R.21-10-002 Workshop on Proposals for Implementation Track Phase 3

Wednesday, February 8, 2023

10 a.m. – 4:30 p.m.

California Public
Utilities Commission

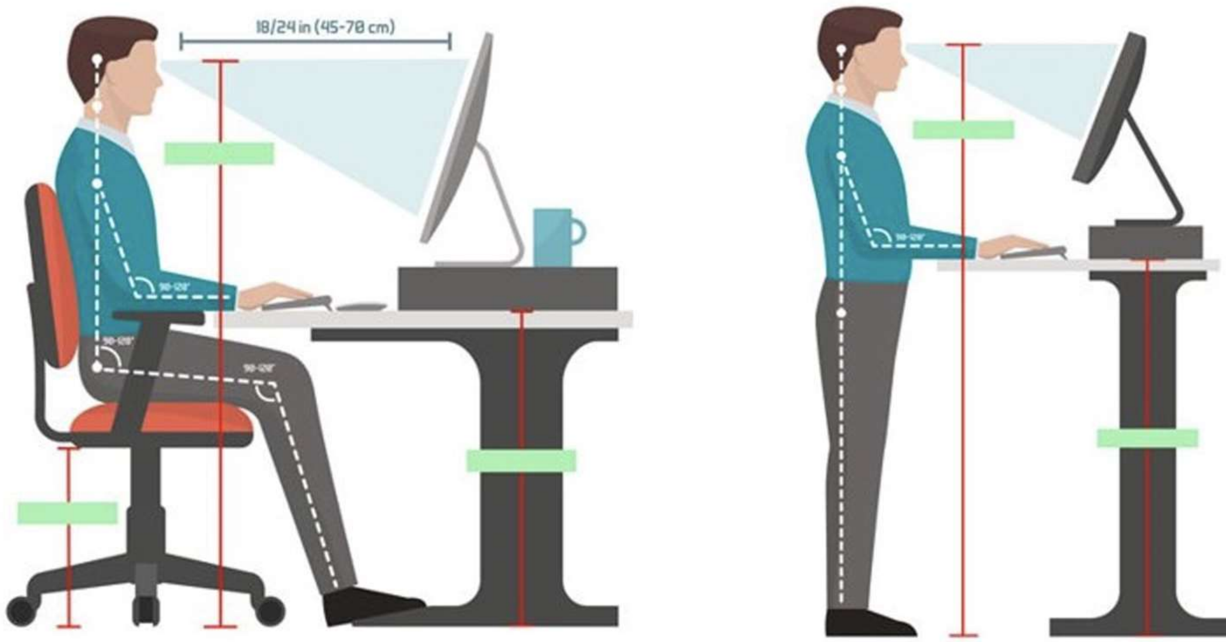
Logistics

- 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)
    - Sasha Cole
    - Simone Brant
    - Natalie Guishar

- Safety
    - Note surroundings and emergency exits
    - Ergonomic check



Logistics

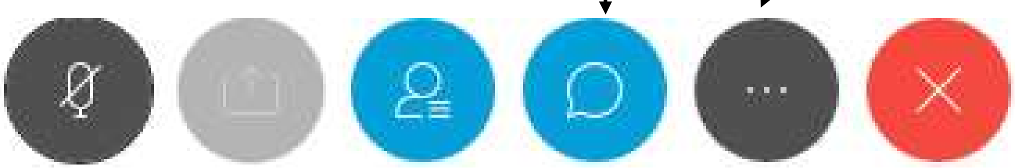
- All attendees have been muted
- Presenters for each topic will be identified as panelists only when their topic is being addressed
- To ask questions, please use the "Q&A" function (send "To All Panelists") or raise your hand
- Questions will be read aloud by staff; attendees may be unmuted to respond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

Mute/ Unmute

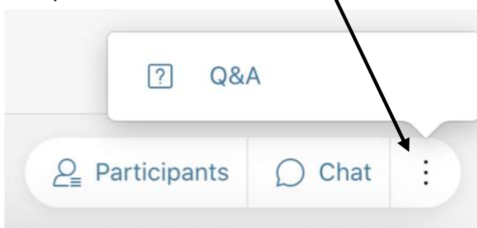
Participant List

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.

Time	Topic	Presenter/s
10:05 to 10:15 am	**Introduction**	
10:15 to 10:25 am	**Opening Remarks by President Reynolds**	President Alice Reynolds (CPUC)
10:25 to 10:50 am	**Thermal Derates Proposal**	Robert Hansen (Energy Division)
10:50 to 11:50 am	**LOLE and Slice of Day Proposal**	Donald Brooks and Behdad Kiani (Energy Division)
11:50 to 12:05 pm	**Discussion on PRM and Effective PRM**	Simone Brant (Energy Division)
12:05 to 12:35	**-----Lunch Break--------**	
12:35 to 12:50 pm	**PRM and Local RA**	Cathleen Colbert (Vistra)
12:50 to 1:30 pm	**CPE Proposals**	Lauren Carr (CalCCA), Cathleen Colbert (Vistra), Natalie Guishar (Energy Division)
1:30 to 2:00 pm	**Energy Division DR Proposals**	Natalie Guishar and Eleanor Adachi (Energy Division)
2:00 to 2:10 pm	**-------- Break---------------**	
2:10 to 2:25 pm	**Multi-year RA Proposal**	Mary Neal (AReM),
2:25 to 3:10 pm	**RA imports**	Lauren Carr (CalCCA), Michele Kito (Energy Division)
3:10 to 3:15 pm	**-------- Break---------------**	
3:15 to 3:30 pm	**MCC Buckets, MCAM, Recoverable Costs for CAM Replacement**	Luke Nickerman (PG&E)
3:30 to 4:15 pm	**Open Q&A time**	

Implementation Track Calendar

Implementation Track Phase 3 Schedule (excluding FCR and LCR Issues)	
Party and Energy Division proposals filed	January 20, 2023
Workshop on Energy Division and party proposals	Early February 2023
Comments on workshop and all proposals filed	February 17, 2023
Reply comments on workshop and all proposals filed	February 27, 2023
Proposed Decision on Phase 3	May 2023
Final Decision on Phase 3	June 2023

Proposed Thermal Power Plant Ambient Derate Model

Estimating available power capacity based on forecast air temperatures

10:25 – 10:50 a.m.

Robert Hansen, PE

Energy Resource Modeling, Energy Division

Introduction

- Staff have studied the effects of high heat on performance and effectiveness of thermal power plants, and have developed a model to address it, based on literature review and research.
- This model will simulate the effects of high heat on thermal power plants, reducing the reliability value of thermal power plants affected by ambient conditions, specifically CTs, Combined Cycle, and Cogeneration facilities.
- This approach will be implemented in stages, starting with Combined Cycle and Combustion Turbine resources in spring 2023, followed by additional thermal powerplants in later 2023.

