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

DATA REQUEST SET CPUC-Supplemental Data Request-008

To: Energy Division
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 1/20/2021

Response Date: 2/16/2021

Question DG-MISC-57_FollowUp:
From the response to DG-MISC-57, it sounds like a CEC forecast was not shared with Quanta, only the SCE forecast. Is that correct?

Response to Question DG-MISC-57_FollowUp:

SCE provided Quanta Technology with the 10-year SCE load forecast (1-in-2 year non-coincident values covering the years of 2018-2029) for each of the distribution substations within the Valley North and South Systems that is derived directly from the CEC forecast as described below. The California Energy Commission (CEC) forecast was the basis of this data provided to Quanta.

SCE is obligated to use the CEC IEPR-derived forecasts for its respective 10-year planning horizons. The CEC forecast is a system-wide forecast and must first be disaggregated to individual distribution substations for use in system-level planning. The 10-year SCE load forecast for each of its radial electrical systems are derived by taking the SCE system-wide CEC energy forecast, disaggregating it to the individual distribution circuits, and then reaggregating it up to the distribution substations and then to the transmission substations (e.g., Valley Substation) which serve the radial load from the CAISO-controlled transmission grid. The steps of disaggregation and reaggregation are performed in accordance with a methodology vetted through the CPUC Distribution Forecasting Working Group.

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To: Energy Division
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 1/20/2021

Response Date: 2/16/2021

Question DG-MISC-58_FollowUp:
Two clarification questions pertaining to the response to DG-MISC-58:

1. PSLF determines magnitude of overload. How was the time duration of the overloads determined?

2. Only PSLF models were provided. Are the base cases that were provided to Quanta not available?

Response to Question DG-MISC-58_FollowUp:

1. The PSLF analysis is an 8,760-hour analysis; that is, a load flow analysis is performed for every hour of the year over the 30-year horizon of the cost-benefit analysis. For each power flow case, PSLF reports which facilities are overloaded and the magnitude of the overload. As an 8,760 time-series analysis studies power flow cases in one-hour increments, the overloads for each hour are represented as the overload in power expressed in MW and the energy component is expressed in MWh (or the MW overload multiplied by 1 hour). The total duration of each overload is equal to the number of subsequent load flow cases that result in an overload for a given facility as each case represents one hour of the 8,760-hour analysis. For example, consider the following simplified PSLF results for the Auld-Moraga #1 line starting at hour 4,695 out of 8,760 hours, which might represent an afternoon peak in mid-July. This profile is typical of a summer day, in which there are a number of hours of overload prior to and after the peak load for the day (which in this example occurs in hour 4,697).

   Hour 4,695: No overload

   Hour 4,696: Overload of 5 MW of power and 5 MWh of energy

   Hour 4,697: Overload of 10 MW of power and 10 MWh of energy

   Hour 4,698: Overload of 5 MW of power and 5 MWh of energy

   Hour 4,699: No overload

   In this span of time, the Auld-Moraga #1 line is overloaded for a total of 3 hours and the cumulative load-at-risk during this overload is 20 MWh (which is simply the sum of each independent hour's overload). Since the smallest unit of time considered in the PSLF is one hour, any overloads are assumed to be present for the entire hour of that load flow case.

2. Base case files (PSLF files with the suffix of ".sav") for the current Valley South System, Alberhill System Project, and all alternatives were provided. A contingency processor (PSLF file with suffix of ".epcl") was also provided to Quanta Technology as well as to the Energy Division (through SCE's response to Data Request A.09-09-022 CPUC Supplemental Data Request-06 Q.DG-MISC-58). All contingency cases studied can be derived from the base case files that were provided using the contingency processor.

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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 8

To: Energy Division
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 1/20/2021

Response Date: 2/16/2021

Question DG-MISC-61_FollowUp:
Please describe why DERs cannot meet the reliability and resiliency needs of the Alberhill System Project independent of the specific capabilities of the proposed tie-lines.

Flex 1 and Flex 2 would still appear to have an LNBA value, independent of any deferral component. It appears that SCE is suggesting that deferral value is the only value that should be considered as part of LNBA. Is this the case?

