Southern California Edison
A.09-09-022 – Alberhill PTC & CPCN

DATA REQUEST SET CPUC- Supplemental Data Request 12

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Question DG-MISC-83:

Resource Areas/ Topic
Alternatives

Data Gap Question
Provide additional analysis on the Valley South to Valley North plus Centralized Battery Energy Storage System (VS-VN+CBESS) project alternatives as defined in the DG-MISC-83 Attachment 1 – Scope of Additional Analysis Requested Valley South to Valley North Plus Centralized Battery Energy Storage System Alternative.

Response to Question DG-MISC-83:

Executive Summary

SCE's response to Data Request A.09-09-022 CPUC-Supplemental Data Request-012 Question DG-MISC-83 is documented herein. This response provides an analysis of two variations of the Valley South to Valley North and Centralized BESS (VS-VN+CBESS) alternatives documented in SCE's Planning Study.

Scenario 1: Valley South to Valley North plus CBESS with Permanent Transfers (*ineffective* system tie-lines)

Scenario 2: Valley South to Valley North plus CBESS with Temporary Transfers (*effective* system tie-lines)

These alternatives are similar in that they both include subtransmission scope to construct 115 kV lines between the 115 kV Newcomb and Sun City Substations and the 115 kV Valley North System. However, in Scenario 1, Newcomb and Sun City Substations are permanently transferred to the Valley North System (leaving the Valley South System with ineffective tie-lines), and in Scenario 2, Newcomb and Sun City Substations are transferred only during contingency events (thereby providing the Valley South System with effective tie-lines for contingency events). Both versions also include a centralized BESS (CBESS), but the difference in the transfer scenario (i.e., permanent or temporary transfer) results in different system operating thresholds in the Valley South System and thus different sized CBESS to meet N-0 and N-1 planning criteria.

The analysis documented herein determined the required CBESS size for these two scenarios to meet N-0 and N-1 criteria in accordance with SCE's Subtransmission Planning Criteria and Guidelines. Additionally, the two scenarios (including the CBESS) were studied under various Flex scenarios to demonstrate system performance during transformer N-1 contingencies. The analysis to determine both the CBESS sizing and performance of the Flex metrics was also studied, at the request of the Energy Division, with and without a static synchronous compensator (STATCOM) to assess its impacts.

CBESS sizing and the Flex analysis were performed for the year 2031, as this is the final year of SCE's current 10-year planning horizon (covering the years 2022-2031). CBESS sizes were also determined for the years 2035, 2040, and 2045 in order to demonstrate the subsequent CBESS deployments needed to meet continuing load growth.

The CBESS sizes were calculated based on several assumptions which minimize the sizing relative to what would actually be required to implement a project but nevertheless are useful data for the purpose of screening the feasibility and cost-effectiveness of the Energy Division's proposed variations of the VS-VN+CBESS alternative. These screening level results are provided in Table ES-1.

Table ES-1. Screening Level BESS Sizing

Effective Year	**Scenario 1**		**Scenario 2**	
	Without STATCOM (MW / MWh)	**With STATCOM (MW / MWh)**	**Without STATCOM (MW / MWh)**	**With STATCOM (MW / MWh)**
2031	168 / 836	158 / 766	168 / 576	158 / 537
2035	203 / 1070	195 / 1012	203 / 876	195 / 818

Table ES-1 demonstrates that Scenario 1 (VS-VN+CBESS with Permanent Transfers) requires a CBESS with an identical power capacity (megawatts or MW) to Scenario 2 (VS-VN+CBESS with Temporary Transfers), but a larger energy capacity (megawatt-hours or MWh). This is due to the ability of Scenario 2 to use the system tie-lines between the Valley South and Valley North Systems, which would allow for Valley South load served by Newcomb and Sun City Substations to be dropped and then transferred to the Valley North System while the spare transformer at

Valley Substation is placed in service to the Valley South System. This would provide SCE system operators with a means to prevent the Valley South System load-serving transformers from exceeding system operating thresholds during transformer contingency events. Scenario 1 does not have system tie-lines that allow for load to be transferred from Valley South to Valley North and therefore requires a larger CBESS to keep load below system operating thresholds for a longer period than Scenario 2.

High-level cost estimates were developed for Scenario 1 and Scenario 2 (sized for the year 2031, and with and without the STATCOM) using similar methodology and inputs to the cost estimates developed and documented in SCE's Planning Study. Additionally, market participation for the CBESS was determined, again, using an identical approach as in SCE's Planning Study. Table ES-2 provides these cost estimates and associated market participation revenue. Note that the total costs represent the costs to construct the projects and do not subtract out the revenue generated by the CBESS.

Table ES-2. Nominal Cost Estimates ($M)

	Scenario 1		Scenario 2	
	With STATCOM	Without STATCOM	With STATCOM	Without STATCOM
Total Costs	795	821	675	684
Present Value Market Participation	69.8	65.4	62.0	58.1

The cost estimates provided in Table ES-2 represent estimates in nominal dollar for comparison with the Alberhill System Project cost in nominals of $545M. The data indicates that both VS-VN+CBESS alternatives (Scenario 1 and 2) exceed the cost of the Alberhill System Project. Beyond 2031, these scenarios would require capital expenditures (e.g., additional CBESS facilities, interconnecting substations, subtransmission line upgrades, etc.) which would further increase the cost difference between these VS-VN+CBESS-based alternatives and a substation-based solution like the Alberhill System Project.

The analysis described herein demonstrates the minimum required BESS sizing for a VS-VN plus CBESS system to meet SCE Planning Criteria and Project Objectives 1 and 3 in the CPUC FEIR for the ASP Project. As noted above the resultant minimum cost of such an alternative, even over a very short (approximately 4-year) time horizon, significantly exceeds that of the ASP despite providing insignificant resilience benefits and not satisfying Objective 2 of the FEIR. Additional costs and operational challenges would continue to accrue for the VS-VN plus CBESS beyond this period, wherein the ASP most-likely represents an effective 30-year solution for all of the needs of the Valley South System.

1.0 Background

In Decision (D.) 18-08-026 for the Alberhill System Project (ASP) proceeding, the California Public Utilities Commission (CPUC) took no action on the ASP and directed Southern California Edison (SCE) to supplement the existing record with specific additional analyses. These additional analyses include, in part, a planning study and associated cost-benefit analysis (CBA) that address the project needs (including the context of applicable planning criteria and reliability standards), identify additional alternatives (including those that include distributed energy resources (DERs)), and compares relative cost-effectiveness. SCE filed a Motion to Supplement the Record with these analyses first in May of 2020[1] and amended its motion in February of 2021[2]. SCE's analysis concluded that the Valley South System's capacity, reliability, and resilience needs continue to be urgent, and that the ASP continues to be the most effective and cost-effective alternative to meet these needs.

In December of 2021, the CPUC Energy Division issued a draft Staff Report which concluded that overloads on the Valley South transformers, that occur as a result of forecasted load growth, could be resolved by a combination of tie-lines and battery storage and that this solution would perform as effectively as the proposed ASP. Specifically, the draft Staff Report advocated for further consideration of a project alternative that transfers two substations (Newcomb and Sun City) from the Valley South System to the Valley North System and installs distributed battery energy storage systems (BESS) in the Valley South System.

In January 2022, SCE provided comments on the draft Staff Report that identified, in addition to other concerns, that the analysis performed by Energy Division staff consultants did not properly consider SCE planning criteria and common industry planning standards and guidance. SCE noted that the BESS proposed alternative was substantially undersized to meet the transformer N-1 contingency reliability criterion that is the fundamental driver for the ASP project objective to create system tie-lines. Additionally, the BESS proposed alternative would not address the project objective related to the resilience associated with geographically and electrically diversifying the source of power to the San Jacinto Region that would otherwise be accomplished via a new substation. The SCE comments thus concluded that additional analysis of the Valley South to Valley North alternatives was not warranted because those alternatives would not meet the ASP project objectives.

In June 2022, the Energy Division Staff issued data request A.09-09-022 CPUC-Supplemental Data Request-012 to analyze two variations of the VS-VN+BESS alternative in which, for both cases, the BESS was located at a centralized location (VS-VN & CBESS where "C' indicates centralized). Additionally, for the purpose of the analysis, the BESS was requested to be sized to

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[1] SCE Second Amended Application and Motion to Supplement the Record (May 2020)

[2] Amended Motion to Supplement Record (February 2021), SCE in June 2021 filed Second Amended Motion to Supplement the Record to Correct Clerical Error.

meet the minimum SCE planning criteria for transformer N-0 conditions and N-1 contingencies and therefore meeting the project capacity and reliability needs reflected in Project Objectives 1 and 3 in the CPUC issued FEIR[3] through 2031. SCE notes that, in sizing at these specific limits and only through 2031, the sizing understates the actual BESS sizing that would be required to implement the project. This is because in addition to meeting this basic sizing requirement to meet transformer N-0 and N-1 conditions, actual BESS sizing would need to address requirements in both power (MW) and energy (MWh) considering N-1 generation contingency requirements (an unplanned outage of a generation resource), battery performance degradation over its operating period, battery "round-trip" efficiencies, year-to-year volatility in system loading, load forecast uncertainty (including impacts of the latest California Energy Commission's (CEC) most recent Integrated Energy Policy Report (IEPR) forecast that reflects significant projected increases in electrical demand due to electrification) and other factors. Nevertheless, SCE considers this sizing approach to be a reasonable first step in characterizing the required scope, cost, and performance of a minimum-sized VS-VN+BESS alternative. The requested level of analysis is to determine:

- the required BESS sizing,
- its feasibility from an electrical performance perspective,
- confirm that it addresses SCE transformer contingency N-0 and N-1 planning criteria, and
- the load-at-risk (LAR) resulting from some beyond N-1 transformation contingencies.