Questions and Comments

- Please hold questions until the end of the presentation
- Submit comments formally to R.21-10-002

The Proposed Model

Resource Properties

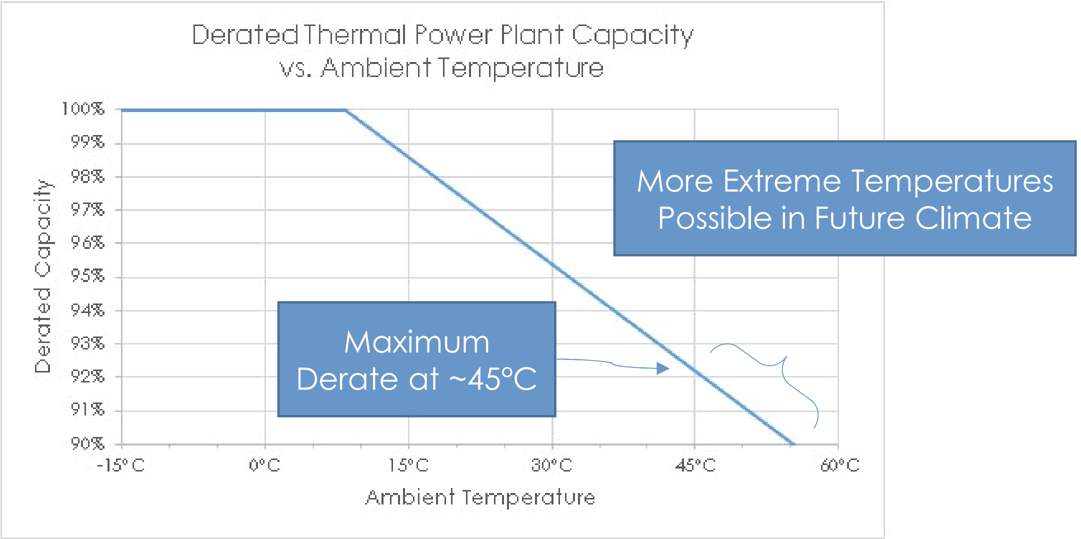
Rated Capacity:	100	MW
Unit Type:	Combustion Turbine	
Temperature at P_{max}:	8.5	°C

CT Derate Slope:	-0.2135% / °C
CC Derate Slope:	-0.1650% / °C

Slope K:	-0.21% / °C
Intercept:	101.81%
Threshold Temperature:	476.88 °C

Correction Factor Function:

T < 8.5°C:	CF = 100%
8.5°C ≤ T ≤ 476.88°C:	CF = -0.21% * T + 101.81%
476.88°C ≤ T:	CF = 0%



Expected Effects

- ELCC and NQC will likely decline. This is in addition to a decline from incorporating unit forced outage rates (EFOR or EFORd) into modeling. Energy Division is developing a proposal to test this model in the Resource Adequacy and Integrated Resource Planning proceeding and use this approach in our future planning studies
- Lower capacities will likely affect planning efforts and results by reducing forecast effectiveness of thermal power plants to meet reliability conditions like loss of load.
  - Generating facilities are expected to have lower efficiency and production during extreme weather events, leading to lower supply coincident with higher demand
  - Reliability value will further decline as ambient temperatures increase
  - Generator outages may exacerbate other Balance of Plant equipment, such as transmission and distribution equipment also affected by high temperatures
  - 3-8% lower capacity during high temperature weather (780 to 1300 of 26,000 MW installed CC and CT)

Next Steps – Timeline

- This proposal was issued by ALJ Ruling in the RA proceeding on January 20, 2023, for comments and development by stakeholders
- This model can be used to incorporate temperature events into Resource Adequacy studies, and potentially used to develop derates and performance factors for types of power plants that are affected by the weather.
- This model can be used for the current climate, as well as future climate change scenarios, potentially allowing for evaluation of power plant performance under climate change scenarios, leading to better ability to meet potential reliability events.

Comparison of This Proposal to Other Efforts

- This approach is comparable to other efforts in the RA proceeding including the UCAP proposal from CAISO
- Other known approaches are not stochastic or hourly, and don't adjustment for future climate conditions
- Derate information sourced from CAISO OMS, not generated from actual weather data. May be incomplete or unable to forecast future effects from increases in temperature.

Ambient Derate Model Criteria

- Based in empirical evidence
- Matches real-world performance of thermal power plants, including gas turbine and combined cycle generation
- Works with historic and future modelled weather data
- Simple to understand
- Integrates with SERVM

Model Calibration Using Reported Curtailments

Applying linear regression analyses to determining derate model parameters

“Curtailment” vs. “Derate”

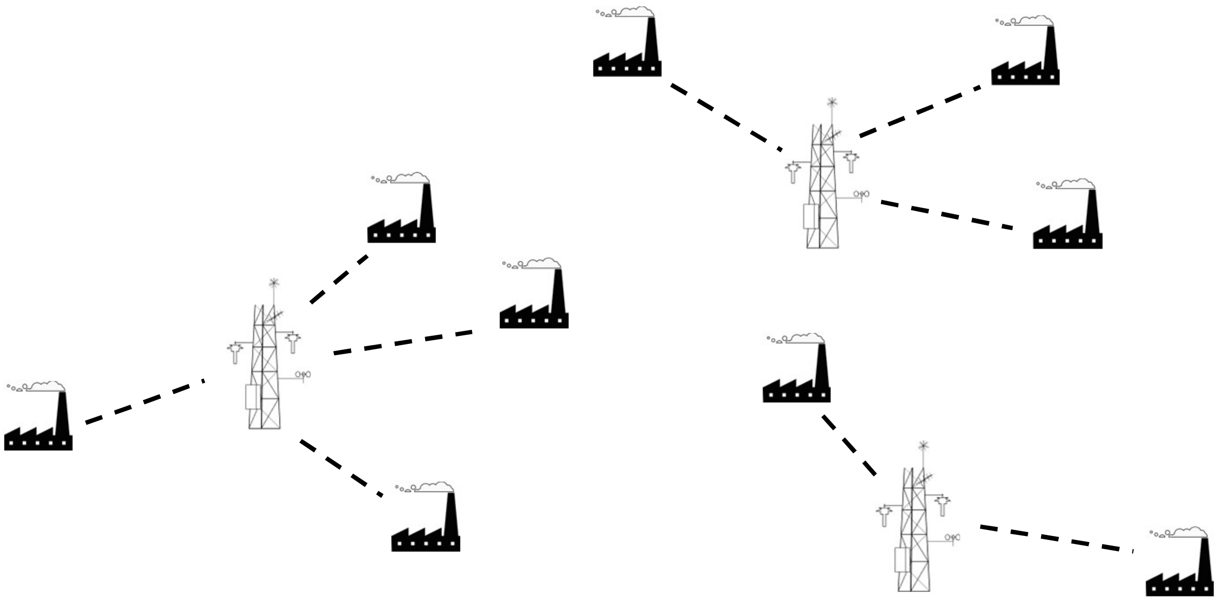
- CAISO collects curtailment data from generation facilities indicating MW unavailable during specified times
- Curtailments are reported for many reasons, including facility testing or maintenance, weather, or grid issues
- The weather-related curtailments (listed as “forced due to ambient temperature”) are analogous to the forecast derates we are modeling
- It should be possible to calibrate the forecast derate model according to historic curtailments

