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 9

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 3/17/2021

Response Date: 4/2/2021

Question DG-MISC-66:
Provide data and associated analyses performed to date which review whether the COVID-19 shelter-in-place has driven changes in customer behaviors that have resulted in changed demand or consumption that would impact the need for capacity, reliability and resiliency improvements in the electrical needs area.

Response to Question DG-MISC-66:

The data and associated analysis that SCE relied upon to review and determine if there were any obvious impacts of COVID-19 on the customer behaviors in electrical energy use/consumption that would specifically impact the need for capacity, reliability, and resiliency improvements identified as needed in the electrical needs area of the Alberhill System Project can be found in SCE's responses to Questions DG-MISC-69 and DG-MISC-72 of this data request set. The appropriateness of the use of this data is discussed further in SCE's response to Question DG-MISC-68. SCE is not aware of any definitive analysis that quantifies, with reliable certainty (for electric system planning purposes), what impacts to any one particular subtransmission planning area have been due to COVID-19. Rather, the analyses performed to date have opined on the general impacts across both much higher-levels (e.g., statewide or utility systemwide) or discrete distribution system level facilities (e.g., distribution circuits).

In SCE's review of the Valley South System (a subtransmission level planning area), there have been no apparent substantial changes in overall system loading that affect the need for a project to meet the capacity need in the Valley South System. Load growth between 2019 and 2020 appears consistent with the overall trend in load growth demonstrated during the past several years.

The preliminary weather-adjusted peak load in 2020 for the Valley South System also correlates very closely to SCE's projected value for 2020 from the prior 10-year forecast covering the years 2020-2029. SCE recognizes that there have been shifts in energy consumption between residential and commercial/industrial customers as a result of COVID-19. These impacts may result in advancements or deferrals of electrical system needs at the distribution system level for which continued assessment is necessary before arriving at planning decisions. However, for a project such as the Alberhill System Project (addressing the needs of subtransmission/transmission system), assessment of the COVID-19 impacts are able to be assessed on a high-level basis (the SCADA data at the Valley South System transformers) and as further discussed in SCE's response to Question DG-MISC-69 of this data request set, SCE observed no pronounced impacts from COVID-19 which would alter the established needs for on the need for capacity, reliability, and resiliency improvements to the electrical needs area.

The capacity need is still present and further confirmed by the preliminary 2020 loading value being nearly identical to the 2020 projected value which was forecast prior to the impacts of COVID-19. The reliability need has been present since the Valley South System was created by splitting the Valley System in 2004 and impacts from COVID-19 have no impact on this. Similarly, the resiliency need driven by the vulnerability of Valley Substation, being the only source of power to hundreds of thousands of customers, is longstanding and is unaffected by variations in load characteristics of short-term economic disruptions such as from COVID-19 impacts.

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 3/17/2021

Response Date: 4/2/2021

Question DG-MISC-67:
Explain how an analysis of the electrical needs area at the individual customer meter level would impact Edison's conclusions regarding capacity, reliability, and resiliency improvements needed.

Response to Question DG-MISC-67:

Individual customer meter data provides limited insight on the needs for the Valley South System (i.e., the subtransmission/transmission level of the system) and does not provide useful insight on the selection of a preferred alternative to meet the specific needs of the system. Analysis of customer meter data can however provide insight on the potential for increased adoption of DERs in the Valley South System and where within the distribution system those DERs might be sourced (e.g., on which distribution circuits). SCE continues to acknowledge that increased and widespread adoption of DERs could partially mitigate the capacity need in the Valley South System, although the required quantity of DERs to be sourced to fully address the expected need over a 10-year planning horizon (under both normal and abnormal system conditions) would be extraordinarily large, cost prohibitive, and impractical considering:

- the magnitude of load in the Valley South System,
- the continued rate of load growth (because it remains a developing area),
- the year-to-year volatility in load around the nominal growth rate,
- the needed margin for DER dependability,
- the needed infrastructure to ensure the dispatchability and reliability of the DER resources, and
- lack of an effective regulatory framework to source these DERs.

While SCE considers DER-based alternatives to be potentially feasible to address certain subtransmission system level capacity needs (e.g., modest subtransmission line or transformer overloads in areas which are not demonstrating continued growth, or which have significant growth potential), they are more appropriate to meet smaller-scale distribution system level capacity needs. In those cases, DER-based alternatives are more likely cost-effective, easier and timelier to implement, easier to control and manage operationally, and carry less risk of customer impacts should performance or sizing not meet actual system needs. Additionally, a market-sourced DER capacity solution specifically for the Valley South System may be challenged by the limitations on deliverability of power from within this radial subtransmission system (e.g., SCE-controlled 115 kV system) to the bulk electric system (e.g., CAISO-controlled 500 kV system). As an example, potential generation interconnection projects may encounter restrictions or constraints on interconnecting due to capacity issues on the bulk electric system where the timing or costs of the needed system upgrades makes the project uneconomically viable.

