	-	111.00	399.60	0.89
COLLIER	4	4	-	323.52	1,164.66	0.90
CONESTOGA	13	13	-	419.14	1,508.92	0.91
DORMAN	13	13	-	383.94	1,382.20	0.88
GRIDIRON	1	1	-	81.33	292.80	0.92
GRUWELL	22	22	-	90.60	326.16	0.92
HORTON	89	89	-	99.20	357.14	0.91
KELLER	1	1	-	243.2	875.52	0.79
LAKELAND	131	131	-	192.87	694.32	0.90
LIMITED	1	1	-	134.22	483.20	0.92
MERLOT	1	1	-	69.60	250.56	0.93
POTTERY	1	1	-	120.00	432.00	0.87
REFEREE	1	1	-	85.33	307.20	0.92
RIDGEMOOR	3296	3296	-	447.84	1,612.21	0.59
ROCKRIDGE	3	3	-	80.79	290.84	0.91
SERNA	9	9	-	289.47	1,042.08	0.87
SUNDANCE	4	4	-	227.19	817.88	0.78
SUNGLASSES	1	1	-	89.07	320.64	0.91
VIA NORTE	30	30	-	127.70	459.72	0.87
VINE	1	1	-	143.33	516.00	0.86

Appendix E – Distributed Energy Resources Adoption and Impact on Load Forecast in Valley South System

Portions of this report have been redacted based on Southern California Edison's claims of confidentiality based on critical infrastructure information and other legal privileges.

kevala

Alberhill System Project

DER Adoption and Impact on Load Forecast in Valley South System

May 27, 2021

kevala

Table of Contents

Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP). This report builds on Kevala's prior analysis of potential adoption of behind-the-meter (BTM) solar+storage in the report *Behind-the-Meter Adoption Propensity Analysis for the Valley South System* (April 16, 2021) and quantifies the impacts of BTM distributed energy resources (DER) on the load forecasts used by SCE in its support of the ASP application.

In that report, Kevala analyzed modifications to load forecasts by potential DER adoption. The analysis indicated that up to 350 megawatts (MW) of photovoltaics (PV) and up to 316 MW of storage could potentially be adopted by residential customers in SCE territory. If realized, these DER penetration levels could greatly impact the power flows in the Valley South system, potentially reducing peak loading.

This report finds that the initial load forecasts result in a significant number of violations in power flow analysis when reduced by incremental DER adoption. Specifically, reducing the peak load by 188 MW via incremental DER adoption in the region results in a reduction of flows on the Valley South transformers. Power flow modeling of DER penetration at this level does not cause high voltage violations. With the addition of voltage regulation equipment, higher penetration levels of DERs could potentially be incorporated into the Valley North and Valley South systems, further reducing the load beyond 188 MW to 316 MW of DER-drive load reduction.

This report does not consider the potential impacts of the load reductions on the ASP or SCE's proposed alternatives. However, in subsequent reports, Kevala will analyze these alternative proposals and their potential to reduce or eliminate certain power flow violations in the Valley South and Valley North systems.

Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) application process. The project is driven by forecasted load growth that SCE expects to overload the two 560 mega volt-amps (MVA) Valley South 500 kilovolt (kV) transformers in 2023.

To support the CEQA process, several technical analyses are being conducted. In the report, *Behind-the-Meter Adoption Propensity Analysis for the Valley South System (April 16, 2021)*, Kevala examined the potential for customers in the Valley South system interconnecting behind-the-meter (BTM) distributed energy resources (DER) (e.g., photovoltaic (PV) and battery energy storage systems (BESS)). The analysis was conducted to evaluate the effect of targeted BTM DER procurement.

This report expands on the findings from the BTM adoption propensity analysis to consider the impact of DER adoption on peak load. Kevala analyzed how peak loads in this area will change with targeted DER procurement efforts beyond the DER adoption propensity forecasted in the ASP and SCE proposed alternatives. After determining the new peak loads from the BTM adoption propensity results, a power flow analysis was performed to determine the new system impacts.

Project Overview

SCE developed the Alberhill System Project Planning Study, which identified project alternatives categorized as conventional alternatives, non-wire alternatives, and hybrid alternatives. The conventional alternatives are designed with transmission and/or subtransmission build-outs with system tie lines to neighboring systems. The non-wire alternatives utilize a centralized BESS design. Hybrid alternatives utilize non-wire alternatives to meet incremental capacity needs but also include conventional alternative approaches to meet the additional capacity needs that could develop.

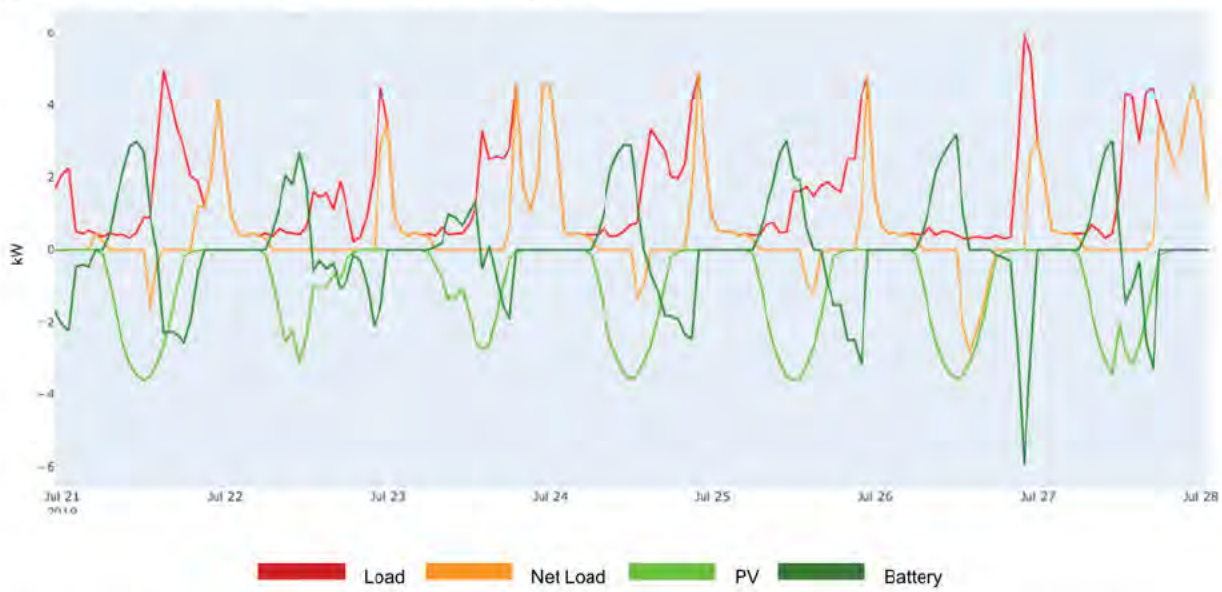
The only proposed alternative that incorporated distributed BESS is the Valley South to Valley North and Distributed BESS in Valley South hybrid solution. This alternative proposes transferring SCE's existing Newcomb and Sun City substations from the Valley South system to the Valley North system and interconnecting three 12 kV BESS at the Auld, Elsinore, and Moraga substations. None of the proposed alternatives considered the impact of more granular adoption of BTM DERs, such as individual customers adopting solar + storage.

Kevala BTM Adoption Propensity Analysis

BTM battery energy storage systems (BESS) can be used to directly offset the customer's energy usage by discharging energy from the battery to reduce the customer's electrical demand, especially during peak demand periods. Another typical application is to send excess stored power back to the grid, often in response to a price or event signal. When paired with solar, BTM storage can store excess generation for use when solar goes offline (e.g., when the sun goes down). This allows for solar + storage customers to further reduce grid-supplied energy consumption during times of peak demand, and likely save costs on their electricity bill through time-of-use rate arbitrage.

Representative solar + storage DER behavior and the resulting impact on a residential customer's load profile is modeled and visualized in Figure 1 below.

Figure 1: Sample Load Profile for Residential Customer



As illustrated in Figure 1, the difference between load (indicated in red) and net load (indicated in orange) is the sum of the electrical output of the PV system and BESS. For residential customers, BESS was modeled so that batteries charge during PV generation and discharge during time-of-use rate periods. Commercial and industrial (C&I) customers were modeled so that batteries discharge to reduce utility demand charges.

The payback period is calculated based on the tariff applied to the load and net load, separately, to produce a monthly bill difference. The greater the bill savings, the shorter the payback period for the BTM resource.

Approach

Kevala utilized their Network Assessor (NA) platform to perform the BTM solar + storage adoption propensity analysis. SCE provided Advanced Metering Infrastructure (AMI) data for the year 2019 which was ingested and stored in the NA platform. Advanced analytics related to grid infrastructure, load, generation, and price were then run to attain solar + storage adoption results. The analysis was optimized for PV and BESS system size to meet payback period requirements.[19]

Ultimately, the analysis identified customers for whom it would be economically efficient to interconnect BTM resources. Inputs of performance, cost of battery storage systems, and current policies and incentive structures correspond to those used by the CPUC in the 2019 - 2020 Integrated Resource Planning (IRP) process. Different scenarios were modeled to demonstrate value of loss load for residential customers and commercial and industrial customers.

The residential scenarios modeled in the analysis are as follows:

- **Scenario 0**: No Value of Loss Load (VOLL), no outages
- **Scenario 1**: 1 outage, 1 hour duration each
- **Scenario 2**: 2 outages, 1 hour duration each
- **Scenario 3**: 3 outages, 1 hour duration each
- **Scenario 4**: 4 outages, 1 hour duration each

The commercial and industrial scenarios modeled in the analysis are as follows:

- **Low Scenario**: 4 outages, 4-hour duration each
- **Medium Scenario**: 6 outages, 4-hour duration each
- **High Scenario**: 8 outages, 4-hour duration each

Results

Kevala's BTM adoption propensity analysis indicated that up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be

[19] The complete list of parameters applied to the analysis is provided in Appendix A.

economically efficient if adopted under the Scenario 4 (4 outages, at 1 hour duration) adoption propensity for residential customers. For commercial and industrial customers, over 5 MW/18 MWh of potential storage would be economically efficient if adopted under a low, medium, or high adoption scenario for a 4-hour battery.

Table 1: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

Table 2: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery BTM Adoption Propensity	Scenario		
	Low	Medium	High
Total C&I customers	869	869	869
Commercial customers	869	869	869
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

The total number of customers that would receive economic benefits by adopting BTM resources at different levels of incentive does not determine how many customers will ultimately adopt these resources. It does indicate a quantifiable increase in the number of economically beneficial adopters as the capacity payment or a perceived value of avoided loss load increases.

The full description of the methodology and analysis of the results is available in the report, *Behind-the-Meter Adoption Propensity Analysis for the Valley South System (April 16, 2021)*.

Valley South System Load Forecast

Due to forecasted load growth, SCE developed ASP and the alternatives to address overloads expected to occur in 2023 on the two 500 kV Valley South transformers. A review of SCE's load forecasting methodology revealed that SCE developed a 10-year peak load forecast based on peak load values that were collected from historical data. The forecast was then normalized to a common temperature base to account for variations in peak temperatures from year to year. Customer load growth and DER forecasts (including energy efficiency (EE), energy storage (ES), demand response (DR), electric vehicle (EV) charging, and distributed generation (DG)) were used to develop the peak load forecast. At the distribution level, SCE used the California Energy Demand (CED) forecast, derived from the California Energy Commission's (CEC) Integrated Energy Planning Report (IEPR), to determine the base load growth. SCE used customer AMI data to inform load disaggregation of the CED forecast to achieve the granularity necessary to account for local area specific electrical needs. Additionally, as appropriate, SCE incorporated any additional load growth that is not reflected in the CED forecast.