Data Sources

- CAISO Prior Trade-Day Curtailment Reports
  - Curtailments are reported as MW reductions in capacity for blocks of time
  - Reports between June 18, 2021 and November 9, 2022 were used
  - http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx
- Historic Hourly Weather
  - NOAA provides detailed hourly weather data for known weather stations
  - Weather data for 2021 and 2022 were retrieved
  - www.ncei.noaa.gov/access/search/dataset-search/global-hourly

Merging Data

- Each resource is associated with the closest known weather station



Merging Data

- Reported blocks of time of curtailment are expanded into separate hours, consistent with weather data
- Curtailment and weather data are joined together based on assigned station and time

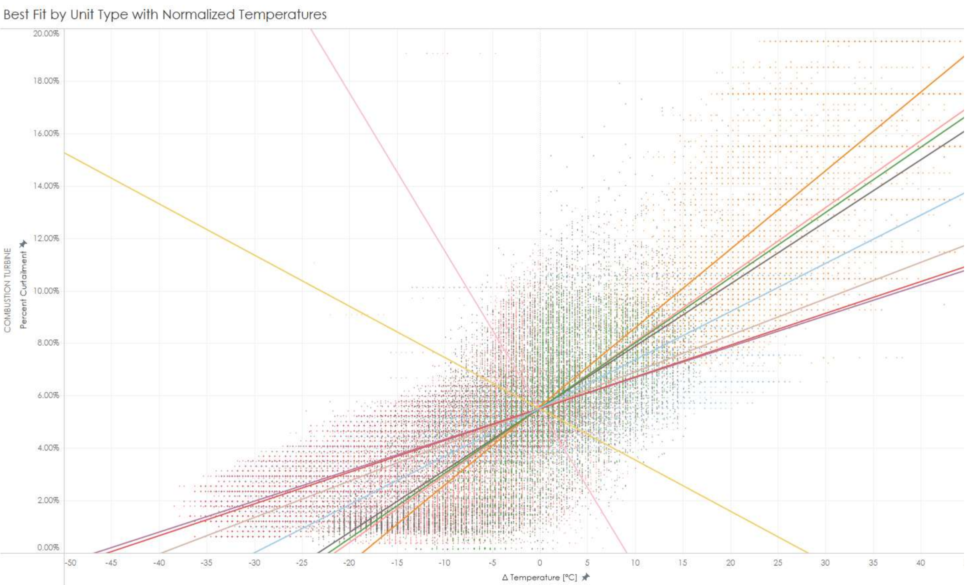
Resource Name	Resource ID	Unit Type	Datetime	Curtailment (MW)	Capacity (MW)	Percent Curtailment	Weather Station ID	Dry-Bulb Temp. (°C)	Dew Point (°C)	Pressure (kPa)	Wet-Bulb Temp. (°C)
Fresno Peaker	AGRICO_6_PL3N5	COMBUSTION TURBINE	6/18/2021 13:00	5.41	22.69	23.84%	KFAT	26.7	15.0	99.6	18.9
Mammoth G2	CONTRL_1_CASAD2	OTHER	6/18/2021 13:00	8.00	10.50	76.19%	KFAT	26.7	15.0	99.6	18.9
Dixie Valley Geo	CONTRL_1_OXBOW	STEAM	6/18/2021 13:00	5.00	60.00	8.33%	KFAT	26.7	15.0	99.6	18.9
Hanford Peaker Plant	GWFPWR_1_UNITS	COMBUSTION TURBINE	6/18/2021 13:00	10.9	98.46	11.07%	KFAT	26.7	15.0	99.6	18.9

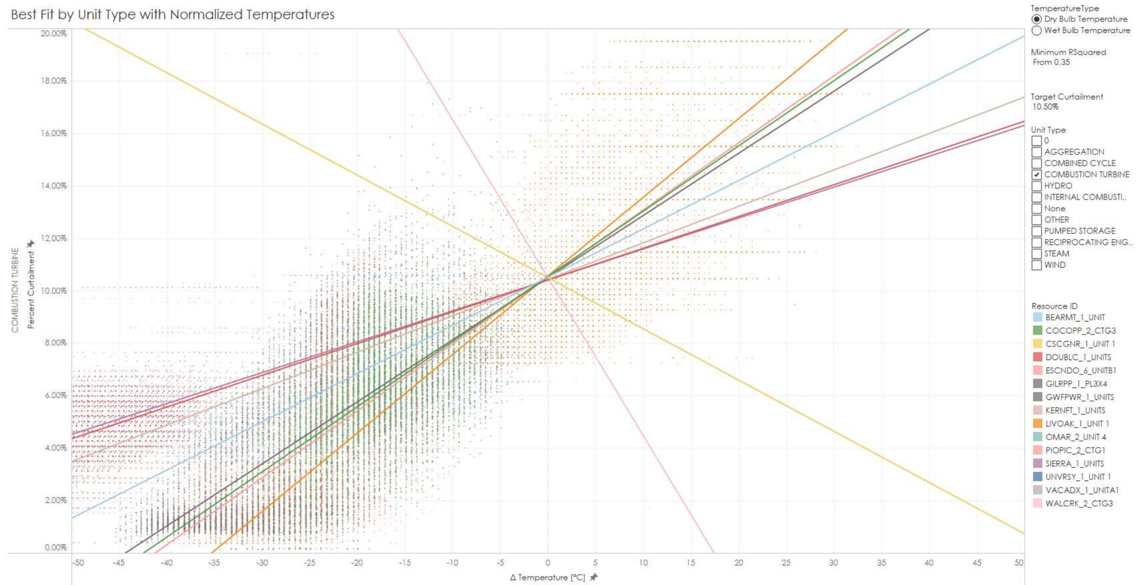
Best Fit Curves for Each Generating Resource

- Use least-squares regression to determine best fit lines for each resource's reported curtailments vs. ambient temperature
- Determine goodness-of-fit based on R-squared values for each resource
- Only resources with R-squared greater than a given threshold are used in next step

