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

DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-1:
What assumption (MWh/acre) was used for evaluating whether BESSs could be sited at existing SCE distribution substations?

Response to Question DG-MISC-1:

SCE used the assumption of 40 MW / 200 MWh per 1.5 acres, which translates to 133 MWh/acre. This includes space requirements for batteries, inverters, step-up transformers, other associated equipment, and required clearances for safe operation.

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Prepared by: Paul Mccabe
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Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-2:
Are there parcels adjacent to Valley Substation which are large enough to accommodate the 50MW/100MWh BESS?

Response to Question DG-MISC-2:

Yes, there is vacant land relatively close to Valley Substation that may be suitable for installation of a BESS. For example, vacant land to the west was studied as part of the siting and routing analysis for SCE's response to the supplemental data request for the Alberhill System Project. This vacant land is located directly east of the Inland Empire Energy Center in Menifee (see Figure C-8 of SCE's response to Item C) and is comprised of six separate parcels totaling approximately 24 acres. Note that there are other vacant/undeveloped parcels in the vicinity of the Valley Substation that have not been studied by SCE to date. However, it is important to note that while a BESS may provide capacity relief of the Valley South System's transformers wherever it is located, there may be other system benefits derived from strategic siting based on power flow analysis.

As an example, since the largest concentration of load in the Valley South System is not located directly adjacent to Valley Substation, but rather 10-20 miles away, consideration of siting a BESS closer to the load pockets would provide several additional benefits including those associated with the power flow on the 115 kV subtransmission lines and system losses.

SCE considered both distributed BESS and centralized BESS solutions. The distributed BESS solution looked to site on already disturbed land at existing SCE substations while the centralized BESS installations reviewed sites that would be adjacent to existing 115 kV lines to minimize new 115 kV line construction. Both types of BESS alternatives were sited at the load centers to maximize their benefits.

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DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Gary Holdsworth
Job Title: Senior Manager, Grid Interconnections & Contract Development
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-3:
Consider if ISP (Independent Study Process) is an option to streamline the process?

Response to Question DG-MISC-3:
An Independent Study Process exists for Rule 21, WDAT, and CAISO interconnection requests, but at a minimum it requires the proposed project to be independent of the Transmission System and earlier-queued requests in the same electrical area. Stated another way, the proposed project is deemed to be electrically independent of earlier-queued projects if it is not anticipated to contribute to the need for or doesn't substantially change a network upgrade and if it is not anticipated to have a relationship with earlier-queued Interconnection Requests in either the Cluster Study Process or the Independent Study Process.

The end-to-end Independent Study Process has a shorter duration than the cluster study process, and an interconnection customer can submit an independent study interconnection request at any time of the year. This can lead to faster overall timeline of the independent study process vis-à-vis the cluster study process. In the independent study process, the interconnection customer has the option to waive the facilities study, which can similarly reduce the overall study timeline. These "streamlining" options are available to any *eligible* independent study project, but beyond these timing advantages, there is no ability to further "streamline" the study process.

Of note, per SCE's WDAT Generation Queue, there are currently two queued projects requesting interconnection into the Valley South 115 kV Bus, which would prevent the option of a new ISP study until those studies were completed. Those projects are WDT1635, an 80 MW energy storage project out of Tenaja Substation, and WDT1636, a 20 MW energy storage project out of Elsinore Substation. Both these projects have completed their Phase I interconnection studies and their Phase II studies will be completed in Q4 2020. Any project that applies for independent study in this area would be evaluated in relation to its independence vs. these two earlier-queued requests.

References:

https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/rules/ELECTRIC_RULES_21.pdf (p. 120, Screen Q)

https://www1.sce.com/nrc/openaccess/SCE_WDATCombinedFile_20150722.pdf (PDF p. 586, Sections 5.5.1 & 5.5.2)

http://www.caiso.com/Documents/AppendixDD-GeneratorInterconnection-DeliverabilityAllocationProcedures-asof-Oct23-2019.pdf (PDF p. 19-20, Section 4.1)

https://library.sce.com/content/dam/sce-doclib/public/regulatory/open-access-information/public-wdat-rule-21-queue/WDAT_Queue.xls (Excel Rows 2241 & 2242)

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/18/2020

Question DG-MISC-4:
Share past examples where the spare was in use and also needed for overload condition simultaneously; what is the probability of that occurring in the future?

Response to Question DG-MISC-4:

Please refer to SCE's Response to Question DG-MISC-13. Two of the incidents listed in that response identify when the spare transformer was in use for overload mitigation and there was a coincident outage of one transformer.

Incident No. 41: On 7/6/2018, while the Valley Substation spare transformer was aligned to the Valley North System to address an outage of one of the two Valley North transformers necessary to repair an ancillary component, load in the Valley South System approached and exceeded 896 MVA. The repair on the Valley North System transformer was accelerated, completed and then the transformer was put back in service. The spare was then taken out of service in the Valley North System and was aligned to the Valley South System.

Incident No. 42: On 8/6/2018, while the Valley Substation spare transformer was aligned to the Valley South System for overload mitigation (SCE notes that on 8/6/2018 loading approached but did not exceed 896 MVA), substation personnel were required to take the spare transformer out of service to repair an oil leak. Following the repair, the spare transformer was placed back in service. SCE notes that the spare had been placed in-service for overload mitigation on 7/23/2018 and operators elected to keep it aligned with the Valley South System throughout the remaining summer peak season. This was to minimize the number of circuit breaker operations (preserving their operating life) associated with repeated operations to place it in-service and then remove it from service on a daily basis as needed. It was removed from alignment with the Valley South System on 9/28/2018.

The probability that the spare is in use due to an outage of one of the four normally load-serving Valley Substation transformers, coincident with Valley South System load being above 896 MVA (the load threshold at which the pre-contingency mitigation is used), is equal to the joint probability of the two events.

Because SCE would not choose to remove a transformer from service in a peak power period for a planned outage, it is assumed a transformer would only be unavailable to serve load due to an unplanned outage. Per NERC's 2019 State of Reliability report, bulk power system interconnected transformers rated higher than 100 kV had an unavailability rate of 0.323% in 2018, which translates to a 99.677% availability of the transformers. Since there are four load-serving transformers at Valley Substation that all need to be in service in order for the Valley Substation to perform its primary function of serving load to the Valley System, the total availability of the Valley Substation is calculated as the product of the availability of each transformer, or 98.714%. The probability that the spare is needed to serve in its function as a spare (i.e., replacing an out-of-service transformer) is equal to 1.286%. This probability is assumed for each year between 2020 and 2025.

The probability that the spare would be required to be installed in parallel with the Valley South System transformers due to the OP-137 operating procedure as a pre-contingency mitigation is equal to the projected hours that Valley South System load exceeds 896 MVA divided by 8,760 (the number of hours in a year). Note in reality, the spare would be required to be in service some number of hours greater than the time in excess of 896 MVA because of the required time needed to align and restore the spare in advance of and after actually exceeding this system load value. Neglecting this period of time before and after the actual overload condition, the required pre-contingency mitigation hours are shown below:

	Year					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Valley South Load Above 896 MVA (Hours)	78	89	99	105	111	118
Probability	0.89%	1.016%	1.13%	1.20%	1.27%	1.35%

Assuming these two events are not correlated, which is a reasonable assumption for a transformer in good condition, the event probabilities can be multiplied to determine the probability of simultaneous needs occurring. The table below provides the total probability that the spare is replacing an out-of-service transformer and would also be required for pre-contingency mitigation due to Valley South System load in excess of 896 MVA.

	Year					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Probability that Spare is Replacing Out-of-Service Transformer	1.29%	1.29%	1.29%	1.29%	1.29%	1.29%
Probability that Valley South System Load Exceeds 896 MVA	0.89%	1.016%	1.130%	1.199%	1.267%	1.347%
Total Probability	**0.011%**	**0.013%**	**0.015%**	**0.015%**	**0.016%**	**0.017%**

These probability values are equivalent to about 1 to 1.5 hours per year of projected annual coincident need in this five-year period. This low value is consistent with SCE's assertion that this is a credible but low-probability event.

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DATA REQUEST SET C P U C - S u p p l e m e n t a l   D a t a   R e q u e s t - 0 0 1

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-5:
Re-confirm whether any of the four existing SCE energy storage procurement programs could be used for implementing an interim solution. For example, does the interim solution exceeding the "typical project size" rule out the use of a program? Is the ESP&IP limited to small project sizes? Is the RUOES full?

