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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.

Rulemaking 19-11-009
(Filed November 7, 2019)

LATE-FILED OPENING COMMENTS OF CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES ON RESOURCE ADEQUACY REVISED TRACK 3.B.1 PROPOSALS, SECOND REVISED TRACK 3.B.2 PROPOSALS AND TRACK 4 PROPOSALS

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For: CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES

Dated: March 15, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

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Center for Energy Efficiency and Renewable Technologies (CEERT) respectfully submits these Late-Filed Opening Comments on the Revised Track 3.B.1 Proposals, Second Revised Track 3.B.2 Proposals, and Track 4 Proposals submitted in this resource adequacy (RA) proceeding. The Revised Track 3.B.1 Proposals were submitted on January 28, 2021; the Second Revised Track 3.B.2 Proposals were submitted on February 26, 2021; and the Track 4 Proposals were submitted on January 28, 2021. These Proposals were submitted pursuant to the Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling, issued in this proceeding on December 11, 2020 (Amended Scoping Memo). These Opening Comments have been filed concurrently with a Motion to Accept Late-Filed Comments.

I.
CEERT'S REVISED TRACK 3.B.1 PROPOSAL

CEERT formally submits its revised Track 3.B.1 proposal to make minor modifications to recently adopted but not yet implemented qualifying capacity (QC) counting rules for hybrid resources. This proposal was workshopped on February 25, 2021. No changes have been made to that proposal. CEERT believes that this proposal is consistent with D.20-06-031 and could be implemented by the Energy Division in the normal course of events for next year's RA showings, and for use in, for example, the proposed integrated resources planning (IRP) Mid Term

Procurement without further Commission action. At worst, this proposal could be formally ratified in this year's annual RA Decision without further analysis or party discussion other than the normal Proposed Decision approval process. CEERT's February 25 workshop presentation material is included as Attachment 1.

The Proposal

In simple sentences, CEERT's proposal is:

A) For a DC coupled hybrid, use the DC rating of the solar array in megawatts (MW) and the DC rating of the battery bank in megawatt-hours (MWh) to conduct the "energy sufficiency" test as Energy Division has proposed in the November 23, 2020 RA workshop to implement D.20-06-031.[1] Then, the QC of the hybrid is the lesser of the AC rating of the shared inverter or the Point of Interconnection (POI) injection rights, adjusted, if necessary, by the energy sufficiency test.

B) For an AC coupled hybrid, the QC value is the portfolio marginal Effective Load Carrying Capability (ELCC) value, as calculated by Astrape Consulting for the Commission, which adopted a least cost/best fit algorithm in an SB 350 compliant setting on the California Independent System Operator (CAISO) grid in the Renewable Portfolio Standard (RPS) proceeding.[2]

Discussion

While the principles involved in CEERT's proposal are applicable to any "hybrid" resource that involves a storage component whether conventional utility scale simple hybrid,

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[1] Energy Division "Track 3.B Workshops: Day 2" presentation which can be found here: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Track%203B%20Day%202%20Presentation.pdf

[2] This study was entered into the RA record by ALJ Ruling on March 10, 2021 and is attached hereto as Attachment 2.

whether behind the meter or in front of the meter or both – including, e.g., adding an element of retail load management to a generation/storage hybrid, microgrids, "slow response" demand response (DR) hybridized with short duration storage to allow fast response from the portfolio, etc. – these "complex" hybrids have other issues that require further discussion and more complicated proposals in future RA proceedings.

All that is required for a resource to be designated a hybrid is to have one or more elements of the hybrid's portfolio from one or more technology classes that are brought together at a single POI with the grid to be bid and dispatched as a portfolio to the grid operator through software. While the grid operator may have visibility to individual elements of the portfolio, the operational interface is with the portfolio as a whole at the POI. Implementation details of this business practice in the CAISO Integrated Forward Market (IFM) have been workshopped, proposed and formally adopted by the CAISO in its Hybrid Resources Stakeholder Initiative Phase 1 and Phase 2.[3] CEERT also believes that minor variations to its proposal are complementary to any of the Second Revised Track 3.B.2 proposals discussed below. However, the details of how it might apply or be extended need to be discussed in Track 3.B.2 depending on which of those proposals are selected for further discussion. Therefore, at this time, CEERT believes its proposal should be used for only in front of the meter solar + storage hybrids and in front of the meter wind + storage hybrids.

Effect of CEERT Proposal

The impacts of CEERT's proposal on QC values for wind or solar + storage hybrids are relatively modest and will have a non- zero but minor impact on RA procurement quantities or RA supply plan showings as compared to the Energy Division proposed calculations pursuant to D.20-06-031. While the precise difference will vary depending on details of each hybrid's

[3] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Hybrid-resources

construction and dispatch, the season of the year, and the composition of other resources on the grid, the impact is always positive or neutral (i.e., the same or higher QC). Preliminary sample calculations for the reasonable upper limit for a very robust solar + storage hybrid (i.e., the highest potential QC value increase) are on the order of 10% for an annual RA value with a maximum of ~20% during June and a minimum of ~5% during December.[4]

As elaborated below, CEERT believes that these modest increases continue to understate the true capacity value of hybrid solar + storage resources but concedes that trying to squeeze the last small increment out of the process at this time is not productive considering the time constraints, the much broader RA reforms to be discussed in Track 3.B.2 and beyond, and the imperative to quickly shore up both the supply side and the demand side of California's RA fleet with near term procurement. However, the relatively modest potential revenue increases this proposal would grant to hybrid developers sends a powerful message to the market that the Commission recognizes the value of hybridization, is willing to provide incremental revenue to justify incremental expense to provide incremental grid services, and that this process is a win-win for both customers and developers. In addition to the modest increases in RA QC value, this signal will allow innovation and real-world experience with designing, building, and operating this emerging class of zero carbon, rapid response, flexible, dispatchable resources.

Further, the modest increase in QC value represented here is probably subsumed by larger benefits associated with, for example, transmission interconnection costs and better utilization of transmission infrastructure, less pressure on "duck curve" issues like ramp rates and curtailment, and risk mitigation for developers cognizant of the very real "regulatory risk" associated with an evolving RA program. All of these benefits are real and quantifiable but could

[4] *See* CEERT's Track 3B.1 Proposal submitted on January 28, 2021 in R.19-11-009 (RA).

be considered out of scope, at least in the short term, in the RA proceeding. CEERT intends to pursue these issues in the IRP proceeding where the metric is not simply QC for RA showing, but levelized cost of energy (LCOE) least cost/best fit for a portfolio of new resources. It will also be a topic in Track 3.B.2 in this proceeding. CEERT's focus here is simply on immediate adoption of its specific near-term proposal in Track 3.B.1.

AC Coupled and DC Coupled Hybrids

The reason why CEERT proposes different but related solutions for AC and DC coupled hybrids requires some elaboration. First, some discussion about the differences between AC coupled and DC coupled hybrids is in order. A DC coupled hybrid collects and controls the DC energy flows from the solar array and to/from the battery storage banks to the shared inverter(s) for conversion to AC and interconnection with the grid. These DC flows are metered for control purposes, but the meters are generally not "revenue quality" or shared with the grid operator for dispatch or settlement purposes.[5] Because this configuration is cheaper to construct and incurs lower DC:AC conversion losses than an AC coupled configuration, there is strong incentive to use this configuration for all new solar + storage hybrid projects.

These same incentives exist for wind + storage hybrids, but current technology and product offering practices for wind turbines favor AC conversion/smoothing at each individual turbine with the collection system to the POI being AC. As a result, it is much more common for wind + storage hybrids to be AC coupled. However, commercial technology exists to collect individual wind turbine output at DC and future wind + storage projects could be DC coupled if the theoretical advantages could be monetized. CEERT's proposal would allow this to happen organically. In the meanwhile, most new solar + storage hybrids will be DC coupled, most new

[5] However, it is current practice to share at least some data and forecasts about these flows with the grid operator for near term planning and market monitoring functions.

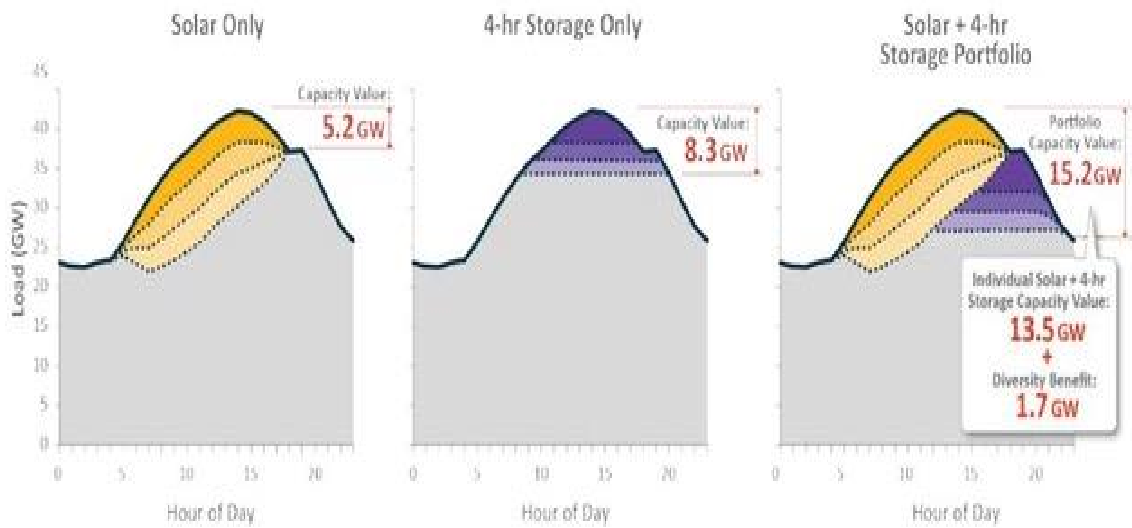
wind + storage and most "retrofits" where storage is added to an existing solar or wind site or solar or wind is added to an existing stand-alone storage site will be co-located or AC coupled. This innovative technology is on a steep learning curve and CEERT's proposal is to at least recognize the impact and allow the process to evolve.

Diversity Benefit of Solar or Wind Plus Storage

One other knotty issue at work here that needs to be brought into the discussion is the whole concept of the "diversity benefit" of RA portfolios that contain both solar and/or wind and storage. The object is not to debate or "resolve" this issue in this Track, but simply to explain why CEERT purposes different implementation of the QC counting methodology for DC coupled and AC coupled hybrids. The Energy Division discovered this concept a couple of RA cycles ago when it first started working on ELCC values for combinations of solar and storage. It noted preliminary ELCC results like 160% of nameplate and wondered whether this was some error in the methodology or something else. Energy Division correctly determined that it was a "portfolio effect" where the total does not simply equal the sum of the parts. This thread has largely been ignored in recent RA proceedings but has been taken up in the literature by modelers and consultants. One of the clearest and most useful explanations has come from E3 and is represented here as Figure 1 from a recent filing E3 made in a Duke Energy IRP case.[6] Figure 1 is excerpted from that filing.

[6] https://dms.psc.sc.gov/Attachments/Matter/dc2333d8-2938-4e1a-aaaa-85270b273568

Figure 1: Illustration of the Synergistic Effects of Solar and Storage



What is at work here is the same phenomenon that Energy Division observed earlier. Several researchers including E3 and the CPUC modeling consultant Astrape have explored this concept. This E3 publication and the Astrape Phase 2 Report are among many to discuss the implications of diversity benefit both for policy considerations and how to refine production cost modeling techniques to faithfully reproduce it. "Diversity benefit" is destined to become a hotter topic as storage and storage hybrids become more common on grids across the country. It is already evident in the emerging discussion about potential changes to storage QC values in future CPUC RA proceedings.

What Figure 1 represents is the well-known fact that higher penetrations of solar lowers the "gross peak" demand and push the "net peak" to a lower value later in the day and eventually to after sunset when marginal new solar has no impact on "net peak." While many parties leap to the conclusion that this means standalone solar marginal QC values are rapidly approaching zero, this is not necessarily true due to the portfolio effect of the "diversity benefit." As E3 shows in Figure 1, the energy from the new solar contributes to a further lowering of gross peak but not net peak that is controlling for RA purposes. However, if storage is present on the system, this incremental solar production on gross peak allows some of the stored energy in the battery to be held back during gross peak hours for later discharge to deal with net peak—thus a "diversity benefit" that cannot be attributed to either the solar or the storage individually but only to the combination of the two.

