Track 3.B.1/Track 4 Workshops

Thursday, February 25, 2021

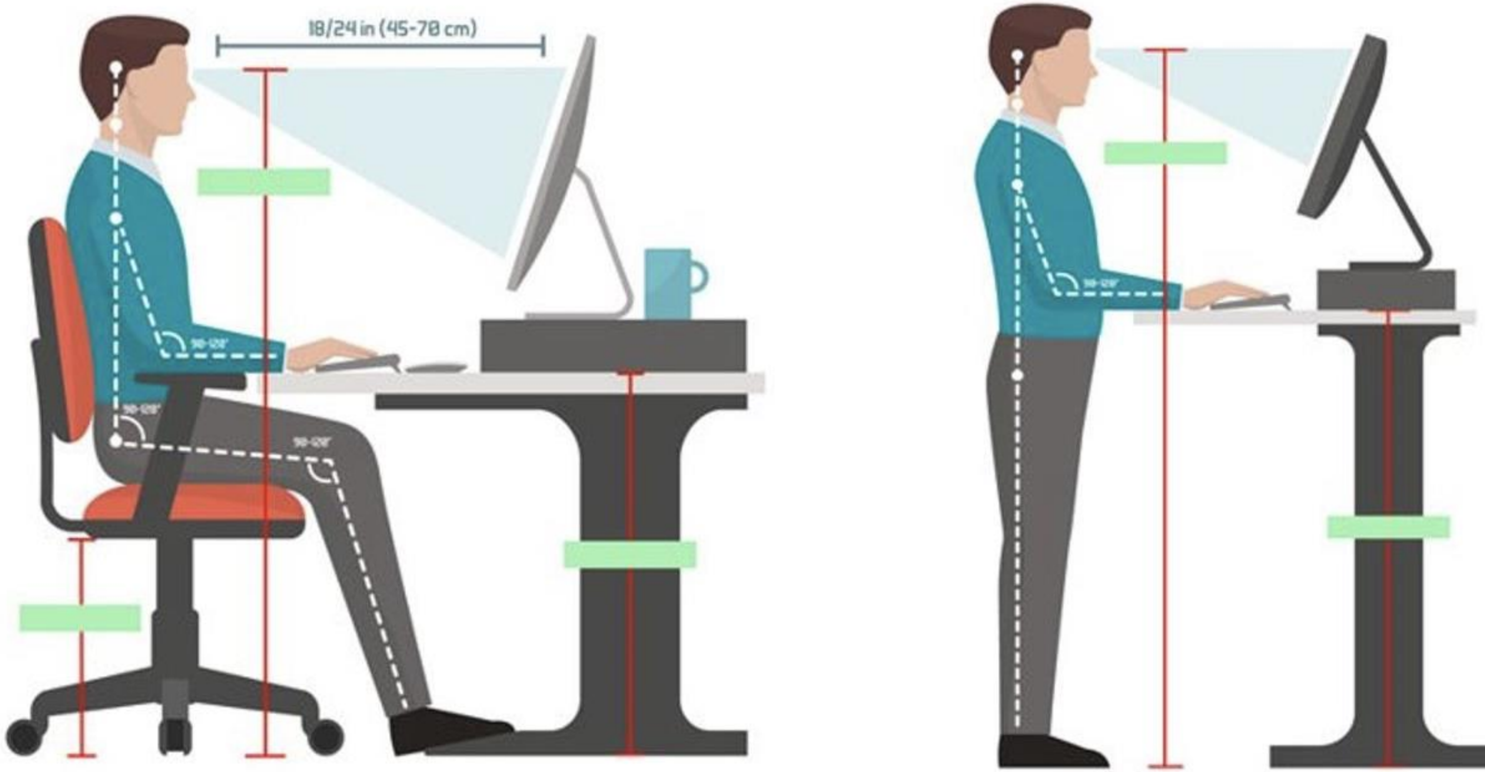
10:00 a.m. – 4:00 p.m.

Logistics

- Online and will be recorded

- Today's presentation & recording will be uploaded onto RA history website
    - https://www.cpuc.ca.gov/General.aspx?id=6316

- Hosts (Energy Division Staff)
    - Simone Brant
    - Linnan Cao
- Safety
    - Note surroundings and emergency exits
    - Ergonomic check



Logistics

- All attendees have been muted
- Presenters for each topic will be identified as panelists only when their topic is being addressed
- To ask questions, please use the "Q&A" function (send "To All Panelists") or raise your hand
- Questions will be read aloud by staff; attendees may be unmuted to respond to the answer. (Reminder: Mute back!)

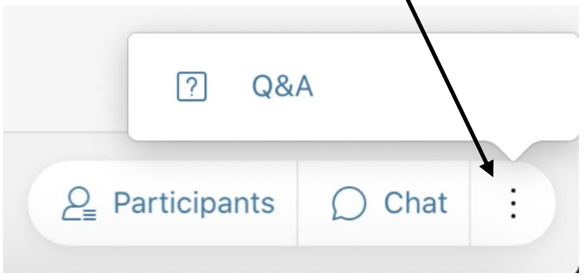
Mute/ Unmute

Participant List

Chat

Audio Options

"Q&A": on the bottom right of screen, click "3 dots"



Ground Rules

- Workshop is structured to stimulate an honest dialogue and engage different perspectives.
- Keep comments friendly and respectful.
- Please use Q&A feature only for questions, or technical issues.
- Do NOT start or respond to sidebar conversations in the Chat.

Agenda

Time	Topics	Presenters/Time Duration
10:00-10:10	Introduction	CPUC
10:10-10:40	RA Imports	CAISO
10:40-11:00	Planning Reserve Margin	Cal PA
11:00-11:45	Availability Limited Resource Procurement	CAISO
11:45-12:15	Locational ELCC	SWPG
12:15-1:15	Lunch	
1:15-1:35	MCC Buckets, Marginal ELCC and DR Adders	CPUC
1:35-3:05	ELCC for DR and Track 4 Proposals	CAISO
3:05-3:30	RA Penalties	CPUC PG&E
3:30-3:50	Hybrid QC	CEERT
3:50-4:00	RA as T&D Function	GPI

RA Import Requirements

10:10 – 10:40 a.m.

Milos Bosanac, CAISO

Import RA: CPUC Workshop

Milos Bosanac
Market and Infrastructure Policy
February 25, 2021

Tightening supply conditions across Western interconnection place greater emphasis on internal and import RA resources

- Recent August and September 2020 system conditions point to the need for reliable and dependable resources, including RA imports.

- CAISO capacity shortfall places greater emphasis on imports to manage grid conditions particularly during net load peak hours.

- Tightening capacity conditions expected across Western interconnection as states move toward cleaner energy policy goals.
  - Retirement of aging baseload resources and coal resources
  - Increased procurement across the west for firm energy, firm transmission supporting imports

- Severe west-wide climate events cause simultaneous tight system conditions across multiple BAAs, impacting once reliable supply diversity benefits.

RA import rules should be considered through the lens of reliability and dependability, ensuring non-speculative supply

- RA imports must be reliable and dependable during all conditions, especially during challenging west wide conditions.
  - Must have high certainty of performance when awarded
  - Must have high certainty of deliverability

- RA import rules should discourage speculative supply.
  - Potential speculative supply indicators/arrangements:
    - High priced energy bids into market to avoid dispatch
    - Supply consists of spot market procurement – supply may or may not be available from hour to hour, day to day
    - Double selling – selling firm energy to multiple entities, expecting all will not call on it simultaneously

CAISO Proposal

CAISO proposal identifies a set of minimum quality requirements for RA imports

- Minimum requirements for RA imports identify common attributes and qualities of RA imports across LSEs, ensuring these are reliable and dependable.

- Minimum requirements:
  - Must be source and/or BAA specific
  - Must meet attestation requirements ensuring commitment to LSE
  - Must be delivered on high priority transmission
  - Must have ability to meet a 24/7 must offer obligation

- Proposed RA import rules would be effective with RA year 2023.

CAISO Proposal – RA imports must identify the source of the generation

- *Eligible RA import resources*
  - Pseudo-tie
  - Dynamically scheduled
  - Non-dynamic resource specific RA imports:
    - Individual resources
    - Aggregation of resource in a single BAA
    - BAA system resources

- *Source specification*
  - Identify Name of resource (and associated e-tag identifier); and
  - Identify source BAA
    - For BAA system resources, only BAA must be identified.

CAISO Proposal – RA imports must be committed to the LSE for the duration of the showing

- RA imports must meet attestation requirements ensuring that the import is solely committed to the LSE (and consequently to CAISO).
  - Not committed to any other parties or uses
  - Surplus to the obligations of the supplier/importer in host BAA or any other contractual obligations
  - Cannot be interrupted for non-reliability reasons
  - Transmission arrangements supporting the RA import have been secured by the time of the showing

- RA imports will need to meet the attestation requirements for both the annual and monthly showings.
  - *Exception* – transmission arrangements attestation requirement only applicable for monthly showings (not annual).

CAISO Proposal – RA imports must be delivered on high priority transmission

- RA imports must be delivered on high priority transmission, providing higher certainty that these will be deliverable if awarded.
  - Firm transmission (7-F curtailment priority) on the last transmission leg to the CAISO system (prior to the CAISO being the transmission provider).
    - Firm transmission is the last type of transmission to be curtailed.
  - Firm transmission, Conditional Firm (6-CF priority), or Monthly Non-Firm (5-NM) priority transmission service on all other intervening transmission legs.

- As noted in the attestation, transmission arrangements supporting RA imports must be in place by the time of the showing (to meet attestation).

CAISO Proposal – RA Import offer obligation

- RA imports will continue to have a 24/7 Day Ahead Market (DAM) must offer obligation, with an interim Real Time Market (RTM) must offer obligation.
  - Today, RA imports have a 24/7 DAM must offer obligation.

- Under the current CPUC Maximum Cumulative Capacity (MCC) buckets, RA imports can be contracted with a 6x16 (6 days, 16 hours) or lesser availability.
  - Not available on Saturday and/or Sundays

- RA import offers into the market on weekends, and around the clock, are important to ensure that sufficient resources are available to meet the grid reliability needs.

Implications of CAISO Proposal

- Imports unable to identify the source of the generation (i.e., non-resource specific) will no longer qualify for RA purposes.
  – System sales, for example, will continue to qualify provided they can identify the source BAA
  – Non-resource specific imports are appropriate for economy energy and hedging, but not RA

- Firm energy contracts, and other contractual frameworks, can continue to support procurement of RA imports.
  – Must meet the new proposed requirements for RA imports.

- CAISO proposal does not preclude the Commission from retaining or imposing further bidding/self-scheduling restrictions for RA imports.