Response to Question DG-MISC-61_FollowUp:

DERs may provide limited reliability and resiliency benefits for select short-duration contingency cases depending the electrical location of the DER within the subtransmission system and the availability of the asset (due to solar irradiation levels, state-of-charge, or other operational constraints). DERs are generally unable to provide substantial benefit to longer-duration contingencies because:

- Solar PV is weather, time of day, and seasonally dependent,
- Energy storage has limited duration before batteries are fully discharged and would need to be charged again; and
- Demand Response is a voluntary program with limits on participation, frequency of use, and duration of use.

Additionally, while DER-based microgrids are being considered for short-term reliability/resiliency applications at the distribution scale (and other limited applications associated with a single line contingency or short-term overloading) there is no demonstrated history nor a regulatory/commercial/technology model in-place to implement a DER-based solution at the scale required to address reliability/resiliency needs in a system the scale of the Valley South System (approximately 200,000 metered customers over a 600 square mile service territory). Due to the system configuration and needs, as well as temporal and asset dependability considerations, the scale of such a DER-based solution would be several orders of magnitude greater than any such system that has been demonstrated even at a pilot scale and thus should not be relied on for the critical near-term needs in the area served by the Valley South System.

Under the current established rules for calculating LNBA, deferral values (along with certain defined CAISO market participation value streams) are the only outputs provided by the LNBA calculation. The value of resiliency is currently being considered in the Microgrid Proceeding; but, until resiliency values are agreed upon and applied consistently across all of the projects in the DIDF, it would be improper to consider Flex-1 or Flex-2 type metrics in calculating LNBA for individual projects.

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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 8

To: Energy Division
Prepared by: Rey Gonzales
Job Title: Sr. Environmental Project Manager
Received Date: 1/20/2021

Response Date: 2/16/2021

Question DG-MISC-62:
Please provide a GIS package (geodatabase or shapefiles) of the GIS data shown on Insignia's GIS Map Viewer: "Alberhill System Project Map Viewer Summary."

Please provide all files associated with each of the viewer tabs listed below:
TAB 1: PROJECT VICINITY
Existing Substation
Existing Transmission/Subtransmission Line
Electric Needs Area

TAB 6: SYSTEM ALTERNATIVES (be sure to include all components/metadata/and attribute data associated with each alternative)
SDG&E
SCE Orange County
Menifee
Mira Loma
Valley South to Valley North
Valley South to Valley North to Vista
Centralized Bess in Valley South
Valley South to Valley North and Distributed Bess in Valley South
SDG&E and Centralized Bess in Valley South
Mira Loma and Centralized Bess in Valley South
Valley South to Valley North and Centralized Bess in Valley South and Valley North
Valley South to Valley North to Vista and Centralized Bess in Valley South

Additionally, please provide the GIS data for existing substations and existing transmission and subtransmission lines. Please ensure that appropriate metadata and attribute data is included within each feature resulting from this request.

Response to Question DG-MISC-62:
Please see the attached file titled "A.09-09-022 CPUC-Supplemental Data Request-008 Question DG-MISC-62.zip". This attachment contains two separate geodatabase files (ASP_GIS_Tab_01.gdb.zip and ASP_GIS_Tab_06.gdb.zip); an attribute table which identifies each feature class located within each geodatabase, the type of feature class, key attributes and a description of the use for each attribute; and a text file containing the unique system alternative names to assist with querying the dataset.

All feature classes include a "System_Alt" attribute which can be used to filter all features in ASP_GIS_Tab06.gdb.