The LAR determination is particularly important considering that the VS-VN+CBESS alternative does not, and cannot by its nature, satisfy FEIR Project Objective 2 which is reflective of the project resilience need. This need is associated with the very large number of customers served by Valley Substation and their resulting vulnerability to singular events that could adversely affect SCE's ability to serve customers from that location. The resilience need cannot be satisfied without a new substation that is diverse both geographically and electrically from Valley Substation. The LAR determination characterizes the impact of this shortfall in the VS-VN+CBESS alternative.

The remaining sections of this document are described here. Section 2.0 of this document repeats Question DG-MISC-83.[4] Section 3.0 begins SCE's response to DG-MISC-83 and provides additional information related to the analysis methodology. Section 4.0 provides SCE's results of the analysis. Section 5.0 provides the cost estimates of the VS-VN+CBESS alternatives. Section 6.0 provides the conclusions of SCE's analysis.

2.0 Question DG-MISC-83

The methodology and assumptions described herein provide the basis for scoping Valley South to Valley North plus Centralized Battery Energy Storage System (VS-VN+CBESS) project alternatives.

[3] Final Environmental Impact Report, at 1-10:11.
[4] Some minor edits have been made to the naming convention of the alternatives for clarity. Additionally, details to the load forecast used in the analysis were added to Section 2.4.

SCE evaluated the system performance of the VS-VN+CBESS alternative under two scenarios to meet the minimum system performance criteria as required by SCE's planning criteria and guidelines and which is consistent with common electric utility practice. Specifically, at a minimum, the performance of the alternative must:

- Ensure all load is served during normal system conditions (i.e., all electrical facilities in-service or "N- 0") and during 1-in-5-year heat storm weather conditions
- Ensure all load is served during abnormal system conditions consisting of a single electrical system component being out-of-service (i.e., "N-1") and during 1-in-5-year heat storm weather conditions

The year of study was specified to be 2031 which is the final year of SCE's last completed 10-year forecast covering the years 2022-2031. A 10-year planning horizon is common for system studies as it is typically adequate for evaluating system performance, identifying system needs, and allowing for solutions to be implemented within the first several years of the 10-year planning horizon. However, SCE notes that for larger and more complex projects (e.g., projects that require permitting and licensing approval from the CPUC such as the Alberhill System Project) that commonly take 5-7 years (or more) to complete, it can be argued that a 10-year planning horizon is not long enough to properly evaluate the cost-effectiveness of an alternative that may only be in service for several years through the 10-year planning horizon.

<u>Scenario 1 – with the initial transfer of two substations from VS to VN plus CBESS</u>

Study system performance *with* the permanent transfer of two substations (Newcomb and Sun City) from Valley South (VS) to Valley North (VN) and with an appropriately sized CBESS located in VS (near Pechanga Substation). The CBESS will be sized to ensure that following the transfer of the two substations, the loading of two load-serving VS transformers will not exceed 896 MVA under normal system conditions (N-0) during 1-in-5-year heat storm weather conditions and the loading of a single load-serving transformer will not exceed 896 MVA under abnormal system conditions (N-1 transformer event) during 1-in-5 year heat storm weather conditions.[5]

<u>Scenario 2 – without initial transfer of two substations from VS to VN plus CBESS</u>

Study system performance <u>*without*</u> the permanent transfer of two substations (Newcomb and Sun City) to VN and with an appropriately sized CBESS located in VS (near Pechanga

[5] Scenario 1 is the VS-VN+CBESS alternative identified in SCE's Planning Study which includes 115 kV subtransmission line scope that transfers two substations from VS to VN thereby reducing the loading of the VS transformers. In Scenario 1, the two substations are transferred initially as part of the normal N-0 system reconfiguration of the system. This alternative does <u>not</u> result in system tie-lines that allow for additional load transfers from VS during N-1 conditions (e.g., an unplanned outage of a VS load-serving transformer). As a result of these tie-lines being unable to further reduce the load of the VS transformers during N-1 contingencies, any load amount above 896 MVA (the maximum emergency loading limit of a single transformer) must be reduced through use of the CBESS and the system loading at all times must be maintained at no greater than 896 MVA at all times (N-0 and N-1 system conditions).

Substation). The CBESS will be sized to ensure that the two load-serving VS transformers will not exceed 1,120 MVA under normal system conditions (N-0) during 1-in-5 year heat storm weather conditions and the loading of a single load-serving will not exceed 896 MVA under abnormal system conditions (N-1 transformer event) during 1-in-5 year heat storm weather conditions.[6]

SCE is providing this analysis to demonstrate the CBESS size that is required considering that under Scenario 1 (no N-1 tie-line transfer capacity) the maximum loading limit of VS is 896 MVA at all times (both normal and abnormal system conditions). Additionally, at the request of the Energy Division, SCE has analyzed Scenario 2 that demonstrates the size of the BESS required to maintain loading of the VS transformers to no more than 1,120 MVA and 896 MVA under normal and abnormal system conditions respectively.

2.1. *System Operating Thresholds*

The scope of each scenario, particularly the battery sizes, are guided by SCE's Subtransmission Planning Criteria and Guidelines (i.e., system operating thresholds) which state that, at a minimum, system performance shall serve all load under N-0 (normal conditions) and N-1 ("Likely Contingency") conditions with limited exceptions.[7] Additionally, studies shall be performed for awareness of impacts and consideration of solutions to address "Unlikely Contingencies" (i.e., N-1-1 and N-2).[8]

SCE's Subtransmission Planning Criteria and Guidelines dictate that sufficient transformer capacity or adequate subtransmission tie-line capacity will be planned to limit or reduce transformer loading (to within defined maximum emergency loading limits) in the event of a transformer outage."[9] Based on this criterion, the Valley South and Valley North system operating thresholds are as follows.

Valley North (<u>normal condition</u> operating threshold because tie-lines are present to reduce load during N-1 contingencies): 1,120 MVA

Basis: VN has existing system tie-line capacity that can reduce loading on the VN during contingency events and the full nameplate rating of 1,120 MVA of its

[6] Scenario 2 presents a variation of the alternative in Scenario 1, and which includes the same 115 kV subtransmission line scope as Scenario 1, but which differs in that it does <u>not</u> transfer the two substations as part of the normal N-0 system reconfiguration of the system. This variation does <u>not</u> reduce loading of the VS transformers under normal system conditions, but rather allows for the temporary transfer of the two substations from VS to VN under N-1 abnormal system conditions. As these tie-lines allow for load reductions of the VS transformers during contingency conditions, the maximum VS system loading is permitted to be up to 1,120 MVA (the total nameplate rating of two 560 MVA load-serving transformers) under normal system conditions and up to 896 MVA under abnormal system conditions. The size of the CBESS is determined by the amount of load reduction required to maintain both of these operating limits.
[7] Sections 2.3.2.1A and 1.3 of SCE's Subtransmission Planning Criteria and Guidelines
[8] Section 1.4 of SCE's Subtransmission Planning Criteria and Guidelines
[9] Section 2.2.1 of SCE's Subtransmission Planning Criteria and Guidelines

transformers during normal conditions is its operating threshold because during an N-1 transformer contingency, load (sufficient to reduce VN loading to below the one-hour transformer emergency rating of 896 MVA) may be shed[10] and then the shed load could then be promptly transferred via tie-lines to the adjacent Vista 115 kV System.

Valley South—Potential Future State Post-Project (normal condition operating threshold *if the solution provides tie-lines with transfer capability*): 1,120 MVA

Basis: Under the assumption that a project were constructed with relays to automatically shed load and which would provide VS with system tie-lines (similar to VN whereby all or most of the load that was shed could be transferred), the full normal-condition nameplate rating of 1,120 MVA of the VS transformers would be the operating threshold.

Valley South – Status Quo Operating State (normal and emergency condition operating threshold because VS *does not* have tie-lines and the proposed project would not create tie-line transfer capability from VS to another system): 896 MVA

Basis: VS does not meet the criterion of having sufficient transformer capacity OR tie-line capacity during a transformer outage. In lieu of tie-lines, a temporary mitigation measure has been implemented to align the emergency spare transformer when system load is projected to exceed 896 MVA, as this is the maximum one-hour emergency operating limit of a single Valley Substation transformer. Placing the spare transformer in service prevents a scenario in which a single transformer outage leaves the second transformer exposed to load in excess of its maximum emergency rating, which could result in a catastrophic failure, personnel injury, and/or loss of load. The operational risk, and therefore the system operating threshold, is identical *with* or *without* an actual transformer failure since system operators must always have means to protect the remaining in-service transformer (i.e., by having sufficient transformation capacity or adequate tie-line capacity). Should a transformer actually fail, there are only two remaining transformers available to serve Valley South and a subsequent transformer failure would expose the single remaining transformer to loads in excess of its maximum emergency rating and potentially lead to catastrophic failure. As such, load is limited to 896 MVA consistent with SCE's planning criteria and guidelines.

[10] VN has existing automatic load-shedding relays in place designed to drop sufficient load to ensure load remains no greater than 896 MVA during an N-1 contingency.

2.2. Summary of the VS-VN+CBESS Scope

The scope of the VS-VN+CBESS alternatives (both with and without the initial transfer of two substations) include the following key components:

- New 115 kV subtransmission lines between Valley South and Valley North Systems. These 115 kV lines would enable the transfer of Newcomb and Sun City Substations from the Valley South System to the Valley North System. The operational status of the new 115 kV lines will be guided by the scenario under study. When permanently transferring load initially they would be termed “source lines” and when transferring load temporarily during contingencies they would be termed “tie-lines.”
- Centralized Battery Energy Storage System in the Valley South System (CBESS)
- Reactive power support through a STATCOM to reduce the reactive power flow through the Valley South System transformers

The VS-VN+CBESS alternative was evaluated under two scenarios. The differences are embedded in the use of new 115 kV lines as 1) permanent initial transfer or 2) temporary transfers only during contingencies. SCE studied both scenarios with and without use of the STATCOM device.