It is also reasonable to consider the potential for targeted front-of-meter (FOM) and behind-the-meter (BTM) DER applications to address reliability and resiliency concerns at the distribution substation/circuit level. However, there is no DER-based alternative that can effectively address the subtransmission and transmission system events that are characteristic of the reliability and resiliency needs in the Valley South System. These events are:

- forced or unplanned subtransmission line outages that could occur at anytime and anywhere in the system, affecting on the order of a hundred MWs of load and requiring up to a day to address and/or,
- transmission substation transformer outages that could affect several hundred MWs of load for a period of day to weeks.

The required scale (duration, capacity, and locational diversity) and technical complexity of a FOM or BTM DER-based alternative makes such a solution technically infeasible for meeting the Valley South System's reliability and resiliency needs. There is no demonstrated history in the industry of adopting a DER-based alternative (FOM or BTM) for a reliability/resiliency need at this scale.

Additionally, any conventional solution that effectively meets the reliability and resiliency need (i.e., one which addresses the reliability/resiliency needs with system tie-lines) will consequently also address the capacity need for many years by allowing for load transfers addressing capacity needs for at least the near term. Therefore, it would be duplicative, inefficient, and not cost effective to attempt to concurrently source DERs in the Valley South System for the purpose of meeting any portion of the system need.

Finally, from a system alternatives perspective, SCE's analysis of alternatives that include "distributed BESS" (represented by FOM DERs) effectively represent the system performance of any FOM or BTM DER-based alternative in addressing the stated project needs in the Valley South System. This is significant because this approach allows for DER-based alternatives to be evaluated in the project alternatives analysis phase in an expeditious and resource-efficient manner. The feasibility and performance of such an alternative can be determined from this approach without producing the false-level of precision that would be derived from a detailed customer meter level analysis that was performed many years prematurely. Analyzing a DER-based alternative in this manner also eliminates the time-consuming activities associated with acquiring and processing customer meter data at this stage of the project's lifecycle. In any scenario or stage of evaluating a DER-based alternative, the appropriate time to consider evaluating AMI data would be at a time much closer to the required implementation date. Further refinements to the DER-based alternative could then be evaluated, such as consideration of using AMI data to inform the analysis of whether a BTM implementation may be preferred over the studied FOM version.

Finally, evaluations that include assessment of AMI data that are performed in the present (years before implementation) would no longer be valid at the time of implementation due to the dynamic nature of the distribution system and continually evolving policy, and would require restudy in the future. Accordingly, the value of SCE providing additional AMI data (e.g., data from 2020) to further inform the BTM DER propensity analysis is minimal as it relates to determining the preferred alternative for this project.

Question DG-MISC-68:
Is SCE using SCADA or AMI data to quantify COVID-19 impacts? If so, can you describe how? If not, can you explain why not and what alternative approach is being taken?

Response to Question DG-MISC-68:

SCE does not typically intake customer meter AMI data in performing its annual demand forecasting activities for distribution and transmission substations. At the distribution circuit level, all customers connected to that circuit contribute to the aggregate coincident loading of the circuit at any given time. For system planning activities, collecting AMI data for every customer on every circuit and then correlating that to a coincident time would not yield data that would be more useful than the aggregated values measured by SCADA. In fact, using the AMI data would likely introduce errors and inaccuracies. For instance, AMI data is recorded at predetermined intervals of time depending on the customer type/size. This data is collected per the prescribed process; however, it does not mean than at any given moment in time, every meter is recording a value at just that moment. It is necessary to have an aggregate coincident value for planning purposes. In contrast, measuring SCADA data at any given moment in time does just that, it provides the aggregate coincident loading value for all customers served by that electrical facility for any given time. Additionally, not all customers have smart meters providing AMI data and for those that do, on occasion if an error occurs in recording or collecting AMI data, estimates must be made. Lastly, as AMI data is collected at the end-user, aggregation to higher levels of the electrical system will not represent power system losses that occur en route to delivery (e.g., power measured through the Valley South System transformers capture all power the system consumes, both from the customers demand and the losses associated with its delivery).

Use of AMI data can be particularly useful in near-term planning activities for distribution system facilities. Examples include facilities that do not have SCADA data available, the evaluation of focused areas of a circuit to determine and evaluate such things as the quality of the power being delivered and determining the potential capacity to host distributed energy resources. Use of AMI data for higher-level system planning activities requires a significant level of effort to avoid errors or inaccuracies and such effort is unnecessary if SCADA data is available.