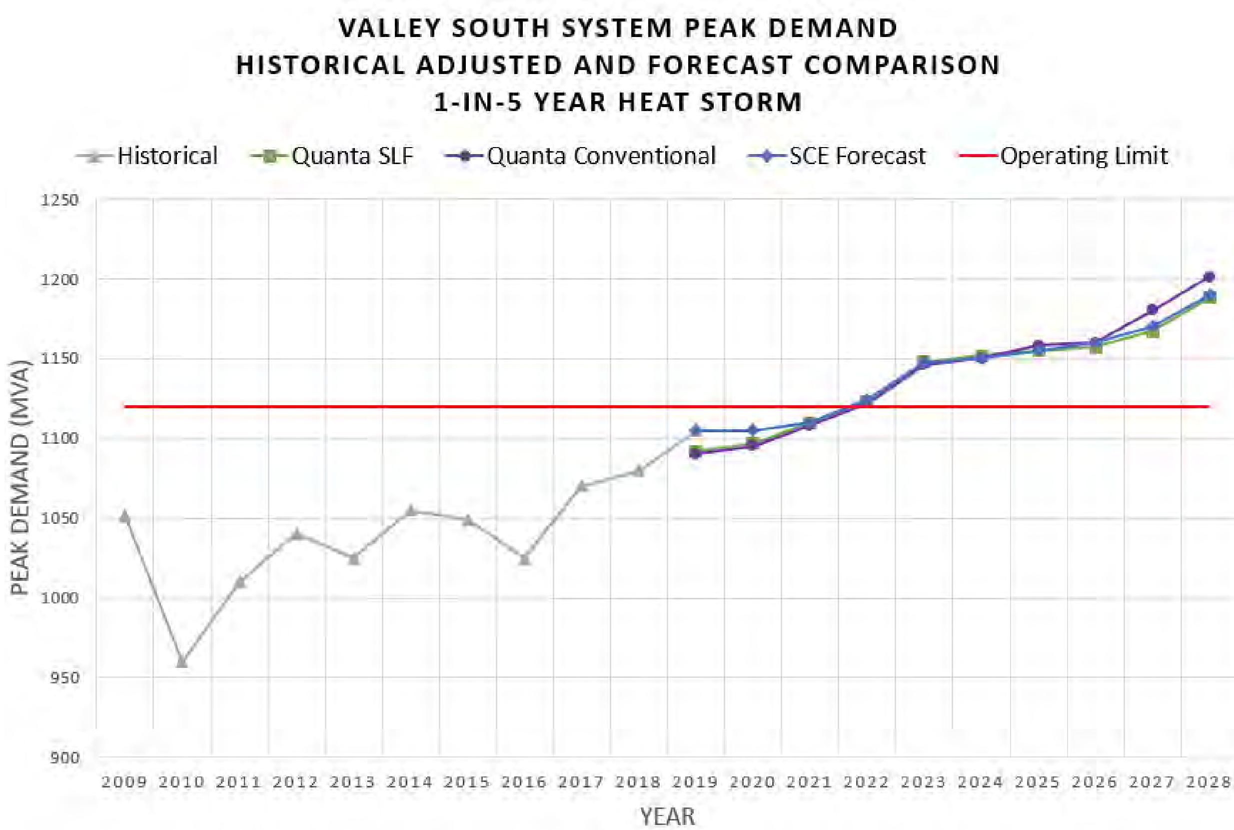
SCE retained Quanta Technology to conduct several technical analyses including a cost benefit analysis and several load forecasts based on different methodologies and sensitivities. These included:

- A conventional 10-year load forecast which was extended to produce a 30-year (2019 to 2048) 1-in-5-year peak load forecast that was based on historical substation load normalized to a common temperature.
- A spatial load forecast which produced a 30-year (2019 to 2048) net peak system load. This involved the forecasting of peak load, customer count (based on zoning and land-use data), and customer energy consumption within a particular electrical needs area. Non-traditional factors such as PV, EV adoption, and EE were incorporated by disaggregating the CEC's CED forecast at the subdivision level.
- A spatial base load forecast where DERs were assumed to continue historical trends
- Spatial effective PV load forecast where DERs were varied as reflected in the CED

- Spatial PV Watts sensitivity forecast in which the unadjusted CED PV forecast was incorporated.

Quanta selected the Spatial effective PV load forecast as the likely future long-term load forecast scenario and used the extended 2019-2048 forecast to conduct their analyses. A comparison of the SCE and Quanta 10-year load forecasts are depicted in the figure below and further assessed in Kevala's load forecast analysis[20].

Figure 2: Graph representation of the Valley South system peak demand forecast



[20] *Review of SCE's Load Forecast and Performance Metrics (June 2021)*

DER Adoption Impact on Load Forecast

The Valley South system load forecast was modified based on the DER capacities determined through the BTM DER propensity analysis. As SCE peak load does coincide with PV system peak production, BESS were utilized for their dispatchability which enables effective peak load reduction. The PV capacities determined in the propensity analysis were significant. However, PV production peaks earlier in the day than the system peak and were therefore helpful in reducing the overall energy consumption throughout the day. Because of this, only the BESS capacity was used to model the reduction in peak load as the PV capacity would not be available during SCE's peak load period.

Table 3 below shows the reduced peak load based on the potential BESS capacity under each scenario. As the BTM DER propensity is driven by several factors including incentives, it is difficult to predict when the full potential capacity represented under each scenario could be adopted. To account for the uncertainty in rate of adoption, the scenarios were applied over the course of several study years representing load forecasts spanning 2022 to 2028. This study period allows for an analysis of the power flow impacts and considers whether BTM DER adoption occurs over the course of months or years. This approach also identified the BTM DER adoption level at which system impacts were observed.

The results of the power flow analysis of the impacts of BTM DER are summarized in Table 3 below.

Table 3: Peak Load Reduction Based on Capacity of BTM DER

Scenario	Total BESS (MW)	2022 Net Load (MW)	2023 Net Load (MW)	2024 Net Load (MW)	2025 Net Load (MW)	2026 Net Load (MW)	2027 Net Load (MW)	2028 Net Load (MW)
Scenario 0	14	1118	1132	1138	1145	1152	1160	1169
Scenario 1	32	1100	1114	1120	1127	1134	1142	1151
Scenario 2	81	1051	1065	1071	1078	1085	1093	1102
Scenario 3	188	944	958	964	971	978	986	995
Scenario 4	316	816	830	836	843	850	858	867

[redacted]

[redacted]

[redacted]

kevala

[redacted]

[redacted]

kevala

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

kevala

[redacted]

System Voltages

In addition to the system capacity, the voltages were also assessed. As BTM DER installations increase, voltages on the system begin to rise on the 115 kV system. Consequently, the voltage violations are highlighted to ensure they are addressed as part of the DER interconnection process. Any costs associated with required voltage regulation equipment would need to be considered.

The high voltages were observed in the alternative case, but not in the base case or in the ASP case. Transferring load service for the Newcomb and Sun City substations represented a 195.8 MW load reduction on the Valley South system. This transfer, compounded by the further reduction in peak loads, results in high voltages in the Valley South system. Under scenarios 0, 1, 2, and 3, the magnitudes of the voltages on two buses steadily increased as more capacities of DER were installed. Under scenario 4 when the peak load is reduced by 316 MW, eleven buses were in violation of voltage criteria in the alternative case.

It was found that scenario 3 is the appropriate level of DER installations that can be achieved without needing to install voltage regulation equipment to mitigate high voltages. To mitigate high voltages above and beyond the scenario 3 levels of DER, SCE could include requirements in the DER interconnection process to ensure that new DER installations do not result in voltage violations. These could include specifying power factor or volt-var operating threshold values and requiring the installation of inverters with grid responsive features. More traditional methods such as voltage regulators or reactors can also be implemented to mitigate the high voltages.

No low voltages were observed on the base, alternative, or ASP cases under any of the DER adoption propensity scenarios.

kevala

Conclusions

In scenario 4 of Kevala's BTM DER propensity analysis, Kevala demonstrated that up to 350 MW of PV and up to 316 MW of battery energy storage could potentially be adopted by residential customers in SCE territory. This report determined that these levels of potential DER adoption substantially affect load and could make an impact on the power flows in the Valley South system. The BTM DER propensity analysis identified DER capacities which were then applied to the peak load forecast and power flow analyses. The results indicated that with the current configuration and no other projects, 188 MW of BTM BESS could eliminate the overloads on the Valley South transformers under normal system conditions. Overloads were not observed on the Valley South transformers under the worst single contingency or under the worst double contingency.

In the alternative case where service for Newcomb and Sun City substation loads were transferred to the Valley North substation, power flows over the Valley South transformers were sufficiently reduced such that they did not overload under normal or contingency conditions. Voltage criteria violations were also assessed. Eleven buses were observed to experience voltages at 5 percent above their nominal voltage in scenario 4 when the peak load was reduced by 316 MW. In scenarios 0 through 3, two buses had voltages at 5 percent above their nominal voltage. No low voltages were observed in the base case, alternative case, or under any of the DER adoption propensity scenarios.

Power flow results indicate that the BTM DER propensity that can be installed without causing negative impacts on the system is scenario 3. This scenario outlines the situation where DER is adopted to mitigate 3 outages for 1 hour duration each, totaling 188 MW of BESS and 261 MW of PV. The BESS capacity was used to model the reduction in peak load as the PV capacity would not be available during SCE's peak load period. This 188 MW reduction in peak load relieves the overload on the Valley South transformers and does not cause high voltages on the 115 kV system. Therefore, it appears that scenario 3 is the appropriate level of DER installations that can be achieved without needing to install voltage regulation equipment to mitigate high voltages.

These results confirm the findings of the tie-line analysis, whereby some tie-lines in combination with distributed PV and BESS yield results comparable to the ASP. In the tie-line analysis, the minimum DER required to relieve the overloads on the Valley South transformers was modeled. This analysis goes further and determines the BTM DER propensity, then evaluates what the impacts to the system would be with increased installed capacity.

From the power flow results under each of the BTM DER propensity scenarios, it appears that scenario 3 may be the appropriate level of DERs where the maximum benefits of load reduction are derived and at scenario 4, costs associated with projects to mitigate high voltages would need to be considered.

The two remaining Kevala analyses will do the following:

- Assess the load forecasting methodology and system performance metrics used by SCE in evaluating and ranking the alternatives
- Provide an electrical engineering analysis which will review the system reliability and resiliency metrics used by SCE to evaluate ASP and the alternatives. This will incorporate the power flow analyses conducted for the tie-line analysis and the BTM DER propensity analysis.