Benchmarking – Industry Practice

Industry Practice – RTO/ISO requirements for RA imports

RTO/ISO	Source	Transmission	Commitment/Attestation
MISO	Registration of External Resource – identifying physical resource	Firm transmission to the border	Certify that identified External Resource are not otherwise committed elsewhere
SPP	Requires resource test, which requires identification of physical resource	Firm transmission from external resource to load	Attestation – external capacity not otherwise used in any other BAA or in RA construct
PJM	Pseudo-tie only allowed. Requires submission of operational information, and execution of must offer agreement which identifies physical source.	Firm transmission to PJM border	Letter of non-recallability that energy and capacity from unit is not recallable to any other control area or by seller, and is exclusively dedicated to use in PJM.
ISO NE	Identification of generating resource	Firm transmission to border	Must demonstrate/verify the resource is not committed or sold to more than one entity
NYISO	Name and location of resource	Firm transmission to border	Certification that unforced capacity sold to LSEs has not been sold elsewhere for each month they intend to supply capacity.

Industry Practice – FERC pro-forma Open Access Transmission Tariff (OATT) & Western Transmission Providers/BAAs

- FERC *pro-forma* OATT requires, for LSEs serving load with Network Integration Transmission Service (NITS), that an off-system designated network resource must:
  - Identify source BAA
  - Identify transmission arrangements to border (firm or conditional firm transmission)
  - Submit an attestation that the resource (or portion designated) has not been committed to 3rd parties for duration of designation period.

- Western Transmission Provider OATTs have adopted the same or substantially similar requirements for designation of off-system resources serving Native or Network Load with NITS.

LSEs across the west are seeking and securing reliable and dependable imports in light of last Summer's heat wave

- Procurement across the western interconnection has placed an emphasis on increased dependability of imports.
  - Last Summer's heat wave affected multiple BAAs simultaneously

- LSEs relying on imports to serve load are seeking to secure more reliable and dependable imports through requirements in their Requests for Proposal (RFP):
  - Firm energy with firm transmission across applicable transmission systems
  - Firm energy from an identifiable existing resource or resources
  - Not sourcing from California

Appendix

Proposed RA Import Attestation Language – CAISO Tariff

1. The resource(s) supporting the proposed RA Import is/are:
   a. Owned by the Load Serving Entity for which the RA Import would provide RA capacity; or
   b. Contractually obligated by the seller of the resource(s) supporting the proposed RA Import to provide RA Capacity to the Load Serving Entity.
2. The quantity of RA Capacity on the Supply Plan from the proposed RA Import can be provided by the resource(s) supporting the proposed RA Import without securing capacity from additional resources.
3. The portion of the capacity from the resources(s) supporting the proposed RA Import is surplus to the obligations of that resource(s) to serve load or meet other commitments in the Host Balancing Authority Area.
4. The portion of capacity from the resource(s) supporting the proposed RA Import has not been, and will not be, sold or otherwise committed to any party other than the Load Serving Entity to which the proposed RA Import would provide RA Capacity.
5. Delivery to the CAISO Balancing Authority Area of the RA Capacity shown on the Supply Plan can only be interrupted because of:
   a. A transmission curtailment;
   b. An Outage of the resource(s) supporting the RA Import; or
   c. Reliability reasons as determined under the Host Balancing Authority Area's FERC tariff.
6. Transmission service of proper firmness has been reserved for delivery to the CAISO Balancing Authority Area of the proposed RA Import.

Planning Reserve Margin

10:40 – 11:00 a.m.

Kyle Navis and Christian Lambert, Cal PA

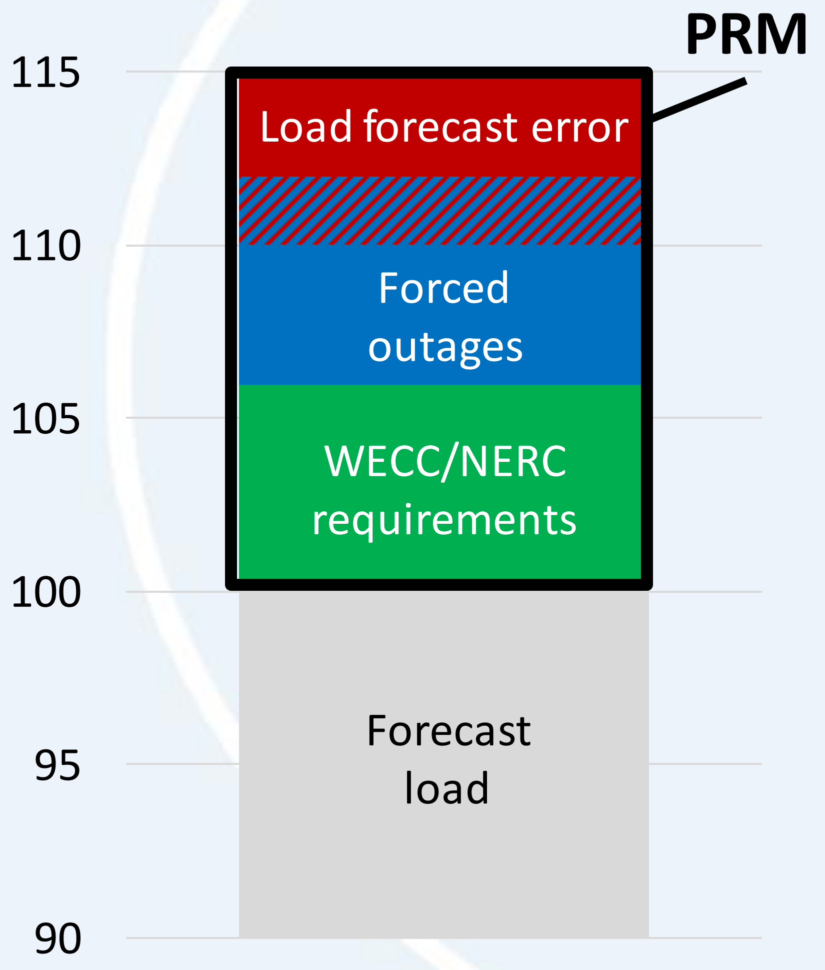
Planning Reserve Margin

Christian Lambert
christian.lambert@cpuc.ca.gov

Kyle Navis
kyle.navis@cpuc.ca.gov

Part I: Background and Basics

- PRM raises RA requirements 15% above CEC's 1-in-2 forecast peak demand
- 15% PRM adopted in D.04-01-050 includes:
  - 6% reserves
  - 4%-6% forced outages
  - 3%-5% load forecast error



The next 3-5 years

Supply tightening	Supply expanding	Contextual changes
• **Diablo Canyon** retirement in 2024-2025 • **OTC** plant retirements • **Tightening import** markets from accelerating WECC coal retirements • **Hesitation in the import** markets to comply with CPUC import rules—potential for additional CAISO RA import rules	• D.19-11-016 authorized **3,300 MW** incremental resources – primarily energy storage over 2021-2023 • D.21-02-028 **(emergency OIR) incremental procurement** • 4,700-10,400 MW under consideration for **incremental procurement in the IRP** for 2023-2026 (2/22/21 Ruling)	• **Extreme weather events**—need to reconsider which forecast to use • **CEC re-evaluating its methods** for calculating the 1-in-5 and higher forecasts to account for climate change / extreme weather events • CAISO **data on forced outages** may also require a higher PRM

Increasing the PRM won't solve short-term tight supply, and sequencing matters

- **2021**: PRM changes won't impact this year's outcome; changes to the PRM are considered in R.19-11-009
- **2022**: R.20-11-003 may authorize procurement for next year on similar terms to D.21-02-028; CPUC adopts new PRM by Q2 for RA Year 2023
- **2023 is the key year** for new PRM to go into force

Analysis so far

- SCE (R.20-11-003) and Energy Division (Track 3B.2 workshops) have presented LOLE studies looking ahead
- **CAISO proposal:** a 17.5% PRM for 2021 in R.20-11-003 and the same for 2022 in this proceeding
  - 1-in-2 load forecast
  - 6% reserves + 4% forecast error + 7.5% forced outages
    - Note: NERC Generator Availability Data System (GADS) shows a 7.2% rate
  - Cal Advocates estimates requirements would increase by about **2,523 MW** to meet this over 2021-2022
    - Note: the 2020 IEPR continues the CEC trend of increasing loads (incremental to prior IEPR); additional capacity will be needed

Part II: Considerations— Choosing the right forecast under climate change-induced uncertainty

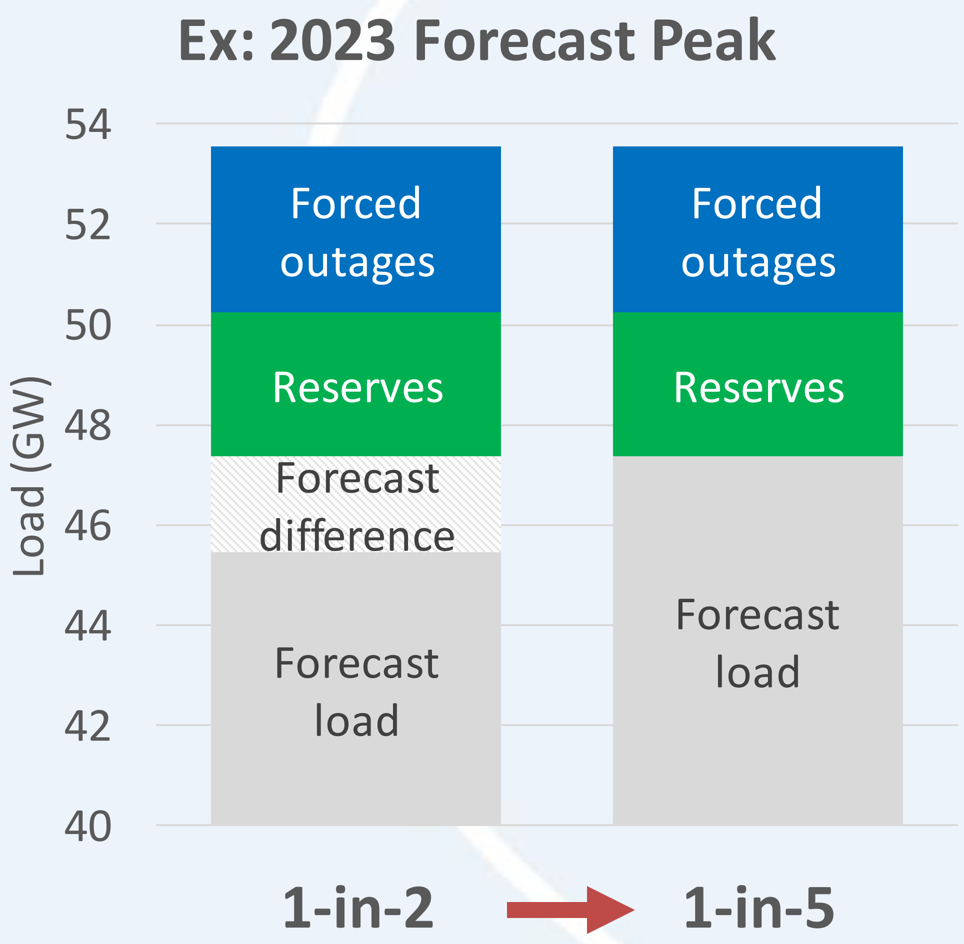
- CAISO suggested a 1-in-5 forecast and removing the 4% forecast error from the PRM (RA Enhancements initiative)
- Cal Advocates sees merit to proposal
  - More accurately accounts for longer tails in weather distributions caused by climate change
  - Fat tails are not evident in the 2019 and 2020 IEPRs, CEC statements suggest the 2021 IEPR will include new methodologies supporting the 1-in-5 and higher forecasts