Normalize Temperatures

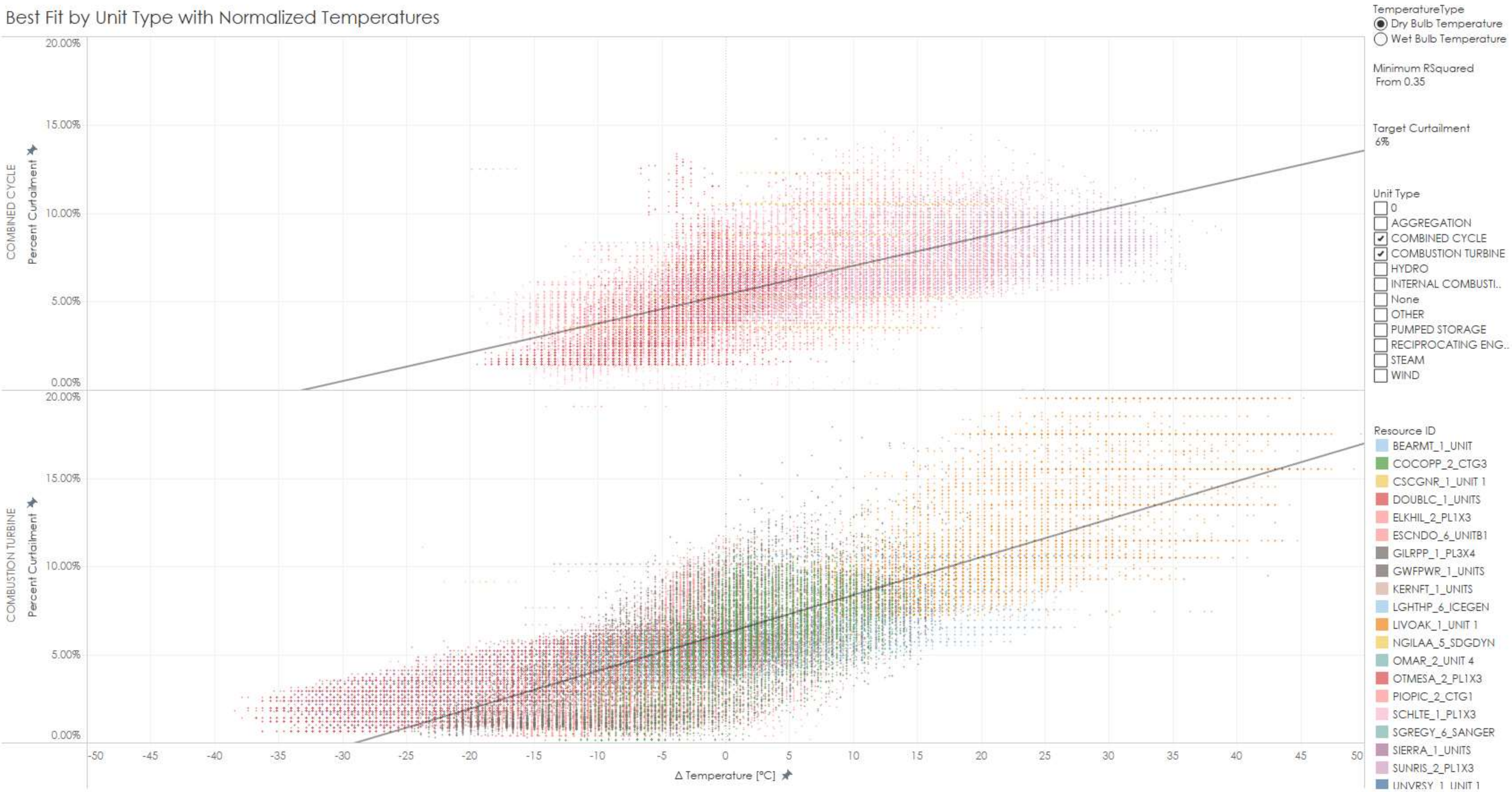
- Shift each resource’s curtailment curve such that they intersect at a given curtailment
- Determine optimal target curtailment based on results of regression analyses by unit-type





Best Fit Curves for Each Unit Type

- Use normalized temperatures to compare curtailments for resources within each unit type
- Only combustion turbines and combined cycle resources passed each step to return valid results
- The opposite of the slope of the best-fit curve for each unit type can be input in the proposed model


Best Fit by Unit Type with Normalized Temperatures
COMBINED CYCLE
Percent Curtailment
COMBUSTION TURBINE
Percent Curtailment
20.00%
15.00%
10.00%
5.00%
0.00%
-50 -45 -40 -35 -30 -25 -20 -15 -10 -5 0 5 10 15 20 25 30 35 40 45 50
Δ Temperature [°C]
TemperatureType
Dry Bulb Temperature
Wet Bulb Temperature
Minimum RSquared
From 0.35
Target Curtailment
6%
Unit Type
0
AGGREGATION
COMBINED CYCLE
COMBUSTION TURBINE
HYDRO
INTERNAL COMBUSTI..
None
OTHER
PUMPED STORAGE
RECIPROCATING ENG..
STEAM
WIND
Resource ID
BEARMT_1_UNIT
COCOPP_2_CTG3
CSCGNR_1_UNIT 1
DOUBLC_1_UNITS
ELKHIL_2_PL1X3
ESCNDO_6_UNITB1
GILRPP_1_PL3X4
GWFPWR_1_UNITS
KERNFT_1_UNITS
LGHTHP_6_ICEGEN
LIVOAK_1_UNIT 1
NGILAA_5_SDGDYN
OMAR_2_UNIT 4
OTMESA_2_PL1X3
PIOPIC_2_CTG1
SCHLTE_1_PL1X3
SGREGY_6_SANGER
SIERRA_1_UNITS
SUNRIS_2_PL1X3
UNVRSY_1_UNIT 1

Results

- The curtailment analysis can be used to calibrate the proposed ambient derate model by applying the slopes of the linear regression curves by unit-type to the temperature-dependent regime
- Derates are defined as percent of capacity available, so slopes are reversed
- Derate Slopes:
  - Combined Cycle: -0.1650% per °C
  - Gas Turbine: -0.2135% per °C

Example Calibrated Derate Model

Resource Properties

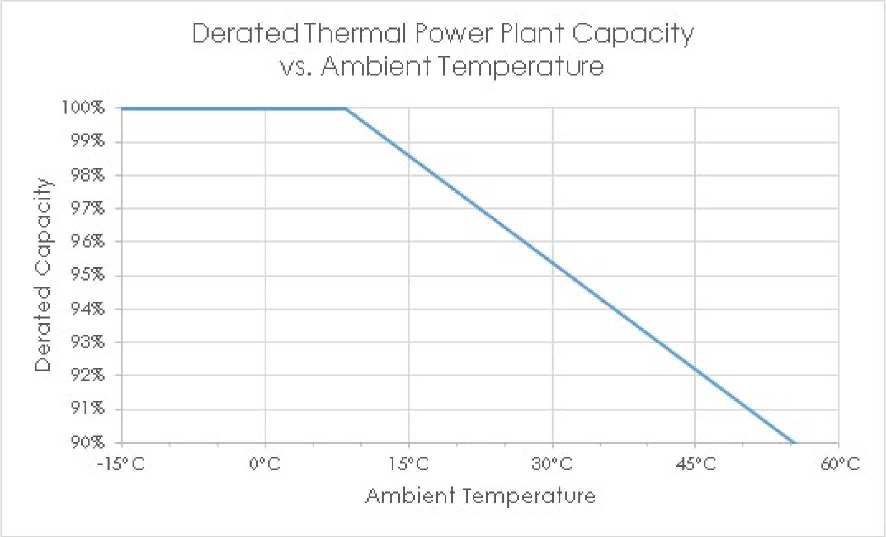
Rated Capacity:	100	MW
Unit Type:	Combustion Turbine	
Temperature at P_{max}:	8.5	°C