Appendix A: Full List of Parameters for BTM Adoption Propensity Analysis

Table 10: Residential Analysis Inputs and Assumptions

Input	Residential Assumptions
Rate	Customers subject to SCE's 2020 time-of-use rate Peak: 4:00pm-9:00pm Summer: June-September Winter: October-May
PV System Size, Performance, and Cost	Photovoltaic kilowatt (kW) size is optimized based on household energy consumption. A minimum threshold of 3 kW of PV system capacity was applied for the analysis. PV performance is modeled using National Renewable Energy Lab (NREL) PV Watts. PV system cost is aligned with the Integrated Resource Plan (IRP) 90 assumptions on dollars per watt ($/W) for 2020.
Storage System Size, Performance, and Cost	7 kW/13.5 kWh lithium-ion battery Adoption for number of batteries is optimized for each customer based on historic load and payback period Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate

	Storage system total cost (hardware plus installation) is approximately $12,600
Policy Assumptions	Customers are eligible to benefit from the solar investment tax credit (ITC) and Self-Generation Incentive Program (SGIP) based on current program incentive levels and rules for enrollment.
Payback Period	10 years or fewer
Value of Loss Load	Scenarios are tested at a value of $9.47/kWh based on SCE's Value of Service Study assumptions for 1-hour outages. ● Scenario 0: No VOLL, 0 outages ● Scenario 1: 1 outage, 1 hour duration ● Scenario 2: 2 outages, 1 hour duration ● Scenario 3: 3 outages, 1 hour duration ● Scenario 4: 4 outages, 1 hour duration

Table 11: Commercial and Industrial (C&I) Analysis Inputs and Assumptions

Input	**C&I Assumptions**
Rate	Customers are subject to appropriate SCE rates based on load and to demand charges.
PV System Size, Performance, and Cost	N/A
Storage System Size, Performance, and Cost	Adoption for the number of batteries is optimized for each customer based on historic load and payback period. Storage performance uses estimates used in the 2019 IRP assumptions on dollars per watt ($/W) for 2019 10-year warranty 90% Round trip efficiency 2% Annual degradation rate Storage system total cost (hardware plus installation) is approximately $12,600
Policy Assumptions	Customers are eligible to participate through SGIP, based on current incentive levels in SCE territory. Customers are not additionally incentivized through participation in other markets (i.e., demand response).
Payback Period	8 years or fewer
Value of Loss Load	• Low Scenario: 4 outages, 4-hour duration each • Medium Scenario: 6 outages, 4-hour duration each • High Scenario: 8 outages, 4-hour duration each

Appendix B: BTM Adoption Propensity Analysis Results

Table 12: Residential BTM Adoption Propensity

BTM Adoption Propensity	Scenario				
	Scenario 0	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Customers	1,966	4,592	11,568	26,804	45,210
Total Customers (%)	4%	8%	21%	49%	82%
Sum of Total PV (MW)	4	103	162	261	350
Sum of Total BESS (MW)	14	32	81	188	316
Sum of Total BESS (MWh)	27	62	156	362	610
Annual VOLL ($)	$0	$127.85	$255.69	$383.54	$511.38

Table 13: C&I 2-Hour Battery Adoption Propensity

2-Hour Battery BTM Adoption Propensity	Scenario		
	Low	Medium	High
Total C&I customers	520	520	520
Commercial customers	520	520	520
Total power (MW)	0.81	0.81	0.81
Total capacity (MWh)	1.45	1.45	1.45
Average payback period (yr)	1.41	0.93	0.70

Table 14: C&I 4-Hour Battery Adoption Propensity

4-Hour Battery BTM Adoption Propensity	**Scenario**		
	Low	**Medium**	**High**
Total C&I customers	869	869	869
Commercial customers	869	869	869
Total power (MW)	5.03	5.03	5.03
Total capacity (MWh)	18.10	18.10	18.10
Average payback period (yr)	1.30	0.86	0.65

Appendix F – Review of SCE's Electrical Engineering Analysis for the Alberhill System Project

Alberhill System Project

Review of SCE’s Electrical Engineering Analysis for the Alberhill System Project

June 18, 2021

Table of Contents

kevala

Executive Summary

This report, produced by Kevala, Inc. (Kevala) was drafted in support of the California Public Utilities Commission (CPUC) analysis of Southern California Edison's (SCE) application for a Certificate of Public Convenience and Necessity (CPCN) for potential changes to the Alberhill System Project (ASP). This report builds upon Kevala's prior tie-line analysis, load forecast and performance metrics analysis, and distributed energy resource (DER) analysis to evaluate the reasonableness of the electrical engineering analysis performed for the ASP by SCE.

As part of the proposed Alberhill System Project, SCE identified an initial list of project alternatives that include minimal investment alternatives, conventional alternatives, Non-Wire Alternatives (NWAs), and hybrid alternatives. The proposed project and the alternatives were evaluated by SCE based on a load forecast which is expected to result in overloads that necessitate the proposed project. In this analysis, SCE's approach to the power flow study for the ASP is assessed relative to typical power flow study approaches used at similar electric utilities. SCE's study approach was found to be reasonable and consistent with widely used study approaches employed by similar utilities, such as Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E).

Kevala further expanded on the preliminary tie-line analysis documented in the report *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021) to identify the right sizing of battery energy storage systems (BESS). This report determines the need for a 143 MWh centralized BESS to cover the forecasted load peaks at the Valley South substation over the course of the year under single and double contingencies.

kevala

Introduction

Southern California Edison (SCE) has proposed the Alberhill System Project (ASP) to meet a service need in 2023 and is currently undergoing the California Environmental Quality Act (CEQA) process. The project is driven by forecasted load growth that SCE expects will cause the Valley South system's two 560 MVA 500 kV transformers to become overloaded in 2023. This report documents a review of SCE's electrical engineering analysis of the ASP and the proposed alternatives, and assesses whether the electrical engineering analysis used by SCE to evaluate the ASP and the alternatives is reasonable.[21]

Findings from Kevala Analyses

Kevala has conducted several analyses as documented in the following reports:

- *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021)
- *Behind-the-Meter Adoption Propensity Analysis* (April 16, 2021)
- *DER Adoption and Impact on Load Forecast in Valley South System* (May 27, 2021)
- *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021)

An overview of the findings from each analysis are provided in Table 1 below.

Table 1: Summary of Findings from Kevala's Analyses

Report Title	Summary of Findings
Preliminary Results: Tie-Line Power Flow Analysis	• Proposed tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers. • Transferring service for two substations to the Valley North system and interconnecting distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements. • An assessment using both the worst single contingency and the worst double contingency showed that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads under ASP and all alternatives. • BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is

[21] A thorough review of the performance metrics used by SCE in assessing the results of their electrical engineering analysis is presented in Kevala's Report: *Evaluation of SCE's Load Forecast Methodology and Performance Metrics* (June 11, 2021)

kevala

	most effective when combined with tie-lines.
Behind-the-Meter Adoption Propensity Analysis	● Up to 350 MW of residential solar and 316 MW/610 MWh of residential storage would be economically efficient if adopted under the highest adoption scenario that was modeled. ● Alberhill System Project is to increase system operational flexibility and maintain system reliability by creating system tie lines that establish the ability to transfer to substations from the current Valley South System. Due to this objective, adoption of BTM resources on their own could not meet all the project objectives. ● Evident that customers in the Valley South interconnecting solar + storage could alleviate capacity constraints on the Valley System.
DER Adoption and Impact on Load Forecast in Valley South System	● Results indicated that with the current configuration and no other projects, 188 MW of BTM BESS could eliminate the overloads on the Valley South transformers under normal system conditions. ● In the alternative case where service for Newcomb and Sun City substation loads were transferred to the Valley North substation, power flows over the Valley South transformers were sufficiently reduced such that they did not overload under normal or contingency conditions. ● Eleven buses were observed to experience voltages at 5 percent above their nominal voltage in scenario 4 when the peak load was reduced by 316 MW. Power flow results indicate that the BTM DER propensity that can be installed without causing negative impacts on the system is scenario 3 (DER is adopted to mitigate 3 outages for 1 hour duration each, totaling 188 MW of BESS and 261 MW of PV).
Evaluation of SCE's Load Forecast Methodologies and Performance Metrics	● The load forecasting methodology used by SCE was found to be comparable to methodologies used at PG&E and at SDG&E. ● This assessment also ascertained that SCE may have used a common performance metric, Loss of Load Expectation (LOLE), and adapted it to create a similar metric, Load at Risk (LAR), in order to suit their system. ● Consequently, project alternatives with tie-lines were weighted more heavily than alternatives without.

Assessment of Electrical Engineering Analysis

To perform this assessment, Kevala, Inc. (Kevala) reviewed the revised documents released by SCE in their refiling, including SCE's *Planning Study* (February 1, 2021) and Quanta Technology's (Quanta) reports, *Reliability Analysis of Alberhill System Project* (February 1, 2021) and *Benefit Cost Analysis of Alternatives* (February 1, 2021). This report is also informed by the Kevala analyses that are described in Table 1, above.

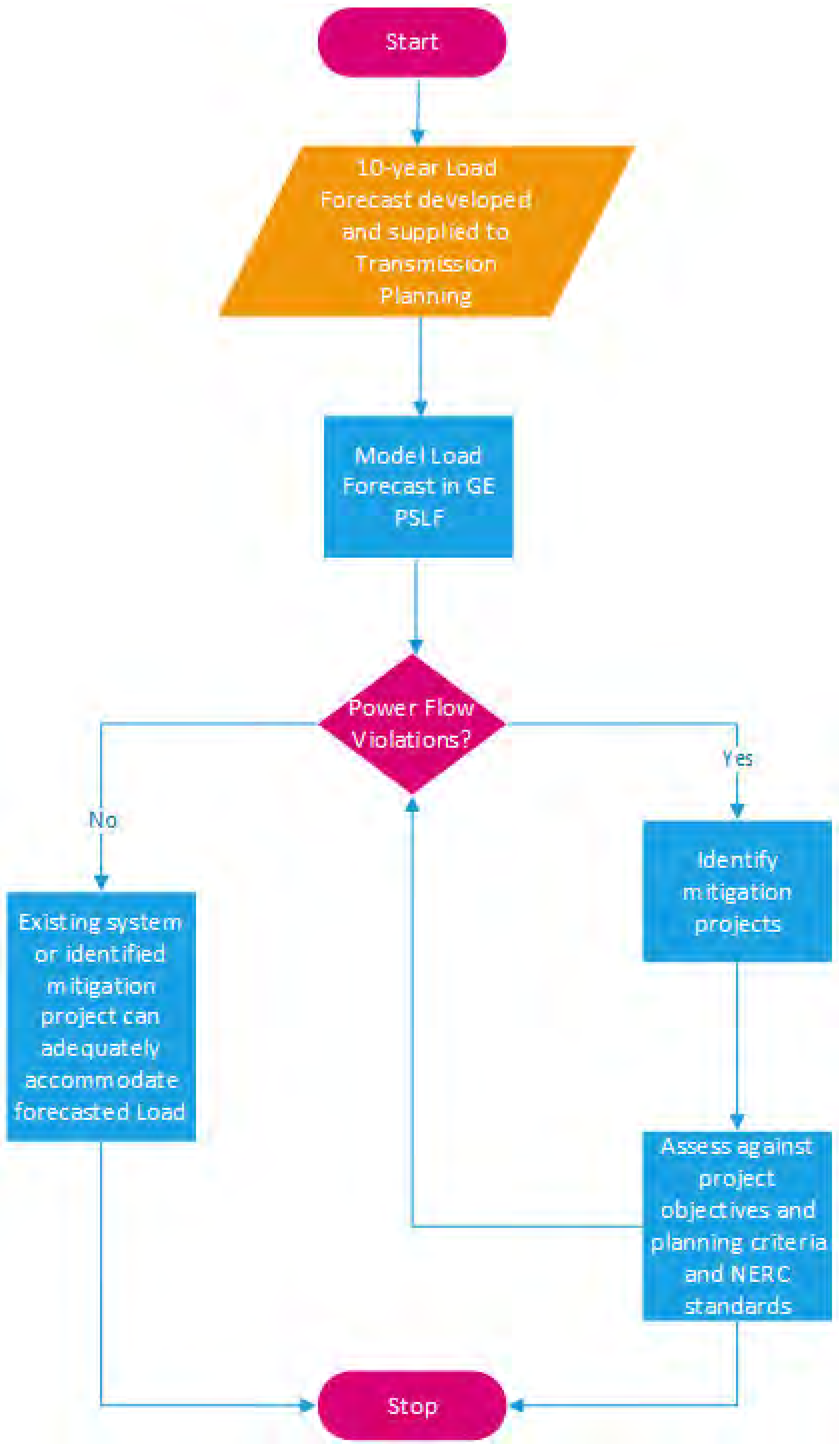
This report in particular expands on the preliminary findings of the tie-line power flow analysis by identifying the battery energy storage system (BESS) sizing that coincides with the forecasted peak loads at the Valley South substation over the course of the year. The battery capacity and duration of charge and discharge identified in the report, *Preliminary Results: Tie-Line Power Flow Analysis* (April 12, 2021), represents the minimum size BESS required for the Valley South system. In contrast, the *DER Adoption and Impact on Load Forecast in Valley South System* (May 27, 2021) report identified the maximum amount of distributed energy resources (DER) that can be interconnected in the Valley South system without causing system issues, such as voltage violations. This analysis finds the right-size BESS for the Valley South system.