This phenomenon is not efficiently and transparently captured in most current production cost models – especially non-chronological ones like SERVM. However, CAISO's IFM platform with its sophisticated "look ahead" features does accurately capture the diversity benefit and, with a little special attention, dispatches the real CAISO bid stack system appropriately. Some additional tweaks to allow this feature to flow seamlessly into the day ahead unit commitment algorithms and especially the Residual Unit Commitment (RUC) piece of the IFM are underway. These changes are related more to weaknesses noted during last August stress hour events and systemic under scheduling of day ahead load that allowed clearing of export trades without sufficient resources to firm up those exports. While this work is only peripherally related to the "diversity benefit" and is too much information for this siloed RA proceeding, the bottom line is that the "diversity benefit" will be appropriately captured in the real-world security constrained dispatch without special attention.

However, it will NOT be captured in production cost modeling used to calculate RA ELCC values without concerted special effort. Astrape did the detailed modeling this using "dispatch heuristics" in its RPS related ELCC calculations. This background is included as an explanation of ongoing "research" as a justification for early action in this Track rather than specific "evidence" to support CEERT's proposal. We are now ready to turn to the specific reasons why CEERT chose the precise features to be considered at this time in this Track.

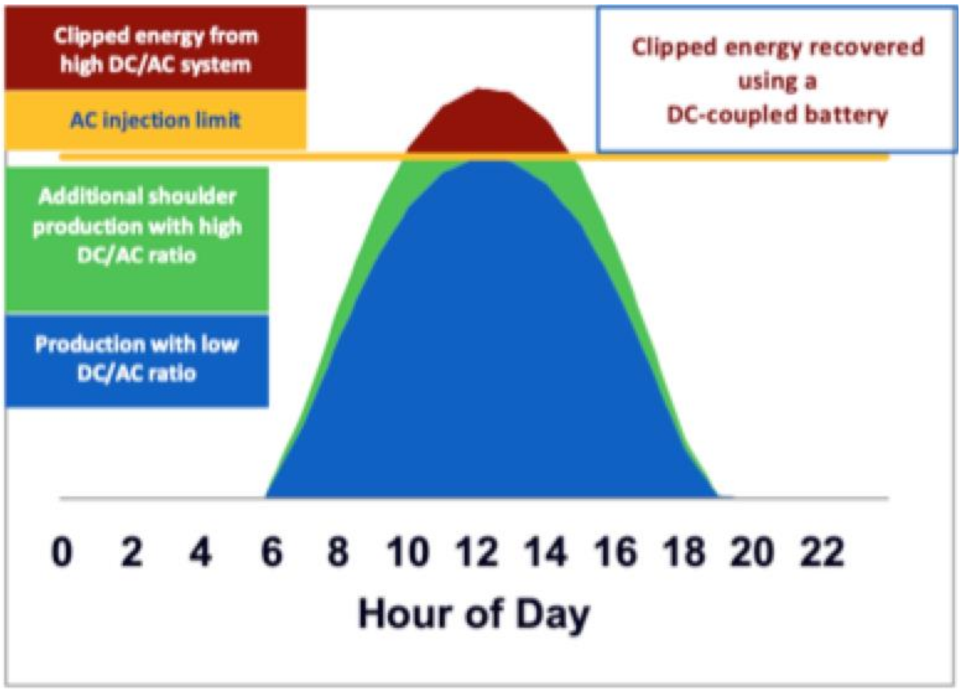
History in This Proceeding and Need for Early Action

CEERT has attempted in previous workshops and filings to introduce these concepts but in the rush to get a Proposed Decision out by June every year to allow the annual RA showing process to proceed and the press of larger issues with larger more conventional elements of the RA portfolio there has never been enough time or energy to publicly fully vet this emerging issue with resources that are not yet represented at scale on the grid. This simply must change NOW in light of the prospect of procuring gigawatt levels of hybrids that dominate the CAISO Interconnection queue and will be operated for the next 40 years.

We all must recognize the potential and the risk here and begin to learn by doing. This will not happen if we continue on a path of penalizing innovation with overly simplistic RA counting rules for hybrids, so they are either not designed and constructed with providing incremental grid services in mind, or not procured at all because these benefits are ignored in the procurement metric of least cost RA net qualifying capacity (NQC). As such, hybrids have trouble competing with existing gas for RA. This whole range of issues will become much more transparent and tractable as we move towards dealing with energy sufficiency in RA reforms in Track 3.B.2 and beyond.

For DC coupled hybrids, all of this diversity benefit "complication" is at least partially dealt with in the energy sufficiency test proposed by Energy Division. The big piece that is still left out in that process is the value of recovery of "clipped energy" in a high inverter ratio DC coupled hybrid. This particular feature has been talked about several times by CEERT and others in previous workshops and is at least generally understood and accepted by many parties. It is represented by Figure 2 below that has appeared in all of CEERT's previous filings on the subject plus several offline briefings of numerous parties including the Energy Division.

Figure 2. DC Coupled Hybrid Energy Production Considering Inverter Loading Ratio



What Figure 2 represents is the impact of "clipped energy" (red in Figure 2) and "incremental shoulder energy" (green in Figure 2) on total energy availability from a solar + storage DC coupled hybrid with high inverter loading ratio. Inverter loading ratio (DC rating of the solar array divided by the AC rating of the inverter) (ILR) is a common long-standing feature of solar project design stretching back almost 40 years to the early photovoltaic (PV) demonstration projects at Southern California Edison's (SCE's) Lugo substation, Pacific Gas and Electric's (PG&E's) Carrizo Plains projects, and Sacramento Municipal Utility District's (SMUD's) Rancho Seco installations all at the 1-3 MW scale during the 1980s. All of these projects were designed with an ILR of ~1.05-1.10 mainly to account for array losses.

Today because of market economics, technology evolution and cost trends where PV panel prices are a lower percentage of total project costs, most newer solar projects in the past few years are installed with an ILR of ~1.3 (the illustration in Figure 2 has an ILR of 1.3). The solar fleet on average is between 1.10 and 1.15 ILR (more like the blue in Figure 2). When the Energy Division uses historic production records to calculate the energy available to charge the hybrid batteries to implement the current RA QC methodology from D.20-06-031, the result is an implied ILR significantly below what the new solar project will utilize. Therefore, the calculation only captures the blue, underestimates the green and ignores completely the red energy. Thus, the new proposed Energy Division methodology systematically underestimates the energy available from a DC hybrid and yields a lower QC value. If this methodology is carried over into IRP procurement as currently proposed under a least cost/best fit LCOE metric, it will result in systematically underestimating not only RA QC, but the total value of a DC hybrid including contribution to greenhouse gas (GHG) emissions, contribution to mitigation of duck curve problems like ramping and curtailment, ability to provide ancillary services, etc.

All of these problems can be easily and seamlessly largely mitigated if the Energy Division were to use the same historic record as representing the DC rating of the solar fleet for its energy sufficiency test – thus capturing both the red and green energy as well as the blue energy on Figure 2. This simple "fix" is not perfect mainly because it does not capture the full "diversity benefit" or the tendency to locate new solar in higher insolation locations with new and clean solar panels not subjected to the slow output degradation incurred by the older solar fleet. Using the historic data as the DC rating in new ELCC-rooted QC calculations preserves, for now, the conservatism imbedded in current solar ELCC values, but recognizes the clear and substantial energy contribution available from high inverter ratio DC coupled hybrids.

CEERT believes that the advent of DC coupled hybrids capable of recovering the clipped energy with at least some incremental revenue available from slightly higher NQC values will lead to DC coupled hybrids being built to at least a 1.5 inverter loading ratio and potentially as high as 2.0. At this point, a new DC coupled hybrid would appear to the grid as a fully dispatchable, zero start time, no Pmin, fast ramping, 7x12 strip of energy from 10am until 10pm and the conversation about this resource having zero or near zero NQC value will be all but over. Making this simple, transparent, no regrets tweak now, consistent with D.20-06-031, will mean a small reduction in the conservatism built into RA NQC for solar but a huge difference in long term LCOE procurement value.

For AC coupled hybrids, the ability to capture the red clipped energy like a DC coupled hybrid is not available, period, nor is any of the diversity benefit captured by the simple addition of the QCs of the individual solar and battery components to arrive at the portfolio QC adjusted by the POI rights as currently practiced under D.20-06-031. However, Astrape has provided, with the RPS marginal ELCC value table reproduced below, an easy, transparent, fully vetted way to recognize much of this diversity benefit in a setting deliberately chosen to represent the 2030 grid using the same input parameters and modeling platforms as the CPUC IRP. All CEERT is proposing here to use this information already available to the CPUC and all parties to this proceeding and intended for use in future energy related procurements in this RA capacity related setting. CEERT believes this is consistent with D.20-06-031 and very important in the IRP Mid Term procurement resource selection process that proposes to use RA derived NQCs as part of its resource selection process.[7]

[7] *See, e.g.,* Slide 27 of March 10 IRP Workshop presentation which can be found here: https://www.cpuc.ca.gov/General.aspx?id=6442463413

TABLE 1. AC Hybrid QC Values for IRP RSP Grid Scenario[8]
% Of POI Injection Rights

	2022	**2030**
1-hr Tracking PV AC Hybrid	99%	93%
2-hr Tracking PV AC Hybrid	100%	100%
4-hr Tracking PV AC Hybrid	100%	100%
1-hr Wind Hybrid	90%	88%
2-hr Wind Hybrid	92%	90%
4-hr Wind Hybrid	96%	93%

The principal mechanism for capturing the diversity benefit of the AC hybrid in these calculations is to assign it to "short duration" storage. The diversity benefit allows 1- or 2-hour storage, which arguably has zero or at best 25-50% of nameplate QC standing alone, to provide nearly equivalent benefits in a hybrid configuration of much longer duration storage (at least in the modeling world – the real world will be much more transparent). This is why the narrow, targeted, transparent and easily implemented "fix" for AC coupled hybrids is important – both for near term RA showings and inclusion in the pending very large IRP procurement. If we completely ignore all of this, these valuable resources will not be able to compete in the 7 to 10 gigawatts (GW) of new procurement – a missed opportunity that will not present itself again for at least five years. CEERT's proposal offers a conservative but meaningful early step in a long and very consequential process.

Summary

CEERT urges adoption of its proposal in this RA Track and in this RA decision. The impact is very modest on RA NQC values for near term RA showings, is consistent with existing Commission practice, and retains a conservative approach to valuing solar or wind plus storage hybrids. At the same time, it will provide a significantly positive impact on, at least, resource selection in the upcoming very consequential IRP procurement. We need to keep in mind that

[8] Attachment 2, at pp. 3-4.

IRP stands for "integrated" planning. We need to integrate the latest thinking on RA counting rules into that plan.

II.
OTHER REVISED TRACK 3.B.1/4 PROPOSALS

CEERT believes the time to further discuss further variations or a change to Track 3.B.1 or Track 4 proposals is over. It is time, in this Opening and Reply Comment round, to decide what to do with them in context of a Proposed Decision. Accordingly, CEERT gives for each of the Track 3.B.1 and 4 proposals that were workshopped on February 25, its preference for potential inclusion in a Proposed Decision with a brief explanation of its reasoning. Any "open" proposals that were not workshopped on February 25 but surface in party Opening Comments will be the subject of CEERT's comments in Reply. The following comments are presented in the order they were presented at the February 25 workshop. The "grade" score is "Pass" if it is CEERT's recommendation that it should be included in the Proposed Decision without further substantive revisions or workshop level discussions. The "Fail" score recommends it be at least deferred as a discrete proposal in the Proposed Decision subject to new insights in this Opening/Reply Comment round.

RA Imports –CAISO

Grade: Pass

CEERT believes this proposal is well fleshed out and responsive to the issue of "speculative imports" without upsetting the critical history of trading practices in the Western Interconnection for a net importing state such as California. It has been vetted in a robust Stakeholder Initiative process at the CAISO including both importers and exporters (recognizing that most parties routinely switch sides at various times of day and seasons). CEERT recommends adoption in the Proposed Decision subject to final party comments and Commission decision.

Planning Reserve Margin –Cal PA

Grade: Fail

CEERT believes the issues and concepts presented here are thoughtful and deserving of further consideration, but believes the issue has been subsumed, for now, in all of the debate surrounding the Extreme Weather proposed procurements[9] and the proposed IRP Mid Term procurement[10] proceeding. Adopting this proposal in this year's RA decision will only insert confusion in how those procurements and their near-term results mesh with next year's RA showings. The issue does deserve more fulsome discussion in Track 3.B.2.