For the Alberhill System Project, the SCE project team reviewed SCADA loading data at the Valley

South System level to gain insight as to whether there were any obvious COVID-19 impacts on the overall system loads that were observable. SCE did not discern any. Please see the three graphics below. Figure 1 presents three years of 8,760 hourly demand data (for observation of an entire year) for the Valley South System for the years 2018-2020. Figure 2 presents hourly data but is focused only the four summer peaking months of June through September (for observation of the summer peak season) for the same years 2018-2020. Figure 3 presents hourly data but is focused only the single highest loading day of the year for the same years 2018-2020 (for observation of the daily load shape).

Figure 1

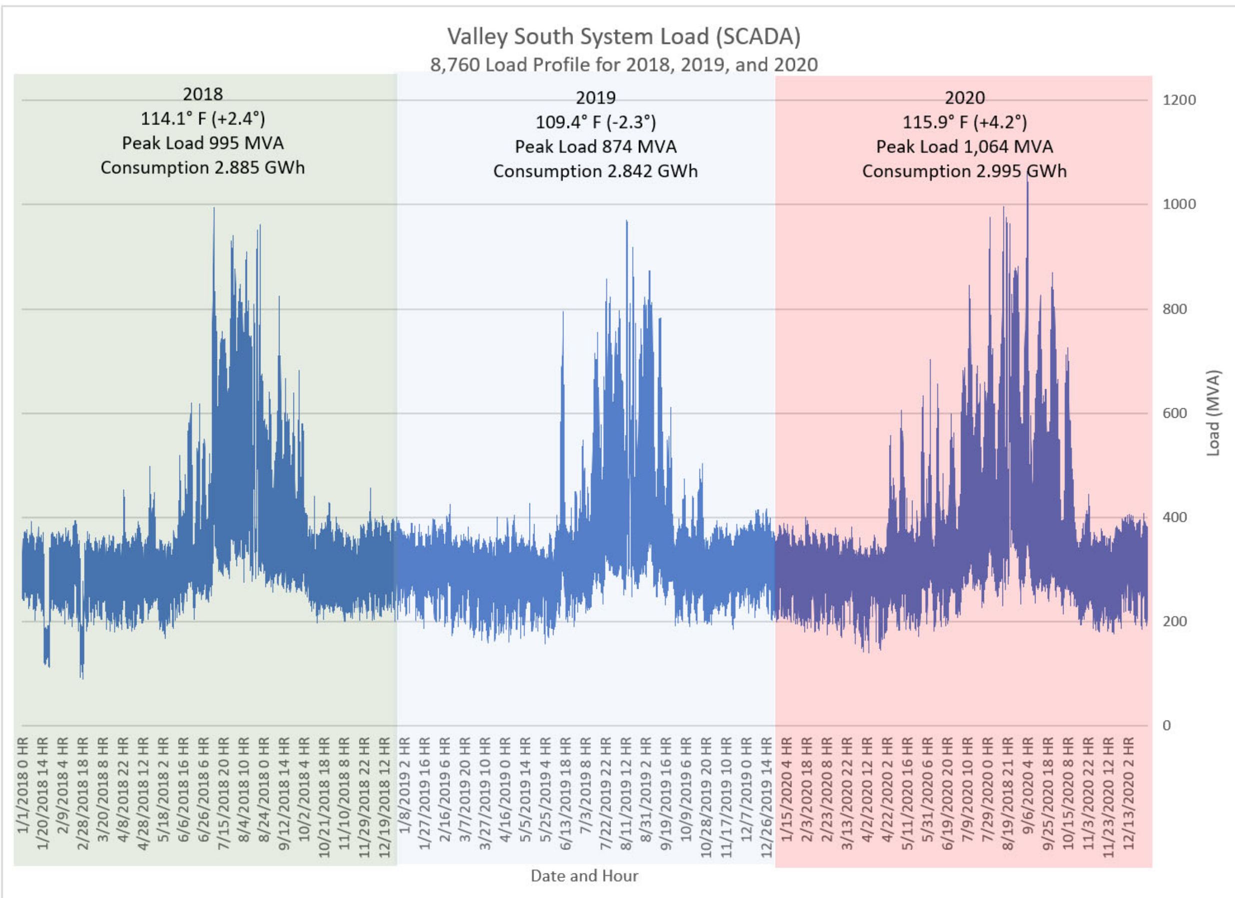


Figure 2

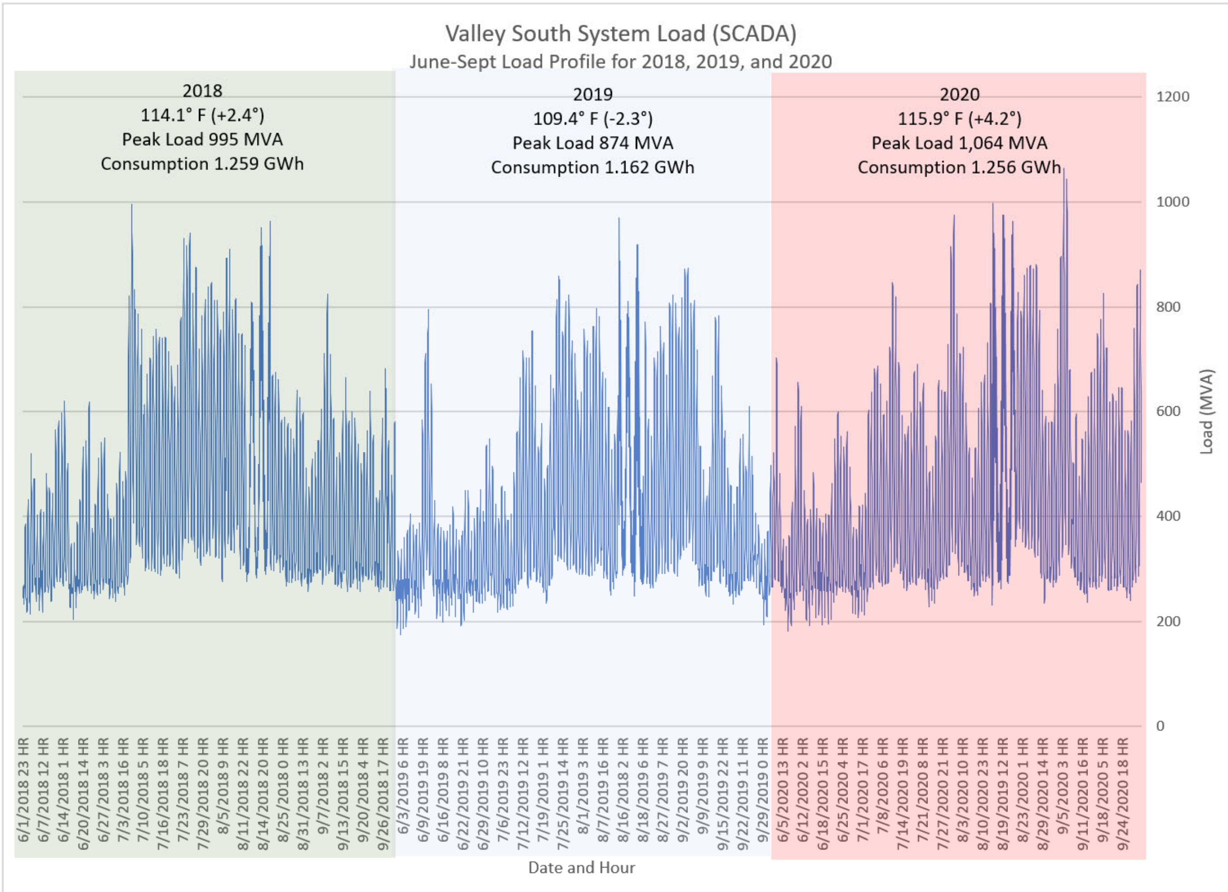
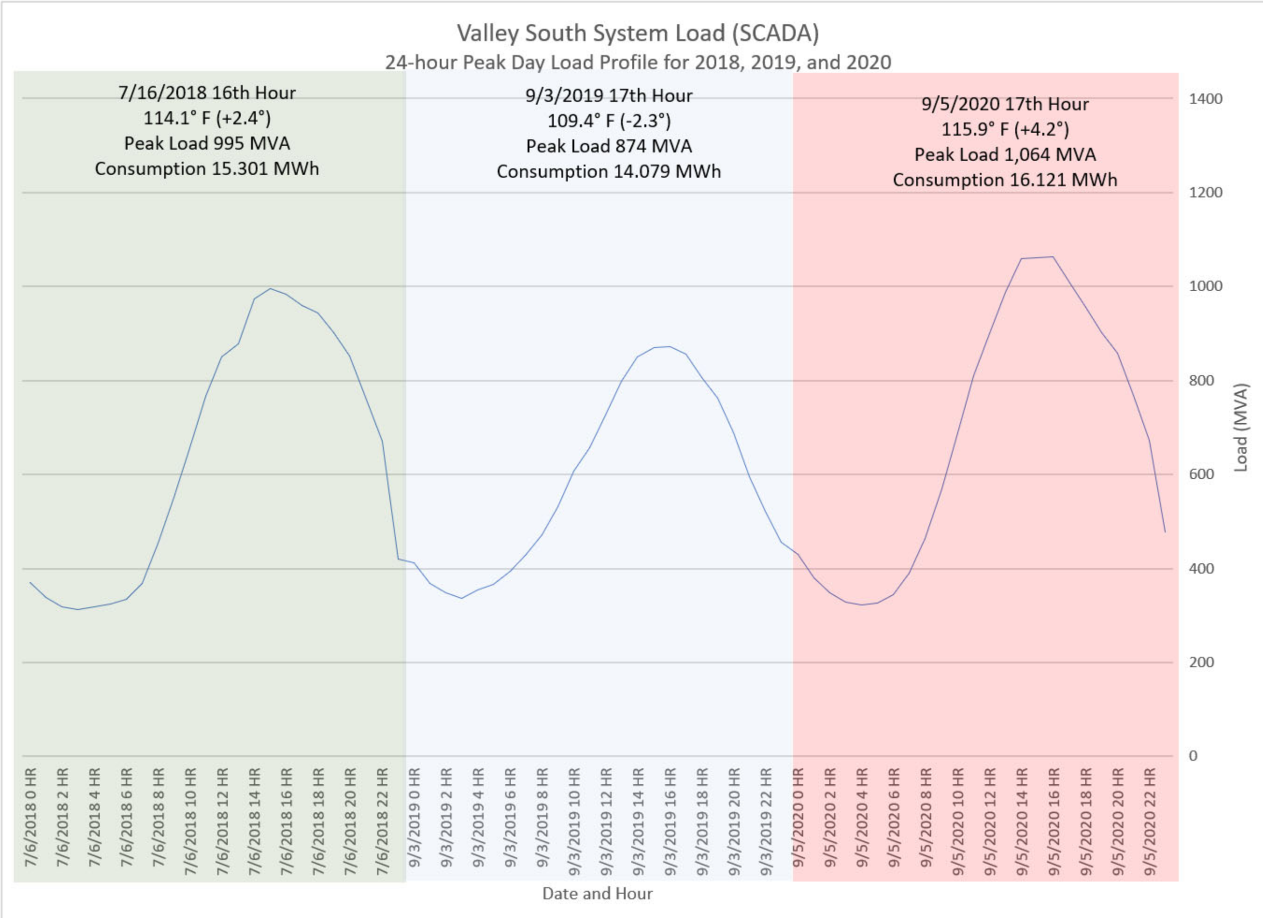