Overview of SCE's Electrical Engineering Analysis

The ASP and each of the alternatives was evaluated by SCE by performing an electrical engineering analysis. To determine the reasonableness of the power flow study approach that was applied by SCE, Kevala reviewed the analysis as outlined in *SCE's Revised Planning Study* (Exhibit C-2, filed February 1, 2021), as well as Quanta Technology's (Quanta) report *Forecasted Impact on Service Reliability Performance* (Exhibit F-1, filed February 1, 2021).

SCE's power flow study approach consisted of modeling forecasted load in General Electric's Positive Sequence Load Flow (PSLF) cases. Power flow studies were then conducted on these cases to determine whether SCE's existing system as modeled could accommodate the forecasted load. These power flow studies assessed SCE's system under normal conditions, single contingency conditions, and double contingency conditions. Based on the results of these power flow studies, SCE identified potential projects to mitigate any line overloads, transformer overloads, or voltage criteria violations. When designing potential projects to mitigate overloads or voltage violations, particularly overloads on the Valley South transformer, SCE assessed the power flow results against project objectives as well as subtransmission planning criteria and guidelines. Figure 1 below illustrates the typical power flow study approach used by utilities and is consistent with SCE's power flow approach. The difference between a typical approach and SCE's approach is observed after the power flow analysis. Following the analysis, SCE developed metrics to evaluate the ASP and alternatives. This difference in approaches is described further in Kevala's *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics.*

Figure 1: Typical Transmission Planning Study Approach


Start
10-year Load Forecast developed and supplied to Transmission Planning
Model Load Forecast in GE PSLF
Power Flow Violations?
No
Yes
Existing system or identified mitigation project can adequately accommodate forecasted Load
Identify mitigation projects
Assess against project objectives and planning criteria and NERC standards
Stop

The results from these initial analyses demonstrate which alternatives are expected to perform best in relieving the Valley South transformer overloads while meeting the project objectives. The ranking of project alternatives from this analysis does not include the application of SCE developed metrics, such as Load at Risk, Flexibility-1, and Flexibility-2[22]. Moreover, this initial ranking is based on incremental improvement over a 30-year study period. Transmission planning studies are typically based on a 10-year load forecast. Mitigation projects, therefore, are also evaluated on their effectiveness in mitigating the violation under that same 10-year load forecast.

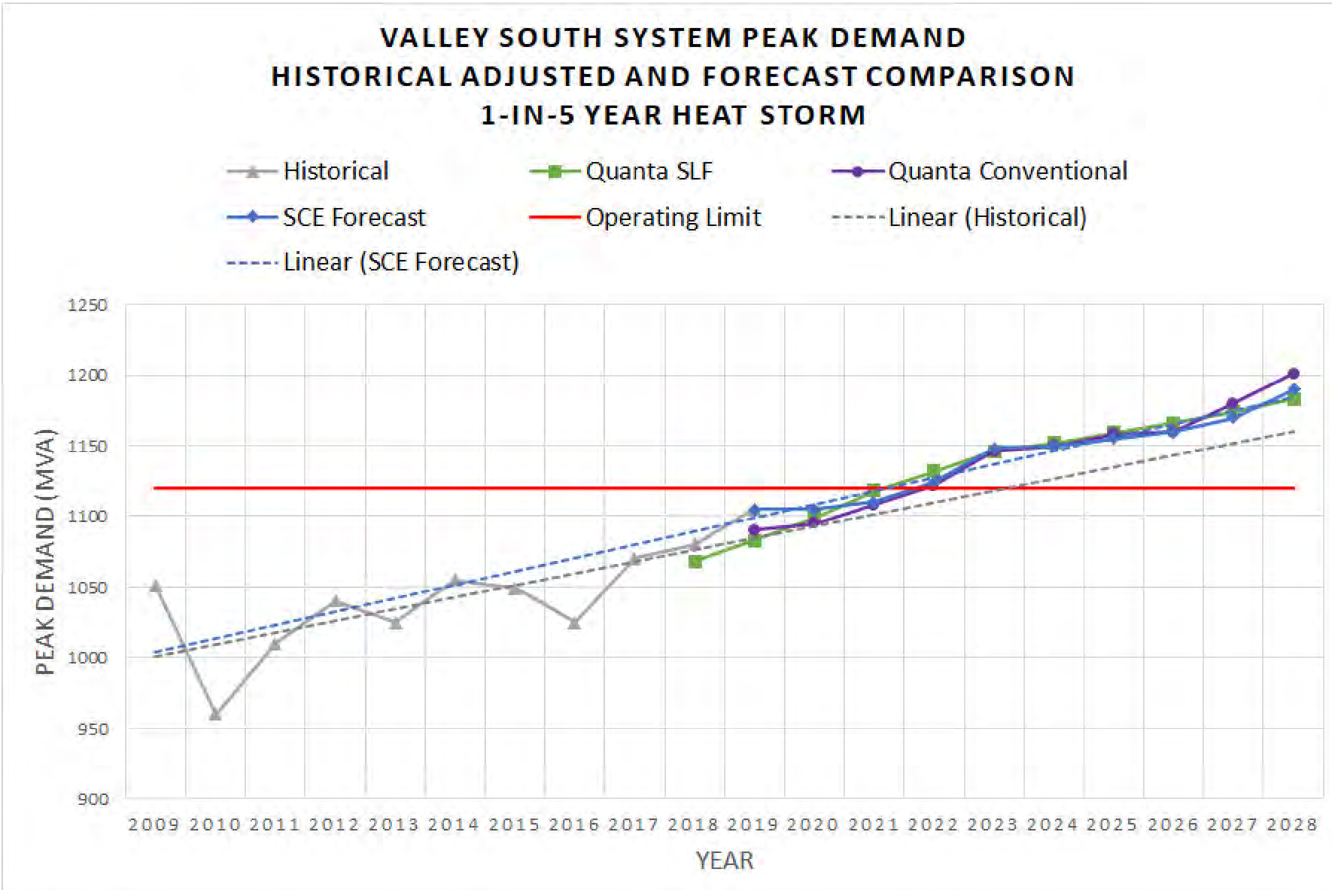
Kevala determined the power flow study approach used by SCE to be reasonable, though the 30-year study term is uncommon. Additionally, the electrical engineering analysis is consistent with the approach widely used by utilities in conducting transmission planning studies.

Once the power flow results were obtained from the electrical engineering analysis, as discussed above, SCE conducted additional analyses, including cost benefit analysis and risk assessments. The performance metrics developed by SCE that were discussed in Kevala's *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021) were then applied to establish a ranking of all the alternatives and the ASP.

As shown in Figure 1 above, the load forecast is the first important assumption made when building power flow base cases. The SCE load forecast, SCE load forecast trendline, Quanta load forecasts, historical load, and historical load trendline demonstrate that the SCE load forecast and Quanta load forecasts are relatively similar. This is visualized in Figure 2, below. The load forecasts could vary depending on the application of a linear trendline. Figure 2 demonstrates that the trendline based on SCE's load forecast is projected to be similar to the Quanta load forecasts. In contrast, the historical trendline shows a lower load growth rate than the SCE forecast and that the Valley South transformers would exceed their ratings a full two years later. This would result in power flow study results that suggest that a smaller project built two years later could mitigate the Valley South overloads.

[22] A full evaluation of the performance metrics developed by SCE is available in *Evaluation of SCE's Load Forecast Methodologies and Performance Metrics* (June 11, 2021)

Figure2: Valley South system load forecast comparison



Supplement to the Tie-line Analysis

Kevala conducted a preliminary power flow analysis of the tie-lines. The findings of this preliminary analysis are summarized as follows:

- Proposed tie-lines that transfer substation service from the Valley South system to the Valley North system are effective in mitigating the overload on the Valley South transformers.
- Transferring service for two substations to the Valley North system and interconnecting distributed BESS in the Valley South system could also mitigate this overload effectively and meet capacity, reliability, and resiliency requirements.
- An assessment using both the worst single contingency and the worst double contingency showed that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads under ASP and all alternatives.
- BESS, whether centralized or distributed, could mitigate the Valley South transformer overload under normal system conditions. However, it is most effective when combined with tie-lines.

In SCE's planning study, a subset of the alternatives with tie-lines were deemed by SCE as inadequate in meeting the project objectives because the tie-lines were ineffective. As part of a data request (DATA REQUEST SET CPUC - Supplemental Data Request - 010), Kevala asked that SCE provide the contingency list which renders those tie-lines ineffective. SCE provided in their response (A.09-09-022 – Alberhill PTC & CPCN) a contingency list as well as an explanation and illustrations. The response shows that the example SCE used to illustrate effectiveness of tie-lines was the resulting overload on the Auld-Moraga 115 kV #2 line following a contingency on the Auld-Moraga 115 kV #1 line. In Figures 2 and 3, the Auld-Moraga 115 kV #2 overload is shown for the Valley South to Valley North alternative as well as for the ASP. This finding is consistent with the results Kevala found in the power flow results conducted for the Tie-line analysis. Moreover, Kevala found the magnitude of the overload to be consistent for both this alternative and the ASP.

