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Southern California Edison Response to Stakeholder Questions in CEC Multi-Year Reliability Presentation

Additional submitted attachment is included below.

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July 23, 2021

California Energy Commission
Docket Office, MS-4
Re: Docket No. 19-SB-100
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.ca.gov

Re: Southern California Edison Company's Comments on the California Energy Commission Integrated Energy Policy Report (IEPR) Workshop

Dear Commissioners:

On July 8, 2021, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California Independent System Operator (CAISO) (Joint Agencies) conducted the *IEPR Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability* (Workshop). SCE appreciates the efforts of the California Energy Commission (CEC) in undertaking this critical multi-year reliability assessment and the opportunity to provide feedback on the inputs and assumptions. SCE agrees with the CEC's approach to use a Loss of Load Expectation (LOLE) study to determine whether additional capacity, beyond that ordered by the California Public Utilities Commission in D.21-06-035, is needed to maintain mid-term system reliability. While the CEC's methodology of "adding incremental [net qualifying capacity (NQC)] resources until the LOLE is at or below 0.1" using pre-determined resource builds is useful for assessing the contributions to reliability of different types of resources (*i.e.,* gas compared to preferred resources), it is important to note that this approach does not consider the cost of the incremental resources or validate the operability and GHG compliance of the portfolio. As such, this analysis should not be directly used to justify additional resource procurement. Instead, any procurement orders for system reliability resources should be supported by an iterative analysis using a capacity expansion model that identifies the optimal and least cost portfolio and meets GHG requirements. For reference, SCE has included a summary of the iterative analysis completed as a part of SCE's 2020 Integrated Resource Plan (IRP) at the end of its Response. While this reliability assessment can help inform agencies and stakeholders about the overall reliability of procurement authorized through D.21-06-035, SCE urges the CEC and CPUC to undertake this more comprehensive analysis before ordering any additional reliability-based procurement. Additionally, while there may be interest in assessing the relative reliability benefits of natural gas generation and GHG-free resources, it is also clear that California's decarbonization ambitions signal that it is unlikely that significant new natural gas generation capacity will be added to the California grid. As such, the value of extensive reliability comparisons related to gas *additions* likely has limited value to the state's resource planning efforts. Instead, it is more valuable to assess the system and local reliability impacts of *less* natural gas generation scenarios as gas retires from the system. Again, SCE appreciates that the CEC and CPUC are collaborating on system reliability studies, however, it is important to also ensure that these studies analyze the most pressing and important issues that the system faces.

SCE provides the following responses to the CEC's questions on Resource Build, Imports, Wind/Solar/Hydro, and Forced Outages assumptions. SCE also offers input on the demand forecast assumptions described in the CEC's July 8, 2021 presentation.

Response to Stakeholder Questions

Resource Build (Slide 20)

The following responds to the CEC's questions on the "planned resource build" associated with the "outstanding procurement orders," namely the procurement ordered in D.21-06-035. While the assumptions listed below (once corrected to use updated ELCC values for hybrid resources) are reasonable for simply modeling the forecast installed capacity resulting from D.21-06-035, they likely are not appropriate for other purposes, such as developing the Preferred Resources Portfolio and Preferred Resources + Gas portfolio for the "scenario studies" described on Slide 4. To make a meaningful comparison of resource contributions to reliability, SCE encourages the CEC to engage with stakeholders to construct portfolios using a true "equivalent" to comparable alternative portfolios.[1]

What resource mix should be used when adding capacity to meet the ordered procurement from all outstanding procurement orders?

	Net Qualifying Capacity					Installed Capacity				
Resource	2023	2024	2025	2026	Total	2023	2024	2025	2026	Total
Hybrid (Solar + 4h Storage)	850	3,150	1,500	-	5,500					
Hybrid Solar						850	4,646	2,568	-	8,065
Hybrid Energy Storage						850	4,646	2,568	-	8,065
Hybrid (Wind + 4h Storage)	150	350	-	-	500					
Hybrid Wind						150	516	-	-	666
Hybrid Energy Storage						150	516	-	-	666
Geothermal	-	-	-	1,000	1,000	-	-	-	1,124	1,124
8h Storage	-	-	-	1,000	1,000	-	-	-	1,000	1,000
4h Storage	1,000	2,500	-	-	3,500	1,000	3,687	-	-	4,687
Total	2,000	6,000	1,500	2,000	11,500	3,000	14,012	5,137	2,124	24,272

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[1] Specifically, SCE continues to have significant concerns with the ELCC values for standalone solar and standalone wind and believes they overstate the contribution of those resources to system reliability during critical hours. For example, SCE has found that the contribution of solar to the 2024 managed net peak load is 0.7% while the ELCC Surface methodology estimates its contribution to be 10.3%. This analysis is consistent with the Final Root Cause Analysis finding that "[t]he CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour." As such, it is critical that the construction of the scenario portfolios ***not*** utilize marginal ELCC for solar and wind as those values do not represent their reliability contribution relative to gas capacity.