Availability Limited Resource Procurement – CAISO

Grade: Fail

Similar to the previous proposal, CEERT believes the issue has been subsumed in the current multiple track procurement rush. Whatever merit there is in this specific proposal is not warranted for inclusion in the pending PD at this time.

Locational ELCC – Southwestern Power Group (SWPG)

Grade: Pass

CEERT believes this proposal is well justified and fleshed out and can be easily and constructively implemented in the Proposed Decision without further revisions or party comments other than in Reply or in final comments following issuance of the Proposed Decision.

[9] Proposed Decision issued in R.20-11-003 (Extreme Weather) on March 5, 2021.
[10] Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements issued in R.20-05-003 (IRP) on February 22, 2021.

Maximum Cumulative Capacity (MCC) Buckets – Energy Division

Grade: Fail

CEERT has serious issues with this specific proposal and believes that the whole construct of MCC Buckets is destined for the waste bin considering its potential to constrain viable options in the current vigorous IRP procurement activity rather than enhance the current RA structure, and the likelihood that Track 3.B.2 will, at least, significantly alter the MCC Bucket program element.

Marginal ELCC – Energy Division

Grade: Pass with revisions

CEERT believes the Energy Division is correct in the notion that marginal ELCC is the appropriate metric for near term QC accounting. However, this well-reasoned specific proposal needs to be modified or expanded to include both CEERT's own ELCC proposal for hybrid resources and SWPG's locational ELCC proposal discussed above before adoption. CEERT believes that Energy Division can successfully accomplish this melding of the three ELCC related proposals in the process of staffing the ALJ for writing the Proposed Decision. CEERT is comfortable that it, and all other parties, have the right to comment on that implementation after the Proposed Decision is issued.

DR Adders – Energy Division

Grade: Fail

CEERT has serious issues with this proposal as well as serious issues with the entire treatment and future of DR "oversight" in numerous Commission proceedings. CEERT believes that California's DR efforts are critical to reliable cost-effective grid operations but are failing badly from almost any perspective whether expectations of the Commission or CAISO, or customer participants, or 3rd party aggregators, or comparison with DR's track record in other venues. It is time for a fundamental reset on DR, not tweaks to a broken process.

ELCC for DR and Track 4 Proposals -- CAISO

Grade: Fail

CEERT believes that this specific proposal is not well fleshed out – in particular how it would mesh with the other Track 3.B.1 proposals or the IRP Mid Term Procurement or Track 3.B.2 proposals for broader RA reform. Whatever marginal gain could be involved here is not worth the time and uncertainty about durability going forward.

RA Penalties – CPUC, PG&E

No comment

RA as a Transmission and Distribution (T&D) Function – Green Power Institute (GPI)

Grade: Fail

CEERT appreciates the thought that GPI expresses here but believes this "proposal" is misplaced in Track 3.B.1. Even if it survives further scrutiny, it is not even close to being implemented this year or considered for a directional Commission decision in the PD. Although it is not officially on the RA record, the subject has been publicly broached and can be taken up again in Track 3.B.

Unforced Capacity (UCAP)—CAISO

Grade: Conditionally Pass

Although not specifically workshopped in the jammed February 25 session, UCAP has been previously workshopped in this proceeding and remains a viable and, in CEERT's opinion, very constructive proposal in virtually any present or future RA paradigm. It remains in active discussion in the CAISO's Stakeholder Initiative process and CEERT judges it nearly ripe for implementation. At a minimum, the Proposed Decision should contain a fulsome discussion and inclusion in proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs in that Proposed Decision.

III.
SECOND REVISED TRACK 3.B.2 PROPOSALS

CEERT gives its assessment of the status and potential for further discussion in Track 3.B.2 or subsequent ALJ/Commission ruling of the three open Track 3.B.2 proposals by SCE/California Community Choice Association's (CalCCA's) "Bottom Up NQE Paradigm", PG&E's "Slice of Day" proposal and Energy Division's take on Prof. Wolak's "Forward Energy Contracting" proposal that were last workshopped on February 8, February 9, and February 10, 2021.

SCE/CalCCA Proposal

CEERT continues to believe, as it has since the proposal was first introduced last year, that this RA reform proposal continues to gain clarity and probity and richly deserves further consideration in subsequent workshops/comment rounds in the ongoing RA Proceeding. While not ready for implementation, it is ready for a directional Ruling by the Commission in the pending Q2 Proposed Decision in this current RA proceeding. CEERT believes the principal open area of concern is the "temporal aspects of NQE." We also believe that this area of concern could potentially be mitigated by grafting in a version of PG&E's Slice of Day proposal for the 4 to 9 pm time window. If this can be accomplished, the remaining "temporal" issues will recede enough to allow adoption. CEERT also believes that, if adopted, principally due to its reliance on a robust, accurate "bottoms up" load and load shape forecast LSE-by-LSE that should come from enhancements of the current CEC load forecasting model, a one year "practice run" should be implemented alongside the current RA methodology that would be used for RA showings in the rollout year. CEERT believes that this is a necessary component for execution of this proposal should it be adopted in the future. Finally, CEERT does NOT believe that this proposal marks an end state of Resource Adequacy given the radical transformation of loads and resources in California over the next 10 to 15 years, but sets us on a course that leads to a "durable and resilient" RA paradigm for the future grid.

PG&E Proposal

CEERT believes that this RA reform proposal, while less ambitious and potentially easier to implement than the SCE/CalCCA proposal, offers a constructive and thoughtful advance that deserves further discussion in Track 3.B.2 or successor tracks if, for no other reason, as a "Plan B" should a fatal flaw appear in the SCE/CalCCA proposal. CEERT is concerned that the current RA paradigm is fatally broken and continued efforts to stick our fingers in the leaking dike will not hold back the tide much longer. The sooner we start down a different, more viable future path, the more reliable and cost-effective California's grid will become. Time is of the essence.

CEERT especially appreciates PG&E's emphasis on energy sufficiency in stress hours and gravitation to an "exceedance" QC counting methodology relying on actual historic performance resource by resource with some sort of technology specific proxy value for new resources without a historic record. Incorporating CAISO's UCAP proposal into this methodology holds promise. CEERT also believes that the proposal's principal weakness is too many slices with the required locational granularity to hold robust, competitive auctions with fungible products with too little benefits of success in actual procurement/showings. We also believe that this proposal is less conducive to encouraging innovation and participation by the multiple diverse active participants in the grid of the future. CEERT also recommends more emphasis on ex post showings total system portfolio checks to tweak preliminary LSE showings before final adoption. It will be challenging to achieve this in a timely manner, but CEERT believes the effort is both doable and necessary.

Energy Division Forward Energy Contracting Proposal

CEERT believes that this proposal derived from Prof. Wolak's laboratory scale work at Stanford is an interesting academic exercise that offers useful insights for potential modification/enhancements to either of the other RA reform proposals. It reminds CEERT of the presentation tour of Prof. William Hogan of Harvard a la the famous "Blue Book" almost 30 years ago. Prof. Hogan and his team gave a dazzling tour touting the virtue of a centralized energy dispatch spot market based on short run marginal cost (principally fuel related) coordinated with fungible financial transmission rights to solve congestion and contracts for differences as the principal hedging mechanism. He vigorously debated the MIT/Enron contingent over whether a centralized single price auction vs. transparent bilateral transactions yielded more competitive, more efficient results, and eventually won that debate, leading to formation of the CAISO real time market and the day ahead Power Exchange experiment. While that experiment failed spectacularly in the real world, it did eventually lead to today's reasonably stable, reasonably efficient energy market that required some external grafting of a "capacity market" we now call Resource Adequacy. CEERT believes the potential advantages of Prof. Wolak's theories are outweighed by the financial and operational execution related risks – especially in a period of tight supply/demand balance in California and the rest of the WECC. CEERT believes that this proposal is too raw and too uncertain to consider further consideration in Track 3.B.2 and should return to the laboratory for more seasoning before trial implementation in some other smaller, less consequential setting than California.

IV.
CONCLUSION

CEERT respectfully submits these Opening Comments, recommends including its Track 3.B.1 Hybrid Counting Rule proposal described again herein in the pending Proposed Decision in this proceeding, recommends further discussion of SCE/CalCCA and PG&E RA reform proposals in Track 3.B.2 or a new slot subject to subsequent ALJ Ruling or Commission Decision, and looks forward to digesting other party Opening Comments for its Reply Comments in this proceeding.

Respectfully submitted,

March 12, 2021

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FOR: CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES

ATTACHMENT 1

Interim QC Counting Rules for Solar/Wind + Storage Hybrids

RA Track 3.B.1 Workshop
February 25, 23021
James Caldwell
CEERT

Hybrids Rule

- Hybrids are defined as resources with multiple elements of varying technology that are combined behind a single point of interconnection with a single resource ID and are dispatched as a “portfolio” by the resource operator/SC.
- By this definition, most resources on the grid today are “hybrids” and virtually all new resources being considered for procurement are “hybrids.”
- All hybrids share two characteristics for RA counting purposes:
  - -They must be defined in the Master File “bottom up”-- that is their dispatch characteristics are resource specific.
  - -Their QC value is a “portfolio” QC, not some combination of individual element QCs.
- These complex characteristics can be simplified/ignored for RA purposes as long as the penetration levels of each hybrid class are ”low” and the number, size and variety of configurations within each class of hybrid are relatively “small.” The easiest simplification is to assume that the QC of the hybrid is the sum of the individual element QCs and that the sum of the individual hybrids on the system is equal to the system QC. The second easiest simplification is to assume that resource location does not matter.
- The increasing penetration of first, storage, and second, use limited resources is driving the complexity and importance of QC counting rules, MCC buckets, etc. The simplifying assumptions above are breaking down rapidly and eventually need to be dealt with explicitly and comprehensively.
- The use of ”system” portfolio reliability assessments ex post resource showings and/or procurement is prominent in early adaptations to this reality, and is integral to recently adopted LCR reforms and all serious “Track 3.B.2” RA reform proposals.
- CEERT’s Track 3.B.1 proposal to use the DC ratings of the storage and VER elements of solar or wind + storage hybrids rather than the AC rating when calculating QC for these hybrids can be thought of as another critical early adaptation in a long RA reform process.
- This “tweak” must be used to assess resource value in the looming IRP “Mid Term” procurement for all of reliability, cost effectiveness and conformance to State energy policy concerns.