CT Derate Slope:	-0.2135% / °C
CC Derate Slope:	-0.1650% / °C

Slope K:	-0.21% / °C
Intercept:	101.81%
Threshold Temperature:	476.88 °C

Correction Factor Function:

T < 8.5°C:	CF = 100%
8.5°C ≤ T ≤ 476.88°C:	CF = -0.21% * T + 101.81%
476.88°C ≤ T:	CF = 0%



Questions and Comments

Thermal Derates based on Ambient Temperatures

Loss of Load Expectation Studies and PRM proposal for 2024 RA Compliance Year Demonstration of Slice-of-Day Implementation of PRM results

10:50 - 11:50 a.m.

Donald Brooks and Behdad Kiani

Energy Resource Modeling Team, Energy Division

Objective and Overview of Presentation

- Objective: To present Loss of Load (LOLE) results for 2024 RA compliance year, translation into Planning Reserve Margin (PRM) for 2024 and demonstrate a draft translation to Slice of Day (SOD) tool. To answer questions from parties and encourage the most informed and effective party comments possible.
- Overview of presentation:
- Present Loss of Load Expectation (LOLE) framework and LOLE results
- Present proposed Planning Reserve Margin (PRM) for 2024 RA compliance year before Slice of Day (SOD) is implemented
- Demonstrate draft translation of LOLE results into the NRDC SOD tool

Questions and Comments

- Please hold questions until the end of the presentation
- Submit comments formally to R.21-10-002

Key Input Assumptions (1)

- 1998-2020 historical weather-based distribution of hourly electric demand, and wind and solar generation
- 2021 IEPR Mid-Mid electric demand forecast
- Major baseline resource update
  - CAISO Master Generating Capability List as of 11/8/2022
  - 11/1/2022 LSE IRP compliance filings, 10/2022 NQC List
  - WECC Anchor Dataset 2032
- 1998-2020 hydro data and methodology refreshed
  - Hourly and monthly data collected from EIA, CAISO, BPA
  - Detrended monthly data used to develop dispatch model
  - Emergency hydro capacity added
- Hydro year disconnected from weather year, resulting in another 23 combinations per weather year in the model (2,645 total cases modeled)
- **Calibration to LOLE by raising or lowering import constraint, NOT using Perfect Capacity or retiring Thermal Generation**
- **Does NOT include any RESOLVE units, ONLY using Baseline resources**

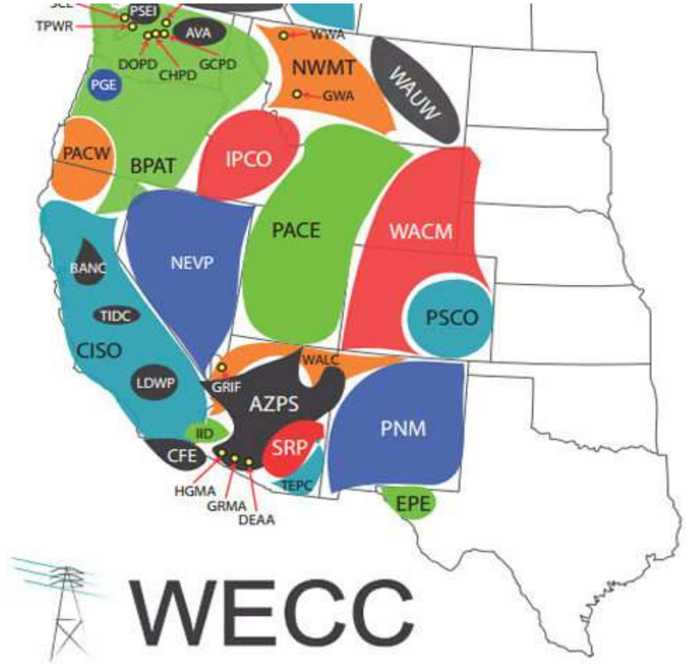
Key Input Assumptions (2)

- 4,000 MW CAISO simultaneous import constraint in HE17-22 imposed Jun – Sept
- Intra-CAISO transmission capability settings.

Path	PGE->SCE	SCE->PGE	SCE->SDGE	SDGE->SCE
Capability (MW)	4000	3000	4740	2500

- Simplified WECC representation - California regions and nearest non-California regions are modeled, farther regions more than one state away are not
- CAISO TAC areas and non-California regions are grouped into co-dispatch regions

Co-dispatch group	Modeled Regions
CAISO	PGE, SCE, SDGE
NW	BPAT, PACW
SW	AZPS, NEVP, SRP, WALC
none	IID, LADWP, SMUD, TID, PortlandGE
Not Modeled	PSCO, IPCO, CFE, BCHA-AESO, TEPC, EPE, NWMT-WAUW, PACE,



Scenario Description

Four different 2024 scenarios examine different import and Path 26 constraints:

- S0: Base Case import at 4,000MW and PGE>SCE at original level
- S1: Import at 3000MW and PGE>SCE at 5,500MW
- S2: Import at 3,500MW and PGE>SCE at 4,750MW
- S3: Import at 3,500MW and PGE>SCE at 4,750MW, 4000MW InDev delay

LOLE_Capacity BaseCase and Path 26 Sensitivities

Scenario S2 resulted in more balanced LOLE across the CAISO keeping them right under 0.1 target

S2 was chosen for use in the SOD tool.

Regions	S0: Base Case Import at 4,000 and PGE>SCE at original level	S1: Import at 3,000 and PGE>SCE at 5,500 (1,500 above original level)	S2: Import at 3,500 and PGE>SCE at 4,750	S3: Import at 3,500 and PGE>SCE at 4,750 , 4,000 MW InDev Delayed
CAISO	0.1045	0.08970	0.09533	0.28767
PGE	0.02919	0.08299	0.05411	0.24197
SCE	0.0695	0.08299	0.07220	0.27227
SDGE	0.10290	0.08970	0.09455	0.28767

Feb. 2022 LOLE study results

Path 26 constraint SCE>PGE	3,000 MW	4,000 MW	5,000 MW	7,000 MW
LOLE	0.107	0.102	0.089	0.075

Methods of Calculating a PRM

- Current NQC counting for all types of resources to show how the portfolio required to maintain 0.1 LOLE would total across each month of the year.
- Translating the SOD framework using the Natural Resources Defense Council (NRDC) tool which compares the hourly demand on the "Worst Day" profile and an exceedance based hourly profile of firm resources, batteries, wind, and solar resources; and
- SOD Framework using the NRDC SOD tool, with the same hourly day demand profile from the IEPR and using solar/wind exceedance values derived from the NRDC workbook published on the CPUC website in preparation for ED workshops in the summer of 2022.