The table above is the "planned resource build" included in Slide 11 of the CEC's presentation. SCE believes that the resource mix assumed to meet the 11,500 MW MTR procurement order presented on Slide 11 is reasonable. Further, SCE agrees with CEC's assumption that no stand-alone solar will or should be procured to meet the MTR requirement because of its low contribution to reliability.[2]

CPUC decision (D.)21-06-035 specifies compliance with the mid-term reliability procurement order will be measured using marginal effective load carrying capability (ELCC) values. Despite SCE's concerns with the use of ELCC on developing the NQC of solar,[3] SCE supports the CEC's approach of converting the ordered NQC volume to installed capacity using marginal ELCC. However, the specific procedure the CEC used to produce the installed capacity numbers seems to translate to nameplate capacities that are too high implying the ELCC values for storage and hybrid resources are too low. For example, the total installed capacity of 4-hour storage in Slide 11 is 13,418 MW (along with 8,731 MW of wind and solar) to meet a 9,500 MW NQC procurement target. Even if the ELCC values used for wind and solar are 0%, this results in an implied average capacity value of 71% for 4-hour batteries. Given the volume and mix of capacity additions, the implied capacity value of batteries is much lower than any studies of which SCE is aware. The implication of this is that significantly more hybrid nameplate capacity will be added in the production cost modeling process than should be given the NQC value of the resources, which would artificially lower the LOLE results. Not knowing the exact procedure used to produce the numbers, SCE recommends the CEC reassess the ELCC application procedure used for the NQC to nameplate conversions.

For hybrid resources, what should be the ratio of energy storage and generation capacity? Should this be different for wind, solar, etc.?

For purposes of the current study, the assumption of 1-to-1 wind and solar resource to 4h battery storage is acceptable and consistent with industry trends.

Is it reasonable to expect significant capacity will come online prior to the required dates?

While it is expected that resources would become operational before the required dates, SCE does not recommend making any such assumptions for these modeling purposes. In other words, SCE recommends that capacity should be assumed to come online on or around the required date.

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[2] In its July 8, 2021 Joint Agency workshop presentation, the CEC correctly demonstrates the diminishing value of resources using marginal ELCC values for solar. Using the value of 2% ELCC for solar in 2026, CEC's example shows that with 1000 MW of NQC solar included in the model during critical hours you end up with about 50,000 MW of installed solar capacity, which just doesn't seem to be a feasible quantity to install in the in the next five years. [July 8, 2021 CEC Joint Agency Workshop] @ 01:56

[3] Specifically, Ordering Paragraph 15 of D.21-06-035 explains that "Commission staff shall publish on our website marginal [ELCC] values to be used for the 2023 and 2024 compliance dates in the decision by no later than August 31, 2021 and for the 2025 and 2026 compliance dates by no later than December 31, 2022.

Imports (Slide 17)

Import assumption is critical to the system reliability study. SCE agrees with CEC's approach to set the maximum available import based on the average of historic RA showings during the summer months. SCE recommends historic RA showings for August HE17 to HE22 be used, as August best represents summer conditions across the WECC.[4]

> How should imports be included in the analysis? Options include historic RA showings, historic economic imports, at what level (min, max, mean, median), something else.
>
> The import limit for July-September 5-10 p.m. in CPUC's SERVM model is 5,000 MW plus intermountain, Hoover, and Palo Verde. This results in import capability of around 7,000 MW. SCE recommends CEC implement a similar maximum import constraint during evening peak load hours in Summer months. This import constraint reflects the tight market condition to bring import from outside CAISO to serve its load.
>
> Should uncertainty related to imports be incorporated into the model? If so, how?
>
> Given the limited study time, SCE recommends that uncertainty be incorporated by using different percentile of RA showings to derive different scenarios. For example, the 50th percentile numbers represent the expected and normal operating conditions. The 25th percentile numbers represent the more constrained conditions.