CEERT Track 3.B.1 Proposals

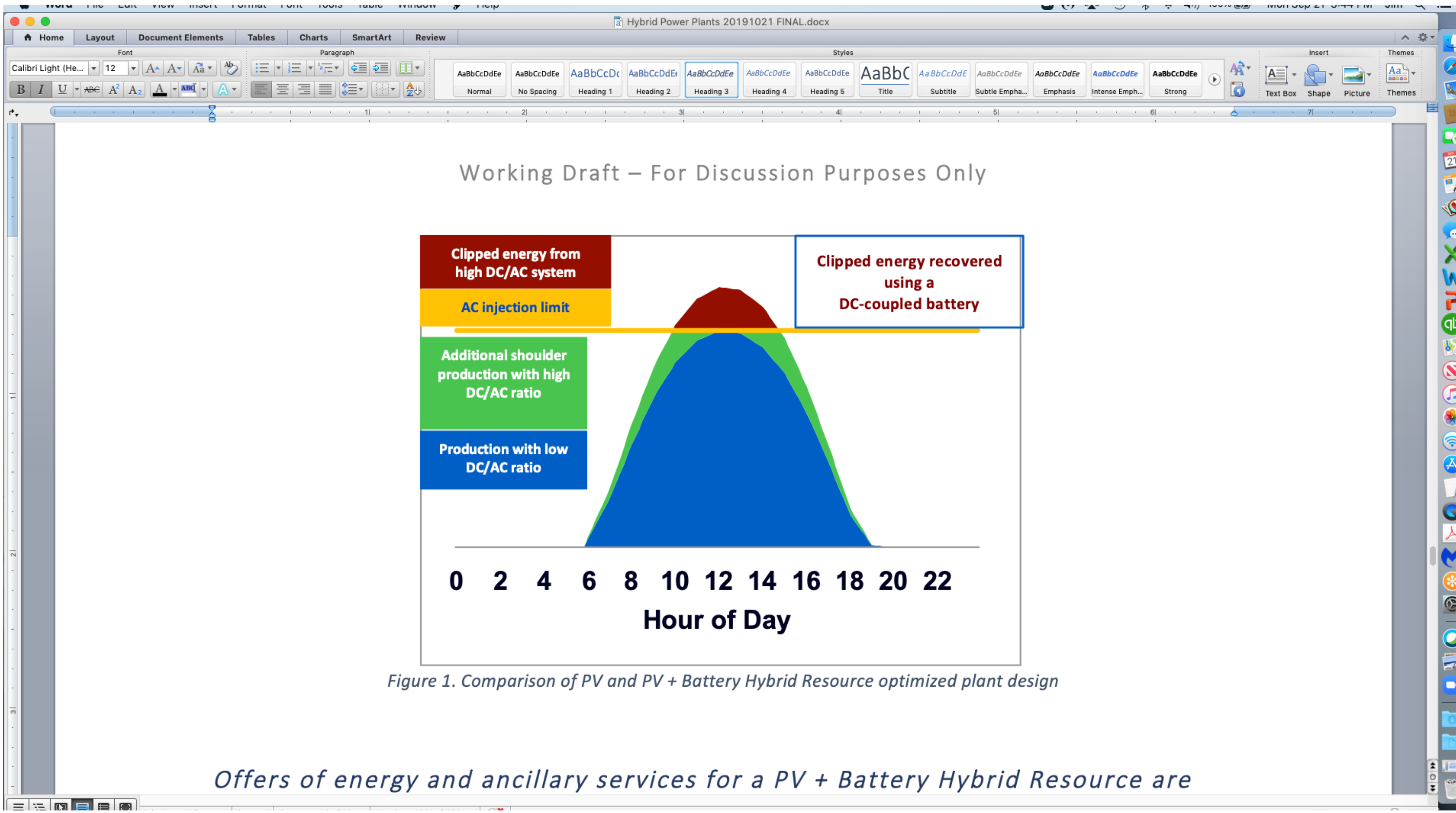
- These proposals would apply only to near term counting rules for wind or solar + storage hybrids, are intended to be consistent with the June 2020 CPUC RA decision (D.20-06-031), and require no further discussion or decision – simply ED implementation of D.20-06-031. Extension of the concepts to other more complex hybrids or the broader implications of other dispatch characteristics on "resource value" should be part of Phase 3.B.2 and in conjunction with whatever "reform proposal" is chosen for further development (PG&E "Slice of Day," SCE/CCA "Bottom Up Energy," or ED "forward energy contracting/hedging"). These wind or solar + storage hybrids would, for now, be placed in the "appropriate" MCC Bucket depending on whether ED's proposal to revise those buckets in this Track is adopted. They would not be "netted off" gross load because they are, by definition, dispatchable.

- For DC coupled hybrids:
  - A DC coupled hybrid with a high ILR looks much more like a dispatchable 7 x 12 strip than a combination of standalone solar and standalone storage as demonstrated by Astrape, E3, and CEERT in previous presentations (see backup slides).
  - Use CPUC's D.20-06-031 implementation "methodology overview" (Nov. 23, 2020 Track 3B Workshop Day 2, Presentation 8) to calculate "energy sufficiency" of the DC coupled hybrid using the DC rating of the solar/wind array in MW (including "clipped energy") and the DC rating of the battery in mwh. If the analysis shows that there is sufficient energy to dispatch the hybrid at full capacity for 5 hrs. from 4 to 9 PM, then there is no derate. If there is too little energy in the hybrid to accomplish that in some or all months, then derate the hybrid QC by that energy deficiency ratio by month.
  - Establish the QC of the DC coupled hybrid as the lesser of the AC rating of the shared inverter or the POI injection rights.

- For AC coupled hybrids:
  - Use the marginal QC value as calculated by Astrape (Tables 1,2,3 in AL 4382-E -- SCE; AL 3665-E – SDG&E; AL 6041-E – PG&E, Dec 29, 2020). For this calculation, "100%" equals the POI injection rights in MW. Excerpts from these Tables reproduced in backup slides.
  - Although this calculation was done for RPS compliance with least cost/best fit criteria, it is consistent with D.20-06-031, and uses the same modeling platform and loads and resource tables as CPUC RA and IRP modeling under an "SB 350 compliance projection." Astrape is the developer/maintenance organization for the RESOLVE/SERVM modeling platform and is under contract with the CPUC Energy Division to support analyses and implement enhancements to the modeling platform.
  - CEERT has filed a Motion for Official Notice of the Astrape RPS studies in this proceeding. (February 19, 2021).

BACKUP SLIDES

Hybrid Resource RA Counting Rules
ESIG/NextEra Results



Hybrid Resource RA Counting Rules
Astrape RPS Study

- Astrape 2020 Joint IOU ELCC Study (Phase 1 published in July, 2020, Phase 2 published in December 2020).

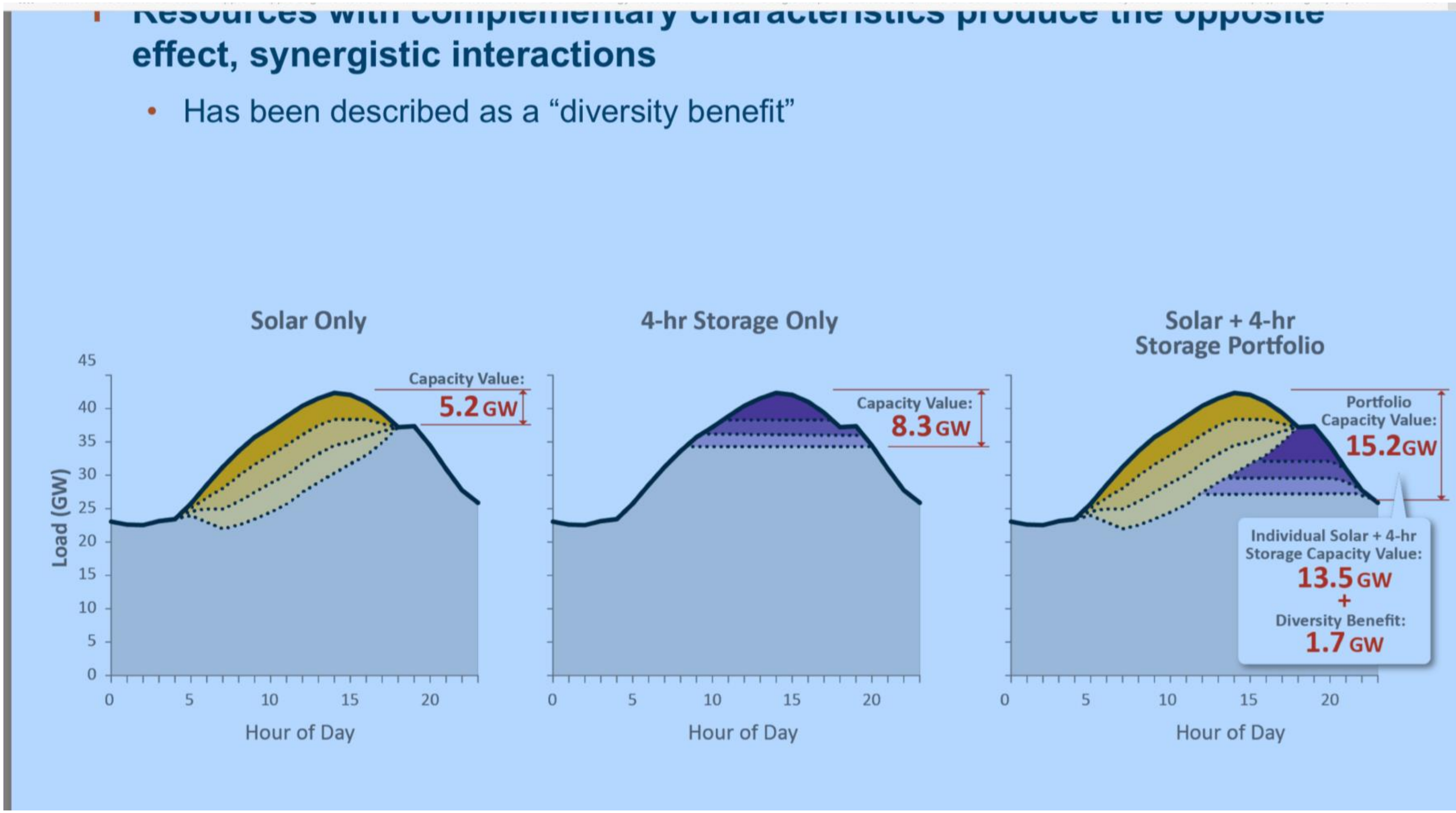
- CAISO Ave Project Marginal ELCC Value (100% = POI injection rights):

	2022	**2030**
1-hr Tracking PV AC Hybrid	99%	93%
2-hr Tracking PV AC Hybrid	100%	100%
4-hr Tracking PV AC Hybrid	100%	100%
1-hr Wind Hybrid	90%	88%
2-hr Wind Hybrid	92%	90%
4-hr Wind Hybrid	96%	93%

See AL 4382-E SCE; AL 3665-E SDG&E; AL 60412-E PG&E, December 29, 2020 @ pp. 3-4 Appendix A)

- Results are for AC coupled projects with 1:1:1 storage/solar or wind/POI capacity with no grid charging. More granular results by location and year as well as more detailed discussion of methodology are included in the Astrape Reports. In addition, the Phase 2 Report corrects an error in Phase 1 results.

Hybrid Resource RA Counting Rules
Recent E3 Results



Not a hybrid project but a "portfolio ELCC" showing the AND impact
Fr :"Practical Considerations for Application of ELCC", Aug 7, 2020, E3 p.7

ATTACHMENT 2

2020 Joint IOU ELCC Study

Report 2

12/11/2020

PREPARED FOR

California Investor Owned Utilities
Southern California Edison Company
Pacific Gas & Electric Company
San Diego Gas & Electric Company

PREPARED BY

Kevin Carden
Alex Krasny Dombrowsky
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Astrapé Consulting

TABLE OF CONTENTS

EXECUTIVE SUMMARY

As directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement"[1] ("Decision") on October 3rd, 2019 in California Public Utilities Commission's ("CPUC's") RPS Proceeding R. 18-07-003, the Commission ordered the California Investor Owned Utilities ("IOUs"), which comprise Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, to perform an Effective Load Carrying Capability ("ELCC") study.

In accordance with the Decision, Astrapé Consulting, acting as contractor, shall provide to the IOUs two reports that summarize the ELCC values for the resource classes and class subtypes located in seven geographical regions (PGE Bay, PGE Valley, SCE, SDGE, AZ APS, NM EPE, and BPA)[2], detail the input assumptions (e.g., load, installed capacity), explain the methodology used to calculate the ELCC values, and compare the impact of the different locations on the same technology types. This document addresses the requirements of Report 2: provide annual, marginal ELCC values for hybrid resources using 1[3]- and 2-hour duration storage, detail the input assumptions (e.g., load, installed capacity), explain the methodology used to calculate the ELCC values, and compare the impact of the different locations on the same technology types. As directed in the Decision, the 2017-2018 Preferred System Plan (PSP) was used as the basis for the analysis. ELCC values are reflective of the system studied and are not applicable to a system with a substantially different load and resource mix.

The major findings of this phase of the study are:

- While studying 1- and 2-hour hybrids, inefficiencies in the storage scheduling heuristics used in Report 1 were found and corrected in Report 2. Report 2 includes updated ELCC values for 4-hour wind hybrids and 4-hour tracking PV Hybrids. A detailed discussion of these findings is included in the "Charging Heuristics" sub-section within the "Input Assumptions" section.
- Battery and renewable hybrid resources of 1- and 2-hour duration are able to provide very high capacity value (92% or greater for all solar hybrid configurations, and 83% or greater for all wind hybrid configurations), where the assumed quantities of renewable resources and storage are each equal to the assumed interconnection capability, and capacity value is measured as a percentage of the assumed interconnection capability.
- The assumptions for short duration battery storage resources in this study - including when modeled as part of a hybrid resource - produce nearly maximal reliability benefit, with ELCC values approaching 100%. These assumptions include ancillary service eligibility with limited deployment and centralized dispatch that actively prioritizes by duration with almost immediate response from each resource. If these assumptions are not accurate for actual operations, the ELCCs will drop significantly. A sensitivity where the resources are modeled as energy only resources demonstrates that 1-hour duration storage is worth approximately 50%.