CEC Load Forecast - Coincident CAISO Load	2021 (MW)	Relative to 1-in-2
1-in-2	45,184	-
1-in-5	47,108	+4.3%
1-in-10	48,162	+6.6%
1-in-20	48,911	+8.2%

Source: CEC 2019 IEPR Data

How to update the PRM

- Move towards a
  1-in-5 forecast + 13%
  6.0% reserves +
  7.0% force outages
- Equivalent to a
  1-in-2 forecast + 17.8%
  6.3% reserves +
  7.3% forced outages +
  4.3% forecast difference
- Align implementation with IRP procurement envisioned in 2/22/21 ruling



Timeline

RA Year	Load forecast + PRM	Rationale
2021	1-in-2 + 15%	**No change;** D.21-02-028 resources will push the contracted fleet above 15%
2022	1-in-2 + 15%	Considering additional contracts from D.21-02-028 and 2022 procurement anticipated in R.20-11-003, contracted fleet will end up in excess of 15%
2023	**1-in-2 + 16.5%** = 1-in-5 + 11.7%	Higher PRM phase-in year: final PRM level TBD, meant to meaningfully exceed the final R.20-11-003 procurement level
2024	1-in-2 + 17.8% = **1-in-5 + 13.0%**	Switch to using 1-in-5 forecast. The heaviest lift, considering retirements of OTC units. 1-in-2 + 6.26%[1] reserves + 7.30% forced outages + 4.26% forecast difference 1-in-5 + 6% reserves + 7% forced outages + 0% forecast error[2]

[1] Difference in reserve and forced outage percentages is due to the differing denominators. E.g. 60% of the 1-in-5 forecast is equivalent to 6.3% of the 1-in-2 forecast.

[2] The increased baseline forecast demand obviates the need for forecast error.

Side-by-side comparison

RA Year	Cal Advocates	CAISO
2021	1-in-2 + 15% + R.20-11-003 resources	1-in-2 + 17.5% (proposed in R.20-11-003)
2022	1-in-2 + 15%[1] + R.20-11-003 resources	1-in-2 + 17.5% (proposed in R.19-11-009, Track 3B.1)
2023	1-in-2 + 16.5%[2]	1-in-5 + 6% under UCAP = 1-in-2 + 23.5%[3]
2024	1-in-5 + 13%[2] = 1-in-2 + 17.8%	1-in-5 + 6% under UCAP = 1-in-2 + 23.5%[3]

[1] If procurement authorized by R.20-11-003 counts towards RA obligations, Cal Advocates would consider a TBD increase to the PRM in 2022.

[2] Does not include UCAP counting.

[3] Cal Advocates estimate; see RA Enhancements Initiative comments, January 15, 2021 for calculations.

Net load peak requirement

- CAISO proposes counting what resources are available at the net load peak/most critical hour after peak
- Net load peak requirement should not include solar, but gross load peak requirement should include all resources
- Has merit and requires further feasibility studies to determine if increasing the gross load peak requirement obviates need for net load peak requirement

Derating thermal resources during high temperatures

- The PRM will be more effective if the allowance for forced outages is less correlated with incidence of load above forecast
- Ambient derate outages are correlated with high load due to temperature impacts
- Ambient derates could be addressed with thermal resource NQC adjustments or pMax test requirements
- Similar principles as UCAP but more limited scope, may be easier to address RA contracting concerns

Final Note: RA vs IRP PRM

- IRP 2/22 ruling suggests a planning need of a **20.7% PRM** to ensure an LOLE of 0.1
  - Higher planning PRM captures both resources needed for the "true" RA PRM plus additional capacity that may be needed to ensure the charging of storage
- While this is an IRP issue, the RA proceeding will eventually need to consider if and how storage will be charged to provide its RA attributes
- CAISO will make Minimum State of Charge recommendations in RA-E for 2021-22 and will open a stakeholder initiative for future years

Availability Limited Resource Procurement

11:00 – 11:45 a.m.

Catalin Misca, CAISO

Availability Limited Resource Procurement

Catalin Micsa
Senior Advisor Regional Transmission Engineer

CPUC workshop
February 25, 2021

Changing Landscape

- Historically RA procurement was mostly based on nuclear and gas resources that can produce 24 hours per day, currently are being replaced with renewable (wind and solar) resources plus battery storage technology that can produce limited hours per day.
- Intermittent resources like wind and solar are almost entirely non-dispatchable (at least not in the upward direction).
- Battery storage is highly dispatchable, however it has limitations both in MW and MWh output, it also has to charge (more than discharge) – can be highly constrained especially in local areas that have limited transmission and/or other resources.

Capacity and Energy Procurement

- Reliability must be maintained 24 hours a day and it will become more and more challenging without resources that can produce 24 hours a day
- Battery storage development (especially local) can be guided to areas of the grid that permit charging as well as discharging both under normal and under emergency conditions
- Future local capacity procurement must account for LSEs' capacity and energy needs, including ability to charge battery storage

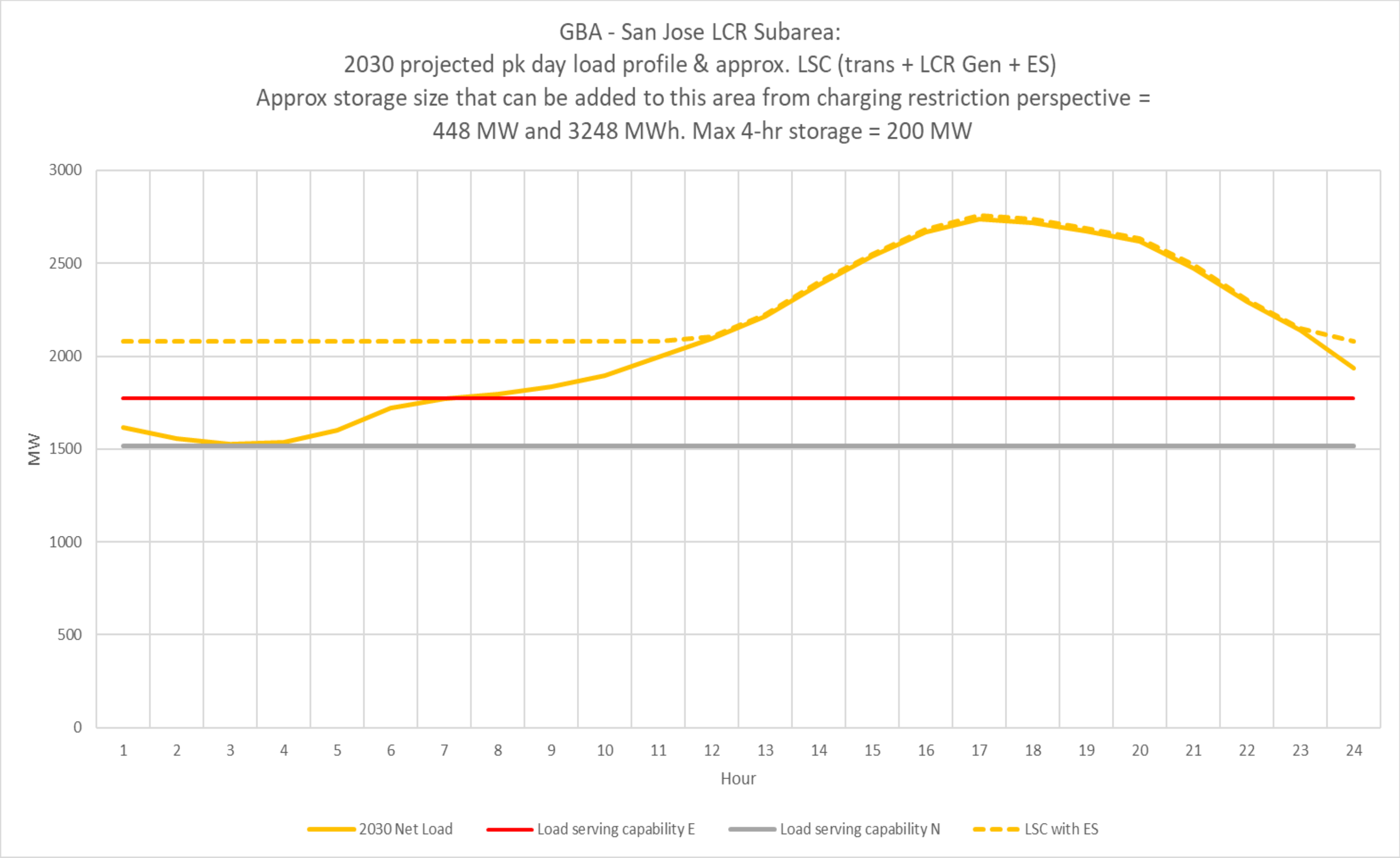
Battery Storage

- Currently there is high regulatory and commercial interest in this technology
- Highest interest is in building 4-hour battery storage resources, mostly due to RA counting rules.
- Mixed expectations
  - maximize the local and system RA value
  - minimize the CAISO back-stop costs
- For all “4 hour” batteries installed in local areas, once the local need passes the 4-hour mark, they do not eliminate the local need for other local resources on a 1 MW for 1 MW basis.