The different system operating thresholds that govern operations are described for each of the two scenarios below. The specific role of each system component (e.g., CBESS, tie-lines, STATCOM) is described below from the perspective of different system operating thresholds (e.g., normal condition and emergency condition).

Scenario 1: Valley South to Valley North plus CBESS with Permanent Transfers

Normal conditions: Transformer capacity margin in Valley South was achieved in this scenario via the use of the permanent transfer of Newcomb and Sun City Substations from Valley South to Valley North. The lack of Valley South tie-line transfer capacity requires the Valley South System to operate at no greater than the 896 MVA operating threshold (normal condition operating threshold without tie-lines), in preparation for an unplanned outage of a Valley South transformer. The magnitude and duration of any load in excess of 896 MVA (see Section 2.0 above) defined the power (MW) and energy (MWh) requirements of the CBESS. The STATCOM device was modeled at the CBESS location to regulate the bus voltage to 1.0 per unit to optimize the size of the CBESS while also ensuring voltage remained within required operating limits.

Emergency conditions: For Valley South, the CBESS was sized for emergency conditions (896 MVA) due to the lack of system tie-lines. However, as described immediately above in the “normal conditions” section, the CBESS would already be sized for 896 MVA in preparation of an N-1 transformer outage in Valley South and thus the sizing is identical for both normal and emergency conditions. The STATCOM device was sized in the same manner as identified for normal operating conditions.

Scenario 2: Valley South to Valley North plus BESS with Temporary Transfers

Normal conditions: Transformer capacity margin in the Valley South and Valley North Systems was achieved in this scenario via the use of a CBESS in Valley South to reduce load below the system's operating threshold (1,120 MVA). The availability of tie-line capacity (via the new 115 kV lines that would allow for the transfer of Newcomb and Sun City Substation ~200 MVA) would enable Valley South to operate up to 1,120 MVA while Valley North would also be operated to 1,120 MVA as it has existing tie-line transfer capacity. The magnitude and duration of the load in excess of the system operating thresholds defined the power (MW) and energy (MWh) levels of the CBESS. The STATCOM device was modeled at the CBESS location to regulate the bus voltage to 1.0 per unit to optimize the size of the CBESS while also ensuring voltage remained within required operating limits.

Emergency conditions: (i.e., loss of Valley South transformer): As defined within SCE's planning criteria, the emergency operating threshold of 896 MVA was applied for the first hour of the contingency event. Under this condition, power was interrupted to Newcomb and Sun City Substations (would be implemented through automatic load-shedding relays) after which the new 115 kV lines restored service to Newcomb and Sun City Substations via Valley North. Additionally, the spare transformer was switched in-service to the Valley South System. The magnitude of the load in excess of the emergency operating threshold defines the power requirement (MW) of the supplemental CBESS. The energy (MWh) of the CBESS was only sized for a duration of <u>one</u> <u>hour</u> which is assumed to be sufficient time to place the spare transformer in service in the Valley South System. The STATCOM device was sized in the same manner as identified for normal operating conditions.

2.3. BESS Sizing Factors

The minimum size of the CBESS is in accordance with the system operating thresholds described in Section 3.0. The sizing of the CBESS for this analysis will not include factors impacting the sizing to account for round-trip efficiency, battery degradation, BESS resource N-1, or additional margin to account for things such as forecast uncertainty, so in an actual project application of this alternative, sizing would be significantly larger than described in Section 3. The CBESS size (MW) is driven by the need to meet the Valley South System transformer capacity operating thresholds under both N-0 <u>and</u> N-1 conditions to prevent overloads. Use of the STATCOM device is studied to optimize the CBESS sizing to keep the Valley South transformers within operating limits. The analysis sized the CBESS to meet the system requirements through 2031. For this analysis, it was assumed that following project approval and completion of construction (assumed operating date of 2027), the identified CBESS size required to satisfy capacity through 2031 would be installed at the initial in-servicing of the project (i.e., 2027). SCE notes that by 2031, the incremental CBESS additions for the next period of time (e.g., 2032 or through some other period) would also need to be installed.

- Valley South to Valley North plus CBESS with Permanent Transfers
  - Valley South
    - CBESS + STATCOM: CBESS sized (and optimized with the STATCOM) to maintain loading levels of the Valley South System transformers to no greater than the emergency condition operating threshold of 896 MVA (because under this scenario VS would not have tie-lines)
- Valley South to Valley North plus BESS with Temporary Transfers
  - Valley South
    - CBESS + STATCOM: CBESS sized (and optimized with the STATCOM) to maintain loading levels of the Valley South System transformers to no greater than the normal condition operating threshold of 1,120 MVA for Valley South (because under this scenario VS would have tie-lines)
    - CBESS + STATCOM: CBESS sized (and optimized with the STATCOM) to maintain loading levels of the Valley South System transformers to no greater than the emergency condition operating threshold of 896 MVA for Valley South (after use of tie-lines to transfer load to Valley North)

1. In-Service Date

The VS-VN+CBESS alternative was assumed to be in-service by 2027 (several years after deficiencies are present) and was sized for system needs through the study year of 2031.

2. CBESS Location Considerations

In the analysis, the CBESS was sited in a location that considered *both* optimizing the size of the BESS (i.e., results in the least amount of MW and MWh to achieve zero LAR under N-0 and N-1 operating thresholds) and in an area with undeveloped land on which it could be considered reasonable to construct a CBESS substation. Siting the CBESS did not consider impacts to existing subtransmission lines (i.e., the Auld-Moraga #2 subtransmission line overload which is expected to develop over the analysis period[11]).

2.4. Study Considerations and Flex Metrics.

Battery sizes for the Valley South to Valley North Plus CBESS alternative were determined based on addressing transformer N-0 and N-1 scenarios as described further in Section 3 below.

The analysis focuses on the year 2031 (the 10th year of the current 10-year planning horizon) but also provides additional expected BESS sizing information for the years 2035, 2040, and 2045 for

[11] The expected Auld-Moraga #2 overload is not a driver for the ASP project but was subject to much discussion in the draft Staff Report. SCE's Planning Study and responses to several data requests showed that this overload could be addressed in various different manners.

awareness of the expected ongoing increases to the required BESS sizing. The analysis is driven by a Valley South System load forecast derived from the CAISO 2018-2028 IEPR (extended beyond 2028 using the mid-range Effective PV forecast[12]. This is to be consistent with the SCE Planning Study and benefit/cost analysis referenced in Section 1.

Based on the sizing criteria above, no load at risk (LAR) would be accrued for either scenario during transformer N-0 conditions and N-1 conditions through 2031. However, the analysis revisits and expands the Flex-2 metrics addressed previously in SCE's Planning Study and BCA analysis.

Flex-2-1

For Flex-2-1 (complete outage of Valley Substation for two weeks), SCE studied the outage during peak summer loading conditions with the peak day occurring in the middle of the two weeks and in the year (2031).

In this case, LAR was accrued throughout the two-week outage for all customers unserved in the Valley South and Valley North Systems after the load transfer from Valley North to Vista is made using the available Valley North tie-lines. CBESS is assumed unavailable to reduce LAR after it was fully discharged during day 1 of the event due to a lack of BESS charging or synchronization capability.

This is considered a "high-impact- low-probability" event and thus an "Unlikely Contingency" under SCE's planning criteria, but its impact should be considered due to the potential large number of affected customers.

This metric is unchanged from the scenario considered in SCE's Planning Study and BCA analysis referenced in Section 1.

Flex-2-2-A- Short Duration Outage with Availability of On-site Spare Transformer

Flex-2-2-A evaluated the impact of a 6-hour outage of a Valley South transformer. The on-site spare transformer was assumed to be available by the start of hour 2 of the outage (i.e., two transformers serving VS for the remaining 5 hours of the outage). In this case, LAR (if any) would only be accrued during hour 1 prior to the spare transformer being placed in service. SCE notes however that with the properly sized BESS resources, no LAR was accrued inFlex-2-2-A.

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[12] A mid-range ("Spatial Effective PV") load forecast was developed by considering continuing changes in growth rates of DER adoption as reflected in the CEC's 2018 IEPR forecast. The adopted 2018 forecast only goes out to the year 2030. In order to extend IEPR load growth considerations to 2048, a regression method with a saturation tendency was applied to the individual IEPR-derived PV, EV, EE, and DR load impact forecasts. The forecast DER growth rates were determined through regression analysis, then applied to reduce the forecast load to account for expected increases in DER adoption beyond those reflected in historical trends. The Spatial Effective PV forecast also includes an adjustment to account for the expected effective on-peak contribution of installed customer-sited solar PV capacity for peak load reduction, adjusting the amount of generation based on time-of-day and general historical reliability metrics.

The analysis considered the 24-hour period of the peak day of the year with the outage occurring from hours 1400-1900 (peak hour in the middle).

This is a new variation of the Flex 2-2 metric and is considered an N-1 contingency and "Likely Contingency" under SCE's planning criteria.

Flex-2-2-B- Short Duration Outage without Availability of On-site Spare Transformer

Flex-2-2-B evaluated the impact of a 6-hour outage of a Valley South transformer. The on-site spare transformer was assumed to not be available during the event (i.e., only one transformer serving VS for the full-6-hour outage). In this case, LAR was accrued during hours 2-6 for any load that would exceed the long-term emergency loading limit (24 hours) of 672 MVA.