Proposed 18-20% PRM for 2024 RA Year resulting from LOLE studies

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,818	52,474	52,327	53,032	53,894	55,427	55,747	54,949	54,202	52,553	52,161	52,135
SERVM Median Managed Peak	31,319	30,539	29,467	31,073	34,024	40,885	44,840	45,643	44,839	36,076	31,683	32,189
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
SERVM PRM, Median SERVM Managed Peak	165.5%	171.8%	177.6%	170.7%	158.4%	135.6%	124.3%	120.4%	120.9%	145.7%	164.6%	162.0%
CEC PRM, CEC Monthly Managed Peak	159.3%	166.7%	172.7%	158.9%	143.7%	129.8%	121.4%	118.2%	114.5%	135.2%	160.9%	153.8%

Proposed 18-20% PRM for 2024 RA Year (cont.)

- Monthly Net Qualifying Capacity (NQC) required to achieve a LOLE of 0.1 equals ~120-122% of SERVM median CAISO coincident managed peak by month in the summer peak season
- Managed peak demand in the SERVM model is not the same as the monthly peak demand from the CEC Hourly Load Model
- September managed peak demand in SERVM is lower than the corresponding monthly managed peak from the IEPR demand translating to a higher PRM%
- This is strictly an annual study, which is the reason for the large reserve margins in off-peak months.
- Given the heavy reliance on new and in development capacity, any delay could result in the inability for LSEs to meet RA obligations

September Breakdown Per Region of Monthly NQC Modeled Compared to PRM

September breakdown	PGE	SCE	SDGE
Capacity using current NQC calculations	27,482	26,132	4,827
SERVM Worst Day Managed Peak	22,121	27,391	4,759
SERVM Median Managed Peak	19,945	22,626	3,987
PRM, NQC divided by Worst Day Managed Peak	124.2%	95.4%	101.4%
PRM, NQC divided by Median SERVM Sales Peak	137.8%	115.5%	121.1%

Breakdown per region shows how SCE area has the lowest margin of NQC over demand, causing the differences in LOLE across the regions and the Path 26 sensitivities.
This implies that future development ought to be weighed more heavily towards SCE area then PGE's area.

Feb. 2022 Study's Monthly Effective Capacity Requirements and PRM Results (for Comparison)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Effective Capacity: NQC current, new Portfolio ELCC	39,573	40,471	38,118	36,281	39,299	48,865	56,593	55,362	52,098	43,161	40,058	39,419
Effective Capacity: NQC current, UCAP, new Portfolio ELCC	38,063	39,119	36,981	35,391	38,431	47,791	55,050	53,784	50,646	41,881	38,625	37,956
Planned Outages Removal	0	154	564	416	15	137	0	0	0	0	0	0
Planned Outages Removal, UCAP	0	143	527	390	14	130	0	0	0	0	0	0
SERVM Sales Peak	33,364	31,957	31,341	32,502	35,180	44,089	47,253	46,380	43,152	36,452	33,359	34,018
PRM, NQC current, new portfolio ELCC	19%	26%	20%	10%	12%	11%	20%	19%	21%	18%	20%	16%
PRM, NQC current, UCAP, new portfolio ELCC	14%	22%	16%	8%	9%	8%	16%	16%	17%	15%	16%	12%

Compare the PRM, NQC current new Portfolio ELCC to the PRM calculated in slide 1. ~20% PRM needed for 0.1 LOLE

2024 Baseline Portfolio (in Installed Capacity MW)

Category (Capmax MW)	AZPS	BPAT	IID	LADWP	NEVP	PACW	Portland GE	SMUD	SRP	TID	WALC	CAISO
Battery Storage	1,223	48	231	620	1,300	610	5	-	148	-	329	8,969
Firm	11,846	9,622	1,934	8,180	9,016	1,238	1,919	1,995	9,846	548	2,240	40,830
Hydro	-	29,586	84	290	-	987	553	2,611	91	158	2,502	9,175
PSH	-	500	-	1,460	750	-	-	-	176	-	44	1,683
Solar	4,375	1,457	770	2,526	6,658	1,478	142	488	884	120	1,648	18,820
Wind	924	6,339	-	429	150	2,501	659	-	-	-	485	7,670

- Battery Storage and Solar include stand-alone and co-located
- Firm includes biomass, CC, Cogen, CT, geothermal, ICE, nuclear, steam
- Hydro capacity in SERVM is based on available monthly energy and other scheduling parameters, not on actual installed capacity

Capacity (MW nameplate) In Development Between end of 2022 and August 2024

CAISO relies heavily on large amounts of storage, solar and other hybrid generators under development by 2024.

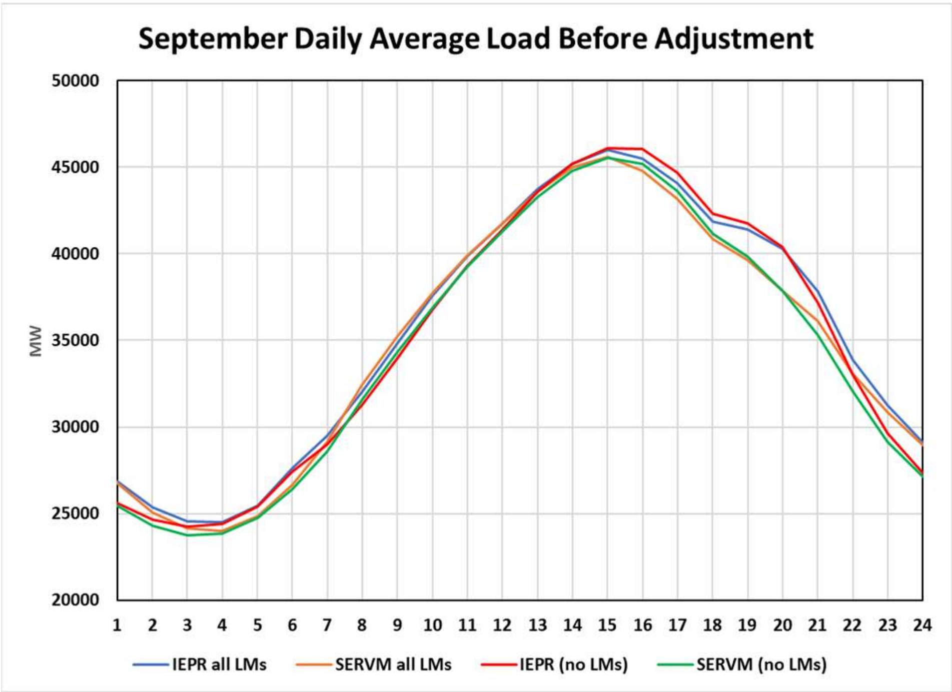
PGE and SCE have almost similar total Capacity In Development by 2024, SCE slightly lower in Battery Storage but higher in Renewables.