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[1] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

[2] Pacific Gas & Electric Bay, Pacific Gas & Electric Valley, Southern California Edison, San Diego Gas & Electric, Arizona Public Service, New Mexico Area and El Paso Electric, and Bonneville Power Administration, respectively

[3] Reference to storage duration means capacity in MW can be multiplied by duration in hours to determine max energy in MWh

Tables ES1 – ES3 provide the recommended ELCC[4] values by technology and region for the study years 2022, 2026, and 2030. The ELCC values for 4-hour hybrids in Tables ES1 - ES3 are an update to those originally shown in Report 1. Results shown have aggregated PGE Bay and Valley results together into the “CA-N”, or California North region, and SCE and SDGE results together into the “CA-S” or California South region[5]. Northern and Southern California were aggregated since the underlying renewable profiles were more similar than suggested by the variability in raw simulation results.

Table ES1. Recommended ELCC Values for 2022[6] (expressed as a percentage of assumed interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	99%	100%	100%	88%	91%	96%
CA-S	99%	100%	100%	91%	93%	96%
AZ APS	95%	96%	97%	92%	95%	100%
NM EPE	95%	96%	96%	92%	95%	100%
BPA	N/A	N/A	N/A	86%	91%	92%
CAISO	**99%**	**100%**	**100%**	**90%**	**92%**	**96%**
Average	**97%**	**98%**	**98%**	**90%**	**93%**	**97%**

Table ES2. Recommended ELCC Values for 2026 (expressed as a percentage of assumed interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	94%	95%	100%	86%	89%	94%
CA-S	95%	97%	100%	91%	93%	95%
AZ APS	94%	94%	97%	90%	95%	97%
NM EPE	93%	91%	95%	90%	95%	97%
BPA	N/A	N/A	N/A	84%	88%	90%
CAISO	**94%**	**96%**	**100%**	**89%**	**91%**	**94%**
Average	**94%**	**94%**	**98%**	**88%**	**92%**	**95%**

[4] For purposes of the ELCC Study, ELCC is calculated as a percentage of interconnection capability, where interconnection capability is assumed equal to (i) the installed capacity of non-hybrid resources, or (ii) in the case of hybrid resources, the installed capacity of the renewable resource or storage device, which are equally sized for all hybrids analyzed.
[5] Report 1 also aggregated into CA-N and CA-S though the labels were PG&E for CA-N and SCE/SDG&E for CA-S
[6] Values for all three study years reflect post-processing to reduce statistical noise.

Table ES3. Recommended ELCC Values for 2030 (expressed as a percentage of assumed interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	93%	95%	96%	86%	89%	93%
CA-S	93%	95%	97%	90%	91%	93%
AZ APS	93%	93%	93%	90%	92%	94%
NM EPE	92%	91%	92%	90%	92%	94%
BPA	N/A	N/A	N/A	83%	88%	90%
CAISO	**93%**	**95%**	**97%**	**88%**	**90%**	**93%**
Average	**93%**	**93%**	**95%**	**88%**	**90%**	**93%**

Comparisons to results for Report 1 are shown in Table ES4. The charging heuristics used in the model in Report 1 assumed alignment between on-site renewable output and low net load periods. This assumption is reasonable for solar hybrids, but not for wind hybrids. Updated wind charging heuristics considered both net load and wind output forecasts and significantly improved capacity value for wind hybrids. Detailed explanation of the drivers of the difference is provided in the "Charging Heuristics" section of this report.

Table ES4. Report 1 and 2 Results for 4 Hour Hybrids (expressed as a percentage of interconnection capability)

4-Hour Hybrid Type	Region	2022		2026		2030	
		Original	Updated	Original	Updated	Original	Updated
Tracking PV Hybrid	CA-N	100%	100%	99%	100%	93%	96%
	CA-S	100%	100%	96%	100%	93%	97%
	AZ APS	99%	97%	96%	97%	91%	93%
	NM EPE	99%	96%	96%	96%	91%	92%
Wind Hybrid	CA-N	54%	96%	44%	94%	39%	93%
	CA-S	47%	96%	35%	95%	32%	93%
	AZ APS	78%	100%	79%	97%	63%	94%
	NM EPE	78%	100%	79%	97%	63%	94%
	BPA	57%	92%	53%	90%	52%	90%

INPUT ASSUMPTIONS

STUDY REQUIREMENTS

Astrapé Consulting was contracted by the California Investor Owned Utilities to examine the annual marginal ELCC values for the resource classes and locations found in Table 1 for 3 study years (2022, 2026, and 2030).

Table 1. Resource Class and Location Combinations Calculated

	Tracking PV Hybrid	Wind Hybrid
PGE Bay	X	X
PGE Valley	X	X
SCE	X	X
SDGE	X	X
AZ APS	X	X
NM EPE	X	X
BPA	N/A	X

In Report 1[7], PGE Valley and PGE Bay regions were aggregated into PGE results, and SDGE and SCE results were aggregated into SDGE/SCE results. This aggregation is continued in Report 2, where ELCC for the PGE Bay and PGE Valley regions is reported for Northern California (CA-N), and the ELCC for SCE and SDGE regions is reported for Southern California (CA-S) regions.

Astrapé performed simulations to determine the ELCC values using the Strategic Energy and Risk Valuation Model (SERVM). The base database was constructed using the 2017-2018 Preferred System Plan (PSP) as directed in the "Decision Adopting Modeling Requirements to Calculate Effective Load Carrying Capability Values for Renewables Portfolio Standard Procurement' ("Decision") on October 3rd, 2019 in California Public Utilities Commission's ("CPUC's") RPS Proceeding R. 18-07-003.[8] A base case of the system is first established by calibrating the CAISO region to a reliability of 0.1 Loss of Load Expectation (LOLE) for each of the three study years (2022, 2026, and 2030) by either adding load uniformly across each hour of the year or adding energy storage capacity. LOLE was determined as the expected number of events where load and ancillary service requirements exceeded available generation, as measured over thousands of annual, chronological simulations. Using the base case from each respective study year, multiple technology and locational ELCC values were studied. Table 2 contains the resource mix at 0.1 LOLE used as the base case simulations for each study year. A 0.1 LOLE level of reliability was determined by simulating the system as shown in Table 2.

[7] Report 1 quantified the marginal ELCC by year for renewable technologies and 4-hour hybrid systems. Filed 07-01-2020 with the CPUC Energy Division

[8] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M316/K882/316882092.PDF

Table 2. Study Year Resource Mix at 0.1 LOLE

Unit Category	Total Capacity by Year (MW)		
	2022	**2026**	**2030**
Battery Storage	1,115	1,514	3,431
Thermal	23,310	22,717	20,726
Nuclear	2,300	0	0
DR/EE	3,906	6,450	8,813
EV	-1,268	-2,198	-3,086
Hydro	6,032	6,032	6,032
PSH	1,832	1,832	1,832
Other Renewable*	2,449	2,519	4,235
Wind	8,566	8,994	9,121
BTM PV	12,301	16,727	20,759
Solar Thermal	1,248	1,248	1,248
Solar_Fixed	7,933	8,187	8,233
Solar_Tracking_SingleAxis	15,222	16,569	16,776
ELCC Adjustment**	-2,737	800	270
Total	**82,209**	**91,392**	**98,391**

** Other Renewable includes biogas, biomass, and geothermal units*
***Negative indicates added load, positive indicates 4-hour storage added*

MARGINAL ELCC METHODOLOGY

After calibrating the system, the study technology resource was added to the system. The load peak was then artificially increased uniformly across all hours until the reliability returned to 0.1 LOLE. The following equation was used to calculate the marginal ELCC value:

$$ELCC = \frac{Load\ Peak\ Increase\ (MW)}{Study\ Technology\ Resource\ Added^{9}\ (MW)} * 100\%$$

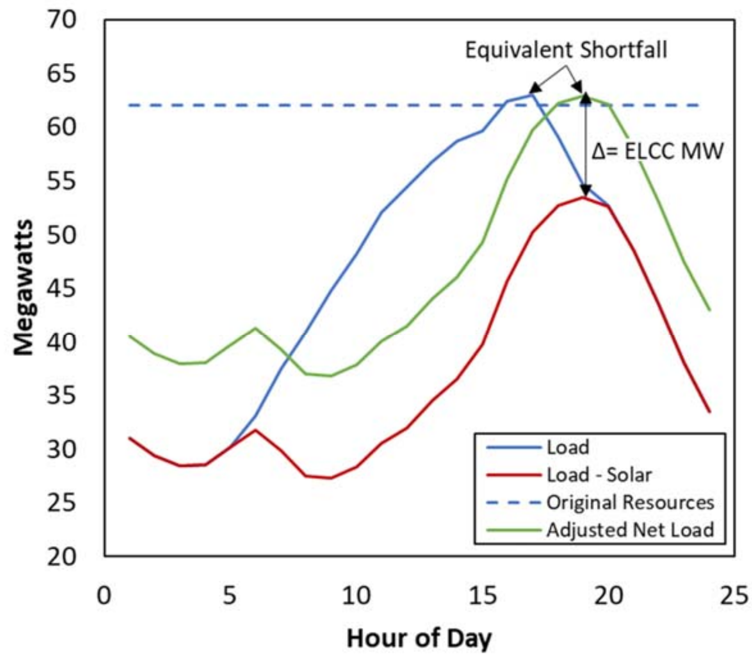
The process is as follows, using illustrative values and a solar resource:

1. Add a 30 MW solar resource to system calibrated to 0.1 LOLE
    a. The LOLE decreases to 0.08, indicating an improvement in reliability
2. Add 10 MW of load every hour
    a. The LOLE increases to 0.1, indicating a return to original reliability
3. The ELCC is calculated as the ratio of step 2 and step 1
    a. 10 MW / 30 MW = 33.3% ELCC

Figure 1 contains a graphic example of the process described above. Marginal resource ELCC is typically analyzed assuming small increments of resources relative to system size. Figure shows an exaggerated visualization for clarity.

[9] Limited by interconnection capability for combined hybrid projects

Figure 1. Marginal ELCC Calculation Methodology Illustration



REGIONS

CAISO is separated into 4 distinct regions in SERVM: PGE Bay, PGE Valley, SCE, and SDGE. The following external regions were included in the study:

- Arizona Public Service Company (AZ APS)
- Balancing Authority of Northern California (BANC)
- British Columbia Hydro Authority (BCHA)
- Bonneville Power Administration (BPA)
- Comisión Federal de Electricidad (CFE)
- Imperial Irrigation District (IID)
- Idaho Power Company (IPCO)
- Los Angeles Department of Water and Power (LADWP)
- Nevada Power Company (NEVP)
- NorthWestern Energy (NWMT)
- PacifiCorp East (PACE)
- PacifiCorp West (PACW)
- Portland General
- Public Service Company of Colorado (PSCO)
- Sacramento Municipal Utility District (SMUD)
- Sierra Pacific Power Company (SPPC)
- Salt River Project (SRP)
- Tucson Electric Power Company (TEPC)
- Turlock Irrigation District (TIDC)
- Western Area Power Administration – Colorado/Missouri Region (WACM)

- Western Area Power Administration – Lower Colorado Region (WALC)

The neighboring resources were assumed to be fully deliverable to CAISO subject to an 11,665 MW aggregated Maximum Import Capability limit (MIC).

All external regions described above were not explicitly modeled, instead North and South neighbor assistance was modeled as a proxy. Table 3 defines which Tier 1 (one tie away) neighboring entities were classified as North and which neighbors were classified as South.

Table 3. Region Definitions for Proxy Neighbor Assistance

Region	Tier 1 Entity
North	BANC
	BPA
	PACW
	TIDC
South	AZ APS
	CFE
	IID
	LADWP
	NEVP
	SRP
	WALC

A time series of imports into CAISO was developed for North and South Tier 1 neighboring entities separately and was based on historic interchange as a function of CAISO net load[10] by season, where net load is calculated as load minus wind, utility scale solar PV, and behind the meter PV ("BTM PV"). By assessing the imports with Tier 1 entities for 2019, the presence of Tier 2+ entities is also reflected, if not explicitly. This relationship was applied to all 35 weather years studied (1980-2014) so that each weather year included a unique profile of assistance from neighboring areas reflective of each year's renewable output and weather conditions. Supporting information for CAISO was retrieved from the EIA website based on 2019 actual data.[11] Total imports were capped at 11,665 MW to reflect aggregate transmission MIC constraints. The average hourly imports as a function of net load is provided in Figure 2. As shown in the figure, imports increase as a function of net load, with the majority of imports from entities connected to the South region, however the incremental imports for each MW of net load becomes attenuated at higher net load periods.