Battery Storage Characteristics - Assumptions

- Storage replacing existing resources are assumed to have the same effectiveness factors
- Charging/discharging efficiency is 85%
- Daily energy charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability (transmission + remaining resources)
- Hydro resources are considered to be available for production during off-peak hours
- The study assumes perfect dispatch; however, this is not possible in reality given all operational uncertainties
- Capped maximum charging at the capacity of storage added
- Amount of storage added is limited to the LCR need
- Includes the greater of 5% or 10 MW margin for both charging and discharging
- Deliverability for incremental capacity is not evaluated

Example: Graph after change (non-flow through area)



California ISO

Battery Storage – Local Graph

- Maximum storage (MW and MWh) that can charge under contingency conditions in order to be available the next day to meet local needs
- Maximum 4-hour storage, added per stakeholder request – it is the maximum MW value where the technical local need = RA counting on a 1 MW for 1 MW basis
- The results represent <u>an estimate of future buildout</u> – actuals could differ mainly due to effectiveness factors
- The new estimates for flow-through areas have a much higher degree of uncertainty because the need to mitigate the main constraint may not follow the "estimated" load curve and could impact the charging/discharging cycle.

RA Counting or Qualifying Capacity

- Local Regulatory Authorities (LRAs) can set the Qualifying Capacity:
  - CAISO has default rules (in case LRAs don't have their own rules)
- Per CPUC rulings and CAISO Tariff, each resource *must* have a single QC (NQC) value.
- The only reason a resource counts for local is because it is located inside a local area.
- CAISO can decrease the QC to NQC, for testing (Pmax), performance criteria (not used) and deliverability.

The Local Capacity Technical Study

- Does not establish RA counting
- Does establish the local RA resources (by delineating the local area boundaries); as long as the resource can be pre-dispatched or can be dispatched up after the contingency in the time allowed for readjustment
- Does establish the individual local RA requirement for each LSE based on their load share ratio within the TAC vs. the total LCR requirement for that TAC
- Does establish the technical requirements.
  - Total MW need by TAC (RA individual enforcement + ISO back stop)
  - MW need by local area or sub-area (RA guidance only + ISO back stop)
  - Effectiveness factors (RA guidance only + ISO back stop)
  - Load charts (RA guidance only + ISO back stop)
  - Battery charging parameters (RA guidance only + ISO back stop)

CAISO local CPM enforcement

- Total MW need by TAC + MW need by local area or sub-area + effectiveness factors
  - First, costs are allocated to individual deficient LSEs on their month by month deficiency bases as available in their year ahead annual showing
  - Second, remaining costs are allocated to all LSEs
- The technical requirements (justification for the local CPM) are public in the LCR report
- Currently energy needs (like load charts and battery charging) are not used to CPM
- During RA Enhancement initiative, the CAISO is seeking authority to enforce local CPM for energy needs. Potentially starting as early as RA year 2022.

CAISO local RMR enforcement

- RMR is not automatic – a resource must be non-RA and must ask (by submitting a signed affidavit) for retirement or mothball
- CAISO can enforce any reliability need (Total MW need by TAC + MW need by local area or sub-area + Effectiveness factors + Load charts + Battery charging limits)
- Costs are divided to all the LSEs in the appropriate TAC(s) that drive the local need.
- The technical requirements (justification for these local RMR contracts) must be made public (if not already public in the LCR reports).

Example:

- A new battery resource with Pmax of 800 MW and energy of 800 MWh is located in a local area
- The local area has an LCR need of 800 MW (with other 1,000 MW of available resources), and a maximum battery charging capability of 110 MW (780 MWh) and a maximum 4-hour battery of 35 MW.
- The new resource will count towards each LSEs individual RA responsibility as 200 MW (both system and local).
- Technically for local only 110 MW (780 MWh) can be used. If the total RA showings (including this resource) is above 890 MW (assuming all units just as effective) then the technical needs are met; else the CAISO could RMR and hopefully in a few years CPM additional resources.

Summary

- Technical needs have not and will not equal RA counting
- CAISO is not advocating for changes in local RA counting at this juncture.
- CAISO suggests LSEs use the analysis as guidance for their future local procurement.
- CAISO's LCR analysis is provided annually for year one and five as well as every other year for year ten.
- CAISO proposes that the local energy analysis becomes enforceable under CAISO local CPM authority starting with RA year 2022.

Summary (con't)

- CAISO does advocate that both the LSEs and LRAs be mindful of local constraints when purchasing new battery storage resources if they want to both maximize the RA value and minimize CAISO back-stop
- While CAISO's proposal is explicitly targeted to local capacity, the same trend is observed at the system level.
- Therefore, CAISO advocates that both capacity and energy be accounted for in future procurement of both local and system resources, that meets both the gross and net peaks as well as meets energy needs 8760 hours a year.

Locational ELCC

11:45 a.m. – 12:15 p.m.

Ravi Sankaran, SWPG

SouthWestern
POWER GROUP

Locational Wind QC /ELCC

Ravi Sankaran
Southwestern Power Group (SWPG)
RA Track 3B.1 & 4 Workshop
February 25, 2021

About SWPG

- Independent developer of utility-scale generation and transmission in the Desert Southwest
- Project Manager/Developer of the SunZia Southwest Transmission Project to deliver up to 3 GW New Mexico wind to western power markets
- Established in 2000, based in Phoenix and Albuquerque, staff of 15
- Owned by parent MMR Group, a privately-held construction services firm based in Baton Rouge, LA

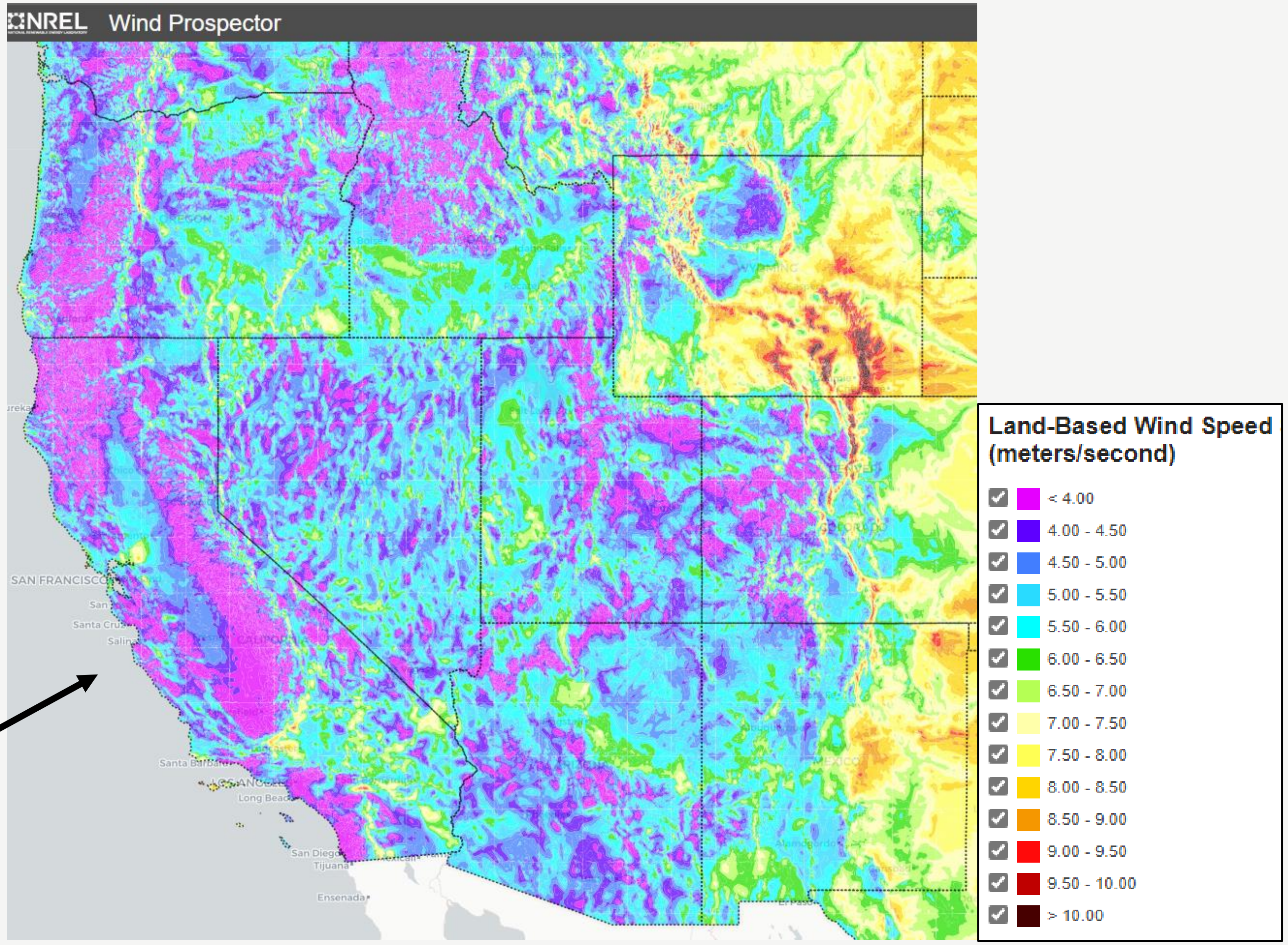
Background

- RA Net Qualifying Capacity (NQC) for all wind projects currently based on uniform monthly ELCC values for all locations, sending misleading RA price signals to LSE's and limiting confidence in RA values
- SWPG therefore proposes higher wind locational granularity using RESOLVE regional Capacity Factors. SWPG's proposed solution submitted in Track 3 August 2020 and refined in 3B.1 January 2021.
- In July 2020 IOU's released Astrape ELCC Study based on the 7 CPUC-directed regions, though more relevant to procurement evaluation than actual NQC allocation; followed by December 2020 2nd report
- Proposed solution focused on wind since wind more location-dependent than other technologies

Current Wind ELCC Technology Factors[1]

Month	CY 2021 Wind ELCC
1	14.0%
2	12.0%
3	28.0%
4	25.0%
5	25.0%
6	33.0%
7	23.0%
8	21.0%
9	15.0%
10	8.0%
11	12.0%
12	13.0%

Current uniform Wind ELCC factors do not capture diversity of wind resource, sending misleading RA price signals