kevala

Figure 2: Valley South to Valley North Alternative

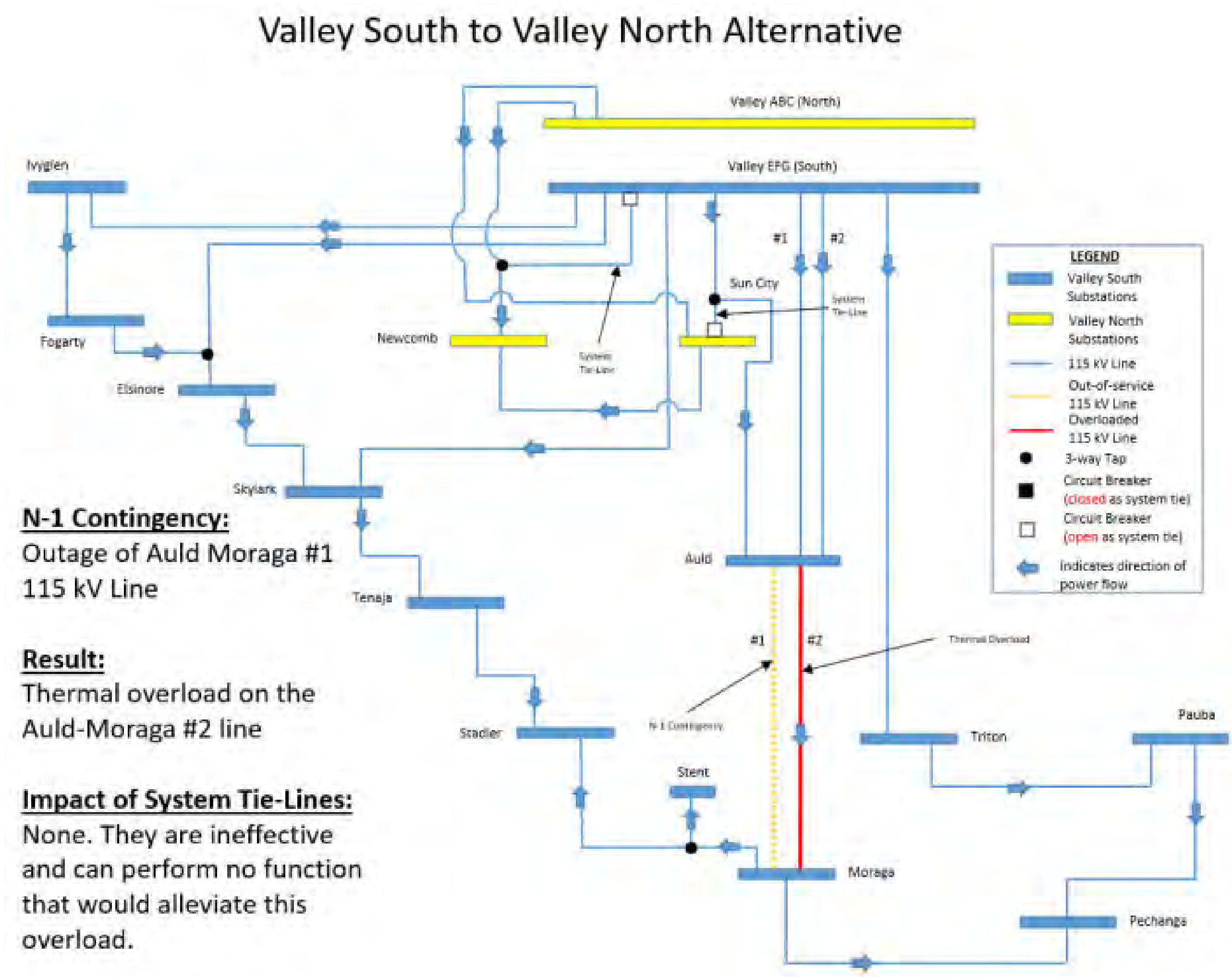
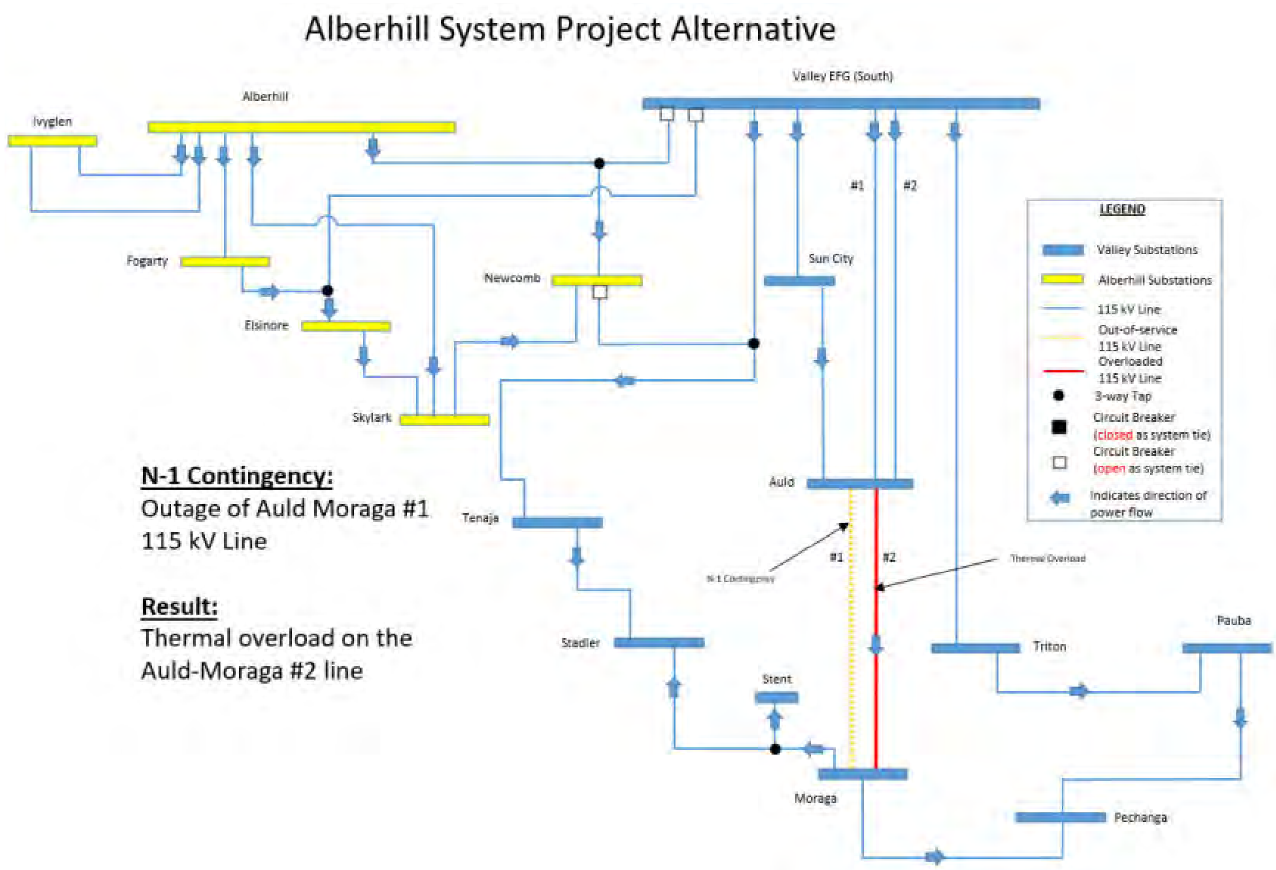
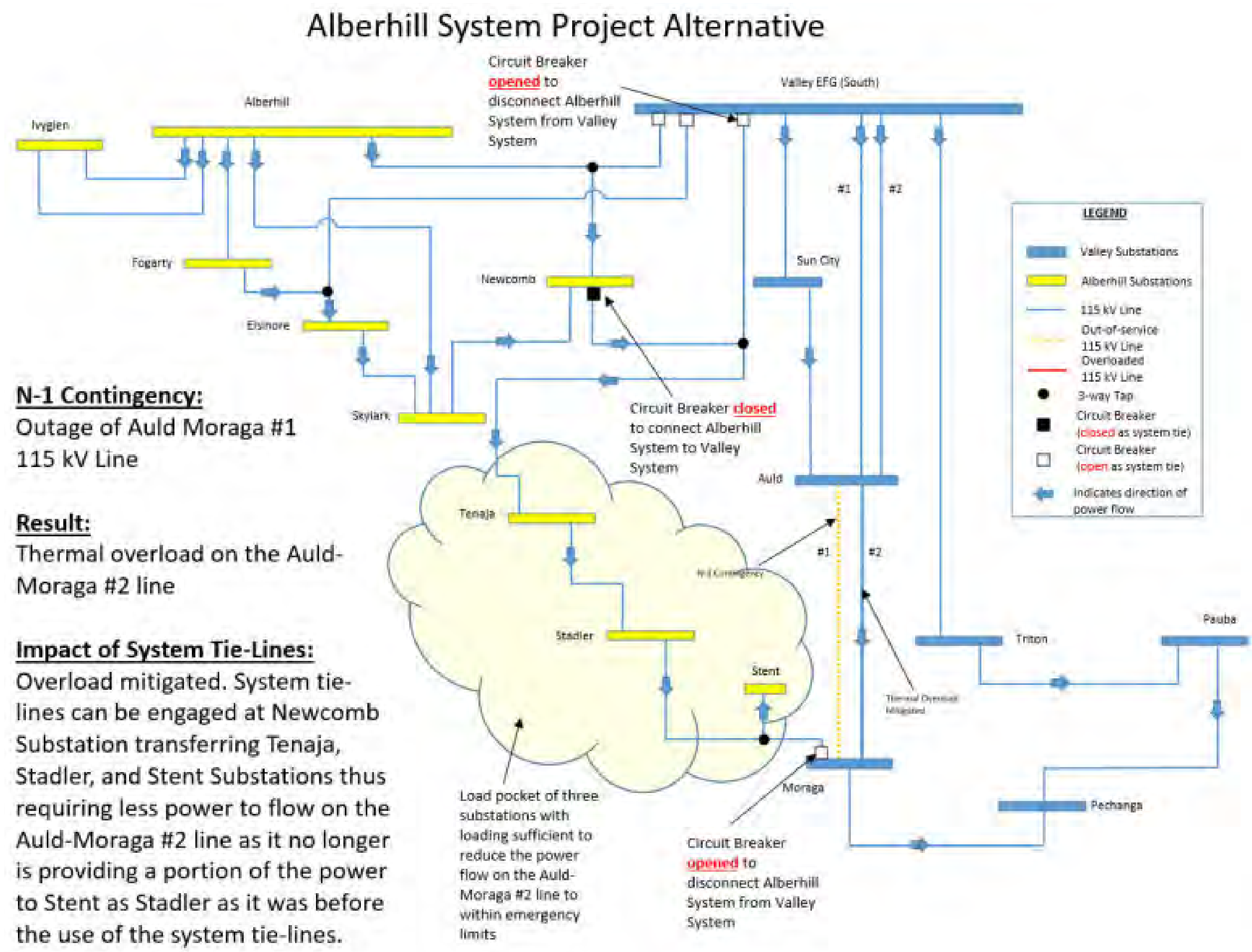


Figure 3: Alberhill System Project Alternative



The illustration in Figure 4 below, appears to show a special protection scheme (SPS) in use to alleviate the Auld-Moraga 115 kV #2 line overload. Without the deployment of this SPS, it would appear that the ASP does not relieve this overload. Kevala's power flow analyses showed that when one Auld-Moraga 115 kv line is out of service, the remaining Auld-Moraga 115 kV line experiences an overload. This result was consistent for all alternatives and ASP. Therefore, it appears that without the use of a SPS, the tie-lines in the Valley South to Valley North alternative are as effective as those in the ASP.

Figure 4: Alberhill System Project special protection scheme



Kevala performed an additional analysis to identify the appropriate sizing for centralized and distributed BESS to mitigate the Valley South transformer overload under normal system conditions. Kevala used their proprietary Network Assessor Battery Sizing Module to determine the required BESS capacity and duration capable of covering the Valley South substation forecasted peaks. The results of the analysis (shown in Table 2, below) identified the MWh required for centralized BESS located at the Valley South substation, and distributed BESS modeled at the Elsinore, Auld, and Moraga substations.

Table 2: Valley South System BESS capacity and duration

Substation	Under Single Contingency Conditions		Under Double Contingency Conditions	
	Size (MW)/ Duration (Hours)	Capacity (MWh)	Size (MW)/ Duration (Hours)	Capacity (MWh)
Valley South	39.0/2.8	107.4	39/3.7	143.2
Elsinore	9.8/4.6	45.0	9.8/6.1	60.0
Auld	15.8/4.8	75.9	15.8/6.4	101.2
Moraga	13.4/4.9	65.2	13.4/6.5	86.9

The BESS capacity values show that forecasted peak loads do not occur frequently during the year. Therefore, the duration of discharge in addition to the charge rate (MW) is important to ensure that the battery is appropriately sized. For example, a 143 MW BESS that operates for only 1 hour would be oversized in capacity and would not have sufficient duration to cover all the peak loads. A 39 MW BESS that has the capability to operate for up to 4 hours, in contrast, would adequately cover those peak hours. Similarly, the distributed BESS modeled at Elsinore, Auld, and Moraga substations, 9.8 MW, 15.8 MW, and 13.4 MW of BESS (respectively), can operate for up to 6.5 hours to cover the few hours during which the forecasted peak occurs. If any of these BESS systems were to operate for 4 hours, for example, the Valley South transformers would experience overloads during the remaining 2.5 hours when the BESS was not supplying capacity.