Response to Question DG-MISC-5:

SCE does not believe that any of the existing programs appear appropriate for implementing an interim BESS solution as a means to reduce reliance on the use of the spare transformer as overload mitigation for the years 2020 through 2025, or the expected in-service date of a comprehensive long-term solution. As documented in SCE's response to DG-MISC-3, the required interconnection study process to interconnect an interim BESS solution (applicable to any of the identified SCE procurement programs) would likely delay its being in-service until sometime after peak season in 2022. Therefore, if assuming a long-term solution is in-service by 2025, the interim BESS solution would potentially only be effective for the peak seasons of the years 2023 and 2024.

Typical project sizes for the Energy Storage Procurement and Investment Plan (ESP&IP) program are 2.5 MW / 4.5 MWh, and while a larger project could be planned, the current legislative and CPUC requirements associated with the AB 2868 framework would result in a total implementation schedule of several years.

Energy Storage Integration Pilot (ESIP) projects were included as part of the 2021 General Rate Case (GRC) proceeding. While this program may be appropriate for future BESS projects, funding and cost recovery would need to be secured during SCE's next GRC.

The Reliability Utility Owned Energy Storage (RUOES) program is designed to fulfill Resource Adequacy requirements from the CAISO. SCE has completed allocation to fulfill this requirement.

Based on the current implementation of the Distribution Investment Deferral Framework (DIDF) program, it is most suitable for projects with a need date of 4 to 5 years from present. As an example, the common in-service date expected for the candidate deferral projects within the most recent DIDF cycle is expected to be approximately 2022 to 2023. Due to the immediate nature of the need (i.e., expected to be needed in 2020) for overload mitigation in the Valley South System, and recognizing the expected need for the mitigation would expire upon the completion of a long-term solution (i.e., 2025), and noting the timing associated with implementing DIDF projects, SCE does not consider DIDF program as a practical means to minimize use of the spare transformer as overload mitigation.

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

DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Josh Mauzey
Job Title: Senior Manager, Grid Edge Innovation
Received Date: 2/14/2020

Response Date: 3/17/2020

Question DG-MISC-6:
Describe approval process for an SCE proposed energy storage project and options for expediting (ED and SCE).

Response to Question DG-MISC-6:
To date projects have been developed in two ways:

• Through the GRC process we have funding for the Distributed Energy Storage Integration (DESI) pilot program. Scope/schedule/budget for specific projects within the program are approved through an internal T&D "stage-gate" process through which all our demonstration and pilot projects are planned and approved for execution. Funding and cost recovery are already approved through the GRC process. Note in the 2021 GRC we did not propose new projects beyond what was proposed in the 2018 GRC.

• Other projects have been proposed through various regulatory proceedings as needs arise. Examples include the 2016 Aliso Canyon projects (built and approved for cost recovery), AB2514 projects proposed in the 2018 Energy Storage Procurement & Investment Plan (not approved) and potential system level reliability-driven projects (currently being proposed under IRP).

SCE has previous experience in expediting energy storage projects by focusing on the following;

- Expedite engineering activities through prioritization and dedicated resources
- Partner with an experienced supplier with an established supply chain for long lead components, such as batteries.
- Leverage existing SCE-owned disturbed sites with minimal environmental challenges

In addition to the activities listed above and other activities SCE can utilize to enable a brief scoping, design and siting process, there may be opportunities for SCE to partner with regulators (Energy Division, consultants, etc.) to facilitate an expedited processing and environmental review. SCE is interested in continuing conversations to discuss process, analyses and other opportunities in a collaborative discussion.

Southern California Edison
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DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-7:
Confirm GNA DDOR and ASP forecasts are the same (responded during the call but can provide references if needed).

Response to Question DG-MISC-7:

The forecast provided in the 2019 GNA/DDOR reports and SCE's current ASP forecast are not identical. At the 9/10/2019 Distribution Planning Advisory Group (DPAG) there was discussion surrounding where the Alberhill System Project would rank in the DDOR project prioritization list. SCE was asked to respond to a number of questions. Please see the attached document titled "A0909022-ED-Supplemental Data Request 001-Question DG-MISC-07 SCE Responses to DPAG Questions from ED CEQA Team (1 3 6 7).pdf" which provides both the questions and SCE's responses. Included in these responses is an explanation of the difference between the GNA/DDOR and ASP forecasts.

SCE Responses to the 9/10/19 DPAG Questions from CPUC CEQA team (1 to 7)

1. **Identify the specific dates forecasted for the Alberhill System Project.**

   SCE typically uses the term "electrical needs date" in licensing project proceedings. "Electrical needs date" is used to identify the date of a project's system need (e.g. when a system operating or criteria violation is first projected to occur or has already occurred).

   SCE uses the terms "grid needs date" and "operating date" as required by the Distribution Investment Deferral Framework (DIDF). "Grid needs date" refers to the five-year period defined within the DIDF GNA and DDOR reports that identifies the particular years and the associated deficiency values and percentages of the identified system needs consistent with the report period. "Operating date" is used to identify the expected date the proposed project would be completed and in-service to address the identified system need and can also be referred to as "in-service date." For additional context, *Deficiency, Deficiency %,* and *Operating Date* are defined in Table 3 of SCE's 2019 GNA narrative.

   a. Electrical needs date (licensing language): 2022
   b. Grid needs date (GNA/DDOR language): 2022
   c. Operating date (GNA/DDOR language and licensing language): 6/1/2025
   d. Projected or planned in-service date (language not specifically used in licensing or GNA/DDOR): 6/1/2025

2. **Explain how a 2022 need date impacts the 2019 DDOR Forecast Certainty metric, which was based, instead, on a 2025 need date. Please update Table 1, below. In addition, show the complete computation for the updated Forecast Certainty metric score using 2022.**

   SCE response in progress.

3. **In Decision D.18-08-026 the Commission took note of the Alberhill project cost being $464 million or more. The "Unit Cost of Traditional Mitigation" is stated as $217,382,000. Elaborate on the distinctions between these two project cost estimates.**

   The two "costs" cited are not two separate and independent project cost estimates. The $217M amount is the subtotal of expenditures expected to occur during SCE's 2021 GRC cycle (through 2023) out of the total project forecast of $464M (through 2027). SCE provided this number, rather than the total (which reflect expenditures through 2027), because it reflects the expenditures identified in its 2021 GRC[1] and is thus consistent with D.18-02-004, Ordering Paragraph 2h.

4. **SCE stated by email on 9/5/19, "If this was an off [GRC] cycle year, the $470M number would have been provided." Explain how a $470 million project cost impacts the 2019 DDOR LBNA calculations and Cost Effectiveness metric, which were based on the $217 million cost. Please update Table 1, above. In addition, show the complete computation for the updated Cost Effectiveness metric score, which combines the MW and MWh LBNA values. Use $470 million.**

   SCE response in progress.

[1] See A.19-08-013, Exhibit SCE-02, Volume 4, Part 2 – Workpaper Book B, at p. 337.

5. **Show the complete computation for the Market Assessment metric score.**

   SCE response in progress.

6. **Confirm SCE's plan for providing electrical service to the Valley South System prior to the in-service date.**

   The interim solution SCE intends to use to address the reliability needs of the Valley South System associated with a capacity shortfall is to utilize the spare Valley Substation transformer for the Valley South System whenever peak demand is expected to exceed the operating limits of the two 560 MVA Valley South transformers. As load growth continues, the operating margin of the Valley South System transformers will diminish, and the spare transformer will be used more often (and for longer durations) as an asset for mitigation rather than be used for its original intended purpose, further degrading the reliability and resiliency of the area served by Valley Substation. For the short-term, SCE has accepted the risks associated with this interim solution, expecting that it would initially be relied on for a limited number of hours on a few days per year, until a long-term solution was implemented. The use of the spare transformer as mitigation is not within the typical planning and operating criteria, and it not a substitute for a long-term solution. As the spare transformer is put into service on a more consistent basis to mitigate anticipated overloads, the likelihood of a coincident event that would result in service interruptions increases (since the spare transformer would already be in-service and could not be immediately be used as part of a larger recovery plan). This interim solution is consistent with testimony, oral arguments, comments, and data requests provided by SCE as part of the Alberhill System Project Certificate of Public Convenience and Necessity (CPCN) proceeding (A.09-09-022; see specifically DATA REQUEST SET ED – ALBERHILL - S C E - J W S – 2, 4/5/2019).