The analysis considered the 24-hour period of the peak day of the year with the outage occurring from hours 1400-1900 (peak hour in the middle).

This is a new variation of the Flex 2-2 metric and is considered an N-1-1 contingency of limited duration, and thus an "Unlikely Contingency" but one that would generally be considered in SCE system planning because it is not uncommon to have short-duration outages due to equipment alarms or other minor maintenance issues.

Flex-2-2-C- Long Duration Outage without Availability of On-site Spare Transformer

Flex-2-2-C evaluated the impact of a 2-week outage of a Valley South transformer. This condition is reflective of an N-1-1 event, (i.e., one VS transformer failure without the spare transformer available leaving only one transformer serving VS for the full 2-week outage while the off-site spare transformer was mobilized and placed in service.

In this case, for the first day, LAR was accrued for load above 896 MVA for the first hour and above 672 MVA for hours 2-24. For days 2-14, LAR was accrued for any load above the 560 MVA nameplate rating of the single in-service transformer.[13]

This scenario is identical to the Flex-2-2 scenario presented in SCE's Planning Study and would be considered a "high-impact, low-probability" event. This would also be considered an "Unlikely Contingency" under SCE's planning criteria, but its impact should be considered due to the potential large number of affected customers.

2.5. Evaluation of CBESS - Assumptions

- The CBESS was considered available to offset any LAR accrual over the course of the outage event until it was fully discharged.
- Irrespective of system constraints, the CBESS was assumed to be able to fully charge overnight and be available for discharge when required.

[13] For 500/115 kV transformers, after 24 hours the maximum allowable rating is the nameplate rating.

- If the analysis were to indicate the system is unstable due to the combination of the CBESS additions and high system loading, additional scope would have been to make the solution operationally feasible. These events are generally encountered when the balance between generation addition (CBESS) and system load cannot reach a stable equilibrium point, resulting in mismatches due to voltage swings and excessive reactive power flow. These are indicative of challenges in operating the Valley South System under increased loading conditions with a single transformer in service. The additional scope could include additional capacitor banks, adjusting transformer tap settings, adjusting voltage schedules at the Valley South 115 kV bus, or adding devices such as a STATCOM.

2.6. *Planning-Level Cost Estimates*

SCE developed planning-level cost estimates for each of the two VS-VN+CBESS variants consistent with the methodology (including the component cost inputs) used in SCE's previous benefit-cost analysis (BCA) and Planning Study.

SCE notes that CBESS facilities would need to be installed and in service by the earliest feasible operating date to meet the system needs (as the operating date is later than the need date) and both are before the study year 2031. Consistent with the analysis provided in SCE's Planning Study, this analysis reflects the necessary CBESS sizing and costs (nominal dollars) to address system needs through 2031 with installation assumed to occur in 2025 (consistent with the Planning Study to allow an "apples-to-apples" cost comparison). Additionally, SCE has provided, for awareness, the size for CBESS additions expected to be necessary (and installed by 2031, 2035, 2040, and 2045) to meet N-0 and N-1 system needs. However, LAR values were not accumulated beyond 2031 for the contingency events that are beyond N-1 (e.g., Flex-2-2-B and Flex-2-2-C). Finally, SCE developed a rough order of magnitude cost estimate for a STATCOM addition so that the Energy Division can assess its cost versus potential added value in reducing BESS sizing.

3.0 SCE's Response to Question DG-MISC-83

The following sections provide SCE's response to A.09-09-022 CPUC-Supplemental Data Request-012 Question DG-MISC-83. This analysis was performed in accordance with the methodology and assumptions described in Section 2.0.

The Valley South to Valley North and Centralized BESS alternatives have similar scope but differ in the sizing of their corresponding CBESS. The CBESS of each alternative was sized to meet the N-0 and N-1 criteria of SCE's Subtransmission Planning Criteria and Guidelines. CBESS sizing results are provided in Section 4.1. A general summary of the steps to determine the CBESS for each alternative is described below:

1. Power flow analyses of each alternative was performed for N-0 or N-1 conditions for the year 2031.
2. Load in excess of system operating thresholds for the two conditions was used to inform initial battery sizing. The condition which resulted in the larger magnitude of load above the system operating threshold was used to determine the power rating of the CBESS. This

ensured that the CBESS had sufficient power capability to mitigate overloads under either N-0 or N-1 conditions. The energy rating of the CBESS was determined by summing the total load above the system operating threshold for the duration of the overload (i.e., total load above the system operating threshold for the first hour, second hour, etc.).

3. Power flow analyses were rerun with the final BESS sizing to validate no overloads were observed.

Power flow analyses were also performed for Flex metrics described in Section 2.4 for each alternative with the CBESS sizes required to meet the N-0 and N-1 criteria. These results are provided in Section 4.

The power flow studies referenced above were performed initially for the peak hour to determine CBESS power size then a time-series analysis was performed for varying durations from a day (24 hours) to 2 weeks (336 hours), depending on the Flex metric contingency being evaluated, to determine the energy size. The studies focused on the year 2031, with an outlook for awareness of the years 2035, 2040, and 2045. A combination of power flow simulation tools has been utilized for this analysis, such as General Electric's Positive Sequence Load Flow (PSLF) and PowerGem TARA. PSLF has been used for base-case model development, conditioning, contingency development, and system diagram capabilities. TARA has been used to perform time-series power-flow analysis.

In this analysis, consistent with the approach used in SCE's Planning Study, the peak load MVA of the load shape has been adjusted (scaled) to reflect the peak demand for each year under study. This is represented by Figure 3-1 for the Valley South System as an example. The MVA peak load is then distributed amongst the various distribution substations in the Valley South System in proportion to their ratio of peak load to that of the entire Valley South System in the base case. A similar approach is used to develop and scale the load shape for the Valley North system so that it can be evaluated for any N-0 and N-1 condition overloads that are accelerated due to the Valley South to Valley North load transfers associated with both scenarios.

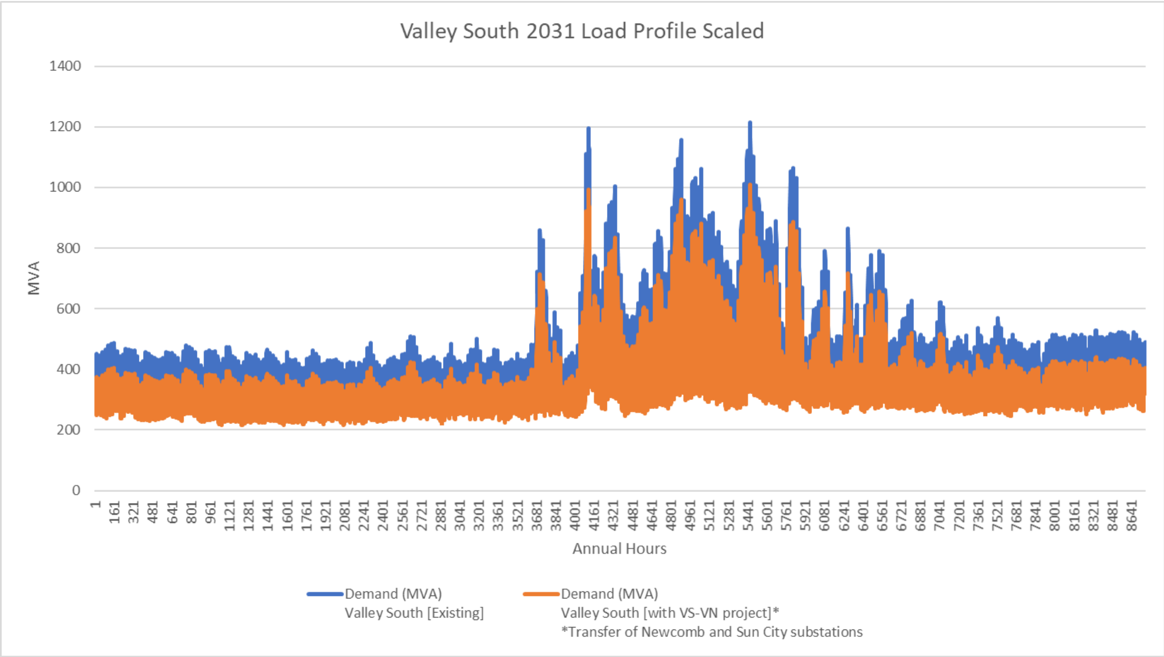


Figure 3-1 : Scaled Valley South Load Shape Representative of Year 2031

When determining the battery sizes or evaluating battery performance for a specific year, the following general assumptions apply across all components of the analysis.

- The batteries were sized without consideration for uncertainties in load forecast, contingency factors, or load variability.
- All batteries have been assumed to have 100% discharge and charge efficiency.
- All batteries have been assumed to have sufficient opportunities to charge overnight irrespective of any system constraints.
- Sizing is based on the same 2018 load forecast used in the original 2020 Planning Study. The most recent IEPR forecast shows substantially higher load growth due to forecasted electrification impacts.

These assumptions are consistent with SCE's approach as described in Section 2 above. Note that applying these assumptions results in CBESS sizing that would be smaller than required for an actual project. Should the screening study documented herein show that further consideration of a Valley South to Valley North plus BESS alternative is warranted, SCE would need to work with the Energy Division to develop more assumptions more reflective of reality in the above areas.

For each scenario, the CBESS substation is located near SCE's existing Pechanga Substation consistent with the initial deployment of batteries for all of the CBESS alternatives evaluated in SCE's Planning Study. As discussed in the Planning Study, this location was identified based on the likely availability of a suitable land parcel and because this is an optimum location in the system to minimize line congestion and any 115 kV subtransmission line scope needed to implement the alternative, along with minimizing the size of the required BESS. This siting consideration precludes the need to consider any LAR resulting from N-0 and N-1 condition line overloads in the screening analysis.