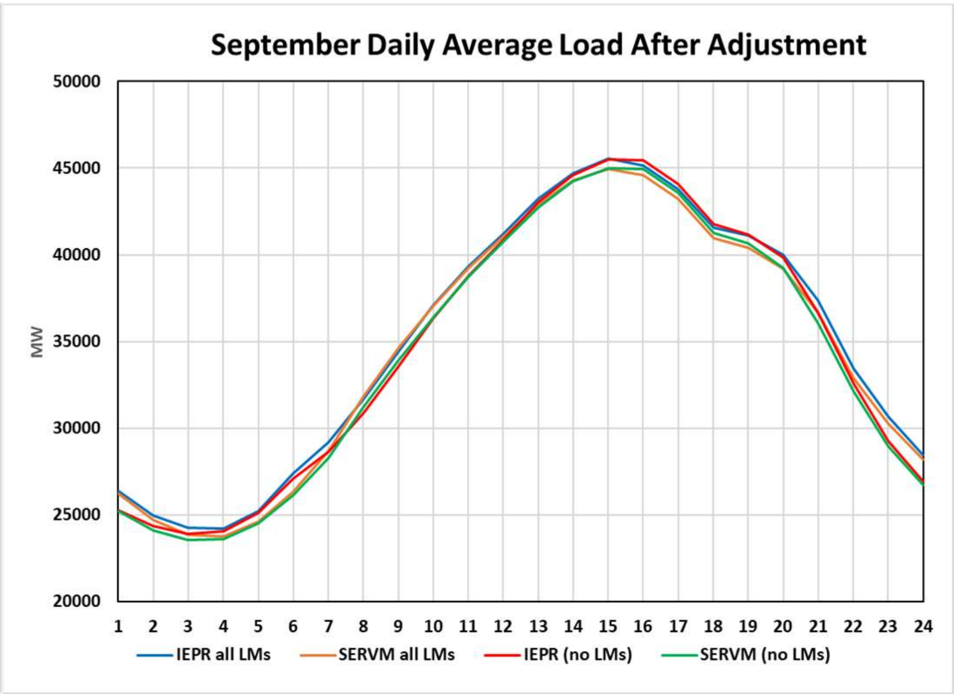
Region	PGE		SCE		SDGE	
Unit Category	Sum of Capmax	Unit Counts	Sum of Capmax	Unit Counts	Sum of Capmax	Unit Counts
Battery Storage	1029.7	9	810	6	306	3
DR			11.6	1		
Hybrid_BattStorage	80	1	237	2		
Hybrid_Solar_1Axis			474	2		
Paired_BattStorage	438	9	280	1		
Paired_Solar_1Axis	969.9	9	715	2		
Solar_1Axis	100	1	258	5		
Solar_Fixed						
Wind	80	1	33.74	1		
Grand Total	**2698**	**30**	**2819**	**20**	**306**	**3**

Updates to Electric Demand Shapes to Reconcile SERVM and IEPR Hours 17:00-22:00 Patterns

- IEPR demand shapes showed slightly higher demand in the early evening during peak months compared to SERVM
- SERVM demand shape was adjusted to account for these observed difference
- This bump effect is currently being investigated with CEC staff and more likely it is resulted because of rebound effects BTMPV consumers are showing in their consumption pattern.

Updates to Electric Demand shapes to Reconcile SERVM and IEPR Hours 17:00-22:00 Patterns

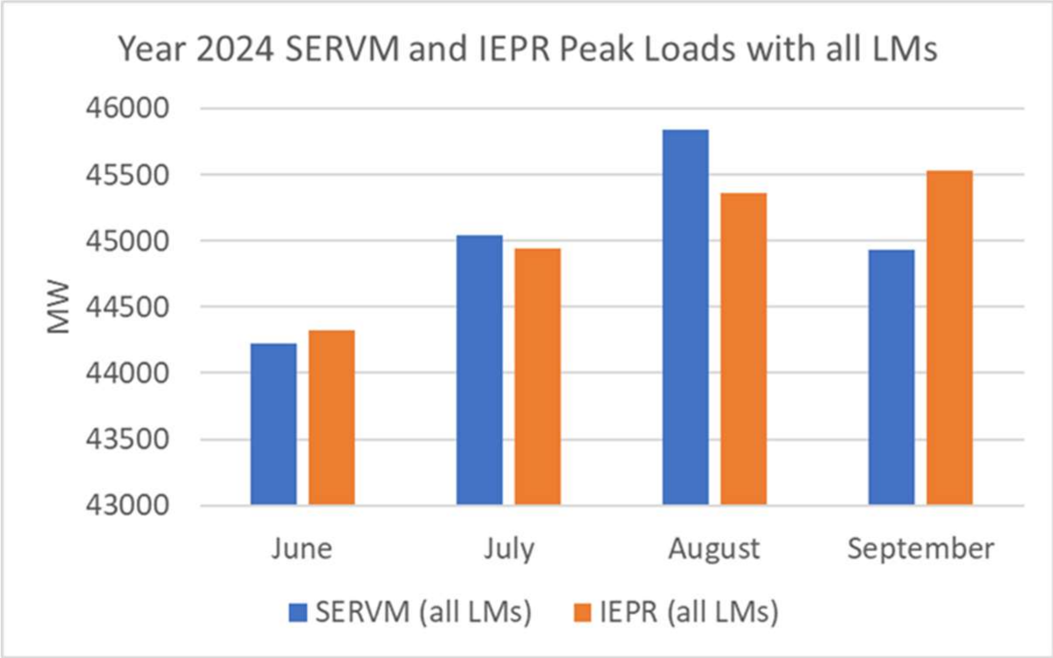




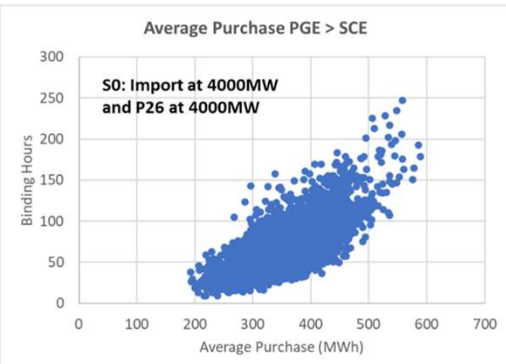
Managed Peak Demand Comparison IEPR to SERVM, Summer 2024

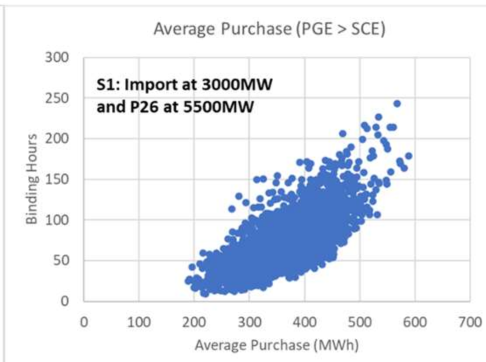
SERVM allocates demand to summer months based on historical dataset (1998-2020) resulting in allocation of peak load to August.