In Kevala's report, *DER Adoption and Impact on Load Forecast in Valley South System (May 27, 2021)*, power flow studies identified a 188 MW/362 MWh BESS as the maximum capacity of BESS or load reducing DER that could be installed in the Valley South system without causing voltage violations. By taking the results of the supplemental tie-line analysis in conjunction with this analysis, a BESS ranging from 143 MWh to 362 MWh would relieve the overload on the Valley South transformers without causing any other issues on the system.

kevala

Conclusions

In this report, SCE's electrical engineering analysis of the ASP is assessed relative to power flow study approaches used at similar electric utilities, such as PG&E and SDG&E. Kevala's review found SCE's analysis to be consistent with widely used study approaches. Once SCE obtained results from this analysis, SCE-developed performance metrics were applied to assess and rank the ASP and the alternatives.

Kevala conducted power flow analyses which found that the Auld-Moraga 115 kV #1 line in the Valley South system experiences overloads following both the worst single contingency and the worst double contingency in the Valley South system. This overload is observed with all the power flow cases including the current configuration of the do-nothing case, the ASP, and the alternatives. This indicates that a mitigation project or a special protection scheme should be studied to address this overload, which appears unrelated to the ASP.

Kevala's previous tie-line analysis was supplemented in this report with a discussion of the right-sized BESS required to cover all hours of forecasted peak load at the Valley South substation. A 143 MWh BESS that is capable of operating for up to 6.5 hours was identified as the appropriate size to cover forecasted peak loads under double contingency conditions.

Appendix G – Integrated Time-Series Benefit-Cost Analysis – SCE Alberhill System Project

Memorandum

To: California Public Utilities Commission (CPUC)

From: WSP USA Inc. (formerly Ecology and Environment, Inc.)

Date: June 18, 2021

Subject: Integrated Time Series Benefit-Cost Analysis – Southern California Edison Alberhill System Project

---

Purpose

The purpose of this memo is to provide results of an integrated time series benefit-cost analysis (BCA). Previous Southern California Edison (SCE) BCAs (May 2020 and February 2021 BCAs and supporting spreadsheets, *Effective Photovoltaic [PV] Forecast*, *PV Watts Forecast*, and *Spatial Base Forecast*) were not appropriately developed over the actual project timeline, and the calculations of the Present Value Revenue Requirement (PVRR) total costs were not shown. While project benefits were treated appropriately in terms of traditional capital analysis net present valuation procedures, project costs were derived using an external program based on the PVRR process. Using this method to compute project costs externally made it unclear that total project costs and annual project costs were calculated appropriately. Further, there were no linkages to annual operations and maintenance (O&M) costs included in the project cost stream (O&M was found in the separate Excel project cost sheet, but not linked to the analysis). In addition, the year project construction was expected to start and the year benefits would begin accruing were not placed into the timeline correctly. For all alternatives, the project benefits and O&M costs designated within the model were accruing in years before the project was constructed (prior to the facility operational in-service date), thus yielding an erroneous BCA comparison among the alternatives under review.

Accordingly, the tasks described below were undertaken to gain a clear understanding of actual benefits and costs associated with the various alternatives.

Methodology

Using data from the SCE February 2021 BCA and the associated spreadsheets, three distinct BCAs were developed on the 13 *Effective PV Forecast* project alternatives annual costs and benefits streams, since SCE considered the *Effective PV Forecast* to reflect future demand most accurately. Each analysis described below employed integrated, appropriately timed benefit streams extending over the respective operational period(s). Total project costs were either based on SCE's PVRR cost or on an appropriately timed net present value (NPV) of cost streams with and without uncertainty and battery revenues. To evaluate the different cost effects (PVRR or NPV), the resulting net benefits and benefit-cost ratios (BCRs) were compared to those of the SCE February 2021 BCA and associated spreadsheets submission.

All BCAs involved an integrated time series (where the time series of the costs and benefits of each alternative were appropriately integrated with their construction and O&M timeline). This procedure adhered to a traditional capital improvement BCA.

BCA1

The first BCA model applied a constant 10 percent discount rate (NPV) to the costs, rather than employing the PVRR costs. Appropriately timed benefits were then compared to the appropriately timed NPV costs, arriving at an equitable assessment of net benefits (NPV benefits above NPV costs) and ensuing BCRs.

BCA2

The second BCA analysis took BCA1 and removed the uncertainty cost factors and battery revenues, deriving net present valuations of appropriately timed cost and benefit streams, their relative net benefits and BCRs. Appropriately timed benefits were then compared to the appropriately timed NPV reduced costs arriving at an equitable assessment of net benefits and resulting BCRs.

BCA3

The third BCA analysis also included appropriately timed benefits; however, with this analysis, the analyst used SCE's PVRR costs, which included both uncertainty and battery revenues. Appropriately timed benefits were then compared to the appropriately timed PVRR costs arriving at equitable net benefits and related BCRs.

References

WSP USA Inc. used or referred to the following spreadsheets:

1. *Project Costs: A.09-09-022 ED-Alberhill-SCE-Supplemental Data Request 003 Question DG-G-1 Revised Attachment 1 of 11*, received March 24, 2021.
2. *BCA: Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, received March 24, 2021.
3. *Exh G-2 Revised Cost Benefit Analysis Report A0909022-SCE ASP*.

4. *Exh C-2 Revised Planning Study A0909022-SCE ASP*.
5. *Exh I-1 Revised Best Solution and Rankings*.
6. *Exh F-1 Revised Forecasts A0909022-SCE ASP*.
7. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-55 Answer*.
8. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-55 Revised Answer*.
9. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-56 Answer*.
10. *A.09-09-022 CPUC-Supplemental Data Request-006 Q.DG-MISC-56 Revised Answer*.
11. *PVRR Model: A.09-09-022 TURN-SCE-Alberhill-007 Question 14_ Attachment 1 of 1\EPV RR Models*, received March 25, 2021.

Detailed Methodology and Results

The SCE BCAs' (as referenced above) stream of costs and benefits (for the 13 alternatives) show all project costs between 2022 and 2025, while the benefits begin in 2022, before any of the projects are complete. This lack of proper timing does not ensure a fair comparison of costs and benefits among the alternatives under review. Benefits were incorrectly entered/discounted in the first year of the time series, as if beginning before the project is constructed rather than after completion of construction (the year benefits would truly begin).

The stream of undiscounted costs and benefits have been properly entered into new time series spreadsheets for each alternative based on the accurate sequence of project-related events: (1) construction period (the year of construction start through the year of construction completion); (2) O&M spending; and (3) years of accrual of benefits.[1]

In the first model, BCA1, a constant 10 percent discount rate was applied across the board to the costs rather than applying the array of PVRR-based factors. A constant discount rate was used because the PVRR figures, which are used and added to the total project costs in the SCE BCAs, varied significantly among the alternatives. These factors influenced the final costs applied in the BCR because they were based on many factors (e.g., interest rates, applied taxes, depreciation, salvage values, revenues generated, etc.) and their derivation was difficult to track, reproduce, and verify.

Using the proposed stream of undiscounted capital costs, O&M costs, and benefits over the project life span, and discounting these expenditures using a 10 percent discount to the base year, allows for an equitable comparison of benefits and costs associated with each alternative. This method of calculation also allows for comparing efficiency effects among each alternative in terms of capital spending and benefit accrual over time.

The findings of this time series BCA were then compared to the BCA *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3.*

[1] The revised undiscounted costs and benefits, received March 24, 2021, were used as inputs.

In BCA2, two uncertainty factors ("to address uncertainties of load-reducing technologies and California's electrification goals," per page 216 of *Exh G-2 Revised Cost Benefit Analysis Report*, and "due to the lack of environmental analysis, licensing, and engineering design efforts," per page 18 of *Exh C-2 Revised Planning Study*) and the battery revenues were removed from the time series costs stream.

In BCA3, as a sensitivity analysis, SCE's PVRR costs, which include both uncertainty and battery revenues, were used.

The results of all three model runs were compared to the revised BCA *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, which found the BCRs listed in Figure 1.

Table 6-4. SCE Effective PV Forecast – B/C Ratio

#	Project	Benefit ($M)	Benefit-Cost Ratio
D	Menifee	$3,648	11.02
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	$2,468	8.54
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

Figure 1. SCE Effective PV Forecast – Benefit Cost Ratio

BCA1, a time series analysis, is a traditional capital improvement benefit cost analysis. It does not use SCE's PVRR computations, rather it uses the estimated stream of undiscounted capital costs, O&M costs, and benefits (as provided in SCE's spreadsheets), all timed correctly, over the project life span, including both uncertainty and battery revenues, then discounted these expenditures equitably using a 10 percent discount to a common point in time (the base year). This analysis resulted in the following BCR rankings. SCE BCRs and net benefits are consistently higher than the capital analysis (of BCA1) among all alternatives, which brings up the question *was the PVRR figure appropriately discounted*? In any event, conducting the capital analysis using the 10 percent discount rate reveals that the Alberhill System Project (Alberhill) is similarly ranked fifth with a BCR of 6.3; however, with the SCE analysis, Alberhill was ranked fourth with a BCR of 9.0. In terms of net benefits, BCA1 model shows a net benefits reduction from $4.3 million to $1.7 million, but Alberhill remains first in both evaluations.[2]

[2] The analyst did not change benefits, as calculated by SCE, except for adjusting them in time and how those benefits are discounted, (i.e., ensuring benefits begin after construction is completed).