For scenarios that included STATCOM devices, an iterative approach was used to optimize STATCOM sizing to minimize the BESS sizing in satisfying N-0 and N-1 transformer scenarios.

4.0 Results

This section provides CBESS sizing results for each alternative as well as the performance against each of the Flex metrics described in Section 3.2. Note that analysis confirmed that it is likely possible to maintain system stability in the Valley South System through 2031 despite the combination of substantial BESS additions and high system loading. It is possible, and in fact likely, that additional scope beyond BESS additions would have to be added to make a large-scale BESS solution operationally feasible in the years beyond 2031.

4.1. BESS Sizes

4.1.1. Scenario 1 – Valley South to Valley North plus CBESS with Permanent Transfers

CBESS sizes for Scenario 1 are provided in the following table. Results for the years 2031 and 2035 without and with a 50 MVAR STATCOM are included.[14]

Table 4-1. Scenario 1 CBESS Sizes

Effective Year	CBESS Size without STATCOM (MW / MWh)	CBESS Size with STATCOM (MW / MWh)
2031	168 / 836	158 / 766
2035	203 / 1070	195 / 1012

[14] It was observed that a 50 MVAR STATCOM was optimal from the perspective of regulating voltages at the CBESS substation at 1.0 per unit, without causing high voltages elsewhere in the Valley South System. For the 2031 and 2035, no appreciable system improvement was observed by increasing the STATCOM size beyond 50 MVAR.

The following figure shows the modeled 2031 peak day load profile versus the system operating threshold of 896 MVA for this scenario.

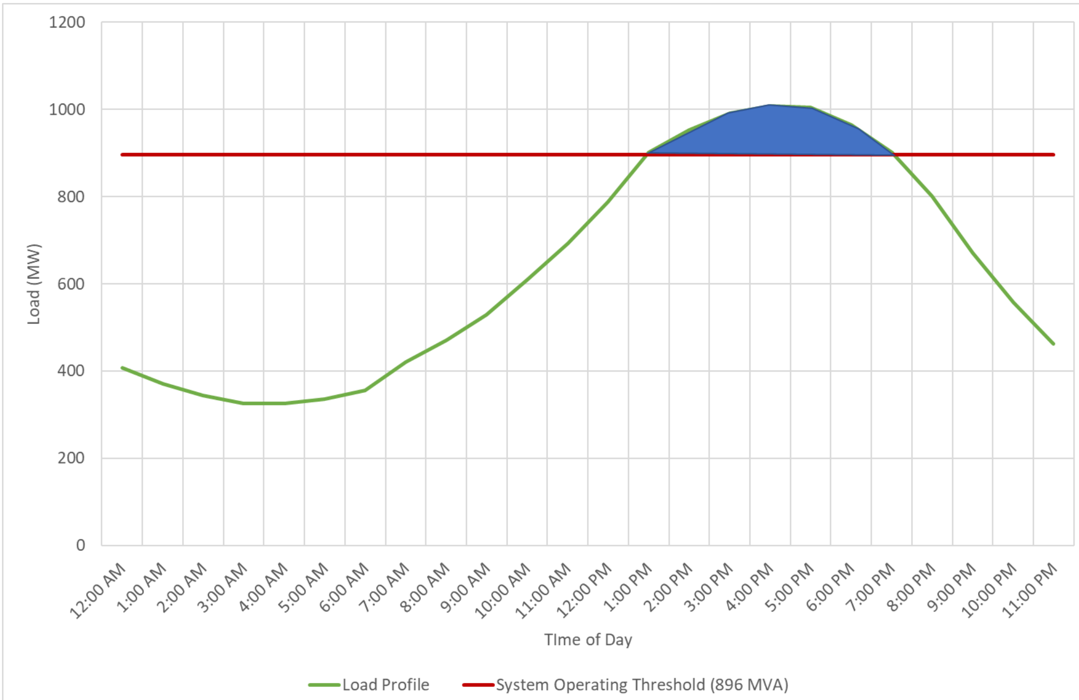
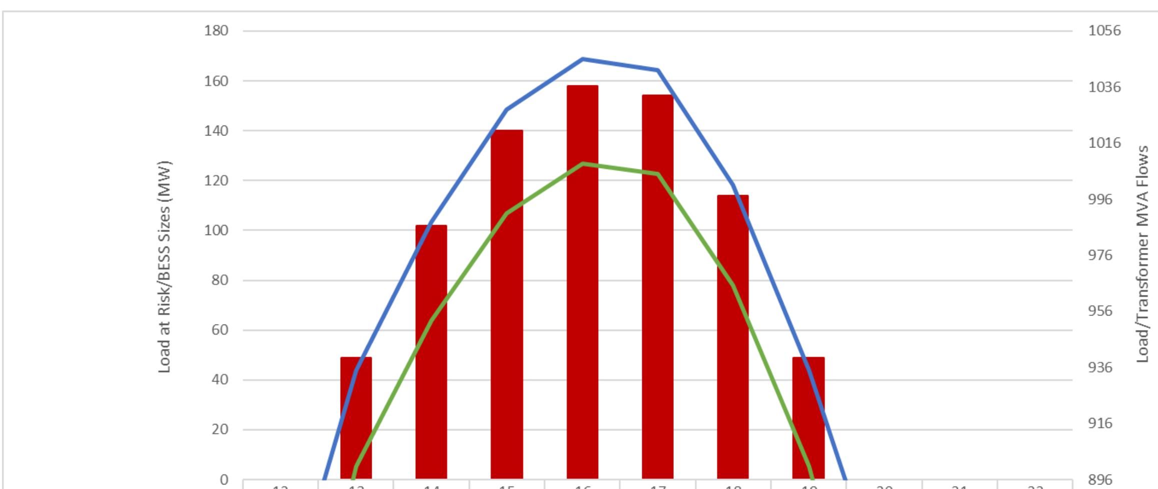


Figure 4-1. Load Profile for Scenario 1 with STATCOM BESS Sizing

The figure below details the above load profile in tabular form. Note that this figure provides results for the version of this alternative with the STATCOM device.



	12	13	14	15	16	17	18	19	20	21	22
Load at Risk/BESS Sizes	0	49	102	140	158	154	114	49	0	0	0
Transformer MVA Flows	842	935	988	1028	1046	1042	1001	935	854	716	594
Load	788	901	953	991	1009	1005	965	901	801	671	557

Figure 4-2. Hourly Results for Scenario 1 with STATCOM

The row titled “Load” represents the raw Valley South System load aggregated directly from the Valley South distribution substations. The row titled “Transformer MVA Flows” represents the flows on the Valley South transformers, accounting for the system load plus losses. The row titled “Load at Risk/BESS Sizes” represents the load above system operating thresholds (i.e., load at risk) which is used to determine the CBESS size.

Scenario 1 with the above battery sizes satisfies N-0 and N-1 planning criteria.

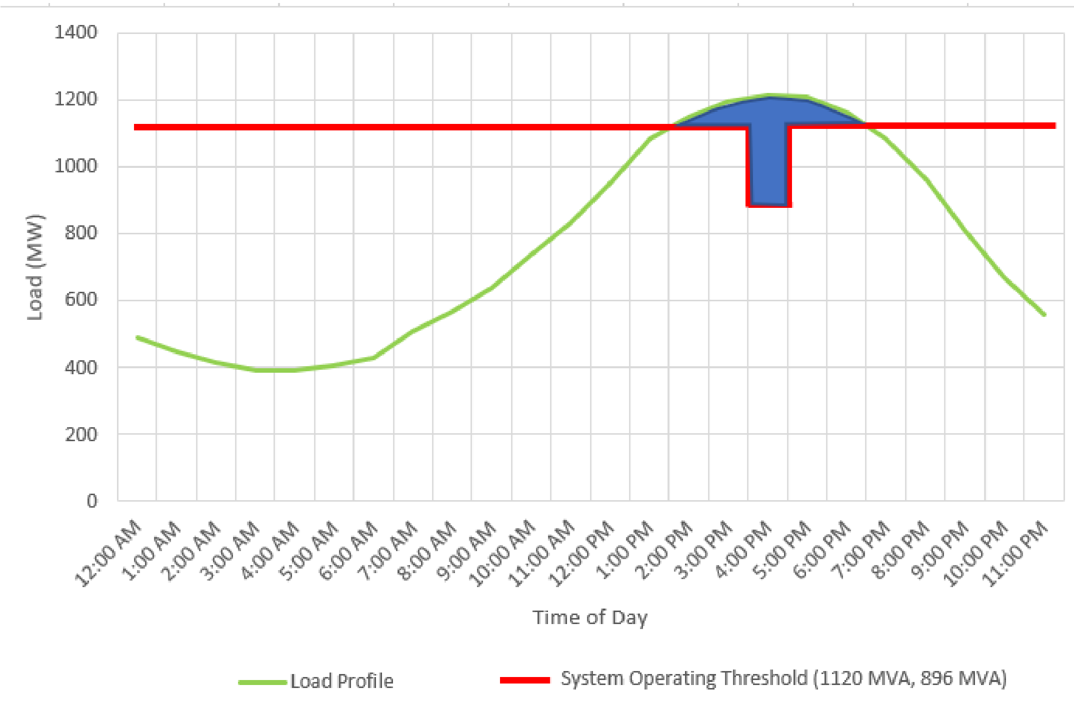
4.1.2. Scenario 2 – Valley South to Valley North plus CBESS with Temporary Transfers