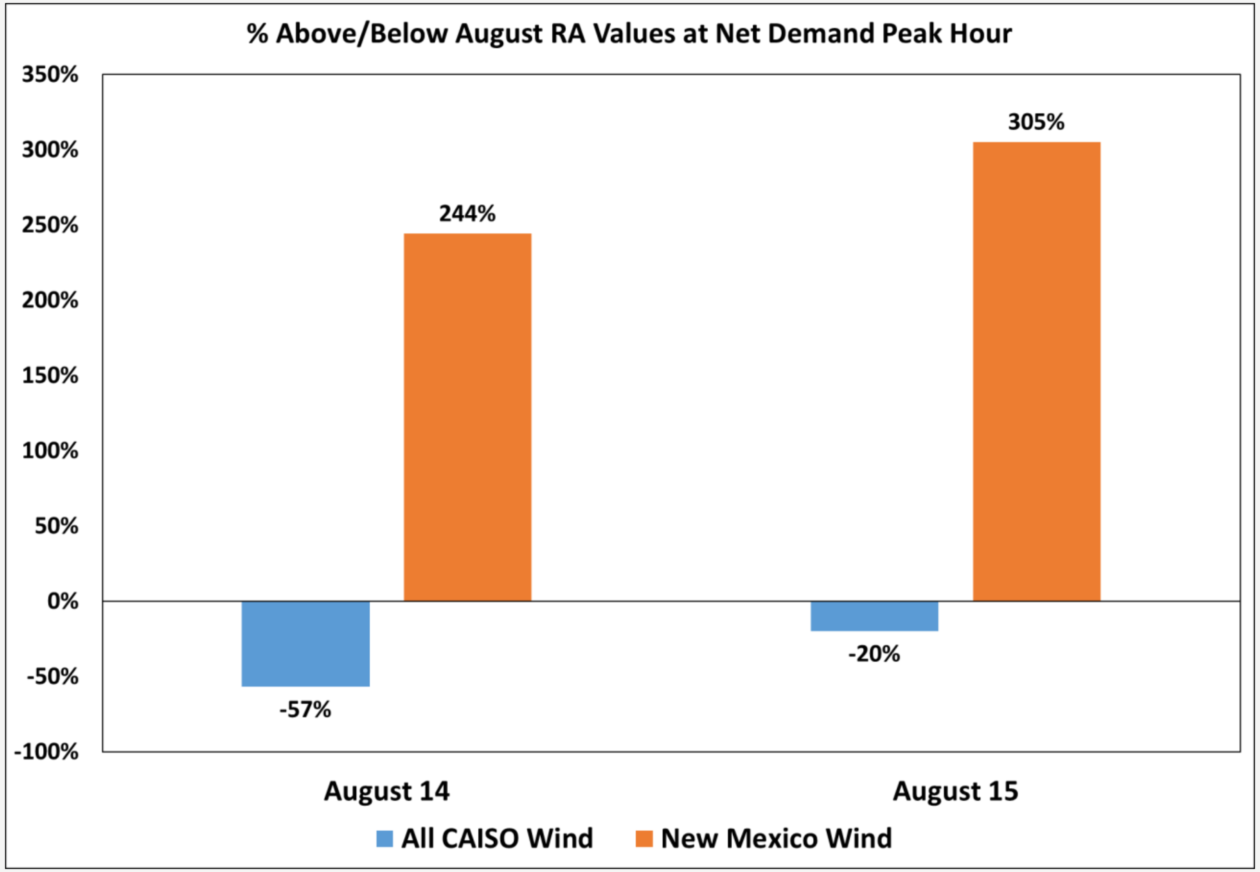
[1] Source: CAISO Final Net Qualifying Capacity List 2021

Consequences of Uniform Wind ELCC from August 2020 Heatwave

Final Root Cause Analysis of Mid-August 2020 Extreme Heat Wave, January 13, 2021, pp. 49-50:

"The total wind fleet within the CAISO collectively bid into the day-ahead market about 230 MW (20%) less than the RA obligation at the net peak demand on August 14 but 120 MW (10%) more on August 15. In contrast, actual energy production during the net demand peak was 640 MW (57%) less and 230 MW (20%) less [than the RA obligation] on August 14 and 15, respectively."

NM wind produced 244% and 305% above August RA value during net demand peak hour on August 14 and 15, respectively, compared to total CAISO wind fleet at -57% and -20%.



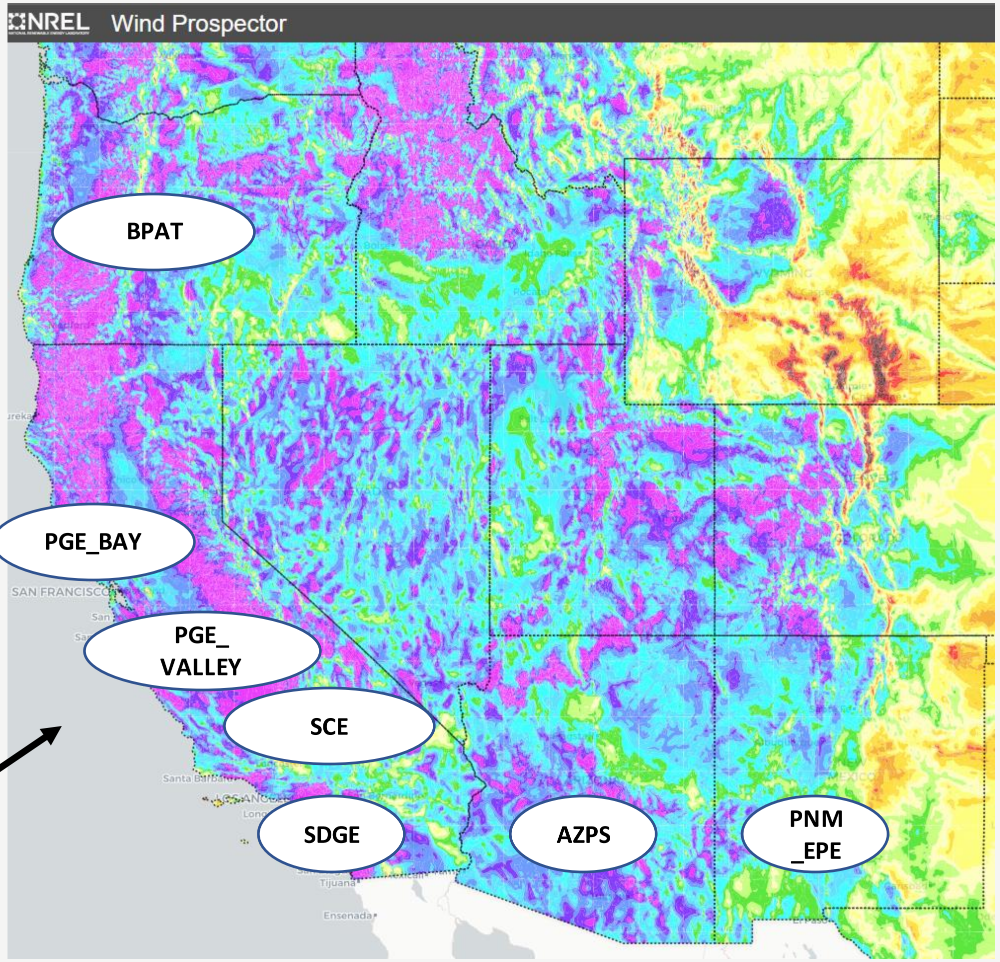
Source: NM wind data from operating wind farms in Curry County, NM. Graph shows % above August RA value based on energy dynamically scheduled to CAISO Scheduling Point at net demand peak hour August 14 and 15, 2020.

Joint IOU Astrape ELCC Study Areas

Astrape Study based on seven (7) regions prescribed in D.19-09-043[2]:

Locations	SERVM Region
Northern CA (CA-N)	PGE_BAY
	PGE_Valley
Southern CA (CA-S)	SCE
	SDGE
Northwest US (OOS-NW)	BPAT
Southwest US (OOS-SW)	AZPS
	PNM_EPE

7 regions studied provide increased granularity, but tied to utility service areas rather than wind resource areas and in limited geographies



[2] *Source: CPUC D.19-09-043, Table II at 20*

IRP Inputs RESOLVE Wind Capacity Factors

Wind shapes taken from NREL Wind Integration National Dataset Toolkit Candidate Onshore Wind Resources shown below[3]

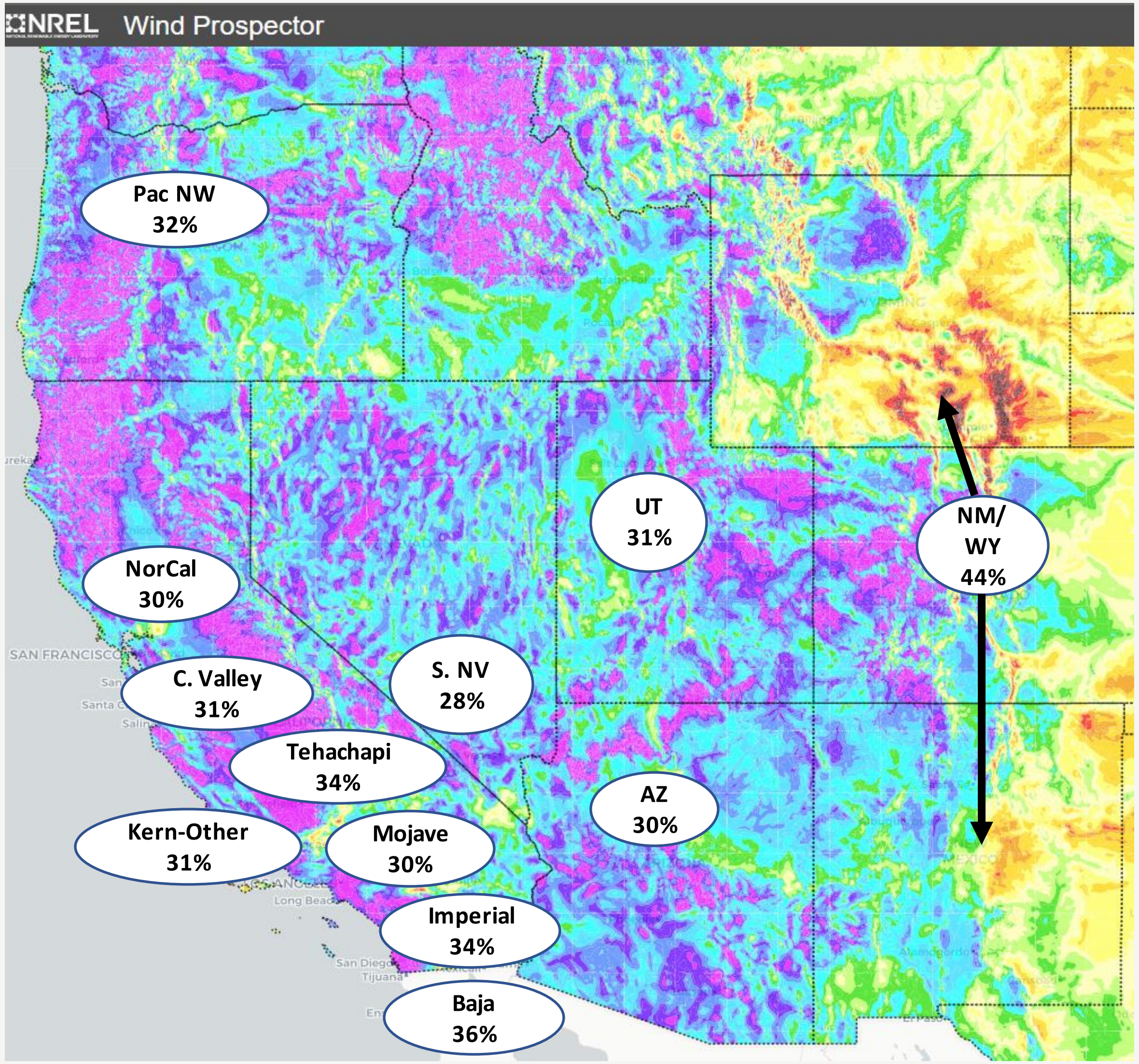
Resource	Capacity Factor	Resource	Capacity Factor
Arizona_Wind	30%	Pacific_Northwest_Wind	32%
Baja_California_Wind	36%	Pisgah_Wind	31%
Carrizo_Wind	31%	Riverside_Palm_Springs_Wind	34%
Central_Valley_North_Los_Banos_Wind	31%	Sacramento_River_Wind	29%
Greater_Imperial_Ex_Wind	34%	SCADSNV_Wind	30%
Greater_Imperial_Wind	34%	Solano_subzone_Wind	30%
Greater_Kramer_Wind	31%	Solano_Wind	30%
Humboldt_Wind	29%	Southern_CA_Desert_Ex_Wind	30%
Idaho_Wind	32%	Southern_Nevada_Wind	28%
Inyokern_North_Kramer_Wind	31%	SW_Ext_Tx_Wind	36%
Kern_Greater_Carrizo_Wind	31%	Tehachapi_Ex_Wind	34%
Kramer_Inyokern_Ex_Wind	31%	Tehachapi_Wind	34%
New_Mexico_Wind	44%	Utah_Wind	31%
North_Victor_Wind	31%	Westlands_Ex_Wind	31%
Northern_California_Ex_Wind	29%	Wyoming_Wind	44%
NW_Ext_Tx_Wind	30%		