Valley South System Load (SCADA)
June-Sept Load Profile for 2018, 2019, and 2020
2018
114.1° F (+2.4°)
Peak Load 995 MVA
Consumption 1.259 GWh
2019
109.4° F (-2.3°)
Peak Load 874 MVA
Consumption 1.162 GWh
2020
115.9° F (+4.2°)
Peak Load 1,064 MVA
Consumption 1.256 GWh
1200
1000
800
600
400
200
0
Load (MVA)
6/1/2018 23 HR
6/7/2018 12 HR
6/14/2018 1 HR
6/20/2018 14 HR
6/27/2018 3 HR
7/3/2018 16 HR
7/10/2018 5 HR
7/16/2018 18 HR
7/23/2018 7 HR
7/29/2018 20 HR
8/5/2018 9 HR
8/11/2018 22 HR
8/14/2018 20 HR
8/25/2018 0 HR
8/31/2018 13 HR
9/7/2018 2 HR
9/13/2018 15 HR
9/20/2018 4 HR
9/26/2018 17 HR
6/3/2019 6 HR
6/9/2019 19 HR
6/16/2019 8 HR
6/22/2019 21 HR
6/29/2019 10 HR
7/6/2019 23 HR
7/12/2019 12 HR
7/19/2019 1 HR
7/25/2019 14 HR
8/1/2019 3 HR
8/7/2019 16 HR
8/16/2018 2 HR
8/18/2019 6 HR
8/27/2019 7 HR
9/2/2019 20 HR
9/9/2019 9 HR
9/15/2019 22 HR
9/22/2019 11 HR
9/29/2019 0 HR
6/5/2020 13 HR
6/12/2020 2 HR
6/18/2020 15 HR
6/25/2020 4 HR
7/1/2020 17 HR
7/8/2020 6 HR
7/14/2020 19 HR
7/21/2020 8 HR
7/27/2020 21 HR
8/3/2020 10 HR
8/10/2020 23 HR
8/19/2019 12 HR
8/23/2020 1 HR
8/29/2020 14 HR
9/5/2020 3 HR
9/11/2020 16 HR
9/18/2020 5 HR
9/24/2020 18 HR
Date and Hour

Figure 3



Many factors impact loading levels both in demand (kW) and in energy consumption (kWh). Examples include weather, economic conditions, customer behavior, and public and regulatory policy. SCE recognizes that the impacts of COVID-19 shifted how customers consumed electricity during 2020 resulting in an increased consumption by residential customers and a reduction in commercial/industrial customers; however, demonstrating these results via an analysis of AMI data is unnecessary for the planning activities associated with transmission substation transformer capacity (i.e., that which is associate with the Alberhill System Project). The overall impact can be assessed using higher system level SCADA such as in the examples provided in Figures 1, 2, and 3.