Figure 2. Average Hourly Imports by Zone

[10]Unless noted otherwise, net load will be defined as gross load less BTM PV, utility scale solar PV, and wind generation

[11] https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/CISO

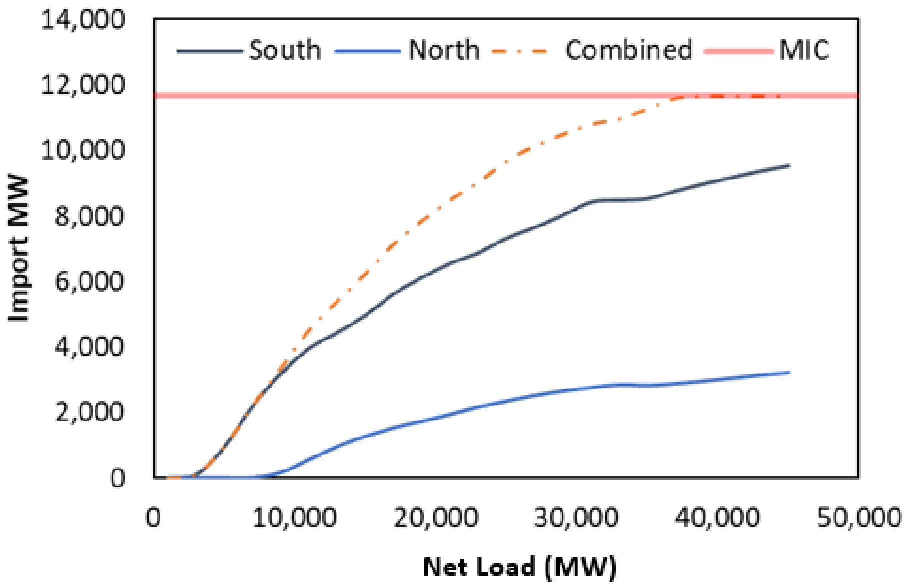
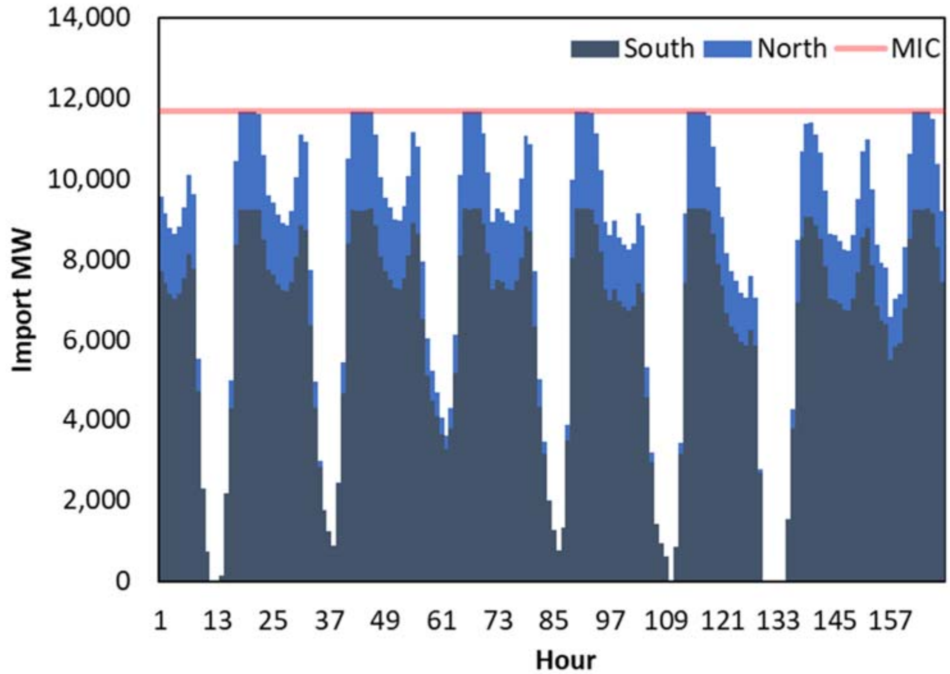


Figure 3 provides an illustrative example of a week of imports for both the North and South zones.

Figure 3. Imports – 1 Week Illustrative Example



LOAD SHAPES

Hourly load was modeled for each of the 4 CAISO regions within SERVM. To capture the effects of weather uncertainty, load shapes in the 2017 – 2018 PSP were originally developed by Astrapé for thirty-five historical weather years (1980 – 2014) to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on provided historical weather and load data. Other inputs into the neural network program consisted of an hour of week factor, temperature, and average temperatures from the past 8, 24, and 48 hours. Different weather and load relationships were built for each month. These relationships were then applied to the 1980 – 2014 weather profiles to develop 39 synthetic load profiles for the future study years (2022, 2026, and 2030). The synthetic load profiles represent expected load given customer electric use patterns today if historic weather conditions were to occur. The forecast peak load and energy by study year for each CAISO region is displayed in Table 4.

Table 4. Peak Load and Energy by Weather Year and Region

	Peak Load (MW)			Energy (GWh)		
	2022	**2026**	**2030**	**2022**	**2026**	**2030**
PGE Bay	9,289	9,699	10,029	47,700	49,694	51,237
PGE Valley	13,093	13,728	14,234	65,837	68,863	71,232
SCE	25,994	27,424	28,511	115,740	121,608	125,890
SDGE	5,009	5,297	5,490	22,688	23,815	24,522
CAISO	53,385	56,148	58,264	251,965	263,980	272,881

RENEWABLE PROFILES

The wind and solar shapes for all study locations are from the 2017-2018 Preferred System Plan originally developed by Astrapé. The wind profiles were produced using historical metered output from wind facilities in California from 2010 to 2014. The raw data was normalized to 100% by dividing the hourly output by the maximum annual capacity for each of the five years. A correlation was created between the wind output and load for each of the studied regions. Profiles for 1980 to 2009 were created by selecting the day that most closely matched the total load out of all the days +/- 5 days of the source day. For example, the wind profile for January 10, 1981 was selected by looking at the load from January 5 to 15 from all source years (2010 to 2014) and selecting the date that most closely matched the load of January 10, 1981. Each unique wind profile in all California regions used the same historical day (e.g. all January 1, 1980 used December 27, 2011 for all profiles) to preserve the historical diversity between wind projects in California. Hours 24 and 1 were interpolated from hour 23 and 2 to avoid a drastic hourly change in output. Wind profiles for BPA were based on publicly available hourly wind data.[12] Wind profiles for other zones were synthetically developed from a combination of NREL profiles[13] and proprietary wind data.

Solar shapes in the 2017-2018 PSP were developed by downloading data from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer.[14] Data was downloaded for 170 different cities for the years that were available at the time: 1998 through 2014. Historical solar data from the NREL NSRDB Data Viewer included variables such as temperature, cloud cover, humidity, dew point, and global solar irradiance. The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) for each year and city to generate the hourly solar profiles based on the solar weather data for both fixed and tracking solar PV plants.[15] SAM inputs included the DC to AC ratio of the inverter module and tilt and azimuth angle of the PV array. Output data from SAM was then normalized to 100%. Solar profiles for 1980 to 1998 were selected by using the daily solar profiles from the day that most closely matched the total daily load out of the corresponding data for the days available. 1998 to 2014 profiles came directly from the normalized raw data. The profiles were aggregated for each region by averaging the cities that fell within each region.

An indicative set of renewable profiles was selected for both CA-N and CA-S, which best represents the constituent regions. For the two aggregated CAISO regions, marginal ELCC values were calculated for each of the following technologies: BTM PV, fixed PV, tracking PV, tracking PV hybrid, wind, and wind hybrid. AZ APS and NM EPE marginal ELCC values were calculated for the following technologies: fixed PV, tracking PV, tracking PV hybrid, wind, and wind hybrid. Marginal ELCC values were calculated for the following technology types in BPA: wind and wind hybrid. For each case, 500 MW increments for each respective technology and location were added. The average annual capacity factor for the set of profiles used for each technology and region is provided in Table 5.

Table 5. Average Capacity Factor for Renewable Profiles Used

[12] https://transmission.bpa.gov/Business/Operations/Wind/
[13] https://www.nrel.gov/grid/wind-toolkit.html
[14] https://nsrdb.nrel.gov/
[15] https://sam.nrel.gov/

	BTM PV	Solar Fixed	Solar Tracking Single Axis	Wind
CA-N	20.7%	25.9%	31.2%	27.5%
CA-S	21.0%	26.8%	33.3%	24.8%
AZ APS	N/A	27.6%	32.1%	30.2%
NME PE	N/A	27.1%	31.1%	30.2%
BPA	N/A	N/A	N/A	30.9%
Average	**21.2%**	**25.9%**	**30.8%**	**28.2**%

TECHNOLOGY ASSUMPTIONS

TRACKING PV HYBRID

The tracking PV hybrid units used the tracking PV solar shapes and capacities defined in Table 6 below.

Table 6. Tracking PV Technology Assumptions

Region	Solar Shape	Capacity (MW)	Inverter Load Ratio (ILR)	Capacity Factor (%)
CA-N	PGE Valley Tracking	500	1.18	31.2
CA-S	IID Tracking	161.0	1.29	33.3
	SDGE Tracking	339.0	1.29	
AZ APS	AZ APS Tracking	500	1.11	32.1
NM EPE	NM EPE Tracking	500	1.11	31.1

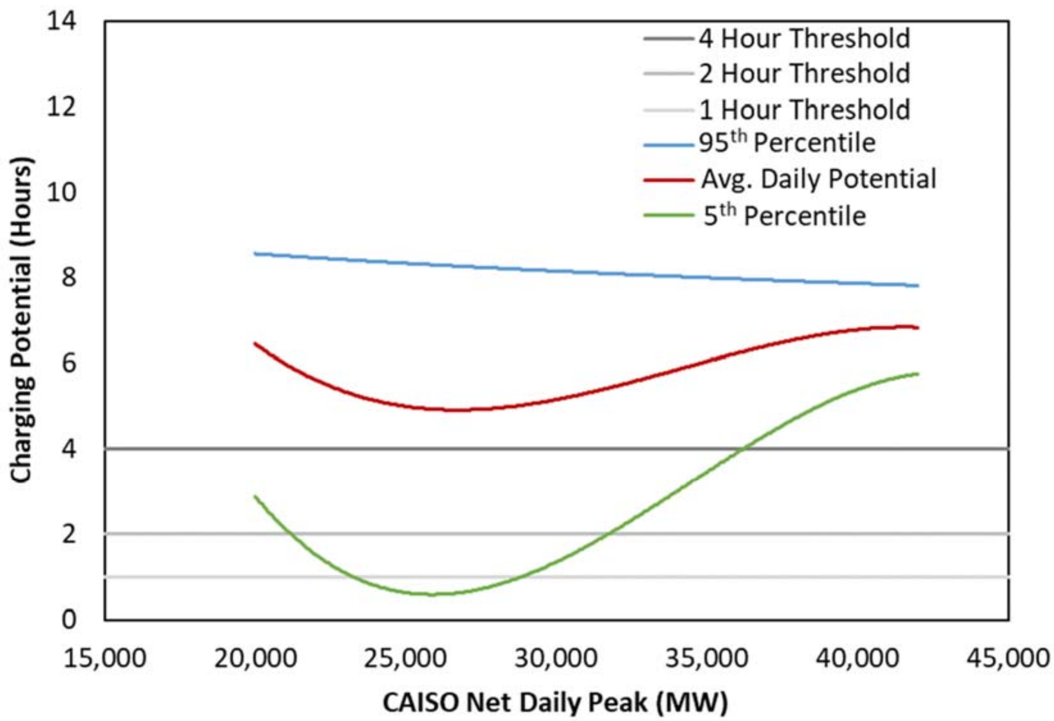
Though solar shape allocation may have differed between hybrids, the tracking PV units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on an assumed 500 MW interconnection capability.[16] The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, and used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding tracking PV unit. As DC coupled would be expected to result in relatively higher ELCC than AC coupled, the tracking PV and battery units were assumed AC coupled to serve as a conservative estimate of hybrid configuration ELCC. A sensitivity was performed to determine the optimal configuration to be used for this study. The results of the sensitivity are discussed in Appendix A of Report 1.