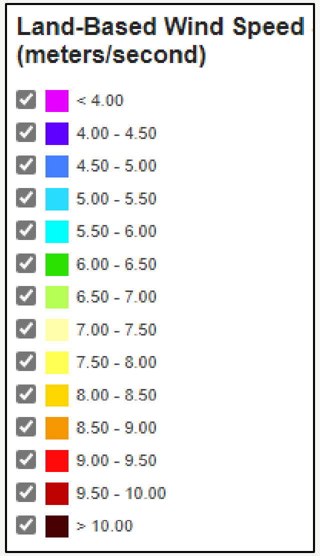
Table 48 lists CF% for 31 Candidate Onshore Wind Regions, but can easily be consolidated by proximity (next slide)

[3] *Source: CPUC Inputs and Assumptions: 2019-2020 IRP, November 2019, Table 48*

Consolidated RESOLVE Candidate Wind Resource Areas

- NREL Capacity Factors can be consolidated from 31 to 12 with negligible loss in granularity
- 12 regions have median 31% CF%





Resulting ELCC Values by Wind Region

Based on 31% Median CF%, each of 12 regions given multiplier based on CF% value relative to the median.

Resulting monthly ELCC's shown below:

		REGIONS AND MULTIPLIERS BASED ON MEDIAN CF%											
	Current	S. NV	NorCal	Mojave	AZ	C. Valley	Kern-Other	UT	Pac. NW	Tehachapi	Imperial	Baja	NM/WY
Month	ELCC	0.90	0.97	0.97	0.97	1.00	1.00	1.00	1.03	1.10	1.10	1.16	1.42
1	14.0%	12.6%	13.5%	13.5%	13.5%	14.0%	14.0%	14.0%	14.5%	15.4%	15.4%	16.3%	19.9%
2	12.0%	10.8%	11.6%	11.6%	11.6%	12.0%	12.0%	12.0%	12.4%	13.2%	13.2%	13.9%	17.0%
3	28.0%	25.3%	27.1%	27.1%	27.1%	28.0%	28.0%	28.0%	28.9%	30.7%	30.7%	32.5%	39.7%
4	25.0%	22.6%	24.2%	24.2%	24.2%	25.0%	25.0%	25.0%	25.8%	27.4%	27.4%	29.0%	35.5%
5	25.0%	22.6%	24.2%	24.2%	24.2%	25.0%	25.0%	25.0%	25.8%	27.4%	27.4%	29.0%	35.5%
6	33.0%	29.8%	31.9%	31.9%	31.9%	33.0%	33.0%	33.0%	34.1%	36.2%	36.2%	38.3%	46.8%
7	23.0%	20.8%	22.3%	22.3%	22.3%	23.0%	23.0%	23.0%	23.7%	25.2%	25.2%	26.7%	32.6%
8	21.0%	19.0%	20.3%	20.3%	20.3%	21.0%	21.0%	21.0%	21.7%	23.0%	23.0%	24.4%	29.8%
9	15.0%	13.5%	14.5%	14.5%	14.5%	15.0%	15.0%	15.0%	15.5%	16.5%	16.5%	17.4%	21.3%
10	8.0%	7.2%	7.7%	7.7%	7.7%	8.0%	8.0%	8.0%	8.3%	8.8%	8.8%	9.3%	11.4%
11	12.0%	10.8%	11.6%	11.6%	11.6%	12.0%	12.0%	12.0%	12.4%	13.2%	13.2%	13.9%	17.0%
12	13.0%	11.7%	12.6%	12.6%	12.6%	13.0%	13.0%	13.0%	13.4%	14.3%	14.3%	15.1%	18.5%
AVG	19.1%	17.2%	18.5%	18.5%	18.5%	19.1%	19.1%	19.1%	19.7%	20.9%	20.9%	22.2%	27.1%

Summary and Conclusions

- Urgent need for wind ELCC locational granularity to improve confidence in RA NQC allocations and send appropriate procurement signals, especially in light of extreme weather events
- Proposed solution offers following benefits:
  - Utilizes NREL resource data already in RESOLVE and aligned with SERVM
  - Covers all major wind resource areas serving CA market
  - Simple and can easily be “bolted on” to existing NQC factors
  - Good near-term solution while awaiting longer-term solutions
  - Compatible with static or marginal/dynamic ELCC methodologies

Lunch **Break**

Until 1:15 p.m.

Energy Division Proposals

1:15 – 1:35 p.m.

Simone Brant, CPUC

Energy Division Proposals

- Marginal ELCC for New Solar
- Adjust MCC Buckets
- DR MCC Bucket
- Demand Response Adders and Credits
- Revise RA Penalty Structure

Marginal ELCC for New Solar

- The marginal ELCC value for solar is nearly 0 (recent ELCC study for RPS found 5% in 2022)
- In constrained system want to encourage development of new resources that address system reliability challenges particularly in evening hours as the sun sets
- Propose that any solar contracted after the Track 4 decision receives a 0 QC value
- Existing solar continues to receive average ELCC

Adjust MCC Buckets

- The DR MCC Bucket and Buckets 1 and 2 require availability only on weekdays
- Not aligned with 2020 August and September peak loads when 3 of 6 highest peak days occurred on weekends and ~3,000 MW not available
- Propose requiring Saturday availability for all RA resources
- Also, propose increasing Bucket 1 availability to at least 100 hours per month rather than 40. Aligns with 4 hrs/day Monday-Saturday
- Eliminate Category 2 (8 hrs/day including 4-9 p.m.)

Proposed Revision

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions but must be available Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May - September	8.3%
1	Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 100 hours per month	17.4%
2	Monday – Saturday, 16 consecutive hours that include 4 PM – 9 PM	34.8%
3	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

DR MCC Bucket

- Assess whether the current cap of 8.3 percent is appropriate or whether a lower one should be considered for DR serving as a reliability resource, in light of the DR performance issues identified in the root cause analysis.
- Consider minimum dispatch requirements. Potential options include 24 hours/month which would align with the DR MCC bucket or 60 hours over the summer months.
- Consider maximum bid prices. PDR resources are expected to dispatch under typical, not just emergency conditions. Allowing resources to bid at the $1,000 (soon to be $2,000) price cap results in dispatches under only extreme conditions. Staff requests input on what a reasonable bid cap would be.
- Disallow startup costs for PDR resources. Startup costs are generally used by thermal resources in the Masterfile to account for the costs associated with turning on a gas plant. While most DR resources do not have any associated startup costs in the Masterfile, several providers have high startup costs. This, on top of bids at the cap, nearly ensures that a resource will never be dispatched economically. Staff propose requiring that all DR resources have startup costs of $0.

Demand Response Adders and Credits

- Currently demand response QC values are grossed up by TAC-specific transmission & distribution loss factors and a 15% planning reserve margin adder
- CAISO has said they will not accept credits for these adders or DR not on supply plans after 2021 (PRR 1280)
- Questions:
  - Should the Commission require the investor-owned utilities to include their demand response resources on supply plans or are there barriers that must first be addressed?
  - If demand response resources are not put on supply plans and the CAISO follows through with its proposed BPM revision, how can this capacity be counted?
  - Should, and if so how should, the transmission and distribution (T&D) and/or the PRM adders be retained and accounted for in CAISO's system?
    - Is it appropriate to include the transmission and/or distribution adder in the Net Qualifying Capacity (NQC) value of a DR resource?
    - Would including adders subject DR resources to RAAIM penalties?
    - Are there technical barriers to including adders in a resources NQC value or CAISO systems that would need to be changed?

ELCC for DR and Track 4 Proposals

1:35 – 3:05 p.m.