In 2020, the Valley South System peaked at its all-time highest loading value and highest energy consumption for a single year (surpassing 2018). However, SCE notes that 2020 was also a higher-than-normal peak temperature year and several degrees higher than 2018. In Figure 1 the recorded peak demand clearly appears in line with expectations given the temperature. In fact, preliminary analysis of SCE's forecast show that for 2020 the weather-adjusted peak value (reflecting the downward adjustment of the recorded peak to reflect what would be expected during a normal 1-in-2 year value) was within 1% of the projected value from SCE's last 10-year forecast (produced without the knowledge of the impending pandemic). Additionally, in Figure 1, the energy consumption for all of 2020 was 3% higher than the average of the three years but SCE notes that the temperature was also 2.4% higher than the average of the three years. Figure 2 provides data focused on just the summer months and the performing the same comparison of energy consumption during 2020 yields an increase of 2.4% higher than the average of the three years (for the summer months) and this also correlates well with the higher-than-average temperature recorded in 2020 (2.4% higher than the average of the three years). Figure 3 provides data focused on the single highest peak day of each of the three years. Commonalities can be observed including the load shape, peak time, off-peak minimum loading, and energy consumption relative to temperature.

None of these observations when viewed (independently or collectively) to evaluate the impacts of COVID-19, offer any support of any obvious COVID-19 impacts or offer any support that suggests use of AMI data is superior to the use of SCADA.

The above three examples are specific to the Valley South System electrical needs area for the Alberhill System Project. They may not represent all other areas within SCE's service territory; however, SCE reiterates that it is important to remain focused on local area data and trends due to the radial system design of its electrical system. SCE concludes that for the Valley South System, loading values (both peak demand and energy consumption) recorded in 2020 were consistent with what would be expected given the temperature, do not demonstrate unusual deviations from historical values, and therefore COVID-19 impacts do not appear to be significant and do not warrant an additional time-consuming analysis of AMI data.

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
Received Date: 3/17/2021

Response Date: 4/1/2021

Question DG-MISC-69:
Provide data and associated analysis to identify whether 2020 peak system loading values or load profiles are consistent with or deviate from historic levels. Additionally, include specific data related to the August 14-19, 2021 stage 3 emergency event. Explain how an analysis performed at the individual customer meter level might impact this conclusion.

Response to Question DG-MISC-69:

Please see SCE's response to Question DG-MISC-68 of this data request set for information related to 2020 loading values versus that of historic values.

As it relates to the August 14-19th stage 3 emergency event, SCE does not believe a time consuming and data intensive analysis performed using data at the individual customer-meter level for the Valley South System would yield insights that would be more meaningful than evaluating readily available SCADA data. SCE's radial system design delivers power from the transmission system via a single point of interconnection and the data inherently already represents the aggregate customer meter data and does so in a coincident manner. In fact, and as mentioned in SCE's response to Question DG-MISC-68 of this data request set, evaluating AMI data across hundreds of thousands of customers and attempting to derive a coincident peak loading value (including accounting for data capture errors or estimates, for customers that have opted out of the smart meter program, and for system losses from power delivery) for the Valley South System is likely to introduce errors and inaccuracies. For instance, AMI data is recorded at predetermined intervals of time depending on the customer type/size. This data is collected per the prescribed process; however, it does not mean than at any given moment in time, every meter is recording a value at just that moment. It is necessary to have an aggregate coincident value for planning purposes. In contrast, measuring SCADA data at any given moment in time does just that, it provides the aggregate coincident loading value for all customers served by that electrical facility for any given time.

Additionally, during the August 14-19th event, while loading levels in the Valley South System did attain levels which necessitated the use of the overload mitigation plan (use of the spare transformer for load levels above 900 MVA), this activity was not considered unusual for summer peak conditions (as evidenced by the use of the mitigation over the past several years) and given the higher-than-normal temperatures; however, during the August 14-19th period, there were no system conditions specific to the Valley South System that warranted load shedding. The load shedding that occurred on August 14th and 15th was strictly associated with the statewide resource deficiency in generation resources and not correlated to any specific overloading condition within the Valley South System. This observation is easily made by review of SCADA data at the transmission substation transformer level at Valley Substation and a review from the bottom-up using AMI data would not alter this conclusion.

Southern California Edison
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DATA REQUEST SET CPUC-Supplemental Data Request-009

To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
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Question DG-MISC-70:
Because there will not be a project in place by 2021 summer peak season, what is SCE's plan to address summer peak loading conditions?