CBESS sizes for Scenario 2 are provided in the following table. Results for the years 2031 and 2035 with and without a 50 MVAR STATCOM are included.[15]

Table 4-2. Scenario 2 CBESS Sizes

Effective Year	CBESS Size without STATCOM (MW / MWh)	CBESS Size with STATCOM (MW / MWh)
2031	168 / 576	158 / 537
2035	203 / 876	195 / 818

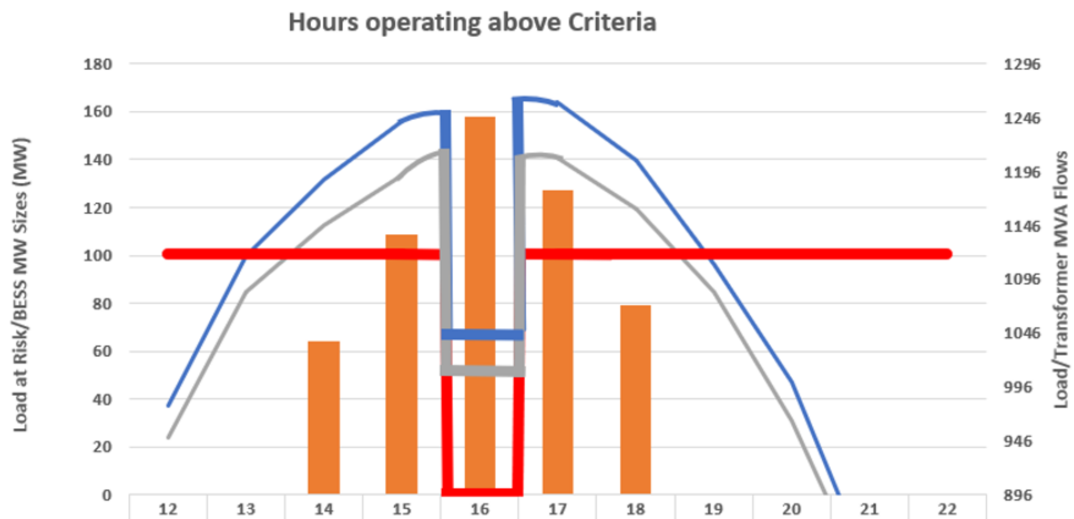
The following figure shows the load profile versus system operating threshold (either 1,120 MVA or 896 MVA) for this scenario.



[15] It was observed that a 50 MVAR STATCOM was optimal from the perspective of regulating voltages at the CBESS substation at 1.0 per unit, without causing high voltages elsewhere in the Valley South System. For the 2031 and 2035, no appreciable system improvement was observed by increasing the STATCOM size beyond 50 MVAR.

Figure 4-3. Scenario 2 with STATCOM Load Profile

The figure below details the above load profile in tabular form. Note that this figure provides results for the version of this alternative with the STATCOM device.



	12	13	14	15	16	17	18	19	20	21	22
Load at Risk/BESS Sizes	0	0	64	109	158	127	79	0	0	0	0
Transformer MVA Flows	978	1118	1188	1242	1046	1260	1206	1110	1001	827	687
Load	949	1084	1146	1193	1009	1209	1162	1084	964	808	671
Criteria Limit	1120	1120	1120	1120	896	1120	1120	1120	1120	1120	1120

Figure 4-4. Scenario 2 with STATCOM Results

The row titled "Criteria Limit" provides the operating threshold for each hour of the load profile. The row titled "Load" represents the raw Valley South System load aggregated directly from the Valley South distribution substations. The row titled "Transformer MVA Flows" represents the flows on the Valley South transformer, accounting for the system load including losses. The row titled "Load at Risk/BESS Sizes" represents the load above system operating thresholds (i.e., load at risk) which is used to determine the CBESS size.

Scenario 2 with the above battery sizes satisfies N-0 and N-1 minimum planning criteria.

4.1.3. Future BESS Sizes

BESS sizes for the Valley South and Valley North Systems were determined for future years for comparative purposes. The battery sizes were observed to escalate (particularly significantly in energy) in years beyond 2035 including the need for batteries in the Valley North System expected between the years 2035 and 2040. The CBESS sizes below are without a STATCOM (the analysis of the future years was done prior to determining the cost of the STATCOM relative the savings associated with reduced battery sizing). However, the data below is relevant to demonstrate the different trajectories of power (MW) and energy (MWh), It is expected that the sizes with STATCOM would be slightly reduced based on the results provided in Sections 4.1.1 and 4.1.2.

Table 4-3. Future CBESS Sizes in Valley South and Valley North (No STATCOM)

Effective Year	Valley South (MW / MWh)	Valley North (MW / MWh)
2031	168 / 576	- / -
2035	203 / 876	- / -
2040	218 / 1096	62 / 62
2045	285 / 1534	135 / 135

As described previously, sizing of the CBESS for this analysis did not include factors impacting the sizing to account for round-trip efficiency, battery degradation, BESS resource N-1, or additional margin to account for things such as forecast uncertainty, and the CBESS sizes presented in Table 4-3 in reality would be larger in an actual project implementation.

4.2. Evaluation of Alternatives Performance for Flex Metrics

Scenario 1 and 2 with the CBESS sizes determined in Section 4.1 to meet N-0 and N-1 criteria were analyzed for the Flex metrics described in Section 2.4. Only the versions of the scenarios with STATCOM were included in these analyses, as inclusion of the STATCOM resulted in smaller CBESS sizes. The resultant LAR for the versions of the scenarios without the STATCOM would be slightly larger than those provided below. Only the year 2031 was evaluated.

Table 4-4. Results for Flex Metric Analyses (2031)

Metric	Outage Duration	Spare Available?	Contingency Type	Load at Risk (MWh)	
				Scenario 1 (permanent transfer) (158 MW / 766 MWh BESS)	Scenario 2 (temporary transfer) (158 MW / 537 MWh BESS)
Flex-2-1	2 weeks	No	Unlikely	195,166	195,166
Flex-2-2-A	6 hours	At hour 2 of outage	Likely	0	0
Flex-2-2-B	6 hours	No	Unlikely	895	1125
Flex-2-2-C	2 weeks	No	Unlikely	12,061	14,474

Note 1: Contingency type is characterized according to definitions in SCE's Subtransmission Planning Criteria and Guidelines.

Note 2: As describe further below, for the Flex 2-1 event, LAR values are identical between the scenarios because it is assumed the BESS resources are not grid-forming and would not have a source to synchronize with.

Additional analysis results and figures are provided in the following subsections.

Flex-2-1

The Flex-2-1 metric studies the complete loss of Valley Substation i.e., there is a complete loss of a synchronizing source from the upstream 500 kV network. Neither of the scenarios provide a reduction in load at risk for the Flex-2-1 metric. The figure below provides the 2-week profile of accrued load at risk.

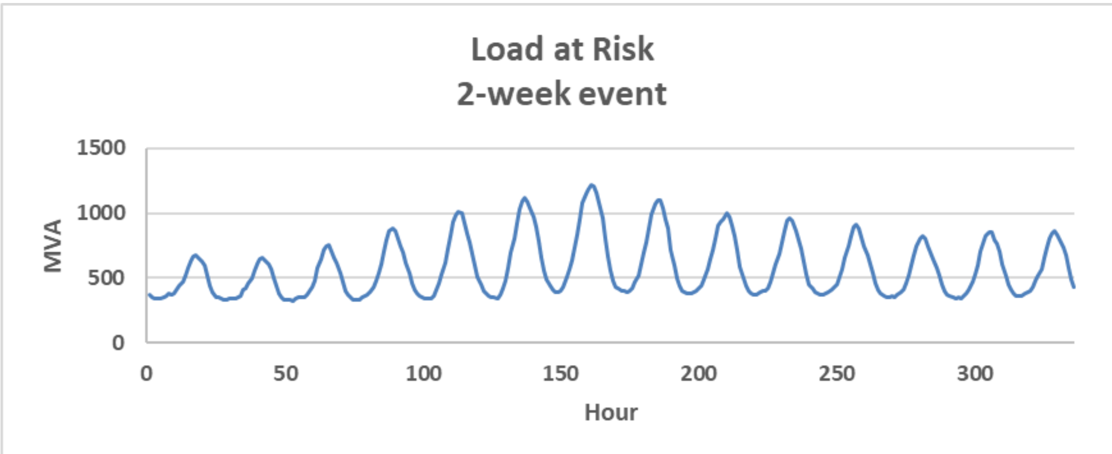


Figure 4-5. Load at Risk Profile for Two Week, Flex-2-1 Metric Scenario

For reference, if a "Grid Forming" capability were assumed for the 168/836 MWh batteries (the largest size in MW and MWh of the scenarios studied for 2031) and they are fully charged prior to the event – the LAR would only be reduced by their discharge capacity of 836 MWh reducing the value from 195,166 to 194,330 MWh, or an inconsequential amount under a Flex2-1 event. Without the availability of other grid-forming resources or backup generators, the batteries would have no opportunities to recharge once fully discharged.

Flex-2-2-A

The Flex-2-2-A metric studies a 6-hour outage of a Valley South transformer with the on-site spare transformer available. Neither alternative scenario would result in LAR because each includes a BESS with a sufficient power rating to cover the overload during the first hour (load above 896 MVA) and has sufficient energy within the CBESS to cover any remaining overloads after the spare is placed into service starting in hour two.

Flex-2-2-B

The Flex-2-2-B metric studies a 6-hour outage of a Valley South transformer without the on-site spare transformer available. The following figures provide the load profile and CBESS discharge results for each alternative.