The following figure was developed to determine if the solar profiles would provide adequate energy to consistently charge the linked energy storage resource. The charging potential of the PGE Bay solar shape describes the amount of energy produced prior to hour 18 by the solar plant, expressed in terms of hours of energy which could be stored within a 500 MW storage device. ELCC is highly correlated with the ability to fully charge prior to the highest net load peak periods. Figure 4 shows that during the highest CAISO net daily load peaks across the year 2022,[17] the coupled solar PV tracking component

[16] See Appendix A in Report 1 for recommendation of maximum combined output.
[17] Considering all solar, wind, EE, and EV.

should be able to consistently charge the studied storage devices (1-, 2-, or 4-hours) with a 90% confidence interval, with an average charging potential of roughly 7 hours. The 90% confidence interval is shown as the difference in the 95th percentile and 5th percentile curves. Because the PGE Bay shape exhibits the lowest annual capacity factor of hybrid resources studied, other configurations are assumed to also have enough energy to achieve a full charge.

Figure 4. Charging Potential of PGE Bay Tracking PV Hybrid



WIND HYBRID

The wind hybrid units used the wind shapes and capacities defined in Table 7 below.

Table 7. Wind Technology Assumptions

Region	Wind Shape	Capacity (MW)	Capacity Factor (%)	Capacity Factor on CAISO Net Peak (%)
CA-N	Wind_PGE Valley	500	27.5	21.6
CA-S	Wind_SDGE	500	24.8	28.0
AZ APS	Wind_AZ APS/NM EPE	500	30.2	27.2
NM EPE	Wind_AZ APS/NM EPE	500	30.2	27.2
BPA	Wind_BPA	500	30.9	44.2

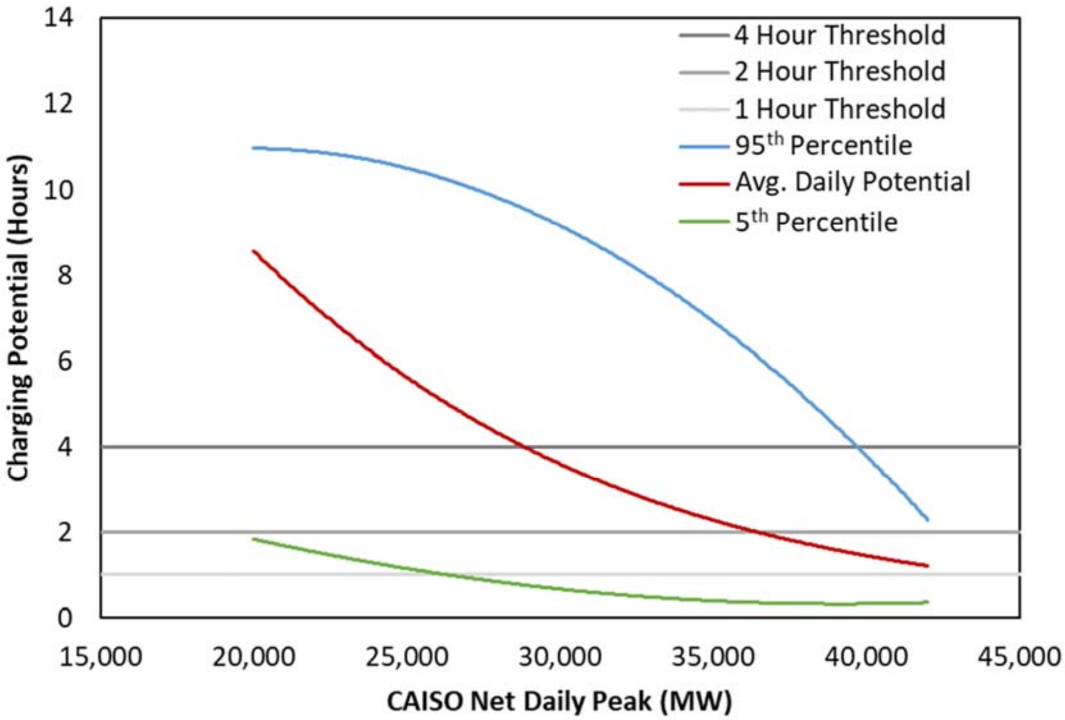
Though wind shape allocation may have differed between hybrids, the wind units and battery units totaled 500 MW each, yielding 1,000 MW of nameplate capacity with 500 MW maximum combined output based on the assumed interconnection capability.[18] The battery units were modeled with 1-, 2-, or 4-hour storage capability, 85% round trip efficiency, used economic commitment and dispatch subject to the constraint that the battery could only charge from the corresponding wind unit.

Figure 5 was developed to determine if the wind profiles would provide adequate energy to consistently charge the coupled energy storage resource. The charging potential of the SCE wind shape describes the amount of energy produced prior to hour 18 by the wind plant,[19] expressed in terms of hours of energy which could be stored within a 500 MW storage device. The figure shows during the highest net daily peaks, the coupled wind would not be able to consistently charge a 500 MW storage device to 4 hours in a 90% confidence interval. The coupled wind is even insufficient for 1- and 2-hour storage devices to consistently provide full charge, considering the 5th percentile is below 1 hour. The expected charging capability at the highest net load periods is expected to be less than 2 hours, with some days as low as a fraction of 1 hour. However, since this product is assumed to be capable of providing AS, its capacity value remains elevated. Considering that the SCE shape exhibits the lowest annual capacity factor on net peak of hybrid resources studied, other wind shapes may have improved charging potentials.

[18] See Appendix A in Report 1 for recommendation of maximum combined output.

[19] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.

Figure 5. Charging Potential of SCE Wind Hybrid

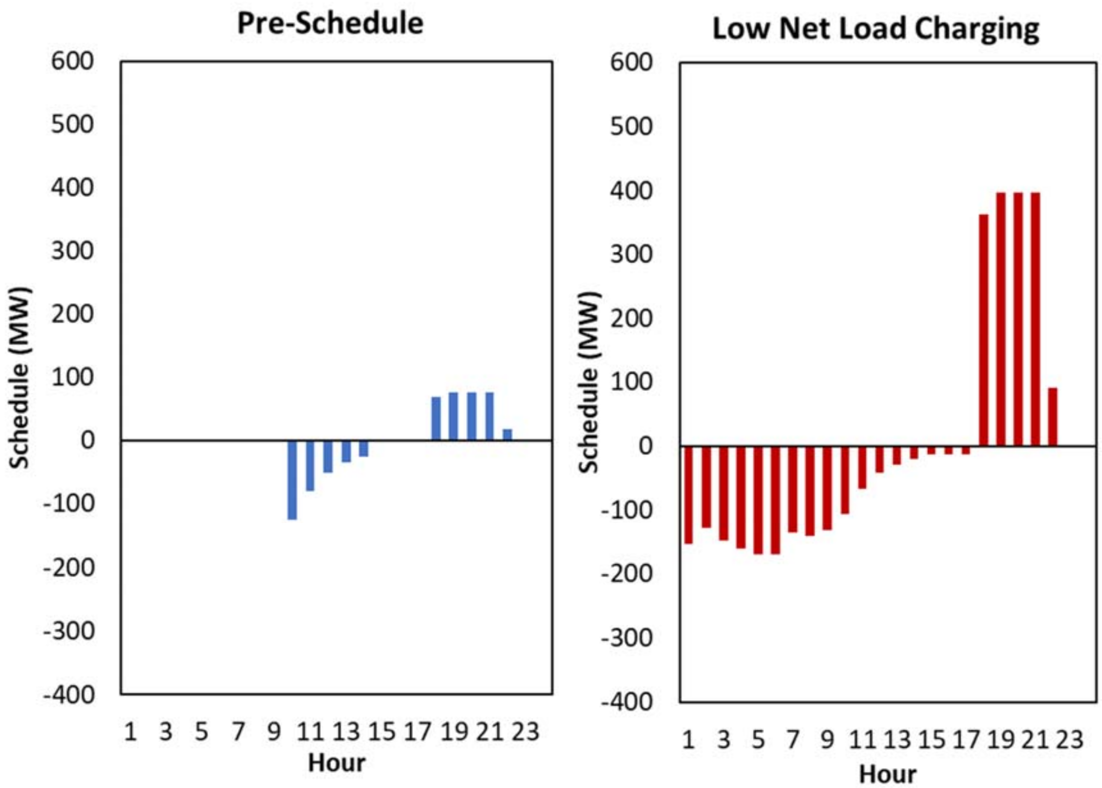


CHARGING HEURISTICS

Embedded in the results for Report 1 is the assumption that energy storage resources will schedule charging and discharging periods day-ahead based on the day-ahead forecast of net load, and then actually charge in real-time from the linked renewable facility at those pre-designated time periods. This assumes market participants would avoid charging at higher priced hours (which generally correspond with the highest net load hours), rather than scheduling charging to maximize state of charge. This was an error which presumed low net load periods (e.g., 10:00 am to 3:00 pm) and wind output would be correlated. This presumption results in inadequate state of charge in advance of high net load periods (e.g., 6:00 pm to 10:00 pm) when energy production is most valuable from a reliability perspective.

For Report 2, the charging heuristic used to schedule storage was updated. The new scheduling procedure assumes market participants will charge hybrid facilities as much as possible prior to the high net load period, prioritizing all lower net load periods in the charging schedule. An example of these two approaches is illustrated below. The prior scheduling heuristic assumed charging would be performed in pre-determined windows based on a day-ahead schedule.

Figure 6. Charging Heuristics (Wind Hybrid)



The distinction between the two operating modes is less impactful for 4-hour solar PV tracking hybrids because low net load periods are highly correlated with solar output. Calculated 4-hour solar PV tracking marginal ELCC values have had a maximum absolute value change of three percent. Table 8 shows the results for 4-hour hybrid projects for each study year. As shown in the table, implementing this approach results in greater ELCC's for wind hybrids, attributable to more consistent charging.

Table 8. Report 1 and 2 Results for 4 Hour Hybrids (expressed as a percentage of interconnection capability)

4-Hour Hybrid Type	Region	2022		2026		2030	
		Report 1	Report 2	Report 1	Report 2	Report 1	Report 2
Tracking PV Hybrid	CA-N	100%	100%	99%	100%	93%	96%
	CA-S	100%	100%	96%	100%	93%	97%
	AZ APS	99%	97%	96%	97%	91%	93%
	NM EPE	99%	96%	96%	96%	91%	92%
Wind Hybrid	CA-N	54%	96%	44%	94%	39%	93%
	CA-S	47%	96%	35%	95%	32%	93%
	AZ APS	78%	100%	79%	97%	63%	94%
	NM EPE	78%	100%	79%	97%	63%	94%
	BPA	57%	92%	53%	90%	52%	90%

SIMULATION RESULTS

Astrapé performed simulations to determine the annual, marginal ELCC values for the defined hybrid resource classes and class subtype locations. Table 9 defines the results for the 2022 study year. The hybrid projects have total nameplate capacity of 1,000 MW (500 MW renewable and 500 MW battery), but the marginal ELCC is calculated as a percentage of the maximum possible simultaneous output from the facility,[2,20] which is 500 MW based on the assumed interconnection capacity.[21] Additionally, the storage component cannot charge from the grid.

Table 9. 2022 Study Results[22] (expressed as a percentage of the interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	99%	100%	100%	88%	91%	96%
CA-S	99%	100%	100%	91%	93%	96%
AZ APS	95%	96%	97%	92%	95%	100%
NM EPE	95%	96%	96%	92%	95%	100%
BPA[23]	N/A	N/A	N/A	86%	91%	92%
CAISO	**99%**	**100%**	**100%**	**90%**	**92%**	**96%**
Average	**97%**	**98%**	**98%**	**90%**	**93%**	**97%**

The results for the 2026 study year are provided in Table 10.