Captial Improvement - Benefit Cost Analysis
(Includes Uncertainty and Battery Revenues)
Millions of ($2019 dollars)

	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	**Total Costs (NPV)**	**Benefits NPV**	**Net Benefits**	**BCR**	**BCR Ranking**	**PVRR COSTS**	**Net Benefits**	**BCR**	**BCR Ranking**
Valley S to Valley N to Vista	$192	$1,268	$1,076	6.6	1	$290	$2,470	8.5	7
Valley South to Valley North	$136	$1,106	$970	8.1	2	$207	$2,156	10.4	2
VS to VN & Distributed BESS VS	$144	$1,111	$967	7.7	3	$232	$2,165	9.3	3
Menifee	$222	$1,702	$1,480	7.7	4	$331	$3,648	11.0	1
Alberhill System Project	**$318**	**$1,996**	**$1,677**	**6.3**	**5**	**$474**	**$4,282**	**9.0**	**4**
VS to VN to VST & Cen BESS VS	$204	$1,266	$1,063	6.2	6	$289	$2,468	8.5	6
SDG&E	$301	$1,867	$1,566	6.2	7	$453	$4,001	8.8	5
Mira Loma	$204	$1,214	$1,009	5.9	8	$309	$2,601	8.4	8
SDG&E and Centralized BESS in VS	$354	$1,885	$1,532	5.3	9	$531	$4,041	7.6	9
VS to VN & Central BESS VS VN	$245	$1,304	$1,059	5.3	10	$367	$2,542	6.9	10
Mira Loma and Centralized BESS VS	$389	$1,461	$1,072	3.8	11	$560	$3,132	5.6	11
Centralized BESS in VS	$353	$1,301	$948	3.7	12	$525	$2,535	4.8	13
SCE Orange County	$504	$1,705	$1,201	3.4	13	$747	$4,021	5.4	12

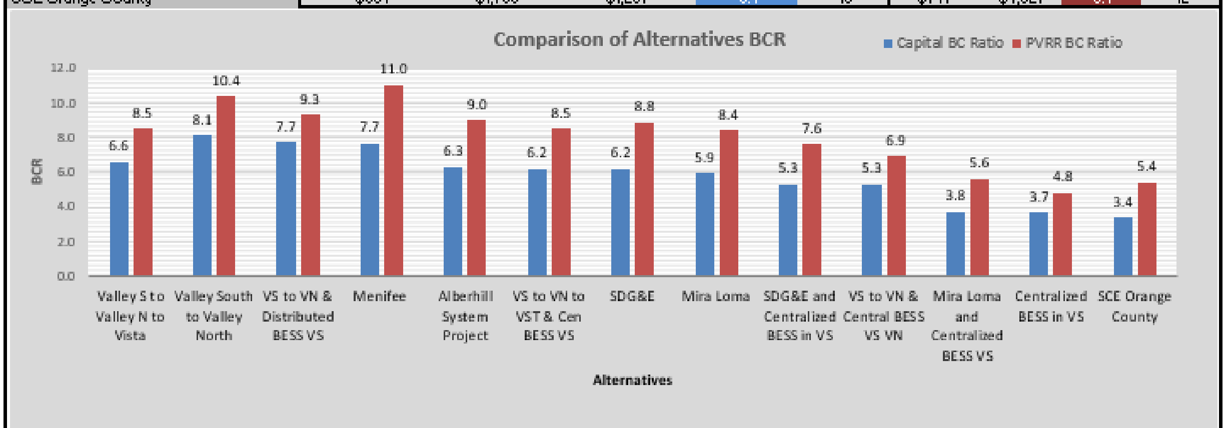


Figure 2. BCA 1: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (includes Uncertainty and Battery Revenues)

BCA2 is similar to BCA1 but excludes uncertainty and battery revenues from the costs streams, while all other time series factors remain the same. Although excluding uncertainty and battery revenues from the capital analysis has closed the BCR gap (between the capital and PVRR analyses), net benefits still are considerably divergent. This can be explained in part from the fact that the SCE benefits were not appropriately treated (discounted) in the year the projects become operational. The reason for the divergence in the costs is unknown. In any event, Alberhill moves to eighth in the BCR ranking compared to fourth with SCE evaluation. In terms of net benefits, as shown in Figure 3, several alternatives show similarly sized net benefits (in the range of $1.7 million to $1.9 million) when compared with Alberhill.

Captial Improvement - Benefit Cost Analysis
(Excludes Uncertainty and Battery Revenues)
Millions of ($2019 dollars)

	CAPITAL ANALYSIS					PVRR ANALYSIS			
Alternative	**Total Costs (NPV)**	**Benefits NPV**	**Net Benefits**	**BCR**	**BCR Ranking**	**PVRR COSTS**	**Net Benefits**	**BCR**	**BCR Ranking**
Valley S to Valley N to Vista	$151	$1,268	$1,117	8.4	1	$290	$2,470	8.5	7
Menifee	$167	$1,702	$1,535	10.2	2	$331	$3,648	11.0	1
Valley South to Valley North	$110	$1,106	$997	10.1	3	$207	$2,156	10.4	2
VS to VN & Distributed BESS VS	$118	$1,111	$994	9.5	4	$232	$2,165	9.3	3
SDG&E	$216	$1,867	$1,650	8.6	5	$453	$4,001	8.8	5
VS to VN to VST & Cen BESS VS	$150	$1,266	$1,117	8.5	6	$289	$2,468	8.5	6
Mira Loma	$152	$1,214	$1,062	8.0	7	$309	$2,601	8.4	8
Alberhill System Project	**$262**	**$1,996**	**$1,734**	**7.6**	**8**	**$474**	**$4,282**	**9.0**	**4**
VS to VN & Central BESS VS VN	$174	$1,304	$1,131	7.5	9	$367	$2,542	6.9	10
SDG&E and Centralized BESS in VS	$252	$1,885	$1,633	7.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$290	$1,461	$1,171	5.0	11	$560	$3,132	5.6	11
SCE Orange County	$358	$1,705	$1,347	4.8	12	$747	$4,021	5.4	12
Centralized BESS in VS	$322	$1,301	$978	4.0	13	$525	$2,535	4.8	13

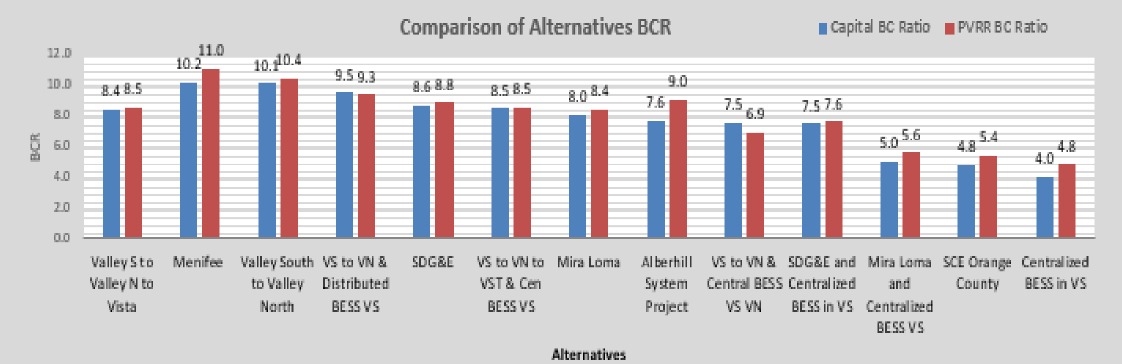


Figure 3. BCA 2: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (excludes Uncertainty and Battery Revenues)

Similar to BCA1, BCA3 is a hybrid capital improvement benefit cost analysis. Unlike BCA1, BCA3 uses SCE's PVRR computed costs and coupled with SCE's benefits timed correctly (including battery revenues and uncertainty). Under BCA3, Alberhill places sixth in the BCR ranking, and in terms of net benefits, as shown in Figure 4, several alternatives show similarly sized net benefits (in the range of $1.7 million to $1.9 million) when compared to Alberhill.

In terms of the Alberhill System Project, BCA1 (using a 10% discount rate) has a total project cost of $318 million (net present value) while BCA3 (using SCE's PVRR computed costs) has a much larger total project cost of $474 million (net present value). While BCA1 and BCA2 use different methods for computing total project costs, both BCA1 and BCA2 include uncertainty and battery revenues, times the accrual of benefits based on their actual occurrence (in-service, operational date), and all other factors are held constant.

MIXED BENEFIT COST ANALYSIS - USING "SCE" PVRR COSTS AND CAPITAL ANALYSIS BENEFITS
Includes Uncertainty and Battery Revenues
Millions of ($2019 dollars)

Alternative	CAPITAL ANALYSIS: SCE PVRR COSTS	Capital Analysis Benefits NPV	Net Benefits	BCR	BCR RANK	PVRR ANALYSIS: PVRR COSTS	Net Benefits	BCR	BCR Rank
Valley South to Valley North	$207	$1,106	$899	5.3	1	$207	$2,156	10.4	2
Menifee	$331	$1,702	$1,371	5.1	2	$331	$3,648	11.0	1
VS to VN & Distributed BESS VS	$232	$1,111	$879	4.8	3	$232	$2,165	9.3	3
VS to VN to VST & Cen BESS VS	$289	$1,266	$977	4.4	4	$289	$2,468	**8.5**	6
Valley S to Valley N to Vista	$290	$1,268	$978	4.4	5	$290	$2,470	8.5	7
Alberhill System Project	**$474**	**$1,996**	**$1,521**	**4.2**	**6**	**$474**	**$4,282**	**9.0**	**4**
SDG&E	$453	$1,867	$1,414	4.1	7	$453	$4,001	8.8	5
Mira Loma	$309	$1,214	$905	3.9	8	$309	$2,601	8.4	8
VS to VN & Central BESS VS VN	$367	$1,304	$937	3.6	9	$367	$2,542	**6.9**	10
SDG&E and Centralized BESS in VS	$531	$1,885	$1,354	3.5	10	$531	$4,041	7.6	9
Mira Loma and Centralized BESS VS	$560	$1,461	$901	2.6	11	$560	$3,132	5.6	11
Centralized BESS in VS	$525	$1,301	$776	2.5	12	$525	$2,535	4.8	13
SCE Orange County	$747	$1,705	$958	2.3	13	$747	$4,021	5.4	12

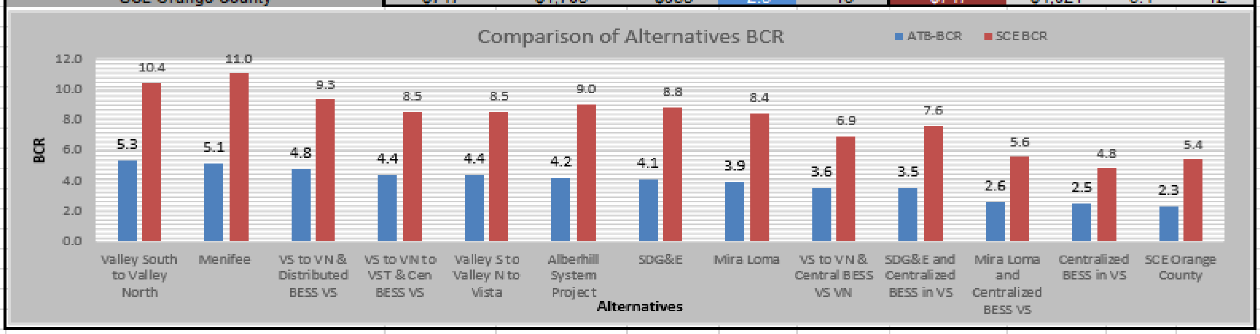


Figure 4. BCA 3: BCA Capital Analysis Compared to SCE BCA PVVR Analysis (includes Uncertainty and Battery Revenues)

Summary

Regardless of which costs are used (NPV or PVRR), Alberhill is not the most cost-effective alternative.

Based on the above analysis, several alternatives were determined to yield a much lower project cost when compared to the proposed Alberhill System Project and to have a better BCR (a reflection of cost versus benefit efficiency). For example, Valley South to Valley North, at a cost of about $207 million, could be built twice and have lower life cycle project cost ($60 million less) compared to the Alberhill facility. Furthermore, the net benefits would outpace that of Alberhill by $277 million. The same generalized statement of net savings/benefits is attributable to Valley South to Valley North to Vista and Distributed BESS in Valley South (cost $289 million), in which SCE costs (including uncertainty and battery revenues) are used in conjunction with appropriately timed benefits. These two alternatives also appear to be economically viable based on the BCA2 analysis. Since there are alternatives that are smaller scaled and viable, two smaller projects could be implemented separately at different points in time in the future (one now and one later, based on needs) and possibly cost less than Alberhill and produce the best benefit to cost ratio with more overall benefits.

Memorandum

To: California Public Utilities Commission

From: WSP USA Inc. (WSP)(formerly Ecology and Environment Inc.)