7. **Please justify the installation of a new 1,120 MVA, 500/115-kV Alberhill Substation when the need is not expected to exceed 83.3 MW through 2028 (Table 2). For SCE planning purposes, our understanding is that MVA and MW are equivalent power expressions. Hence, 1,120 MVA is much, much larger, than the 83.3 MW need in 2028. The DDOR indicates that 16.8 MW (3 hours; per "Candidate Deferral Add Info" tab) could solve the need and defer the substation through 2023. How much storage (MW and duration) would be needed to defer the substation need for the entire 10-year planning horizon.**

   "Please justify the installation of a new 1,120 MVA, 500/115-kV Alberhill Substation when the need is not expected to exceed 83.3 MW through 2028 (Table 2). …"

   SCE is currently undertaking a broad look at possible system solutions for the Valley South System at the CPUC's direction as part of the Alberhill System Project (ASP) proceeding. The CPUC's 2018 Decision (D.18-08-026) took no action on the ASP, directing SCE to supplement the existing record with additional analyses including an updated load forecast and an evaluation of alternatives which may satisfy the needs of the Valley South System. Specifically, the CPUC requested a benefit-cost 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.

In accordance, SCE is currently developing an updated project forecast to refine Project need and assessing the benefit-cost comparison of a variety of alternatives that include energy storage as part of its supplemental analysis. SCE anticipates being able to provide greater detail to the Energy Division in Q4 2019.

Subject to the findings and assertions to be expressed in SCE's analyses per D.18-08-026, SCE notes that while the 1,120 MVA is greater than the expressed 83.3 MW[2] of need through 2028, ASP is *not* proposing 1,120 MVA (two 560 MVA transformers) to address load-serving capacity only. Consistent with SCE's testimony in the ASP proceeding, one of the ASP transformers is proposed as a spare. Absent the spare, any unplanned outage of the transformer in-service would result in loss of electrical service to all of the customers it serves until the outage is remedied or transferred back to the Valley South System. In the specific case of ASP, this second transformer also satisfies SCE's reliability criteria requiring each 500/115 kV substation to have an on-site spare transformer. Thus, the load-serving capacity proposed to be installed is actually 560 MVA.

SCE acknowledges that 560 MVA remains greater than the expressed 83.3 MW of need through 2028. With the construction of any new substation, the initial installation of transformer capacity is routinely greater than the demand. This practice is consistent with installation of capacity in a "step function." This means that conventional capacity solutions (*e.g.*, ASP) typically include an installation greater than the initial need but which would require few (if any) incremental additions to meet future load needs. This practice provides a reasonable margin for each electrical system to accommodate future growth and respond to emergency conditions resulting from equipment failures or other unplanned outages.

"*How much storage (MW and duration) would be needed to defer the substation need for the entire 10-year planning horizon*."

As noted previously, as part of SCE's current efforts in response to D.18-08-026, SCE is developing assessing the benefit-cost comparison of a variety of alternatives, including energy storage.

The approximate MW and MWh of storage required to defer the substation need (*i.e.*, the estimated transformer capacity shortfall in the Valley South System) during the 10-year planning horizon as referenced in the question here and presented in Table 2 of the August 15, 2019 Distribution Deferral Opportunities Report (DDOR) submitted by SCE is approximately 83 MW and 269 MWh[3]. These values are subject to change based on the findings and assertions to be expressed in SCE's analyses (per D.18-08-026) to be provided to Energy Division in Q4 2019. SCE notes that the amount of storage potentially needed to defer the *ASP* (as opposed to the *substation need* as referenced in the question here) may be different.

[2] In performing the requested ranking analysis for the Alberhill System Project, SCE determined that the 83.3 MW and 269.1 MWh values previously provided had been based on sizing activities performed prior to the 10-year forecast being finalized. Upon reassessment and using the finalized forecast, the values are 70.8 MW and 174.2 MWh. These values reflect energy storage facilities located downstream at the distribution system level of the system and account for the associated expected energy losses.

[3] As described in Footnote 2, SCE determined that the 83.3 MW and 269.1 MWh values previously provided had been based on sizing activities performed prior to the 10-year forecast being finalized. Upon reassessment and using the finalized forecast, the values are 70.8 MW and 174.2 MWh respectively.

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-8:
What are Edison's obligations related to maintaining reliability under NERC? If Alberhill would be a non-bulk electric system, which reliability criteria apply?

Response to Question DG-MISC-8:

The majority of the scope associated with the Alberhill System Project is non-bulk electric system. Only the 500 kV facilities which include the 500 kV line segments (to loop into the existing Serrano-Valley 500 kV transmission line) and the 500 kV switchrack and circuit breakers are considered bulk-electric system facilities and subject to NERC criteria. The 500/115 kV transformers and all lower voltage facilities are not considered bulk-electric system facilities, are not under CAISO control, and are not subject to NERC criteria.

For non-bulk electric system facilities (thus not subject to NERC criteria), SCE's Subtransmission Planning Criteria and Guidelines are the applicable reliability criteria.

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

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Question DG-MISC-9:
Please provide the analysis regarding Resource Adequacy. In this analysis, SCE evaluated how they would use the June-September period to serve the Valley South Reliability need. What is the load shape across a series of years?

Response to Question DG-MISC-9:

SCE has not conducted an analysis to determine the potential revenue generated from an interim BESS solution participating in the Resource Adequacy (RA) program. The reference to the RA program in the preliminary analysis of the interim BESS solution presented in the January Power Point presentation was only to characterize some of the limitations of the Resource Adequacy program in the context of the RUOES procurement program for expediting an interim BESS solution. SCE is in the process of preparing a formal response to the Energy Division on the use of DERs as an alternative to the temporary mitigation measure currently employed in the Valley South System. SCE will consider the potential for RA payments revenue to the extent applicable, along with other market participation revenue, to offset project costs in this response.

The load shape of the capacity overloads using the Spatial Effective PV forecast is provided in the table below for the months of June through October for 2020-2025 (i.e., the project need date and the estimated in-service date of a comprehensive solution), which represents instances where Valley South System load is projected to exceed the transformer capacity (1,119 MVA).

Valley South System Load Above Transformer Capacity (1,119 MVA): June through October, 2020 - 2025

Incident No.	2022				2023				2024				2025			
	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)
1	1,132	4 PM	5 PM	2	1,128	3 PM	3 PM	1	1,135	2 PM	3 PM	2	1,142	2 PM	3 PM	2
2					1,146	3 PM	5 PM	3	1,152	3 PM	5 PM	3	1,159	3 PM	5 PM	3

Note: Start and end times indicate the discrete hours in which load is projected to be above 1,119 MVA. That is, the reported hourly end-times consider the entire hour and count towards the total incident duration.

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 1

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-10:
Please explain difference between 896 MVA STELL value and the 1120 Capacity Rating. SCE PPT states “Mitigation is required to be implemented at 896 MVA and not at the ultimate substation capacity limit of 1120 MVA because if a transformer failure would occur at loads over 896MVA the remaining transformer would overloaded with respect to its short term operating limit in violation of system operating criteria." Please include in the response an explanation of the System Operating Criteria in general and how it results in a value of 896 MVA.

Response to Question DG-MISC-10:

SCE's Subtransmission Planning Criteria and Guidelines (provided to the Energy Division in SCE's response to Data Request #JWS-03, Question 5) establishes operating limits for A-bank and AA-bank transformers under both normal and contingency operating conditions. The three operating limits that are established in this document include nameplate loading limits, long-term emergency loading limits (LTELL), and short-term emergency loading limits (STELL).

Section 2.3.1 of this document pertains to AA-bank transformers that serve radial load, which is the case for the Valley Substation transformers. The operating ratings defined in this section therefore apply to the Valley Substation transformers. Under normal conditions, the maximum rating is equal to 100% of nameplate rating. Under contingency conditions, the ratings are divided into the LTELL and STELL limits. Critical parameters for the Valley Substation transformers, specifically, which are not to be exceeded under contingency conditions are:

- LTELL Maximum Rating - not to exceed 120% of Nameplate Rating
- STELL Maximum Rating - not to exceed 160% of Nameplate Rating provided that the load can be reduced to the LTELL in one hour

Note: These percentages are defined in accordance with factory heat run tests (FHR) and loading capability studies (LCS) performed by SCE.

In other words, the Valley Substation transformers can operate between the LTELL and the STELL ratings for up to one hour before load would have to drop below the LTELL.

The specific ratings for the Valley Substation transformers are designated as the nameplate limit being 560 MVA, the LTELL limit being 672 MVA, and the STELL limit being 896 MVA.