Table 10. 2026 Study Results (expressed as a percentage of the interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	94%	95%	100%	86%	89%	94%
CA-S	95%	97%	100%	91%	93%	95%
AZ APS	94%	94%	97%	90%	95%	97%
NM EPE	93%	91%	95%	90%	95%	97%
BPA[23]	N/A	N/A	N/A	84%	88%	90%
CAISO	**94%**	**96%**	**100%**	**89%**	**91%**	**94%**
Average	**94%**	**94%**	**98%**	**88%**	**92%**	**95%**

[20] These hours represent the peak net load hours, considering all solar, wind, EE, and EV and serves as a proxy for timing of expected reliability events.
[21] Given the wide range of possible configurations for hybrid facilities, multiple methods of accounting for their ELCC may need to ultimately be employed, but for simplicity and comparability, using maximum possible simultaneous output as the denominator was most appropriate for this report. The implications of hybrid configuration on ELCC are further explored in Appendix A in Report 1.
[22] Values for all three study years reflect post-processing to reduce statistical noise.
[23] Solar PV Hybrids were not studied for BPA

The results for the 2030 study year for each duration of hybrid resource studied are shown in Table 11.

Table 11. 2030 Study Results (expressed as a percentage of the interconnection capability)

Region	1-Hour Tracking PV Hybrid	2-Hour Tracking PV Hybrid	4-Hour Tracking PV Hybrid	1-Hour Wind Hybrid	2-Hour Wind Hybrid	4-Hour Wind Hybrid
CA-N	93%	95%	96%	86%	89%	93%
CA-S	93%	95%	97%	90%	91%	93%
AZ APS	93%	93%	93%	90%	92%	94%
NM EPE	92%	91%	92%	90%	92%	94%
BPA[23]	N/A	N/A	N/A	83%	88%	90%
CAISO	**93%**	**95%**	**97%**	**88%**	**90%**	**93%**
Average	**93%**	**93%**	**95%**	**88%**	**90%**	**93%**

ANCILLARY SERVICES PROVISIONS

Since ancillary services must be maintained during a load shed event, hybrid resources are expected to be able to provide those products at some level, increasing their overall capacity value. By providing spinning or regulation up service, the battery component of the hybrid allows a conventional resource to produce energy, rather than ancillary services. Hybrids were modeled with the ability to provide energy or AS, subject to the maximum interconnection limit of the hybrid facility. To understand the capacity value the provision of AS provides, 2 additional operating heuristics were simulated for the CA-N hybrids for the year 2030. In the "Energy Only" scenario, hybrid resources were exclusively energy arbitrage resources. Energy was scheduled to be dispatched at the expected net peak demand hours. In the "Ancillary Services Only" scenario, hybrid resources did not participate in energy arbitrage. The battery component of the hybrid facility is capable of providing grid services such as regulation or spinning but will not provide energy unless during load shed. "Ancillary Services Only" is not expected to be an actual operating mode a market participant would elect, and is intended to capture the ceiling of possible ELCC. Further, the capacity value of providing AS is expected to decline once battery penetration exceeds the total system AS obligation.

Results for this analysis are shown below in Table 12. The AS heuristic provides more capacity value to wind hybrids, due to the state of charge. Referring to Figure 5, wind hybrids would be expected to be energy limited more than solar resources. As such, the ability to conserve energy by providing AS allows more grid services to be provided during high load periods (e.g. a wind hybrid with 1 hour of charge could provide spinning reserves for 2 hours, then discharge, providing 3 hours of total grid services). This shows more value than an energy only hybrid system, where a wind hybrid with 1 hour of charge would discharge, resulting in 1 hour of total grid services.

Table 12. Ancillary Services Provisions (expressed as a percentage of interconnection capability)

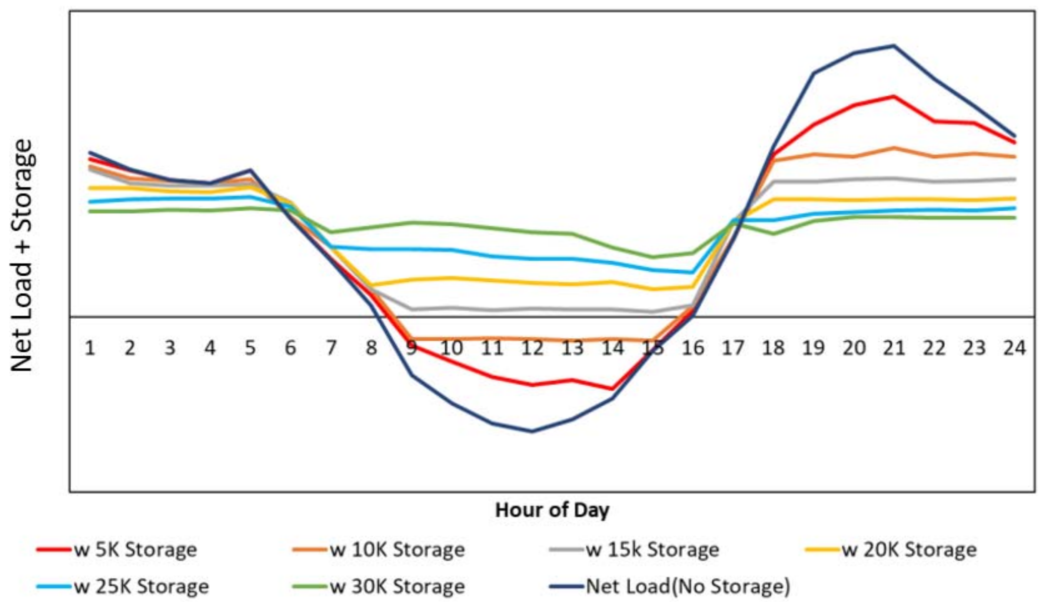
CA-N Hybrid, 2030	Dispatch Heuristic[24]	1-Hour	2-Hour	4-Hour
Solar Hybrid	Energy Only	62%	90%	96%
	Energy and Ancillary Services	93%	95%	96%
	Ancillary Services Only*	100%	100%	100%
Wind Hybrid	Energy Only	55%	78%	80%
	Energy and Ancillary Services	86%	89%	93%
	Ancillary Services Only*	N/A[25]	N/A	N/A

*In the Ancillary Services Only dispatch heuristic, the hybrid is capable of providing grid services such as regulation up or spinning but will not provide energy unless during load shed

RESULTS DISCUSSION

The decline seen in hybrid marginal ELCC can be attributed to increased storage penetration within the CAISO footprint. An extreme version of this concept is shown in Figure 7. As storage penetration increases, the overall load shape flattens. This limits the opportunity for incremental storage, leading to a diminished capacity value.

Figure 7. Impact of Storage on Net Load Shape (Illustrative)



[24] The resources are assumed to be capable of providing all services, but model settings are adjusted to utilize different dispatch heuristics for batteries in each respective case

[25] The Ancillary Services Only dispatch heuristic was not assessed for wind hybrids

This concept, to a lesser degree, is shown for results of this study. The increased battery penetration in 2030 relative to 2022 has the effect of broadening the demand in the evening, reducing the value (as measured by marginal ELCC) that energy-limited systems are able to provide.

Tracking PV and battery units were assumed AC coupled to serve as a conservative estimate of hybrid configuration. Based on the charging potential described earlier in this report, the variable generation portion of the hybrids studied have sufficient energy to fully charge a 1-, 2-, or 4-hour duration battery, and additional energy would not be expected to provide much additional value. Within the analysis, energy clipped by the hybrid inverter is not dispatched to the grid and based on the inverter loading ratios used, clipped energy does not exceed 1.5% on an annual basis for the studied hybrid resources.

The impact of standalone storage penetration on the marginal ELCC of wind hybrids is more pronounced than for solar PV hybrids of the same nameplate capacity. This is because wind hybrids can be thought of as having shorter duration storage than solar PV hybrids for the same nameplate capacities. As shown in Tables 9-11, lower duration storage hybrids have lower marginal ELCC values, all else being equal. The results also show that the marginal ELCC of a hybrid in 2030 is less than that of the same hybrid in 2022 due to increased penetrations of standalone battery storage which result in a flatter net load peak. For these reasons, increasing storage penetration will diminish the marginal ELCC of wind hybrids more rapidly than solar PV hybrids of the same nameplate capacity.

CONCLUSION AND LESSONS LEARNED

CONCLUSION

This report sought to provide the marginal ELCC values for the resource classes and class subtypes located in the seven locations of interest, detail the inputs assumptions (e.g., load, installed capacity), explain the methodology used to calculate the ELCC values, and compare the impact of the different locations on the same technology types.

The marginal ELCC values were observed to decline for all studied resources types as storage and renewable penetration increases in the CAISO footprint. Wind hybrid ELCC values fall slightly faster than solar hybrid ELCC values as these resource types are able to charge less prior to CAISO net load peak periods, rendering them shorter duration devices, and consequently more sensitive to the higher storage deployment in the 2026 and 2030 study years. Despite these differences, wind hybrids retain high ELCC values into 2030 with 1-hour duration, primarily due to the participation in AS.

For the purpose of this study, given the composition of CAISO with no existing hybrid resources, the marginal ELCCs for hybrid resource types equal the average ELCC. Marginal versus average ELCC would be expected to diverge as the penetration of hybrid (i.e. storage backed renewable resources) increases.

LESSONS LEARNED

In reviewing the results and input assumptions, several potential improvements to future ELCC studies were identified:

1. Given the low expectation for storage penetration by 2030 in the 2017-2018 PSP, a number of expected reliability interactions between solar and storage were not detected in this study. Subsequent ELCC studies with higher storage penetrations will explore these interactions.
2. Data quality for out-of-state wind profiles needs to be similar to that for in-state wind profiles to ensure comparisons of the resulting ELCCs are valid.
3. Hybrid results are dependent upon the expected operating mode and charging practices implemented. For Report 2, an improved storage scheduling routine was implemented which is expected to be more consistent with operation of hybrid resource types.
4. The impact of standalone storage penetration on the marginal ELCC of wind hybrids is more pronounced than for solar PV hybrids of the same nameplate capacity.
5. Shorter duration storage devices' (1- and 2-hour) reliability value is dependent on discharging behavior (i.e. provision of ancillary services).

APPENDIX – REPORT 1 UPDATES

Shown below are the final Report 1 values, which include updates to hybrid resources based on updated charging heuristics as covered in Report 2.

Table A1. ELCC Values for 2022 (expressed as a percentage of assumed interconnection capability)

Region	BTM PV	Fixed PV	Tracking PV	Tracking PV Hybrid	Wind	Wind Hybrid
CA-N	4.3%	5.4%	6.9%	100%	21.8%	96%
CA-S	3.6%	4.6%	5.4%	100%	18.0%	96%
AZ APS	N/A	4.6%	5.4%	97%	38.8%	100%
NM EPE	N/A	4.6%	5.4%	96%	38.8%	100%
BPA	N/A	N/A	N/A	N/A	32.7%	92%
CAISO	**4.0%**	**5.0%**	**6.2%**	**100%**	**19.9%**	**96%**
Average	**4.0%**	**4.8%**	**5.8%**	**98%**	**30.0%**	**97%**

Table A2. ELCC Values for 2026 (expressed as a percentage of assumed interconnection capability)

Region	BTM PV	Fixed PV	Tracking PV	Tracking PV Hybrid	Wind	Wind Hybrid
CA-N	1.3%	2.1%	3.4%	100%	17.9%	94%
CA-S	0.6%	1.2%	1.9%	100%	17.8%	95%
AZ APS	N/A	~0.0%	1.9%	97%	30.8%	97%
NM EPE	N/A	~0.0%	1.9%	95%	30.8%	97%
BPA	N/A	N/A	N/A	N/A	32.8%	90%
CAISO	**1.0%**	**1.7%**	**2.7%**	**100%**	**17.9%**	**94%**
Average	**1.0%**	**0.8%**	**2.3%**	**98%**	**26.0%**	**95%**

Table A3. ELCC Values for 2030 (expressed as a percentage of assumed interconnection capability)

Region	BTM PV	Fixed PV	Tracking PV	Tracking PV Hybrid	Wind	Wind Hybrid
CA-N	0.4%	1.3%	3.4%	96%	20.5%	93%
CA-S	~0.0%	~0.0%	~0.0%	97%	17.4%	93%
AZ APS	N/A	~0.0%	~0.0%	93%	30.2%	94%
NM EPE	N/A	~0.0%	~0.0%	92%	30.2%	94%
BPA	N/A	N/A	N/A	N/A	28.2%	90%
CAISO	**0.2%**	**0.7%**	**1.7%**	**97%**	**19.0%**	**93%**
Average	**0.2%**	**0.3%**	**0.9%**	**95%**	**25.3%**	**93%**