Lauren Carr, CAISO

RA Crediting and Demand Response

Lauren Carr
Infrastructure and Regulatory Policy Specialist

Resource Adequacy Track 3B1 and 4 Workshop
February 25, 2021

In Track 3B1 and Track 4 of the RA proceeding, the CAISO proposes several important, interrelated changes

1. End the practice of “crediting” resources against the RA requirement without showing them on supply plans (Track 4)

2. Adopt an Effective Load Carrying Capability (ELCC) methodology for variable-output demand response (Track 3B1)

3. Remove the Planning Reserve Margin adder from demand response capacity values (Track 4)

4. Allow only fast responding Reliability Demand Response Resources (RDRR) to meet local capacity requirements (Track 4)

The Commission should end the practice of "crediting" resources against the RA requirement without showing them on supply plans

- The practice of crediting without showing RA resources erodes the CAISO's ability operate the system reliably based on capacity procured through the local regulatory authorities' RA programs

- The CAISO is committed to finding solutions to the issues that led to crediting practices, but it is also necessary to end the practice to preserve the on-going integrity of the RA program, and the RA fleet the CAISO relies on to maintain reliability day-to-day

- This applies to all local regulatory authorities in the CAISO footprint, and will ensure there is no leaning on others' RA capacity, no discriminatory treatment among RA providers, and no LRA usurpation of the CAISO tariff rules applicable to RA resources

- The CAISO has allowed this business practice in the past but it is not a requirement or process in the CAISO tariff

The practice of crediting undermines the RA program's efficacy and jeopardizes reliability

- Because the credited resources are not shown on a supply plan, the CAISO system does not have any linkage to the actual resources supporting the credit
- Even if these resources are registered in the CAISO's Master File, they are not subject to the resource adequacy must-offer obligation, substitute capacity obligations, or the resource adequacy availability incentive mechanism (RAAIM) incentives
- Additionally, if the credited resources are not backed by actual participating resources on the CAISO grid, they are not subject to exceptional dispatch and are not visible to the CAISO's resource adequacy-related systems

The CAISO initiated Business Practice Manual (BPM) Proposed Revision Request 1280 (PRR 1280) process to ensure equal treatment and reliability of the RA fleet

- PRR 1280 would have rejected any non-net-neutral credits that lower an LRA's RA requirement without a supply plan showing
  - The CAISO would still allow for net-neutral credits (*i.e.*, to facilitate cost allocation across local regulatory authorities or across load serving entities) as long as RA resources are shown on supply plans and therefore subject to CAISO RA rules
- The Commission and stakeholders expressed concern with eliminating credits for IOU demand response programs
  - Concerns largely centered around RAAIM exposure
- PRR 1280 is held in abeyance until the CAISO and Commission work constructively and collaboratively to resolve the crediting issues by August 1, 2021

Stakeholder concerns illuminate issues around the current counting methodology for demand response

- The current qualifying capacity counting methodology does not reflect demand response resources' variability
- If credited DR programs are incapable of delivering their RA capacity value as currently established, then they should be formally recognized and valued as a variable energy RA resource
- If DR were evaluated like other variable resources under an ELCC methodology, then a RAAIM exemption would be appropriate
  - Until that time, DR is a fixed capacity resource subject to RAAIM like all other similarly situated RA resources

The following principles must be incorporated into demand response capacity evaluation

- Must assess DR's contribution to reliability across the year or seasons
  - Should evaluate how DR contributes to system reliability beyond the monthly peak day during peak hours
- Must assess DR's capacity value as a variable resource
  - DR resources are not fixed capacity resources; most have a variable load curtailment nature
- Must assess DR's interactive effects with other resources
  - Use- and availability-limited resources, like DR, can saturate alongside similar resources; incremental amounts of the same resource type adds less and less additional value to the system

The Commission should adopt an ELCC methodology for variable output demand response

- An ELCC methodology informs DR’s contribution to system reliability, considering its load reduction profile, availability, and use-limitations
  - Considers interactive effects of variable and use-limited resources
  - This assessment helps inform program design features and overall investment decisions to ensure procuring best resources at lowest cost
  - Use of an ELCC methodology will provide operational flexibility to demand response resources through bidding actual capability
- Load Impact Protocols (LIPs) could be useful in establishing operational capability of DR resources

E3 study performed in the ESDER process demonstrated demand response can be evaluated under an ELCC

- Used bids to form an 8760 availability profile for demand response
- Captured interactive effects of demand response with other energy-limited resources
- Demonstrated methodology for allocation to different programs based on energy availability
- The work performed in the ESDER process should be used as a springboard for developing ELCC values for DR

Source: E3 Demand Response ELCC Study, http://www.caiso.com/InitiativeDocuments/E3DemandResponseELCCStudy-EnergyStorage-DistributedEnergyResourcesPhase4.pdf

The Commission Should Remove the PRM Adder from Demand Response Capacity Values

- To set system RA requirements, the Commission adds a 15 percent planning reserve margin (PRM) to the peak load forecast to account for forced outages, forecast error, and operating reserves

- To set the QC for demand response, load impacts are multiplied by 1.15 to gross up demand response capacity values by the amount of the PRM

- This practice inappropriately reduces the available resource adequacy capacity needed by the system, for the reasons described in the next slide

The PRM adder wrongly reduces the amount of RA procured

- In real-time, the CAISO must procure sufficient supply and reserves to serve load and meet all applicable reliability criteria at that time, regardless of what the forecast was in the planning horizon
  - This includes load that is subject to curtailment by a supply-side DR resource
- Including a PRM adder wrongly assumes curtailable load does not exist on the system and does not need to be served in the first instance, i.e., essentially treating it like energy efficiency
- Demand response does not reduce the CAISO's reserve requirements or costs, and there is no evidence demand response lowers the system forecast error or lowers the system average forced outage rate

The Commission should allow only fast responding RDRR to meet local capacity RA requirements

- To meet local RA needs, resources must either:
  - Be able to respond within 20 minutes following a contingency event, or
  - Have availability to be dispatched frequently on a pre-contingency basis
- The CAISO cannot pre-contingency dispatch slow RDRRs because these resources can only be dispatched after the CAISO has declared an emergency or warning event
- As a result, the CAISO can only rely on “fast” RDRR to effectively meet local capacity needs
  - “Fast” demand response resources are those that can fully respond within 20 minutes of a contingency event

Slow RDRRs that can partially respond within the 20-minute window cannot partially count toward meeting local capacity needs

- The partial counting approach:

  1. is inconsistent with the current RA rules that require a single resource to have the same local and system qualifying capacity values

  2. does not ensure a firm response within the 20- minute timeframe

- Although the CAISO cannot utilize slow RDRR to meet local capacity needs, demand response providers could create separate resources to distinguish between fast and slow responding resources

These proposals should be adopted together to ensure reliability and comparability of all RA resources

- The commission should commit to developing new qualifying capacity methodology for DR with stakeholders in 2021 to enable its use in 2022
  - Transitional methodology may be needed before fully implementing ELCC
  - A methodology that assesses DR's contribution to reliability would enable the CAISO to revise its tariff to treat DR as a variable resource under the RA rules

RA Penalties

3:05 – 3:30 p.m.

Simone Brant, CPUC

Maggie Alexander, PG&E

Energy Division Proposals

- Marginal ELCC for New Solar
- Adjust MCC Buckets
- DR MCC Bucket
- Demand Response Adders and Credits
- Revise RA Penalty Structure

Revise RA Penalty Structure

- Concerned that despite the recent increase in the summer system penalty price, it remains insufficient to incent compliance. Some LSEs choosing to pay penalties rather than comply
- D. 20-06-031 restructured penalties so summer penalty higher, but annual average price remains $6.66/kW-month. In place since 2010 though RA prices have risen significantly in recent years
- Propose raising average penalty price
  - Suggest options of 10% increase ($7.33/kW-month annual average or $9.77 summer/$4.89 winter) or 20% ($8.00/kW-month ($10.67/$5.33))
  - Increase could be phased in over time
- Propose consideration of treatment of LSEs that continually fail to meet RA Requirements
  - LSEs with outstanding unpaid penalty or with deficiencies of >10% of system RA requirement may not increase load
  - Decertification process implemented for LSEs that are deficient by 50% of RAR for at least 3 summer months

Escalating Penalties Framework for RA Deficiencies

Track 3B.1 Proposal
(R.19-11-009)

February 25, 2021

PG&E's Objectives for an Escalating Penalties Framework

PG&E believes that the current penalty structure is not adequately incenting LSEs to meet their RA procurement obligations. Instances of repeated deficiencies have also been observed.

- Develop an enhanced structure that mitigates the economic decision to pay penalties in lieu of procuring sufficient resources/capacity.
- Mitigate repeated non-compliance occurrences by LSEs.
- Ensure framework is simple, implementable, and fits within/expands upon the existing structure.
- Provide a structure that encourages procuring sufficient resources/capacity over an extended period of time.

Scope of PG&E's Proposed Framework

PG&E's Proposed Framework:

- Does <u>not</u> change the existing penalty structure for Flexible or Local RA requirements – for System RA only.
- Does <u>not</u> change the current penalty price for deficiencies (e.g. $10,000 penalty remains in place)
- Does <u>not</u> suggest updating CAISO's backstop procurement process - CAISO's CPM process will continue to serve as a backstop mechanism

RA Penalty Structure (Background)

- **Current Penalty Structure Should Evolve**: Concern that the current RA penalty structure is no longer sufficient to incent the procurement of resources within the RA program.

- **Repeated RA Deficiencies Can Put System Reliability at Risk**[1]:
  - 2019: 10 of 12 months with a month-ahead deficiency (0.6 to 847.02 MWs)
  - 2020: 4 of 5 months with a year-ahead deficiency (11.44 to 266.67 MWs)
  - 2021: 1 of 5 months with a year-ahead deficiency (1,348.23 MWs)

System RA Deficiency	Current	Proposed
Summer Months (May to October)	$8.88/kW-month	Up to $26.64/kW-month
Non-Summer Months (All Other Months)	$4.44/kW-month	Up to $13.32/kW-month
Escalation Rate	None	Tiered Escalation [Slide 5 for Details]

[1] *The State of the Resource Adequacy Market – Revised (January 2020)*

PG&E's Proposal: Tiered Points with Escalation Rate

- Step 1: An LSE will receive a point (or points) for each instance (i.e., compliance filing) of RA deficiency, regardless of magnitude, if the deficiency is not cured within 5 business days.

	Points for Each Monthly Event*											
Month	JAN	FEB	MAR	APR	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	NOV	DEC
Points Incurred, If Deficient	1	1	1	1	**2**	**2**	**2**	**2**	**2**	**2**	1	1

**Note: Point(s) will also be assigned for uncured deficiencies from the year-ahead filing*

- Step 2: Depending on the points accrued and the tier designation, the LSE will be assessed using the penalty price and multiplier for each RA deficiency.

	Financial Penalty		
	Tier 1	Tier 2	Tier 3
Accrued Points	0 - 5	6 - 10	11+
Price Multiplier	1x	2x	3x
Penalty Price ($/kW-month)	$4.44 or $8.88	$8.88 or $17.76	$13.32 or $26.64

Additional Components

- All points are cumulative and shall roll over to the next RA compliance year(s).
- No trading of points (e.g. an LSE cannot buy-out of a tier designation by selling points to another LSE).
- All accrued points shall be removed if the LSE does not have an RA deficiency for 24 consecutive months.
- The framework would become effective with the 2022 RA compliance year and be on a prospective basis.

Illustrative Example: RA Deficiency Scenario for an LSE

Repeated RA deficiencies will result in the LSE accruing points and moving into escalating tiers that incur increasing financial penalties over time.