The Valley South System is served by two transformers, for a total system nameplate rating of 1,120 MVA. Should load rise above 896 MVA and then one of the two transformers fail, one transformer would remain in-service and be subject to loading values above 896 MVA. This is the basis for the development and use of a pre-contingency mitigation plan, in which the spare Valley Substation transformer is aligned to the Valley South System when system load approaches 896 MVA. With the three transformers aligned, a single transformer outage would not cause either of the two remaining transformers to exceed applicable operating limits, since total system load would still be shared by two transformers. This temporary overload mitigation plan was expected to be used only for several years until a long-term comprehensive project was completed.

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DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 1

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/16/2020

Question DG-MISC-11:
Please provide the transformer usage projections (total of 600 hours per the SCE PPT) for 2020-2025 by incident, magnitude and hours of the day for all 6 years.

Response to Question DG-MISC-11:

The forecasted hours of spare transformer utilization from 2020 to 2025 are provided in the table in the attached document titled "A0909022-ED-Supplemental Data Request 001-Question DG-MISC-11.pdf". These results were determined by tracking the number of hours in which the Spatial Effective PV load forecast (which is the baseline forecast in SCE's response to Item C) would exceed 896 MVA. This is the threshold for when the spare transformer would be placed into service for overload mitigation (see SCE's response to DG-MISC-10). The total number of hours for each year are provided and the total number of hours of spare transformer utilization between 2020 and 2025 is 600 hours.

The actual number of hours in which the spare would be utilized over the next 5 years is highly variable, given the nature of load volatility. The spare is typically placed into service as load approaches the 896 MVA limit, in order to provide adequate time for the necessary switching operations to occur before the load reaches this limit. This would be occurring at a time of peak loading and high temperatures and that it would be common that the system operators would also be monitoring and addressing many other system conditions. Additionally, as discussed in Section 9.2 of SCE's response to Item C, the largest year-over-year swings (either up or down) in load in the Valley South System over the past ten years have been as high 50 MVA. While the results included in the table are based on a load forecast with a gradual increase in load, the actual recorded demand values (and therefore the actual usage of the spare transformer in the future) will likely deviate (both above and below) from the forecast.

Forecasted Valley Substation Spare Transformer Utilization for Pre-contingency Mitigation: 2020-2025

Incident No.	2020				2021				2022				2023				2024				2025			
	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)	Incident Peak (MVA)	Start Time	End Time	Incident Duration (Hours)
1	1007	3 PM	7 PM	5	1025	2 PM	7 PM	6	1040	2 PM	7 PM	6	1051	2 PM	7 PM	6	1060	2 PM	7 PM	6	1068	2 PM	8 PM	7
2	1083	12 PM	8 PM	9	1104	12 PM	8 PM	9	1119	12 PM	8 PM	9	1132	12 PM	8 PM	9	1143	12 PM	8 PM	9	1153	12 PM	8 PM	9
3	911	3 PM	5 PM	3	927	3 PM	5 PM	3	904	4 PM	5 PM	2	902	3 PM	5 PM	3	900	5 PM	5 PM	1	902	5 PM	5 PM	1
4	963	3 PM	6 PM	4	981	2 PM	6 PM	5	943	3 PM	5 PM	3	950	3 PM	5 PM	3	908	3 PM	5 PM	3	913	3 PM	5 PM	3
5	991	2 PM	6 PM	5	1010	2 PM	7 PM	6	996	2 PM	6 PM	5	1005	2 PM	6 PM	5	957	2 PM	5 PM	4	963	2 PM	5 PM	4
6	1048	1 PM	8 PM	8	1068	1 PM	8 PM	8	1025	2 PM	8 PM	7	1035	2 PM	8 PM	7	900	5 PM	5 PM	1	900	4 PM	5 PM	2
7	927	2 PM	5 PM	4	899	3 PM	3 PM	1	1083	1 PM	8 PM	8	1095	1 PM	8 PM	8	1013	2 PM	6 PM	5	1021	2 PM	6 PM	5
8	935	2 PM	4 PM	3	943	2 PM	5 PM	4	904	2 PM	4 PM	3	907	2 PM	4 PM	3	1043	2 PM	8 PM	7	1051	2 PM	8 PM	7
9	910	3 PM	5 PM	3	952	2 PM	5 PM	4	959	2 PM	5 PM	4	967	1 PM	6 PM	6	1105	1 PM	8 PM	8	1114	1 PM	8 PM	8
10	962	2 PM	5 PM	4	926	3 PM	5 PM	3	967	2 PM	5 PM	4	975	2 PM	5 PM	4	913	2 PM	4 PM	3	918	2 PM	4 PM	3
11	920	3 PM	5 PM	3	980	2 PM	5 PM	4	941	3 PM	5 PM	3	948	3 PM	5 PM	3	974	1 PM	6 PM	6	981	1 PM	6 PM	6
12	1016	2 PM	6 PM	5	935	3 PM	5 PM	3	995	2 PM	6 PM	5	1004	1 PM	6 PM	6	983	2 PM	5 PM	4	990	1 PM	6 PM	6
13	1100	1 PM	7 PM	7	1035	2 PM	7 PM	6	951	3 PM	5 PM	3	959	3 PM	5 PM	3	955	3 PM	6 PM	4	962	2 PM	6 PM	5
14	1000	2 PM	6 PM	5	1121	1 PM	8 PM	8	1050	2 PM	7 PM	6	1061	2 PM	7 PM	6	1012	1 PM	6 PM	6	1020	1 PM	6 PM	6
15	913	5 PM	5 PM	1	1018	2 PM	7 PM	6	1135	12 PM	8 PM	9	1150	12 PM	8 PM	9	965	3 PM	5 PM	3	972	2 PM	5 PM	4
16	955	3 PM	5 PM	3	929	5 PM	6 PM	2	1033	2 PM	7 PM	6	1044	2 PM	7 PM	6	1070	2 PM	7 PM	6	1078	2 PM	7 PM	6
17	967	2 PM	4 PM	3	899	4 PM	4 PM	1	945	4 PM	6 PM	3	952	4 PM	6 PM	3	1160	12 PM	8 PM	9	1171	12 PM	8 PM	9
18	936	3 PM	5 PM	3	972	3 PM	5 PM	3	907	4 PM	4 PM	1	912	3 PM	5 PM	3	1053	2 PM	7 PM	6	1061	2 PM	7 PM	6
19					984	2 PM	5 PM	4	988	3 PM	6 PM	4	996	3 PM	6 PM	4	959	3 PM	6 PM	4	965	3 PM	6 PM	4
20					953	3 PM	5 PM	3	999	2 PM	5 PM	4	1008	2 PM	5 PM	4	918	3 PM	5 PM	3	924	3 PM	5 PM	3
21									968	2 PM	5 PM	4	976	2 PM	5 PM	4	1004	2 PM	6 PM	5	1012	2 PM	6 PM	5
22																	1016	2 PM	5 PM	4	1024	1 PM	5 PM	5
23																	984	2 PM	5 PM	4	991	2 PM	5 PM	4
Totals				78				89				99				105				111				118

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

DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-12:
Has SCE performed an economic analysis (e.g. value/risk of unserved energy) of the scenario in which all 600 hours of increased risk can be eliminated by a DER solution? If SCE has already completed this analysis, please provide the results.

Response to Question DG-MISC-12:

SCE has not performed a full economic analysis of the scenario in which all 600 hours of increased risk can be eliminated by a DER solution.

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

DATA REQUEST SET CPUC-Supplemental Data Request-001 and 002

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 6/5/2020

Question DG-MISC-12 - Update:
Has SCE performed an economic analysis (e.g. value/risk of unserved energy) of the scenario in which all 600 hours of increased risk can be eliminated by a DER solution? If SCE has already completed this analysis, please provide the results.

Response to Question DG-MISC-12 - Update:

The attached document discusses the mitigation currently in use in the Valley South System in which the spare transformer is aligned to serve load during periods when capacity margin is insufficient. The purpose of the document is to:

- Describe the planning and operating criteria that drive the use of the mitigation;
- Describe and quantify the mitigation's past use;
- Characterize the associated on-going risk associated with use of the mitigation;
- Describe a prospective interim Battery Energy Storage System (BESS) project to minimize the required use of the current mitigation;
- Describe opportunities and challenges to use existing SCE BESS-related programs and other regulatory options to implement such a project in a sufficiently timely manner in order to be effective in the interim period before a long-term permanent solution can be implemented to meet all of the project objectives; and
- Provide a recommendation for whether or not such an interim project would be cost effective.

Related to this data request, included in this document is a presentation of various BESS sizing and cost scenarios to minimize the use of the current mitigation. A scenario is presented in which mitigation use is eliminated in the period between 2022 (when the BESS is assumed to be in service) and 2025 (when the Alberhill System Project is assumed to be in service, eliminating the need for the mitigation). All 600 hours of projected mitigation use are not addressed because some of this projected use predates the BESS installation.