Date: October 11, 2021

Subject: Benefit-Cost Analysis Review – Southern California Edison Alberhill System Project

---

Purpose

Review of Southern California Edison (SCE) June 22, 2021, Second Amended Motion Benefit-Cost Analysis (BCA) materials (notice of clerical error corrections in *Planning Study and Benefit-Cost Analysis of Alternatives for SCE's Alberhill System Project*) to understand what changes were made in relation to previous versions and to see if the Second Amended Motion Cost-Benefit Analysis and supporting spreadsheets (indicated in the Second Amended Motion notice) changed the timing of costs and benefits (as suggested in WSP's previous review).

Methodology

This review was conducted in a two-step approach.

Step 1: Review Second Amended Motion document changes.
On June 23, 2021, WSP received the following documents (all dated June 22, 2021).

- A0909022-SCE Errata to Correct Amended Motion to Supplement.
- A0909022-SCE NOA Errata to Correct Amended Motion to Supplement.
- Exh C-2: *Planning Study Revision 2.1* A0909022-SCE Errata to Correct Amended Motion to Supplement.
- Exh G-2: Cost-Benefit Analysis report revision A0909022-SCE Errata to Correct Amended Motion to Supplement, revised *Cost-Benefit Analysis Report* by Quanta Technologies dated June 15, 2021, Version 2.1.

In Step 1, WSP reviewed the above documents. However, supporting revised BCA spreadsheets were not supplied to support the description of changes in the documents, as bulleted below. According to the Summary of Revisions in Exh C-2:

1. SCE found a variety of errors in the BCA ("with regard to spreadsheet tabular data," including that "some of the formulas were transferred incorrectly") and made corrections, but SCE says that the cumulative effects of all the changes only resulted in minor net effects.

   WSP findings: After reviewing the first (May 2020 Amended Application) and second versions (February 2021Amended Motion to Supplement the Record) of the BCA spreadsheets, WSP found a variety of minor errors in the tabular data (e.g., some formulas were found to be incorrectly placed or untraceable, along with a few mismatches in data entries). New changes to computed benefit data (as described in pages 2 and 3 of the June 2021 revised Planning Study Exh C-2), which includes changed calculations using Flex-1 metrics, changed assignment of Value of Service monetary values to unserved customer load, and changed monetization rate of commercial and industrial customers, would likely not have been found by WSP nor reflected in the integrated time-series BCA spreadsheets prepared by WSP in June 2021, prior to the filing of SCE's Second Amended Motion. However, if these corrections were minor, as stated by SCE, WSP agrees they would not have changed the overall outcome SCE presented, because the main issue with SCE's BCA (as described in the initial WSP June 2021 memo) remains with SCE's timing and streaming of benefits and operations and maintenance (O&M) spending occurring prior to project completion or in-service date (affecting the overall benefit-cost ratios and ranking of alternatives provided by SCE).

2. In Point #4 (page 4 of Summary of Revisions, Exh C-2), SCE states that the timing of the O&M costs is now applied beginning at the project in-service date.

   WSP findings: In WSP's integrated time-series BCA, WSP incorporated SCE's O&M costs as a separate line item to SCE's project costs or capital expenditures (CAPEX) (not embedded into the present value revenue requirement as done by SCE, for transparency) and correctly timed the O&M spending to begin at the project in-service date (or after the project was constructed). WSP also incorporated SCE's benefits for each alternative to begin at the project in-service date (or after the project was constructed). Since SCE stated that the timing of O&M spending had been corrected, WSP requested the new Second Amended Motion supporting BCA spreadsheets to verify that "O&M costs are now applied beginning at the project in-service date."

3. In Point #5 (page 4 of Summary of Revisions, Exh C-2) SCE states that, "now all alternatives have a common set of assumptions – consistently accruing benefits at the project need date (2022) and entering construction in 2023."

   WSP findings: It is unclear why SCE would continue to start accruing project benefits "at the project need date" and not on the "in-service date," when normal BCA practice is for benefits to begin only after the project is constructed and in-service.

4. In footnote 4 explaining Point #5 (page 4 of Summary of Revisions, Exh C-2) SCE states that "benefits are started on the need date rather than in-service date for all alternatives to maintain consistency among the alternatives, to simplify the analysis, and to ensure that the near-term load forecast has a more dominant impact on the relative performance of the alternatives."

   WSP findings: Claiming past impacts/benefits thought to occur prior to a project in-service operational date is not the proper method to calculate a BCA of alternatives, and SCE's footnote fails to explain its process. If SCE changed the timing of O&M spending from its previous spreadsheet timing (Point #4) to begin at the in-service date, it is unclear why SCE did not correct the timing of the benefits, since "timing of the accrual of benefits" was initially identified by WSP as a concern in a conference call on August 11, 2020. It is also unclear why "near-term load forecast" was needed to ensure a more dominant impact on the relative performance of the alternatives." This practice results in false performance results among alternatives under review. The computation of an alternative's benefits must be based on a realistic corresponding operational forecast moving forward and start on a project's in-service date and not before the facility is operational.

In summary, since revised BCA spreadsheets had not been provided to support the clerical changes in the BCA report (per SCE's Second Amended Motion), WSP requested to review SCE's (third version) spreadsheets to understand what changes were made in relation to the previous versions and to verify whether the third version of the Cost-Benefit Analysis changed the timing of O&M spending. WSP thought that if SCE's revisions were easily traceable, those revisions could quickly be incorporated into WSP's correctly timed BCA spreadsheet analyses from June 2021. However, the WSP analyst determined that if SCE was still attempting to accrue project benefits on a project need date and before the in-service date, minor changes to correct spreadsheet tabular data errors in the BCA would not correct a mistimed analysis.

Step 2: Review Third Revision BCAs.

On August 13, 2021, WSP received and reviewed the following documents (all dated June 22, 2021):

- Third Revision Cost-Benefit Analysis Spreadsheets: *Effective PV Spreadsheet*- A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Attachment 2 of 3_Effective PV (*Third Revision BCA spreadsheet*);
- A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Answer; and
- A.09-09-022 CPUC-JWS-4 Q.01i Revised Answer.

In Step 2, WSP reviewed the Second Amended Motion BCA spreadsheets (third version) in comparison with the February 2021 Amended Motion BCA spreadsheets (second version) alongside the variety of errors in the BCA noted in SCE's June 2021 Second Amended Motion.

Initially, the Alberhill and Valley South to Valley North Alternatives were reviewed for changes in the bottom-line benefit-cost ratio or net benefits. This review found minor adjustments. Most notably, changes found in earlier reviews were flat number inputs linked to database formulas in SCE's database modeling program. Also, certain underlying inputs (figures) were slightly changed, likely due to rounding errors, but they were not to an order of magnitude that would affect the results seen during the earlier reviews. With this being the case, a more in-depth review was undertaken on all the alternatives. In short, no major changes were detected that would affect the final benefit-cost ratios or other economic indicators derived in the analysis. WSP agrees with SCE's June 2021 Second Amended Motion that states "the cumulative effects of all the changes only resulted in minor net effects."

However, with this submission, SCE did not supply O&M cost data incorporated into the Second Amended Motion BCA showing O&M starting at the project in-service date, so WSP cannot verify "the timing of the O&M costs are now applied beginning at the project in-service date." The Second Amended Motion BCA spreadsheets were not much different to the February 2021 Amended Motion BCA spreadsheets. The benefits are still mistimed as they still begin accruing before the project in-service date and the Second Amended Motion BCA does not display the streaming of O&M costs. Therefore, incorporating the minor clerical changes into WSP's integrated time-series BCA (June 2021) would not be productive, and WSP's findings of the second review would not be significantly changed.

Step 3: Review Third Revision BCAs with Tracked Changes.
August 26, 2021: As an added measure of review and to verify that no key changes were missed in the review of third version spreadsheets that would warrant further investigation, on August 26, 2021, WSP submitted a request to SCE Regulatory Affairs for tracked changes versions of the spreadsheets (with highlighted locations to identify where changes, as cited in the Second Amended Motion, occurred in the spreadsheets).

September 10, 2021: SCE Regulatory Affairs sent tracked-version spreadsheets with green highlighted cells identifying changes.

September 16, 2021: WSP compared the spreadsheets, *Cost-Benefit SCE Effective PV Forecast_Tracked.xlsm*, received September 10, 2021 (tracked third version) with the *Effective PV - A.09-09-022 CPUC-JWS-4 Q.01g Second Revision Attachment 1 of 3*, received March 24, 2021 (second version).

Although the highlighted tracked changes confirmed findings identified in Step 2 above, after review, WSP made the following observations:

1. The cells of the tracked third version spreadsheet are password protected, limiting disclosure and the scope of the review (note: the cells of the untracked third version spreadsheets [*A.09-09-022 CPUC-JWS-4 Q.01g Third Revision Attachment 2 of 3_Effective PV*, received by email on August 13, 2021, and reviewed in Step 2] were also password protected).

2. In the second version spreadsheet, the computations of benefits were linked to a sheet titled *Cost Assumptions*. That sheet was included with the second version spreadsheet. However, in the tracked third version spreadsheet, the *Cost Assumptions* spreadsheet was renamed *Cost Data & Assumptions* (as referred to in cells), but a sheet was not included with the tracking spreadsheet, meaning that the computation of benefit cells is not linkable to the individual sources (these cells were also password protected). The purpose for excluding *Cost Data & Assumptions* during this latter round of revisions is unclear.

3. For most alternatives, certain underlying categorical benefit figures were slightly changed (e.g., benefits categories: EENS, FLEX-1, FLEX-2-1, FLEX-2-2, etc.); however the resulting total of aggregated benefits of those alternatives remained unchanged from the second version spreadsheets. Project costs among all alternatives remained unchanged.

4. However, for the Menifee Alternative, the changes resulted in benefits increasing by $234M ($3,882M – $3,648M = $234M) or a 6.4 percent increase. With Menifee's increase of benefits, WSP revisited the retimed *Capital Analysis BCA* (used for the second version spreadsheet, *Effective PV Forecast* review) to see how the benefits from the third version spreadsheet would affect the Menifee Alternative. WSP found that Menifee's benefit-cost ratio (BCR) changed. Applying the prorated increase (6.4 percent) to the WSP retimed *Capital Analysis BCA* caused the retimed benefits to increase from $1,702 to $1,881. Dividing these benefits by total project costs ($331M) yielded a BCR of 5.5 (up 0.4 from the original 5.1 BCR). This change results in Menifee moving up to first place, Valley South to Valley North moving to second place (switching places from WSP's previous analysis), and all other alternatives remaining in their previous positions (Alberhill remaining in sixth place).

Table 1. Adjusted BCR for Menifee per Tracked Changes

	(SCE 2nd REV) PVRR Costs and NPV Benefits	(SCE 3rd REV) PVRR Costs and NPV Benefits	Difference	Percent Change	Capital Analysis (Retimed 2nd REV)	Capital Analysis (Retimed 3rd REV)
Aggregate ($M)	3,648	3,882	234	1.064	1702	1811
Project Cost ($M)	331	331	0	N/A	331	331
BCR	11.22	11.73	0.7	N/A	5.1	5.5

Key:
BCR = benefit-cost ratio
NPV = net present value
PVRR = Present Value Revenue Requirement
REV = revision
SCE = Southern California Edison

In summary, while minor changes were made to interior cell numbers, because the spreadsheet is password protected, their computation cannot be verified. In any case, the final resulting benefits (and costs) among the two spreadsheets are the same (except Menifee). As noted previously, the timing of benefits in the third version spreadsheet is unchanged, and the timeframe of the analysis remains years 2022 to 2048.

No other changes (from third version spreadsheets) were applied to the retimed *Capital Analysis BCA* because the changes are minor and SCE hasn't changed the timing of accruing benefits before project is in service, making the changes primarily inconsequential.