Deficient Monthly Filing	Cumulative Points	Tier (Multiplier)	Penalty Rate ($/kW-month)
April (Non-Summer)	1	1 (1x)	$4.44
May (Summer)	3	1 (1x)	$8.88
June (Summer)	5	1 (1x)	$8.88
July (Summer)	7	2 (2x)	$17.76
August (Summer)	9	2 (2x)	$17.76
September (Summer)	11	3 (3x)	$26.64

Hybrid QC Methodology

3:30 – 3:50 p.m.

Jim Caldwell, CEERT

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.

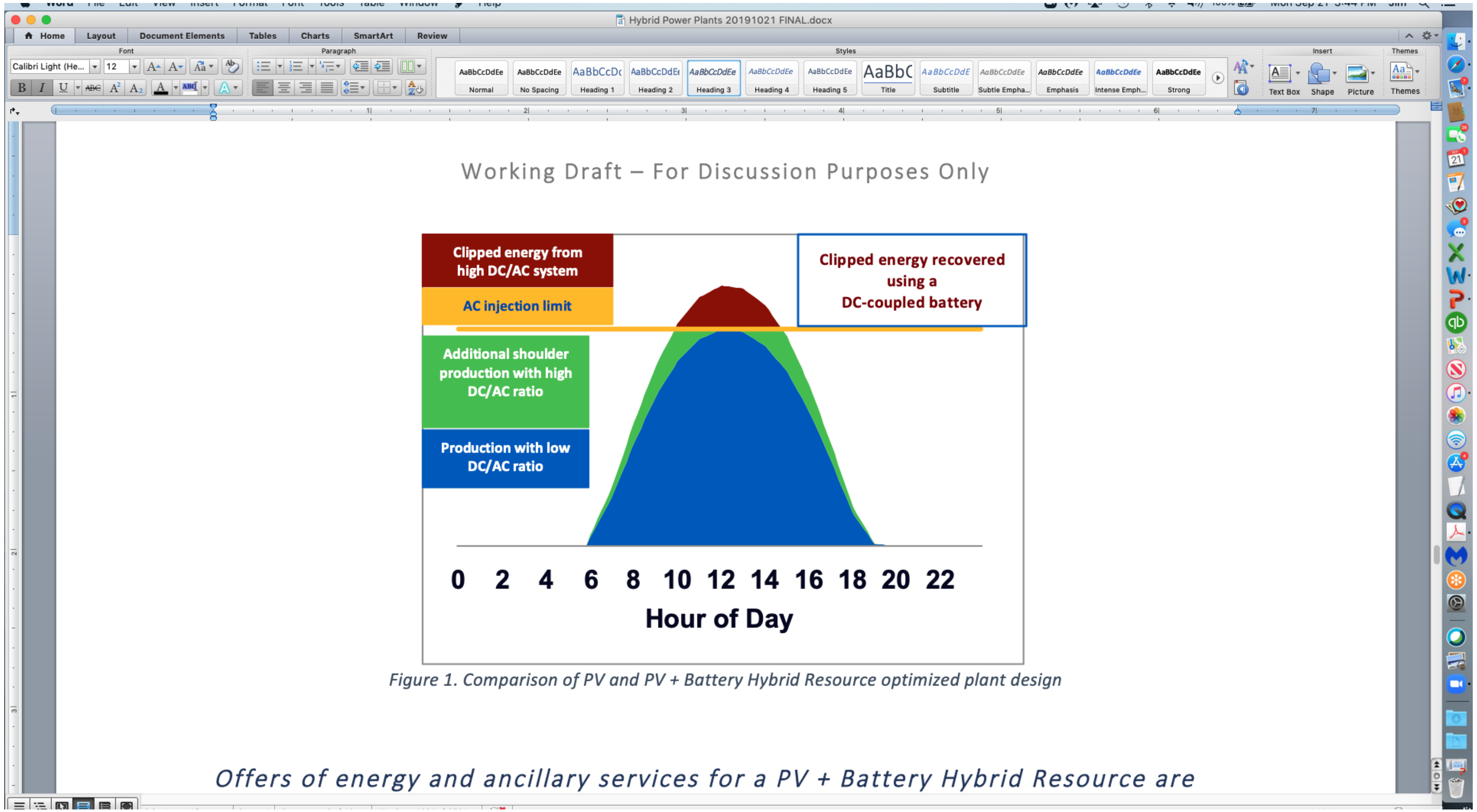
  -Their QC value is a “portfolio” QC, not some combination of individual element QCs.
- These complex characteristics can be simplified/ignored for RA purposes as long as the penetration levels of each hybrid class are ”low” and the number, size and variety of configurations within each class of hybrid 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).

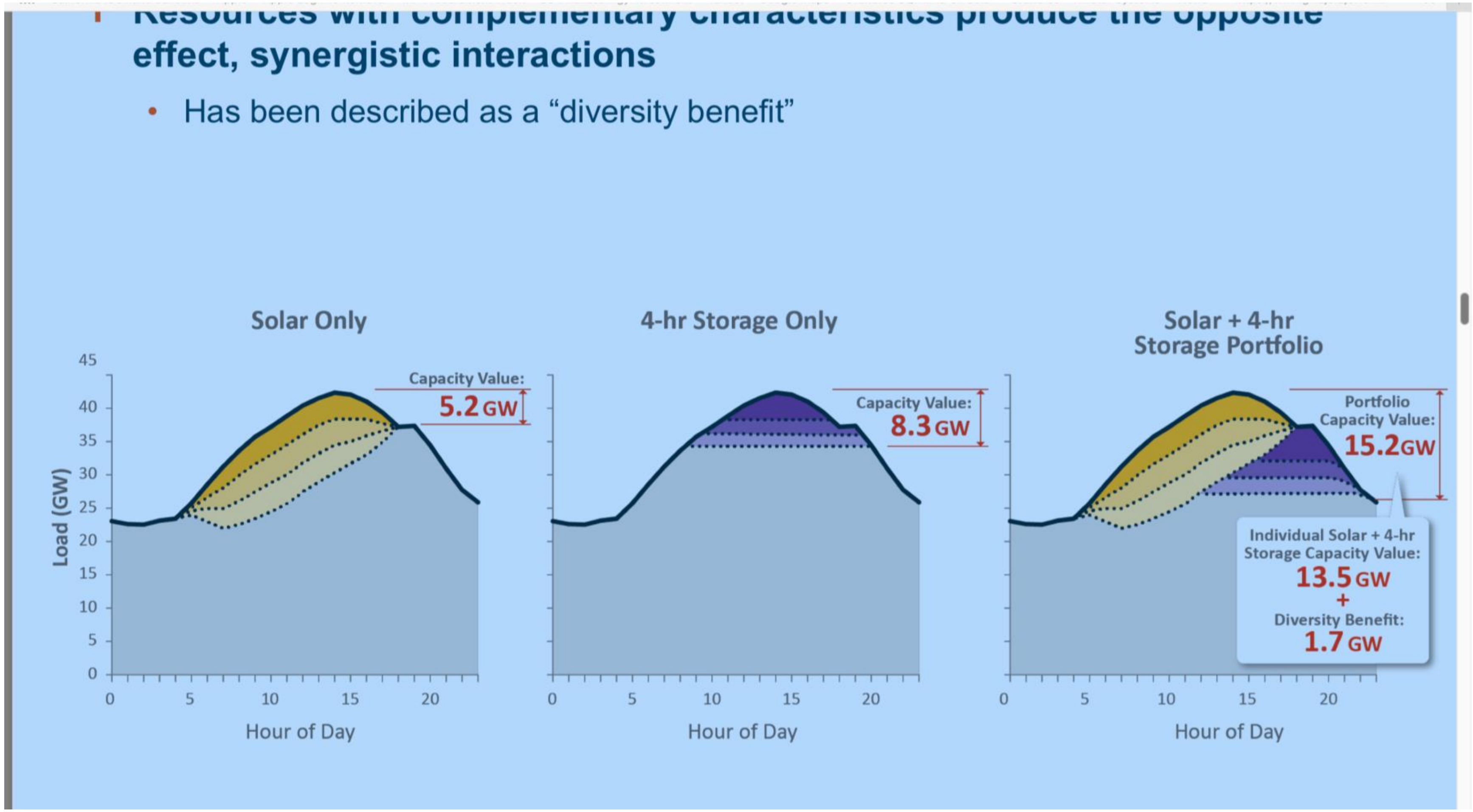
- CAISO Ave Project Marginal ELCC Value (100% = POI injection rights):

	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

RA as T&D Function

3:50 – 4:00 p.m.

Gregg Morris, GPI

Green Power Institute's Track 3B.1 Proposal

RA Track 3B.1 Workshop, February 25, 2021

- Basic Premise: Resource Adequacy is a Transmission and Distribution (T&D) concern, which is designed to ensure the reliability of the grid under stress conditions. As such, the responsibility for procuring the required RA products should fall to the T&D utilities, not the retail energy LSEs.

- The Proposal: Task the T&D utilities with the procurement of RA products and treat the costs of RA procurement like any other T&D expense. This can be done by assigning RA procurement responsibilities to the T&D departments of the wires utilities, or by using central procurement entities (CPEs) of the kind that the Commission created in D.20-06-002 in R.17-09-020 for local RA procurement. In the interest of simplicity we prefer the former, but either structure can work.

Green Power Institute's Track 3B.1 Proposal

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- The Complication: California's wholesale electricity market is bifurcated into energy markets and capacity markets, but in reality every energy product has capacity components, and every capacity product has energy components. With the GPI proposal in effect retail LSEs will be relieved of their obligation to procure RA products, but their energy procurement activities will give them associated capacity values that can be counted towards a T&D RA obligation.

- The Solution: A key aspect of making this proposal work is to ensure that a non-wires LSE can supply its RA holdings to a wires utility and obtain full and fair value for the transaction. An equivalent issue has already been encountered in the creation of the CPEs, and the same treatment can be applied here.

Q&A/Wrap Up

Track 3.B.1 and 4 Calendar

Workshop on Track 4 proposals	February 25, 2021
Comments on proposals	March 12, 2021
Reply comments on proposals	March 26, 2021
CAISO files draft 2021 LCR and FCR Reports	April 2, 2021
Comments on draft 2021 LCR and FCR Reports	April 12, 2021
CAISO files final 2021 LCR and FCR Reports	April 30, 2021
Comments on final 2021 LCR and FCR Reports	May 7, 2021
Reply comments on final 2021 LCR and FCR Reports	May 11, 2021
Proposed Decision on Track 4	May 2021

California Public Utilities Commission

Thank you for attending today's Track 3.B.1 / Track 4 Workshop. Feedback welcome.

Host contact:
Simone Brant –simone.brant@cpuc.ca.gov