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DATA REQUEST SET CPUC-Supplemental Data Request-008

To: Energy Division
Prepared by: Rey Gonzales
Job Title: Sr. Environmental Project Manager
Received Date: 1/20/2021

Response Date: 3/23/2021

Question DG-MISC-62 Revised:
Please provide a GIS package (geodatabase or shapefiles) of the GIS data shown on Insignia's GIS Map Viewer: "Alberhill System Project Map Viewer Summary."
Please provide all files associated with each of the viewer tabs listed below:
TAB 1: PROJECT VICINITY
Existing Substation
Existing Transmission/Subtransmission Line
Electric Needs Area
TAB 6: SYSTEM ALTERNATIVES (be sure to include all components/metadata/and attribute data associated with each alternative)
SDG&E
SCE Orange County
Menifee
Mira Loma
Valley South to Valley North
Valley South to Valley North to Vista
Centralized Bess in Valley South
Valley South to Valley North and Distributed Bess in Valley South
SDG&E and Centralized Bess in Valley South
Mira Loma and Centralized Bess in Valley South
Valley South to Valley North and Centralized Bess in Valley South and Valley North
Valley South to Valley North to Vista and Centralized Bess in Valley South
Additionally, please provide the GIS data for existing substations and existing transmission and subtransmission lines. Please ensure that appropriate metadata and attribute data is included within each feature resulting from this request.

Response to Question DG-MISC-62 Revised:
Please see the attached revised data package titled "ASP_DG_MISC_62 Revised_GIS Request_20210322" in response to DG-MISC-62 which makes the following corrections:

1. Removes 4 polyline features from the System_Alt_Routes feature class that were attributed as Distributed BESS in Valley South. These features were duplicates of four features attributed as Valley South to Valley North and Distributed BESS in Valley South

2. Corrects a typographical error in the System_Alt attribute for one point feature in the Demolish_Existing_Switchrack feature class

As with the original data request response provided February 16, 2021, this package contains two separate geodatabase files (ASP_GIS_Tab_01.gdb.zip and ASP_GIS_Tab_06.gdb.zip); an attribute table which identifies each feature class located within each geodatabase, the type of feature class, key attributes and a description of the use for each attribute; and a text file containing the unique system alternative names to assist with querying the dataset. All feature classes include a “System_Alt” attribute which can be used to filter all features in ASP_GIS_Tab06.gdb.

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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 8

To: Energy Division
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 1/20/2021

Response Date: 2/16/2021

Question DG-MISC-65:
Did SCE consider the implications of more load being transferred from the Valley South to the Valley North if more storage was interconnected in the Valley North system? Please explain why or why not.

Response to Question DG-MISC-65:
SCE interprets this question as inquiring about whether load in excess of what is already transferred in the Valley South to Valley North-based alternatives was considered in the cost-benefit analysis. The Valley South to Valley North-based alternatives propose to transfer Sun City and Newcomb 115 kV Substations from the Valley South System to the Valley North System, which provides sufficient capacity reduction in the Valley South System to meet the 10-year planning horizon and is consistent with SCE's approach in developing the other alternatives studied. This approach developed the scope for alternatives that would initially meet the need of the 10-year planning horizon and then supplemented the alternatives with additional incremental scope additions as needed throughout the 30-year horizon studied. Furthermore, and most importantly, the Sun City and Newcomb Substations are the nearest Valley South System distribution substations to the Valley North System, which minimized the amount of subtransmission scope required to transfer these substations. Other nearby substations (e.g., Auld or Elsinore Substations) that could be transferred to the Valley North System would require a more complex reconfiguration of the Valley South System, since power from the Valley South System transformers flows through these substations (delivering the power required at these substations) before continuing on to the other electrically-downstream distribution substations within the Valley South System. Transferring the Auld Substation would require significant subtransmission scope to effectively bypass these substations and thus not disrupt the power flow in the rest of the Valley South System network.

Additionally, the Valley North System capacity margin (i.e., amount of capacity before reaching its loading limits) effectively precludes transferring additional substations from the Valley South System. Despite only transferring two substations to the Valley North System, the Valley South to Valley North to Vista alternative and the Valley South to Valley North plus Centralized BESS in Valley North alternative result in Valley North System transformation capacity constraints in 2043 for the Effective PV load forecast and in 2036 for the Spatial Base Forecast. Transferring additional substations from the Valley South System to the Valley North System would result in the advancement of the need date for a Valley North System capacity project for each alternative respectively.