Response to Question DG-MISC-70:

For 2021, SCE plans to continue to rely on implementing the mitigation plan (placing the spare transformer in service as a third transformer serving the Valley South System) currently in place for high-loading conditions for the Valley South System while awaiting a CPUC decision on a comprehensive and long-term solution to provide capacity and address deficiencies in both reliability and resiliency. SCE notes that the mitigation plan, while effective in the short-term in addressing capacity shortages, is not a proper long-term solution (does not address the reliability and resiliency needs of the area) and comes with risk. As loading continues to increase before a long-term solution is in place, use of the mitigation plan and the risk associated with relying on the spare transformer more often will continue to increase. The risk results from an increased reliance on the spare transformer to function as overload mitigation which removes it from being immediately available to serve in its primary function of replacing an out-of-service transformer on either the Valley North or Valley South System. Similarly, if the spare transformer is already being used to replace an out-of-service transformer, it would not be available for use as overload mitigation.

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
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Response Date: 4/1/2021

Question DG-MISC-71:
Explain SCE's approach to the DER sensitivity analysis performed, specifically the sizing and placements of DER. At which load levels or DER levels do the DER scenarios become ineffective and rank poorly relative to the other alternatives?

Response to Question DG-MISC-71:

In SCE's analysis, battery energy storage systems (BESS) were used as a surrogate for other distributed energy resources (DERs) primarily because solar power is ineffective in providing capacity late in the day when the Valley South System experiences peak loading conditions, and there does not currently appear to be a path to implement other DER technologies at a scale that would meet the Valley South System capacity needs. The BESS alternatives were sized to mitigate N-0 transformer overloads, resulting in larger BESS installations for the higher load forecast (Spatial Base) and smaller BESSs for the lower load forecast (PV Watts) load forecast. SCE did not, in any of the cases studied, provide more or less DERs than would be required to meet the capacity need.

SCE has performed a load forecast sensitivity analysis in which the size of BESS facilities was varied as required to meet the capacity need, and the results are documented in Section 8.3 of Appendix C of SCE's Amended Motion to Supplement the Record, dated February 1, 2021. Neither load forecast sensitivity case resulted in the DER-alternatives having significantly different rankings relative to the other alternatives and to the base load forecast. In the lower load forecast, the DER-based alternatives ranked slightly higher (with some alternatives moving up a few rankings relative to the baseline load forecast) and in the higher load forecast, the DER-based alternatives performed slightly worse (with some alternatives moving down a few rankings relative to the baseline load forecast). In the baseline and low load forecast analysis, four of the six DER-based alternatives ranked 8th overall or lower. In the high load forecast analysis, all six DER-based alternatives ranked 7th overall or lower.

SCE has not performed a sensitivity analysis in which placement (i.e., location) of the DERs was varied. For the distributed BESS alternatives siting was largely driven by the available space at existing SCE distribution substations because it is expected that siting facilities in this manner would result in a solution that could be timely implemented with the least environmental impact and lowest costs. For the Centralized BESS alternatives, the BESS location was optimized from a system perspective by locating it in an area of the electrical system that resulted in the best performance improvements on power flow values on the subtransmission lines, reduction in power flow losses, maintaining adequate voltage levels, and performance during analysis of contingency conditions. However, the locational sensitivity of benefits is limited because a capacity need can be met from anywhere in the Valley South System (because all power to the Valley South System flows through the transformers at Valley Substation) and the reliability/resiliency benefits of DER solutions for subtransmission level events are inherently limited as compared to those that can be attained by conventional solutions (substations and wires).

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To: CPUC
Prepared by: Paul Mccabe
Job Title: Senior Advisor
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Question DG-MISC-72:
Provide SCE's assumptions about how long COVID-19 induced demand changes are estimated to persist and describe how, if at all, these changes are being incorporated into transmission and distribution planning efforts.

Response to Question DG-MISC-72:

SCE's 2021-2030 forecast will continue to be compliant with the requirement to use the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR). The CEC has incorporated limited COVID-19 impacts in its most current IEPR. SCE's forthcoming transmission and distribution forecasts will reflect the COVID-19 impacts embedded in the IEPR forecast.

SCE is still evaluating the near-term and long-term impacts of COVID-19 on loading values across its system. A review of a sampling of distribution circuits representing predominantly residential and commercial/industrial customer compositions respectively, presented examples where an increase in residential load and corresponding decrease in commercial and industrial load was observed. However, it was also observed that given several similar circuits (those with similar load compositions), the changes in loading between classifications showed inconsistencies thereby making it difficult to confidently make broad conclusions as to the impacts of COVID-19. However, as noted in SCE's response to Question DG-MISC-69 of this data request set, it is not necessary to review each distribution circuit to determine impacts because at the higher levels of the system, use of the total aggregate loading (represented by SCADA data) inherently incorporates the impacts across all the distribution facilities together. This is the appropriate approach in evaluating the capacity need in the Valley South System. SCE continues to evaluate cases across its entire distribution system where initial reviews show potential new system needs attributed to *increases* in demand associated with the COVID-19 impacts described above. Likewise, SCE continues to evaluate distribution system level cases where initial reviews appear to indicate the elimination of, or a significant deferral of, an existing system need attributed to *decreases* in demand associated with the COVID-19 impacts described above. The goal of these reviews is to ensure SCE takes a measured approach in response to the impacts of COVID-19 (i.e., avoidance of both unnecessarily initiating new projects and unnecessarily cancelling existing projects).