INTRODUCTION

Southern California Edison's (SCE's) Valley South System currently serves over 187,000 metered customers, representing over 500,000 individuals and covering a service territory of approximately 600 square miles in southwestern Riverside County. The Valley South System is served by SCE's Valley Substation, which is unique within SCE's electric system in that it is the only substation that interfaces with the California Independent System Operator (CAISO)-controlled bulk electric system at 500/115 kilo-volts (kV) and then directly serves 115/12 kV distribution substation loads. The Valley Substation has been constructed to its ultimate load-serving design capacity of four 560 mega-volt amperes (MVA) 500/115 kV load-serving transformers totaling 2,240 MVA. Two transformers (or 1,120 MVA in total capacity) serve each of the Valley North and Valley South Systems.

The Valley South System has demonstrated peak loading in recent years that result in a 99.9% utilization.[1] Additionally, the Valley South System is the only subtransmission system within SCE's entire service territory that operates with zero system tie-lines to other systems. This lack of system tie-lines results in an isolated system which negatively impacts reliability and resiliency due to the inability to transfer load during both typically planned-for system contingency events (unplanned outages) and more extreme high-impact, low-probability events.[2] This lack of capacity margin and lack of system tie-lines is currently mitigated by aligning the Valley Substation spare transformer to the Valley South System during times of peak demand. The use of this mitigation measure is a temporary and short-term solution for addressing the transformer capacity needs of the Valley South System while awaiting approval to construct a project to comprehensively address the long-term capacity, reliability and resiliency needs of the Valley South System.

SCE has proposed the Alberhill System Project (ASP) as a comprehensive solution to address both the transformer capacity shortfall (expected to occur in 2022 when the system peak load is projected to exceed the ultimate system design capacity of 1,120 MVA), and the longstanding reliability and resiliency concerns (resulting from the system's current lack of system tie-lines) of the Valley South System. As part of the licensing proceeding for the ASP project, SCE submitted a Planning Study to the California Public Utilities Commission (CPUC) Energy Division (ED). The Planning Study provides a business case analysis to evaluate the performance and cost effectiveness of the ASP in addressing these project objectives. In light of the temporary mitigation measure described above and the expectation that ASP or another project would not be able to be implemented for several years (due to the required time to obtain a licensing decision and then construction), the ED has requested SCE to assess whether or not an interim project solution is needed to eliminate or otherwise reduce the use of the current mitigation and how it might be implemented.

[1] The 2018 adjusted peak demand which includes weather adjustments to reflect expected loads during 1-in-5 year heat storm conditions, was 99.9% of the Valley South System's ultimate system design capacity (1,120 MVA).
[2] High-impact, low-probability events are credible contingencies but are outside of SCE's planning criteria. They may be considered for awareness and for use in further differentiating the relative performance between alternatives but are not used to determine the required scope of projects.

The purpose of this document is to:

- Further describe the planning and operating criteria that drive the use of the mitigation;
- Describe and quantify the mitigation's past use;
- Characterize the associated on-going risk associated with use of the mitigation;
- Describe a prospective interim Battery Energy Storage System (BESS) project to minimize the required use of the current mitigation;
- Describe opportunities and challenges to use existing SCE BESS-related programs and other regulatory options to implement such a project in a sufficiently timely manner in order to be effective in the interim period before a long-term permanent solution can be implemented to meet all of the project objectives; and
- Provide a recommendation for whether or not such an interim project would be cost effective.

SCE SYSTEM PLANNING AND OPERATING CRITERIA DRIVING EXISTING MITIGATION

SCE's Valley Substation serves both the Valley North and Valley South Systems via two 500/115 kV load-serving transformers for each system. The Valley South System is served by the 1AA and 2AA transformers, and the Valley North System is served by the 3AA and 4AA transformers. The Valley Substation also has a fifth 500/115 kV transformer (5AA), which is a shared spare transformer that can be aligned to either the Valley North System or the Valley South System to replace one of the four load-serving transformers that may be out-of-service due to either a planned or unplanned outage. Current mitigation plans align the 5AA spare transformer to the Valley South System when load approaches and is expected to exceed 896 MVA, which is the short-term emergency loading limit (STELL) of a single transformer.[3] SCE would allow loading up to the total nameplate rating of the two transformers (1,120 MVA) if there were a means to shed load and then restore service following an unplanned transformer outage (typically performed via load transfer with system tie-lines), but this is currently not implemented because of the lack of system tie-lines in the Valley South System. Therefore, the use of the 5AA spare transformer as mitigation is implemented at 896 MVA to avoid potential overloading (beyond the maximum allowable STELL rating) of either of the remaining transformers should there be an unplanned outage of either the 1AA or 2AA transformers.

In contrast, the Valley North System has an automated load shedding scheme and four system tie-lines to the Vista System, and therefore can transfer load away from the system during an outage of the 3AA or 4AA transformer. This capability to automatically shed load and then restore service by transferring it to an adjacent system allows for loading of the two transformers up to the combined nameplate rating of 1,120 MVA while preventing the remaining transformer from being overloaded (beyond its STELL rating) should there be an unplanned outage of one

[3] The Valley Substation transformers each have a nameplate rating of 560 MVA (continuous rating), a long-term emergency loading limit (LTELL) of 672 MVA (24-hour rating), and a short- term emergency loading limit (STELL) of 896 MVA (1-hour rating). With two transformers are operating together, SCE system operators do not permit loading to exceed 896 MVA without an automated instantaneous loss of transformer load-shedding scheme in place as well as a means to restore service to the shed load.

transformer. The Valley South System has no such automatic load shedding scheme in place. The scheme itself could be implemented but has not been previously considered because of the inability to restore service by transferring substations via system tie-lines. As such, the 896 MVA STELL rating is the maximum allowed loading level for the two load-serving transformers of the Valley South System to ensure preventing an overload condition during an unplanned transformer outage.

Due to a series of events detailed in the Planning Study, the Valley South System evolved to its current configuration having no system tie-lines to other nearby electrical systems. This has resulted in the Valley South System violating SCE's Subtransmission Planning Criteria and Guidelines, specifically the following clauses:

Table 1 – Subtransmission Guidelines Related to Valley South

Section	Guideline	Relevance to Valley South
2.3.2.1.B	Contingency Outages: Adequate transformer capacity and load rolling facilities shall be provided to prevent damage to equipment and to limit customer outages to Brief Interruptions…	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.
2.3.2.4	To avoid Protracted Interruption of Load, tie lines with normally open supervisory controlled circuit breakers will be provided to restore service to customers that have been dropped automatically to meet short-term Likely Contingency loading limits, and to reduce A-Bank load to the long-term Likely Contingency loading level.	The Valley South System currently has no system tie-lines to any other system, and therefore has zero tie-line capacity available to roll load.

The Valley South System requires a comprehensive long-term solution to address forecasted transformation capacity shortfall and the lack of system tie-lines. Until a suitable solution can be constructed, the mitigation scheme is expected to remain in place to prevent a potential overload of the Valley South System transformers during periods of high electrical demand.

PAST USE OF MITIGATION

The mitigation plan was first used in 2017 and again in 2018 for a total of 14 distinct days in which load exceeded, or was projected to exceed, 896 MVA.[4] On seven of the 14 days, the load actually exceeded 896 MVA. The plan was not required to be used in 2019 due to a cooler than typical summer for this area. In 2017 and 2018 the duration of the individual time periods where the load exceeded 896 MVA ranged from approximately one to six hours. When the 5AA transformer is in-service as mitigation, it is not able to serve its intended function as a shared spare transformer immediately available to either the Valley North or Valley South Systems should there be an unplanned outage of one of the four load-serving AA-bank transformers.

There have been two incidents in which the spare transformer was required for its primary function coincident with a potential overload mitigation need in the Valley South System. In July 2018, the spare transformer was aligned to the Valley North System to address an unplanned transformer outage of one of the 3AA/4AA transformers. At the same time, load in Valley South approached 896 MVA, resulting in an acceleration of the repair activities for the Valley North System transformer, and a subsequent re-alignment of the spare transformer to the Valley South System for potential overload mitigation. In August 2018, while the spare transformer was aligned to the Valley South System operators discovered an oil leak on the spare transformer. Operators took the spare transformer out-of-service, repaired the cause of the minor leak and placed the transformer back in-service later that day.