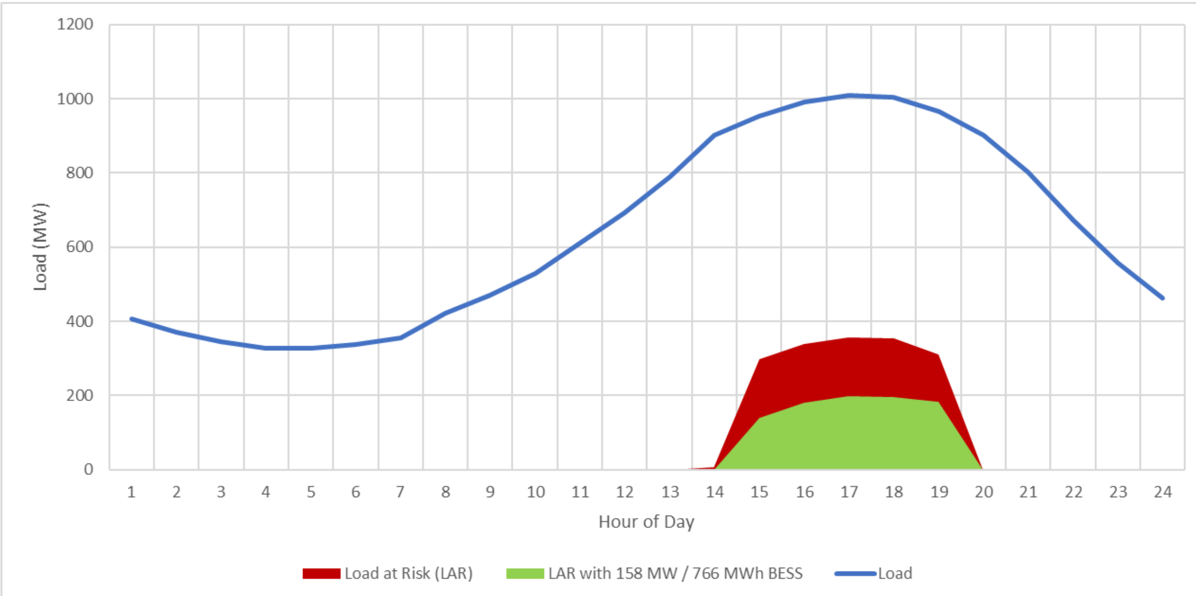


Figure 4-6. Load at Risk Profile for Flex-2-2-B: Scenario 1

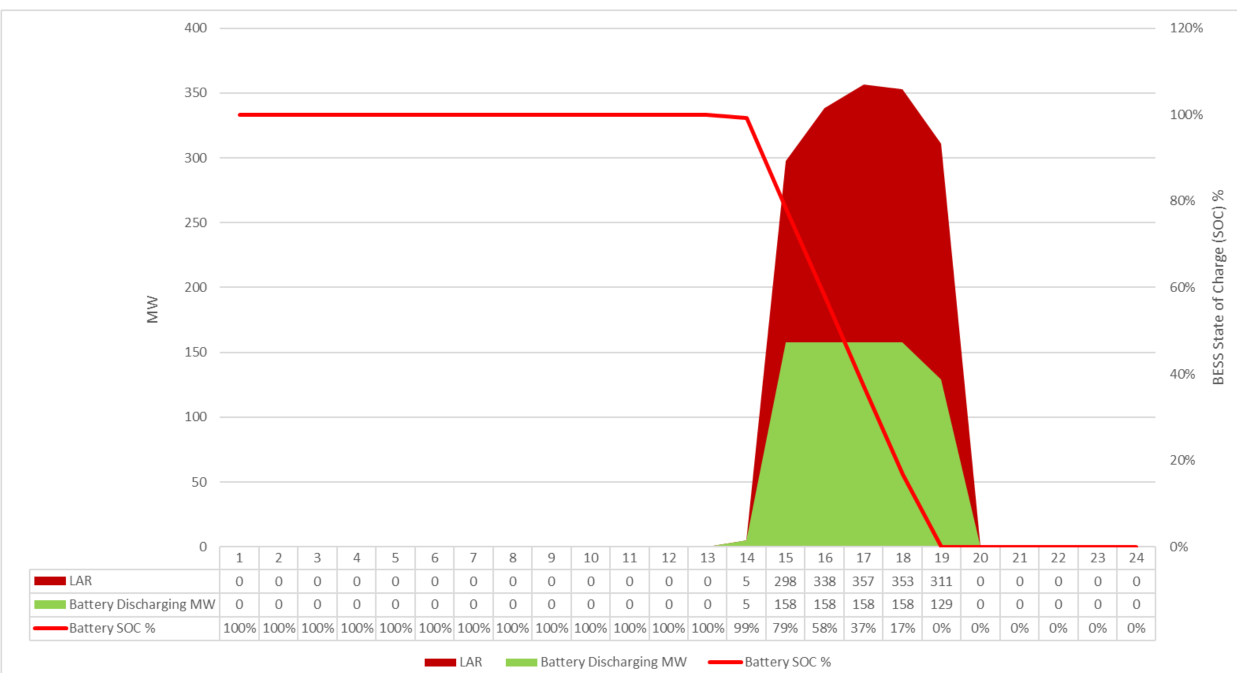


Figure 4-7. BESS Discharge for Flex-2-2-B: Scenario 1

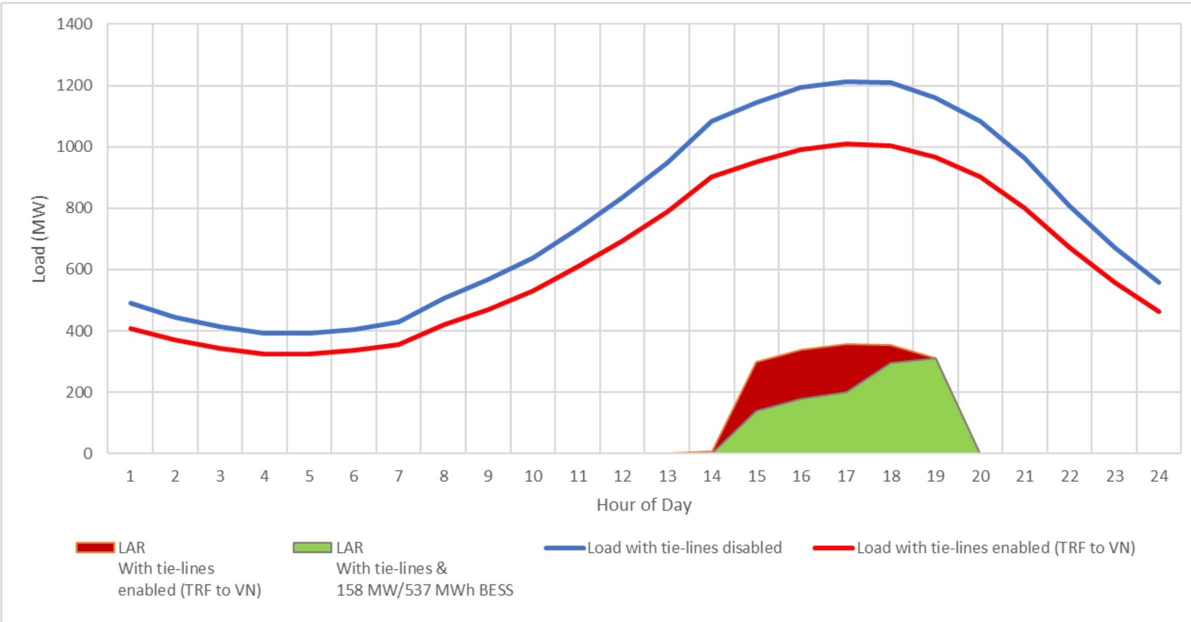
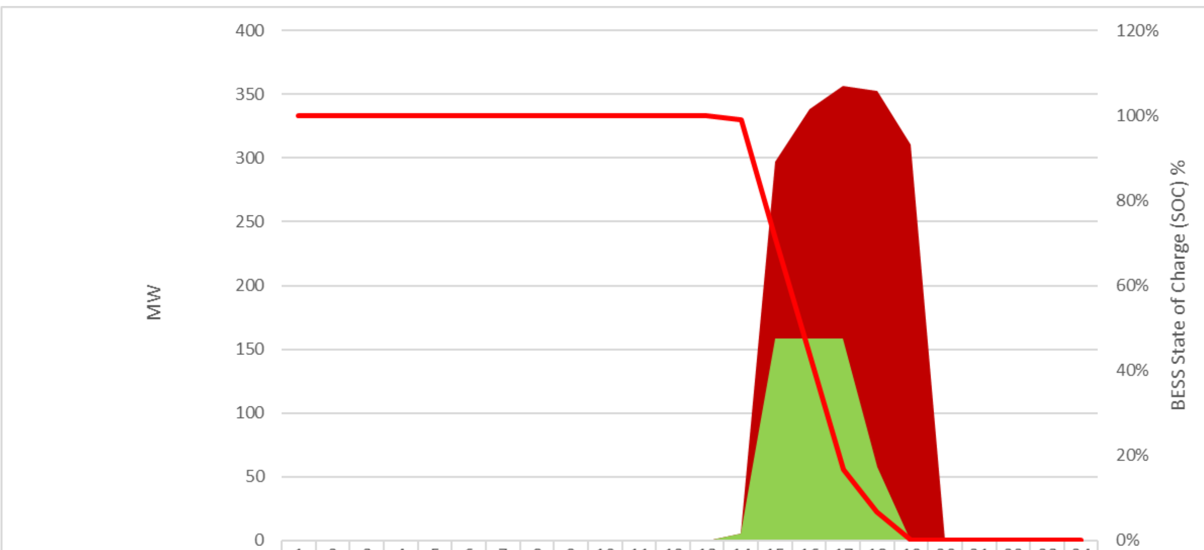


Figure 4-8. Load at Risk Profile for Flex-2-2-B: Scenario 2



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LAR	0	0	0	0	0	0	0	0	0	0	0	0	0	5	298	338	357	353	311	0	0	0	0	0
Battery Discharging MW	0	0	0	0	0	0	0	0	0	0	0	0	0	5	158	158	158	58	0	0	0	0	0	0
Battery SOC %	100	100	100	100	100	100	100	100	100	100	100	100	100	99%	72%	44%	17%	7%	0%	0%	0%	0%	0%	0%

Figure 4-9. BESS Discharge for Flex-2-2-B: Scenario 2

Flex-2-2-C

The Flex-2-2-C metric studies a 2-week outage of a Valley South transformer without the on-site spare transformer available. The following figures provide the load profile and BESS discharge results for each alternative.