In response to what SCE's expectation of the how long the impacts of COVID-19 may persist, as mentioned above, SCE will continue to rely on the annual IEPR forecasts to incorporate the CEC's expectation of how long, and to what degree, the impacts of COVID-19 will persist.

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DATA REQUEST SET CPUC-Supplemental Data Request-009

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Response Date: 4/1/2021

Question DG-MISC-73:
Quantify any estimates of how load changes associated with COVID-19 may have contributed to the August 2020 rolling blackouts and the use of the spare transformer in the Alberhill System.

Response to Question DG-MISC-73:

The August 2020 stage 3 emergency conditions were a result of statewide generation resource issues during statewide high-temperature conditions. Load shedding was initiated by the CAISO and each participating electrical utility was directed to reduce loading by a prescribed amount for a prescribed time. SCE participated in the load reductions and made the determination of how, where, and for how long load shedding would occur within its service territory. The Valley South System contributed to the overall SCE load reduction amount; however, this was only in response to the statewide issue and was completely unrelated to the use of the spare transformer as overload mitigation. It is unclear whether the COVID-19 pandemic contributed to the cause of the August 2020 rolling blackouts; however, the CAISO published a report on the final root cause analysis of the mid-August 2020 extreme heat wave.[1] In the executive summary (page 1), the CAISO identified at least three factors that contributed to the emergency:

1. *The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.*

2. *In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.*

3. *Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.*

The CAISO makes several mentions of the potential impacts due to COVID-19, but concludes that "that while load was lower in the spring months, during July, as air conditioning use increased, the

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[1] Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

CAISO observed minimal to no load reductions compared to pre-COVID-19 conditions."[2]

Among these three root causes, the only one relevant to solutions for Valley South System issues is the conclusion that "r*esource planning targets have not kept pace to lead to sufficient resources that can be relied upon to meet demand in the early evening hours."* This conclusion has direct relevance to the Valley South System specifically in consideration of the assumed DER load-reduction contribution (from the CEC's IEPR forecasts) and in the consideration of the expected impact of DERs in any comprehensive solution that has a non-wires alternative element.

[2] *Id.* at 21.

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Question DG-MISC-74:
Did the weather events or load, other than the time the August 2020 blackouts were occurring, fall into the level of a 1 in 10-year heat storm? If the weather event or load did not fall into the level of a 1 in 10-year heat storm, did it exceed the 1 in 10-year heat storm level or was it below the 1 in 10-year heat storm level?

Response to Question DG-MISC-74:

For the Valley South System, 2020 was considered a 1-in-5 year heat storm year and did not represent a 1-in-10 year heat storm year. Peak loading values for the Valley South System correlated very closely to what was projected (from SCE's last 10-year forecast covering the years 2020-2029) should a 1-in-5 year heat storm occur. The 2020 peak loading values did not rise to the levels that would be expected had a 1-in-10 year heat storm occurred. These conditions occurred during the first week of September, peaking on September 5th. SCE defines a 1-in-5 year heat storm as having a peak effective temperature that exceeds the average peak effective temperature by 4 °F. The average peak effective temperature for the Valley South System is 111.7 °F and the peak effective temperature on September 5, 2020 was 115.9 °F (or 4.2 °F higher than normal). SCE defines a 1-in-10 year heat storm as having a peak effective temperature that exceeds the average peak effective temperature by 6 °F.

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Response Date: 4/2/2021

Question DG-MISC-75:
Is the "Valley South to Valley North to Vista and Distributed BESS in Valley South" alternative discussed in Exhibit I-1 the same alternative as the "Valley South to Valley North to Vista and CENTRALIZED BESS in Valley South" discussed in the Planning Study (Exhibit C-2) (i.e., distributed is a typo)? If not, provide clarification on where a description of the "Valley South to Valley North to Vista and Distributed BESS in Valley South" alternative can be found in the supplemental data filings.

Response to Question DG-MISC-75:

This is a typographical error, as there is no "Valley South to Valley North to Vista and Distributed BESS in Valley South" alternative. The text on page 5 of Exhibit I-1 should read "When excluding those alternatives that do not meet project objectives, the total of 13 alternatives is reduced to six and among those six, the ASP ranks first. Of the 13 total alternatives, the three higher ranked alternatives (Menifee, Valley South to Valley North, and Valley South to Valley North and Distributed BESS in Valley South) do not meet project objectives...".