ASSESSMENT OF RISK ASSOCIATED WITH CONTINUED USE OF MITIGATION

This mitigation plan is temporary and is considered acceptable only because there is a long-term comprehensive solution planned to address the loading and configuration issues in the Valley South System (e.g., the proposed Alberhill System Project). However, until a comprehensive solution is constructed and serving customers, the risk remains, in that the spare transformer is not capable of performing its primary function as a shared spare and serve as overload mitigation at the same time.

Normal System Conditions
Under normal system conditions (all facilities in-service), the Valley North and Valley South Systems are both capable of serving load demands through 2025 (with the use of the spare transformer as overload mitigation for the Valley South System). The forecast 1-in-5 year heat storm peak demand in 2025 for the Valley North and Valley South Systems is 823 MVA and

[4] Note that each day does not necessarily indicate that the spare transformer was required to be used (i.e., load may not have exceeded 896 MVA on all days in which the spare was placed into service). Rather, system operators may place the spare in service as load approaches 896 MVA acknowledging that load changes can occur quickly and that on peak days there are commonly many other concurrent system issues being addressed. Additionally the transformer may not be taken immediately out-of-service when the threshold is no longer exceeded because in some cases, system operators may elect to keep the spare in service during multi-day heat storms to reduce the operational burden and number of circuit breaker operations associated with placing the spare in and out-of-service each day.

1,159 MVA,[5] respectively. In the case of the Valley South System, although the 1,159 MVA demand exceeds the nameplate rating of two transformers (1,120 MVA), with the spare transformer in-service as overload mitigation (in-service as load approaches 896 MVA and remaining in-service even as load exceeds 1,120 MVA) there would be three transformers serving the Valley South System.[6] This would provide a normal condition nameplate capacity of 1,680 MVA (3 x 560 MVA) which is in excess of the 1,159 MVA peak load value. In the case of the Valley North System, the 823 MVA projected peak demand is well within the normal condition nameplate rating of 1,120 MVA for two transformers (1,120 MVA).

Abnormal System Conditions
With the spare transformer aligned to the Valley South System as overload mitigation and under abnormal system conditions (N-1 transformer outage of one of the three transformers aligned to the Valley South System), there would still be two in-service transformers to serve load[7] and there would be no overload. The transformers would be capable of serving up to 1,792 MVA (2 x 896 MVA STELL rating) for one hour and then 1,344 MVA (2 x 672 MVA LTELL rating) for up to 24 hours while the situation was assessed and remedied. In this scenario, load would remain within the prescribed operating limits. The mitigation strategy would perform as intended under these abnormal system conditions until a comprehensive solution is constructed. It would prevent the instantaneous STELL overload of one remaining in-service transformer during an unplanned outage of the second transformer *and* allow load to be served in excess of the total 1,120 MVA nameplate rating of the two load-serving transformers during short periods of peak demand by applying the LTELL rating.

The following operator actions would be required if the spare transformer were aligned to the Valley South System as overload mitigation and an N-1 transformer outage of one of the two transformers aligned to the Valley North System were to occur. If the Valley North System load was above 896 MVA, the automatic shedding scheme would be triggered to bring loading below operating limits and then load would be transferred to the Vista System via system tie-lines. This would result in only a brief interruption in service. If load was below 896 MVA, the automatic load shedding scheme would not be triggered (avoiding the brief interruption of service) and system operators would assess which of the following two actions should be taken.

The first option is removing the spare transformer from the Valley South System and aligning it to the Valley North System, allowing for two transformers to again serve the Valley North System while leaving two transformers to serve the Valley South System. A second option is leaving the spare transformer aligned with the Valley South System and continuing to provide

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[5] Based on the Spatial Forecast APV SCE's Effective PV Scenario documented in Table 2-10 and Table 2-11 of Quanta Technology's report, "Deliverable 3: Benefit Cost Analysis of Alternatives".
[6] This configuration (three transformers operating together) increases the amount of energy (known as short-circuit duty) that would pass through the transformers should an electrical fault occur. Presently, this amount of energy does not exceed the ratings of select electrical equipment in the Valley South System; however, SCE notes that over time as additional resources come on-line (which contribute additional short-circuit duty), it may begin to exceed equipment ratings and would have to be addressed.
[7] If an automated load-shedding scheme is implemented in the Valley South System, which protects the system from transformer overloads due to a second transformer outage (N-1-1), the full capacity of the two remaining in-service transformers (nameplate and emergency ratings) could be credited to serve the system during N-1 contingencies.

service to the Valley North System with a single transformer. The two options have different risks and consequences that must be considered by system operators in the context of the specific heat storm, loading conditions, and anticipated transformer outage restoration period.

Should the spare transformer be shifted to serve the Valley North System, the Valley South System would again have only two transformers serving it. The 2025 projected peak load of the Valley South System is 1,159 MVA and while this value is below the STELL N-1 operating limits of the two in-service transformers (1,792 MVA) serving the Valley South System, it is above the STELL operating limit of a single in-service transformer (896 MVA) should there be a subsequent unplanned transformer outage. This would require the implementation of an automated load shedding scheme for the Valley South System (triggered to interrupt service to approximately 263 MVA of load (1,159 – 896 = 263 MVA)) in the event of a second transformer outage.

Alternatively, the spare transformer may be left in-service in the Valley South System. In this case the Valley North System would be served by a single transformer during this period, risking loss of service to the entire Valley North System should there be a subsequent outage to the remaining in-service transformer. If this subsequent loss of service to Valley North were to occur, operators would then realign the spare transformer from the Valley South System to the Valley North System to restore service to the Valley North System. This would leave two transformers remaining in the Valley South System, which is sufficient to serve load as described above. In this configuration, the Valley South System load shedding scheme described above would only be triggered in the event of a subsequent Valley South System transformer outage.

In summary, between now and 2025, in the context of assessing the risk of reliance on the spare transformer mitigation, there is one scenario within the Valley North and South Systems in which a significant amount of load could go unserved for greater than a momentary outage. This scenario would be in a case where two of the five combined (load-serving and spare) Valley North and Valley South transformers are simultaneously out-of-service (i.e., N-1-1 or N-2) and leave a single transformer to serve load in either system. This transformer outage scenario can be accommodated in the Valley North System with limited customer service interruption due to its current capacity margin and its tie-lines to an adjacent system. The occurrence of this level of contingency event is rare and not considered as planned-for contingencies when sponsoring new projects based on SCE's Subtransmission Planning Criteria and Guidelines. However, contingency events like this are considered by SCE's system operators in designing operational plans and also in system planning, as secondary resiliency attributes are useful in further differentiating various system alternatives designed to address primary project objectives.

POTENTIAL INTERIM BESS SOLUTION

SCE analyzed the effectiveness of using battery energy storage systems (BESS) to reduce reliance on the spare transformer during times of peak demand. Total spare transformer usage was evaluated for years 2020-2025, and various sizes of BESS installations were considered to determine how much spare transformer use could be reduced. The results of the study are summarized in Table 1 below.

Table 1. Reduction in Projected Spare Transformer Utilization for Various BESS Sizes

MW	MWh	Spare Transformer Utilization (Hours, 2020-2025)	Spare Transformer Utilization Reduction (Hours, 2020-2025)	Spare Transformer Utilization Reduction (%)
268	1520	167	433	72%
227	1178	183	417	69%
192	880	199	401	67%
168	670	213	387	64%
144	532	246	354	59%
120	430	288	312	52%
86	282	353	247	41%
61	167	406	194	32%
50	150	444	156	26%
50	100	**447**	153	**26%**
30	60	508	92	15%
0	0	600	0	0%

The BESS is assumed to go into service in 2022, at which point 167 hours of expected spare transformer utilization will have already accrued (this is why the reduction in spare transformer utilization is at most 72%). The results show that in order to mitigate the remainder of the expected spare transformer utilization (433 hours), a BESS of 268 MW / 1,520 MWh would be required. SCE did not perform a detailed cost estimate of a system of this particular size; thus, the cost of a similarly sized system (273 MW / 1666 MWh) is used as a surrogate, and this cost is greater than $500M.[8] Due to the surrogate project spreading out the cost of batteries over 30 years, the actual cost of a such a large project being installed in such a short amount of time is likely to be much higher than $500M.