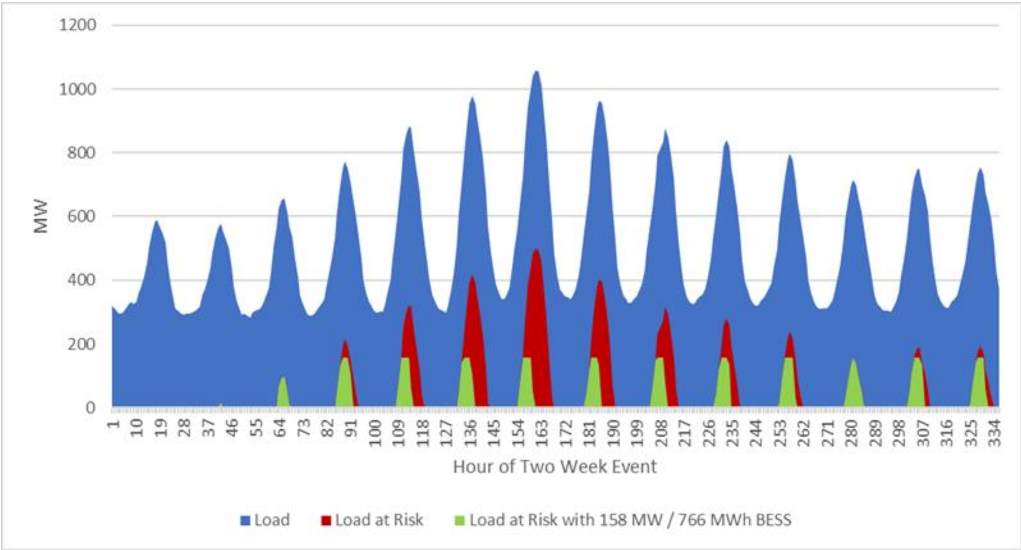


Figure 4-10. Load at Risk Profile for Flex-2-2-C: Scenario 1

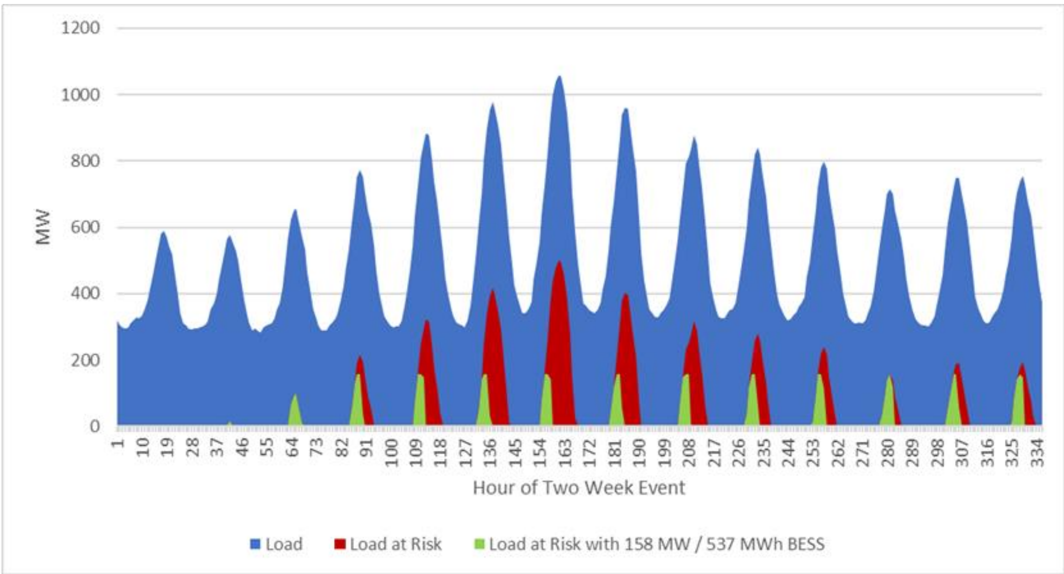


Figure 4-11. Load at Risk Profile for Flex-2-2-C: Scenario 2

5.0 Indicative Costs for VS-VN+CBESS Alternatives Sized to Meet Minimum SCE Planning Criteria

As described in Section 2.6, planning-level cost estimates were developed consistent with the methodology (including component cost inputs) used in the previous benefit-cost analysis and Planning Study.

The scope of the scenario 1 and scenario 2 alternatives closely aligns with the scope of the following alternatives from the Planning Study:

1. Valley South to Valley North
2. Centralized BESS in Valley South

Cost estimates for the new alternatives were developed using the appropriate cost category estimates for the above alternatives. In other words, the costs developed for the Planning Study alternatives were used for the scenario 1 and 2 alternatives when the scope matched. For many of the cost categories, the new alternatives included scope from both the Valley South to Valley North and the Centralized BESS in Valley South alternatives.

BESS costs for the scenario 1 and 2 alternatives were developed for the specific BESS sizes of the alternatives using the same cost inputs as in the Planning Study but for a 2025 in-service date (and accounting for battery price reductions to 2025). Baseline (i.e., without price reduction) BESS cost inputs used in the Planning Study are repeated below:

- Battery Power: $288/kW
- Battery Energy: $271/kWh
- Balance of Plant: $100/kW
- EPC: $101/kWh

The BESS sizes for the scenario 1 and 2 alternatives were slightly smaller than the Centralized BESS in Valley South alternative and therefore the interconnecting substation costs for the scenario 1 and 2 BESS were reduced based on a scaling factor corresponding to the difference in the BESS power nameplate values. Using the power rating (as opposed to the energy rating) is appropriate since the power rating of a substation dictates the configuration and quantity of components (e.g., transformers, bus, breakers). This scaling again serves to underestimate the substation costs because in reality the substation would include additional scope to cover the BESS sizing factors that were omitted from this analysis (e.g., battery degradation, resource N-1, additional margin for load forecast uncertainty) which results in the substation being sized for its ultimate buildout of batteries rather than just for 2031 BESS sizing.

Uncertainty cost percentages for the scenario 1 and 2 alternatives are equal to the Valley South to Valley North and Centralized BESS in Valley South and Valley North alternatives, since the new scenarios have similar scope and therefore similar uncertainty profiles.

Cost estimates for the scenario 1 and 2 alternatives (with and without the STATCOM) are provided below. All costs are nominal dollars and provided in millions of dollars.

Table 5-1. **Nominal** Cost Estimates ($M)

Cost Category	Scenario 1		Scenario 2	
	With STATCOM	**Without STATCOM**	**With STATCOM**	**Without STATCOM**
Licensing	31	31	31	31
Substation	59	47	59	47
Corporate Security	3	3	3	3
Bulk Transmission	0	0	0	0
Subtransmission	78	78	78	78
Transmission Telecom	4	4	4	4
Distribution	2	2	2	2
IT Telecom	1	1	1	1
Real Properties	**8**	**8**	**8**	**8**
Environmental	22	22	22	22
Subtotal Non-Battery Costs	**209**	**197**	**209**	**197**
Subtotal Battery Costs	**340**	**370**	**258**	**276**
Uncertainty	245	253	207	210
Total Costs	**795**	**821**	**675**	**684**

Consistent with the Planning Study, the BESS are assumed to be capable of participating the energy and capacity markets. The resultant market participation revenues are provided below. Note that the "Total Costs" provided in Table 5-1 do not subtract out the market participation revenues from the BESS. Current limitations in reliable deliverability of power from the Valley South System to the Bulk Electric System preclude the ability to capture Resource Adequacy revenue assumed in this analysis. Thus, the values below are expected to exceed those which could be obtained.

Table 5-2. Annual Market Participation Revenue

Year	Energy and Capacity Market Revenues ($M)			
	Scenario 1		**Scenario 2**	
	Without STATCOM	With STATCOM	Without STATCOM	With STATCOM
2025	16.6	15.6	14.8	13.8
2026	16.9	15.8	15.0	14.1
2027	17.2	16.1	15.3	14.3
2028	17.4	16.3	15.5	14.5

2029	17.7	16.6	15.8	14.7
2030	18.0	16.9	16.0	15.0
2031	18.3	17.2	16.3	15.3
Net Present Value (2022 at 10%)	**69.8**	**65.4**	**62.0**	**58.1**

6.0 Conclusions

The analysis described herein demonstrates the minimum required BESS sizing for a VS-VN+CBESS system to meet SCE Planning Criteria and Project Objectives 1 and 3 in the CPUC FEIR for the ASP Project. The resultant minimum cost of such an alternative, even over a very short (approximately 4 year) time horizon, significantly exceeds that of the ASP despite providing insignificant resilience benefits and not satisfying Objective 2 of the FEIR. Additional costs and operational challenges would continue to accrue for the VS-VN+CBESS beyond this period, wherein the ASP most-likely represents an effective 30-year solution for all of the needs of the Valley South System.