Wind, Solar, Hydro (Slide 18)

SCE recommends that the CEC develop stochastic demand, solar, and wind profiles using historical weather data to account for uncertainties. In the past, SCE has used 1998-2017 20-years of weather data found in the CPUC's SERVM model in its reliability study. The solar and wind profiles based on historical weather year conditions represent the variation of solar and wind production during different weather conditions, which can then be used to identify average, upside risk, and downside risk distributions and develop renewable shapes.

> Should solar and wind weather years be linked to each other or demand?
>
> SCE believes that solar, wind and demand profiles should all linked to the weather year conditions. For example, 20 historical weather year (1998 – 2017) demand, solar and wind profiles have been developed in CPUC's SERVM model. Those profiles are linked or correlated to each other in nature by weather year. In addition, correlated solar, wind and demand shapes can reduce the total number of stochastic variables and ultimately reduce the computation complexity.

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[4] Temperatures and demand in most WECC areas outside of California tend to decrease in September. As such, imports should be modeled based on August availability, as August captures the impact of summer conditions throughout the western region.

Should historic profiles or artificially generated solar and wind shapes be used?

As described above, SCE recommends that the shapes be "artificially generated" using distributions that are informed by historic profiles.

How should hydroelectric generation be modeled? Options include monthly NQC value, with no restrictions on generation up to that capacity; historic average fixed shape; distribution of historic profiles to account for uncertainty, and if so, should these profiles be linked to wind and solar weather years?

SCE recommends that the CEC model large hydro as energy-constrained resources while considering the different hydro conditions, such as dry or wet hydrological conditions. Historical information can be used to derive characteristics such as daily energy limit, Pmin, and Pmax to use in the hydro modeling. The Pmax determines the maximum capacity that hydro can contribute to the system reliability during the critical hours, thus it should be aligned with the actual market operations. It is not necessary to link the hydro characteristics to wind and solar weather years. As long as different hydrological conditions are incorporated in the modeling, the uncertainty on hydro generation operating should be captured in the stochastic production cost simulation.

Forced Outages (Slide 19)

SCE recommends that the CEC develop outage patterns for each individual gas generator based on the historical information, such as NERC's historical outage rate. SCE does not recommend the CEC aggregating by type or using an "estimated standard unit size," because size and generator type are key factors that impact the Outage Rate and Mean Time to Repair (MTTR).

Should forced outages be applied to other technology types? For example, forced outages are incorporated into profile shapes for wind and solar.

SCE mainly considers the gas generator outages in its reliability study. SCE recommends that the CEC reflect hydro generator outages by applying a simple de-rating of its nameplate capacity based on historical outages. Hydro NQC can be used as a proxy to determine the maximum capacity of hydro resource after considering the derating of capacity due to outages.

The CEC should implicitly consider the forced outages for wind and solar in the wind and solar profiles that it creates based on the historical information. SCE does not recommend applying forced outages to any other technology types for implementation simplicity.

Should more granular technology types be used?

As described above, SCE recommends that the CEC develop outage patterns for each individual gas generator. However, if the CEC believes they should be aggregated by technology type, SCE recommends the following categories: Combined Cycle Generating Turbine, Cogeneration, Peaker, Reciprocating, and Steam Turbines.

What forced outage rates should be used for each technology?

SCE recommends that the CEC use the actual forced outage rates for CAISO reported in the NERC Generating Availability Data System (GADS) to determine the forced outage rates. SCE has not included specific rates because that data is confidential.

What average outage duration should be used?

SCE recommends that outage duration rates reported in the NERC GADS be used to determine the outage duration. The outage duration varies based on the size and type of generator.

Other comments on Technical Slides/Methodology

Demand Forecast

The CEC described in its July 8 presentation that the raw demand was escalated by 6% to account for operating reserves. It should be noted that escalating demand by 6% for each hour is equivalent to increasing energy requirement by 6% for each hour, which is more stringent than including a 6% reserve requirement. Energy limited resources such as hydro, pumped and battery storage can provide ancillary services to the system but might not have enough energy to satisfy the additional energy need with escalated load. As such, the proposed escalation of load might result in more unserved load and capacity shortage than expected. SCE recommends the CEC analysis transition to co-optimization of energy and ancillary services requirements within the production cost simulation.

SCE thanks the Joint Agencies for consideration of the above comments. Please do not hesitate to contact me at (415) 929-5518 with any questions or concerns you may have. I am available to discuss these matters further at your convenience.