The Planning Study conducted by SCE (which evaluated alternatives to the Alberhill Substation Project) determined that 50 MW / 100 MWh is the expected maximum size for BESS that can be installed at existing distribution substations in the Valley South System without significant substation modifications, and increased environmental impacts since these are previously disturbed sites. SCE previously performed a detailed cost estimate of a system of this size, and determined that the NPV cost of such a system is approximately $66M.[9]

[8] This estimate is based on the Centralized BESS in Valley South alternative described in SCE's response to Item C (ED-Alberhill-SCE-JWS-4: Item C, or the Planning Study). This project was envisioned as a series of incremental BESS capacity additions that would be implemented over the course of 30 years, and was estimated as such. The figured reported in the Planning Study has been adjusted here to remove market participation cost offsets, and is presented on a net present value (NPV) basis. It is clear that the cost of a BESS of this magnitude is too large to be justified as a short term mitigation even if it were able to be implemented in a timely manner.

[9] This estimate was developed using the same methodology as the BESS components of the Valley South to Valley North and Distributed BESS in Valley South alternative of SCE's response to Item C (ED-Alberhill-SCE-JWS-4: Item C). However, the implementation date of the BESS is adjusted to 2022, and the estimate is presented here on a net present value basis (NPV) as opposed to a Present Value of Revenue Requirement (PVRR) basis.

In order to offset the cost, the 50 MW / 100 MWh BESS was considered as able to participate in CAISO real-time, day-ahead, and ancillary services markets. An analysis performed by Quanta Technology, under SCE's direction, found that providing a mix of frequency regulation ancillary services and participation in day-ahead markets through energy shifting/arbitrage would optimize the revenue for such a system, and that participation in these markets for the lifetime of a BESS without additional augmentation (assumed 10 years) would yield a NPV revenue of approximately $16M. The analysis assumes that participation in real-time and day-ahead markets is limited to non-summer months (October – May) until 2026, the year after the assumed 2025 in-servicing of the ASP, at which point the BESS is allowed to participate in energy markets year-round.

Additionally, the BESS could receive payments by offering its capacity for resource adequacy (RA), though the power output would have to be de-rated to 25 MW in order to meet the 4-hour duration requirement by the CPUC/CAISO. The CPUC-published 2018 RA Report contains weighted average, 85th percentile, and maximum prices paid for local RA in the LA basin. These values were used to estimate the additional revenue from payments for fulfilling local RA requirements for 8 months out of the year, at a power rating of 25 MW. A 3% escalation factor was used to account for inflation from year to year, and RA payments were assumed to be received 12 months out of the year starting in year 2026.

Table 2. Local RA Revenue, 25 MW, 8 months/year until 2026, then year-round

Local RA payments in the LA basin ($/kW-month)		NPV (thousands of $)
Weighted average	$3.66	$7,728
85th percentile	$4.25	$8,974
Max	$6.81	$14,379

Ultimately, considering the combination of potentially available market participation revenue of about $30M, a reasonably sized 50 MW / 100 MWh system would likely have a net cost to SCE ratepayers of $30M at a minimum (assuming market participation revenue would be maximized), and would reduce the use of the spare transformer in the Valley South System by only 26%. A 268 MW / 1,520 MWh system, to conceivably relieve all of the expected use of the spare transformer as capacity mitigation, is unreasonably large and costly considering the primary use-case time period, and is not considered a feasible option. Additionally, such a system would likely require a dedicated 115 kV substation and 115 kV source lines to accommodate that amount of capacity, and per GO131D would require a licensing and permitting proceeding for approval.

BESS PROJECT IMPLEMENTATION

In order to implement a BESS project, SCE requires a regulatory framework (program or process) through which to develop the project on its own, or to procure storage from a third-party. In the case where a BESS can be sited within an existing substation(s) and can interconnect at the 12 kV distribution level with limited additional environmental disturbance, an expedited project implementation could reasonably be expected. However, even in this case a BESS project would require a suitable regulatory framework to be implemented.

There are four existing programs that SCE currently uses to procure or develop energy storage:

- Energy Storage Integration Pilot (ESIP)
- Energy Storage Procurement and Investment Plan (ESP&IP)
- Reliability Utility Owned Energy Storage (RUOES)
- Distribution Investment Deferral Framework (DIDF)

The ESIP program is essentially closed to new procurement as energy storage projects procured under this program were already included as part of the 2021 General Rate Case proceedings. The ESP&IP program was set up to address AB2868, which allocated 166 MW of energy storage procurement to SCE. Since the general project size of ESP&IP is 2.5 MW / 4.5 MWh, a project of the magnitude in question is not a good fit for this program. The DIDF program most commonly considers DERs interconnected at the distribution level and is focused on projects that satisfy needs 4-5 years out, with corresponding implementation schedules.

Of these four programs, the RUOES program appears to be the best suited for a project of this size and this application. Unfortunately, the allocation for the RUOES program is complete and cannot accommodate additional energy storage procurement.

The timeline of such a project would be subject to the CAISO/SCE interconnection process, which typically takes a minimum of 2 years and can take as long as 5 years for complex projects. A potential way of expediting this process is to replace the usual queue cluster interconnection study with an independent study. However, performing an independent study would preclude the energy storage asset from participating in RA, thus increasing the total cost to SCE ratepayers by as much as $14M.

A final alternative is for SCE to propose a stand-alone project to the CPUC. The timeline for such a process is unclear and would not preclude any of the interconnection study and process requirements. Unless an expedited proceeding were undertaken, this would likely push project completion to some year beyond 2022, further diminishing the value of the project. However, this remains a suitable pathway to procurement so long as activities can be coordinated to optimize the timeline of the project.

RECOMMENDATION

SCE currently has in place an operating procedure that utilizes the Valley Substation spare transformer to mitigate potential overloads in the Valley South System during periods of peak electrical demand. Concurrently, peak electrical demand in the Valley South System is forecast to exceed the existing transformation capacity in 2022. Until a permanent solution is constructed to relieve the concentration of load in the Valley South System, such as the Alberhill System Project, the spare transformer overload mitigation procedure will be needed to maintain compliance with SCE planning and operating criteria and thereby ensure reliable service to customers.

The feasibility of an energy storage project to eliminate the need for the potential overload mitigation procedure was analyzed and such a project would not likely be constructed and placed in service any earlier than 2022. The size of a project that would eliminate the use of the spare transformer for the years 2022-2025 is too large to be implemented quickly and cost-effectively. The largest project identified that could be implemented within a reasonable time frame, i.e., by the year 2022, is on the order of 50 MW / 100 MWh. After accounting for potential revenue to offset the cost of such a project, it would cost SCE ratepayers approximately $30M over the expected 10-year life of the BESS. Also, the project is expected to only eliminate up to 26% of the potential hours the spare transformer would be needed.

SCE has concluded that developing a BESS or procuring energy storage to mitigate use of the spare transformer at Valley South is not a cost-effective solution in reducing the risk of service interruption to customers. Considering the low probability that the spare transformer would be needed to replace a main transformer while serving the Valley South System for potential overload mitigation, the cost of a system that would completely eliminate the risk is unreasonable (>$500M). Additionally, this risk would only be eliminated after the project is in service, which would, at best, be comparable to the current proposed schedule for a project like ASP. A reasonably sized system would still be a significant cost to SCE ratepayers, while eliminating only about a quarter of the risk of using the spare transformer to serve load for an additional few years. Note that, as discussed in the ASP Planning Study,[10] the use of the spare transformer to serve load is only one element of the overall unacceptable level of risk that exists in the Valley South System. SCE continues to recommend that SCE and the ED continue to focus attention on a permanent solution to address both the projected peak electrical demand and the lack of system tie-lines that threaten the reliability and resiliency in the Valley South System.

[10] See A.09-09-022 ED-Alberhill-SCE-JWS-2 Q.01c Response

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

DATA REQUEST SET C P U C - S u p p l e m e n t a l D a t a R e q u e s t - 0 0 1

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/16/2020

Question DG-MISC-13:
Regarding the interim solutions webinar: Can you express the historic use of the temporary transformer as both a number of hours in addition to the number of total days (shape magnitude and duration)?

Response to Question DG-MISC-13:

The attached document titled “A0909022-ED-Supplemental Data Request 001-Question DG-MISC-13.pdf” provides a table of the historic use of Valley Substation spare transformer from its installation date in 2012 until present. This includes all use associated with overload mitigation, unplanned outages, and planned outages (for testing, maintenance, inspection, and construction). Total usage is equal to 9,358 hours over 368 unique days. Note that each hour of use does not necessarily indicate that the transformer was needed to be used, since the transformer may have been in-serviced due to an anticipated need and may not have been taken immediately out-of-service when the need is no longer present.