Very truly yours,

/s/

Dawn Anaiscourt

Appendix: Summary of SCE's Reliability Study Design as submitted in SCE's 2020 IRP

The intent of the reliability study included in SCE's 2020 IRP is to develop an optimized portfolio that meets California's goal of reducing economy-wide GHG emissions level in a reliable and cost effective manner, while also meeting other state goals[5] and operational requirements of the CAISO system. SCE utilized ABB CE capacity expansion modeling and PLEXOS production cost modeling (PCM) simulation software, based on the specific requirements of each process step, in creating, analyzing, and validating resource portfolios.

The following provides an overview of the process and modeling tools that SCE used:

1. Build the optimized (*i.e.,* least-cost) CAISO resource portfolio that satisfies the required constraints[6] using ABB CE capacity expansion modeling.
2. Perform PCM simulation production cost modeling to evaluate the portfolio's operational feasibility (*e.g.,* meet the load and associated ancillary services and ramping requirements in each hour, satisfy transmission limitations and individual generation constraints) and validate the GHG emissions. If there are any unserved load and violations of limitations, constraints, and targets, the updated requirements will be implemented to rerun the capacity expansion model to create a new system-wide resource portfolio.
3. Assess system reliability by the LOLE study using PLEXOS Monte Carlo simulations considering the uncertainties on load, wind, and solar generation, and gas generation outages. If the CAISO system-wide generation portfolio does not meet the 1-in-10 LOLE reliability standard, the PRM requirement will be increased to rerun the capacity expansion model and create a new system-wide resource portfolio.

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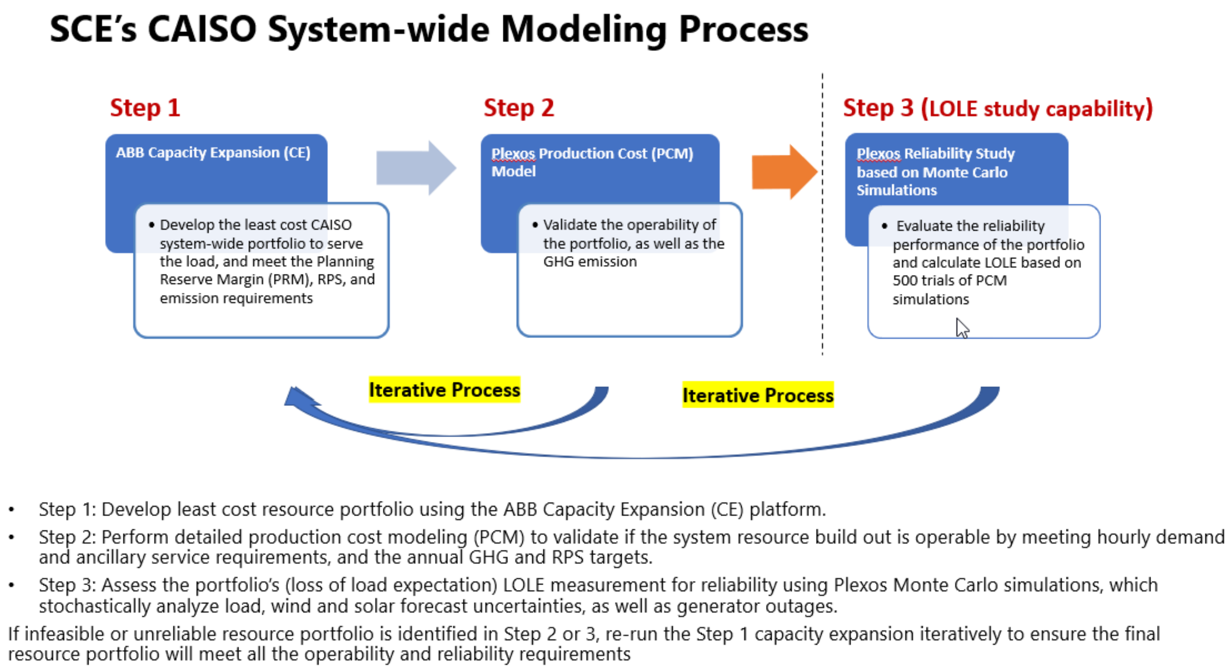
[5] *See* Cal. Pub. Util. Code §§ 454.51(a), 454.52(a)(1).

[6] Required constraints include meeting GHG targets and RPS requirements.



This iterative process of running ABB CE modeling and PLEXOS PCM simulations ensure that the least-cost resource portfolio built by ABB CE is both operable to meet the hourly demand, ancillary service requirements, and GHG target in the deterministic PCM simulations, but also reliable while meeting the 1-in-10 LOLE reliability standard in the 500 Monte Carlo PCM simulations.