Historic Valley Substation Spare Transformer Utilization: 2012 - Present

Incident No.	Year	Start	Stop	Days	Hours	Total Hours
1	2013	04/23/2013 6:00	04/26/2013 13:00	3	7	79
2	2013	04/29/2013 7:00	06/23/2013 13:00	55	6	1326
3	2013	07/23/2013 4:00	07/23/2013 6:00	0	2	2
4	2013	07/25/2013 14:00	07/25/2013 21:00	0	7	7
5	2014	01/28/2014 9:00	01/31/2014 14:00	3	5	77
6	2014	04/21/2014 6:00	04/22/2014 18:00	1	12	36
7	2014	04/24/2014 3:00	04/25/2014 15:00	1	12	36
8	2014	05/05/2014 8:00	05/07/2014 21:00	2	13	61
9	2014	05/09/2014 9:00	05/09/2014 18:00	0	9	9
10	2014	08/06/2014 5:00	08/06/2014 11:00	0	6	6
11	2014	08/29/2014 15:00	08/29/2014 20:00	0	5	5
12	2014	10/06/2014 7:00	10/10/2014 17:00	4	10	106
13	2015	01/29/2015 6:00	02/02/2015 16:00	4	10	106
14	2015	02/02/2015 21:00	02/03/2015 14:00	0	17	17
15	2015	03/05/2015 6:00	03/05/2015 20:00	0	14	14
16	2015	04/20/2015 8:00	04/22/2015 17:00	2	9	57
17	2015	08/27/2015 12:00	08/27/2015 15:00	0	3	3
18	2016	04/15/2016 7:00	04/15/2016 19:00	0	12	12
19	2016	06/22/2016 9:00	07/01/2016 16:00	9	7	223
20	2016	09/12/2016 8:00	09/15/2016 8:00	3	0	72
21	2016	10/18/2016 5:00	10/18/2016 7:00	0	2	2
22	2017	01/07/2017 16:00	01/07/2017 18:00	0	2	2
23	2017	01/09/2017 6:00	04/15/2017 10:00	96	4	2308
24	2017	04/16/2017 10:00	05/06/2017 9:00	19	23	479
25	2017	05/15/2017 4:00	05/18/2017 6:00	3	2	74
26	2017	05/18/2017 17:00	05/20/2017 10:00	1	17	41
27	2017	05/22/2017 4:00	05/22/2017 20:00	0	16	16
28	2017	05/23/2017 4:00	05/23/2017 16:00	0	12	12
29	2017	05/25/2017 11:00	05/25/2017 13:00	0	2	2
30	2017	05/30/2017 8:00	06/02/2017 19:00	3	11	83
31	2017	08/15/2017 5:00	08/15/2017 16:00	0	11	11
32	2017	08/29/2017 14:00	08/29/2017 23:00	0	9	9
33	2017	08/30/2017 13:00	08/31/2017 9:00	0	20	20

Historic Valley Substation Spare Transformer Utilization: 2012 - Present

Incident No.	Year	Start	Stop	Days	Hours	Total Hours
34	2017	08/31/2017 12:00	08/31/2017 17:00	0	5	5
35	2017	09/01/2017 14:00	09/01/2017 20:00	0	6	6
36	2017	09/02/2017 16:00	09/02/2017 20:00	0	4	4
37	2018	01/23/2018 6:00	01/27/2018 17:00	4	11	107
38	2018	02/05/2018 8:00	02/10/2018 14:00	5	6	126
39	2018	02/12/2018 7:00	02/17/2018 19:00	5	12	132
40	2018	03/01/2018 12:00	03/02/2018 11:00	0	23	23
41	2018	06/01/2018 10:00	07/09/2018 21:00	38	11	923
42	2018	07/23/2018 16:00	09/28/2018 10:00	66	18	1602
43	2018	10/16/2018 6:00	10/17/2018 16:00	1	10	34
44	2018	10/23/2018 5:00	10/24/2018 16:00	1	11	35
45	2019	04/26/2019 2:00	04/26/2019 21:00	0	19	19
46	2019	04/27/2019 1:00	04/27/2019 13:00	0	12	12
47	2019	04/29/2019 7:00	05/05/2019 8:00	6	1	145
48	2019	05/06/2019 7:00	05/11/2019 18:00	5	11	131
49	2019	06/03/2019 12:00	06/16/2019 20:00	13	8	320
50	2019	09/05/2019 23:00	09/06/2019 8:00	0	9	9
51	2019	11/12/2019 4:00	11/12/2019 18:00	0	14	14
52	2020	02/10/2020 3:00	02/15/2020 16:00	5	13	133
53	2020	02/18/2020 4:00	02/22/2020 14:00	4	10	106
54	2020	03/02/2020 2:00	03/08/2020 17:00	6	15	159
					Total	9358

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

DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 3/16/2020

Question DG-MISC-14:
Regarding the interim solutions webinar: Can you express the forecasted number of hours utilized in total days, total hours, and duration of each event, rather than purely in number of hours?

Response to Question DG-MISC-14:

Please see SCE's response to DG-MISC-11, which provides the forecasted spare transformer utilization.

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

DATA REQUEST SET CPUC-Supplemental Data Request-001

To: CPUC
Prepared by: Gary Holdsworth
Job Title: Senior Manager, Grid Interconnections & Contract Development
Received Date: 2/14/2020

Response Date: 3/13/2020

Question DG-MISC-15:
Please explain the queue cluster study process or independent interconnection study process?

Response to Question DG-MISC-15:
Queue Cluster Study process: The process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of evaluating the combined system impacts and developing combined mitigation measures in the form of required network upgrades, as well as the interconnection facilities for the individual projects in a queue cluster. The CAISO and SCE WDAT interconnection procedures both use the Queue Cluster process.

Independent Interconnection study process: A separate interconnection study process for interconnection requests that are deemed eligible to be studied independently from other projects in the interconnection process/queue. The CAISO and SCE WDAT interconnection procedures both include the Independent Study process for eligible projects.

Common Definitions:

Queue Cluster Study process: Annual process by which generation and storage interconnection requests apply for interconnection during a cluster application window which is open in April of each year. Interconnection Requests that are submitted in the same cluster application window then are grouped into electrically related study groups by geographic areas and are studied at the same time for the purpose of cost sharing of required upgrades amongst the cluster study group participants. The cluster study process provides a more equitable cost allocation and is more time efficient than the previous serial interconnection process, which studied interconnection requests one at a time in queue order, and which would put more of a cost burden on individual interconnection requests that triggered upgrades. The Cluster Study process includes a Phase I and Phase II study, with increasing financial security requirements as the interconnection request moves through the process. The Cluster Study process is also the method the CAISO uses to determine Full Capacity or Partial Capacity Deliverability status under its TP Deliverability allocation process. For further information, refer to the CAISO Appendix DD GIDAP (link below).

Independent Interconnection study process: Generation and storage interconnection requests that apply any time during the year and which are deemed eligible to be studied independently of the Transmission System and other earlier-queued projects because they don’t trigger, contribute to, or modify required network upgrades. Eligibility for the independent study process is determined using two tests, one for the transmission system, and one for the distribution system. The CAISO performs the transmission system test, and SCE performs the distribution system test. The distribution test hinges on whether the project is electrically related to an earlier-queued project that has yet to complete a Phase I cluster or system impact study. The independent study process uses a system impact study followed by a facilities study. The independent study process is outlined in Section 4 of the CAISO Appendix DD GIDAP (see link below) and Section 5 of SCE's WDAT Attachment I (see link below).

http://www.caiso.com/Documents/AppendixDD-GeneratorInterconnection-DeliverabilityAllocationProcedures-asof-Oct23-2019.pdf

https://www1.sce.com/nrc/openaccess/WDAT/eTariff_Z-WDAT_Attachment_I_5.0.0.pdf

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

DATA REQUEST SET CPUC-Supplemental Data Request-001 and 002

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 2/14/2020

Response Date: 8/11/2021

Question DG-C-4 Revised:
The Planning Study mentions that it makes sense to do an “incremental cost-benefit analysis” where alternatives with widely disparate benefits are compared; when this is conducted, the ASP is superior to all other alternatives. Where can we find these results?

Response to Question DG-C-4 Revised:

Revision 1 of this data request is being submitted to reflect changes documented in Southern California Edison’s Second Amended Motion. The original data request response has been updated to correct page number references and incremental cost benefit ratios.

A discussion for the incremental cost-benefit analysis can be found in Section 8.2.2 of SCE’s response to Exhibit C-2. The results of this analysis are found in Table 8-7. The results demonstrate that the Alberhill System Project has a 2.8 incremental benefit to incremental cost ratio over the Menifee Alternative.

SCE’s Second Amended Motion can be found at the following CPUC website https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=390886186.