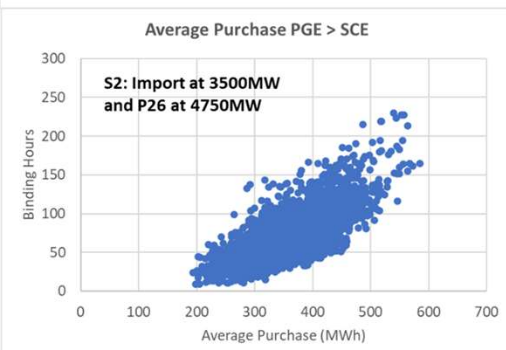
IEPR utilizes a single hourly load model which allocates peak load to September.

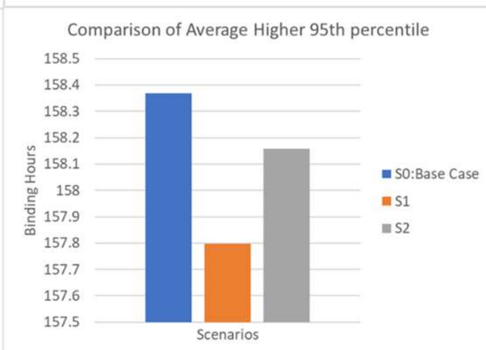


2024 Study: Path 26 at 4750 MW and Import at 3,000MW – Annual Binding Hours and Summary Stats





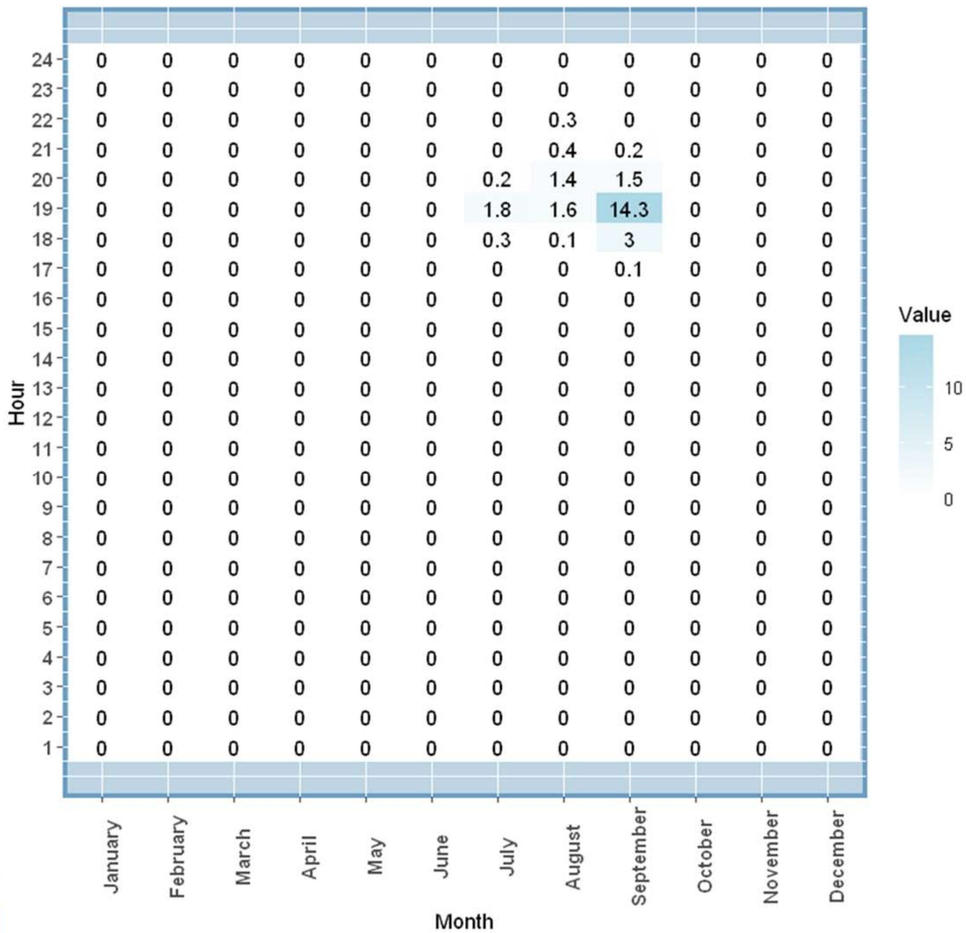




PGE>SCE	S0: Base Case – Original Levels		S1		S2	
	Import at 4,000 MW and P26 at 4,000 MW		Import at 3,000 and P26 at 5,550 MW		Import at 3,500 MW and P26 at 4,750 MW	
	Average Purchase	Binding Hours	Average Purchase	Binding Hours	Average Purchase	Binding Hours
	MWh	hr	MWh	hr	MWh	hr
Mean	360.35	71.35	357.60	71.21	359.12	71.06
Minimum	192.88	9.00	189.26	9.00	193.48	9.00
Average Higher 95th Percentile		158.368		157.798		158.159

Statistical analysis on binding hours for each scenario confirming LOLE pattern in three scenarios S0, S1 and S2.

PGE: EUE (MWh) by Hour and Month



- Bulk of EUE occurs in September evening hours.
- the EUE hours shift later, likely due to further peak shift from solar penetration.

NOTE: The chart only shows hours with nonzero EUE in at least one month. The graded color scale shows the magnitude of the EUE in a given month-hour. Dark blue indicates the largest EUE, followed by light blue ,and white.

SCE: EUE (MWh) by Hour and Month

Hour	January	February	March	April	May	June	July	August	September	October	November	December
24	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0.3	0	0	0	0
21	0	0	0	0	0	0	0	0.4	0.2	0	0	0
20	0	0	0	0	0	0	0.2	1.3	1.4	0	0	0
19	0	0	0	0	0	0	1.7	1.5	14.7	0	0	0
18	0	0	0	0	0	0	0.3	0.1	15.5	0	0	0
17	0	0	0	0	0	0	0	0	0.1	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0

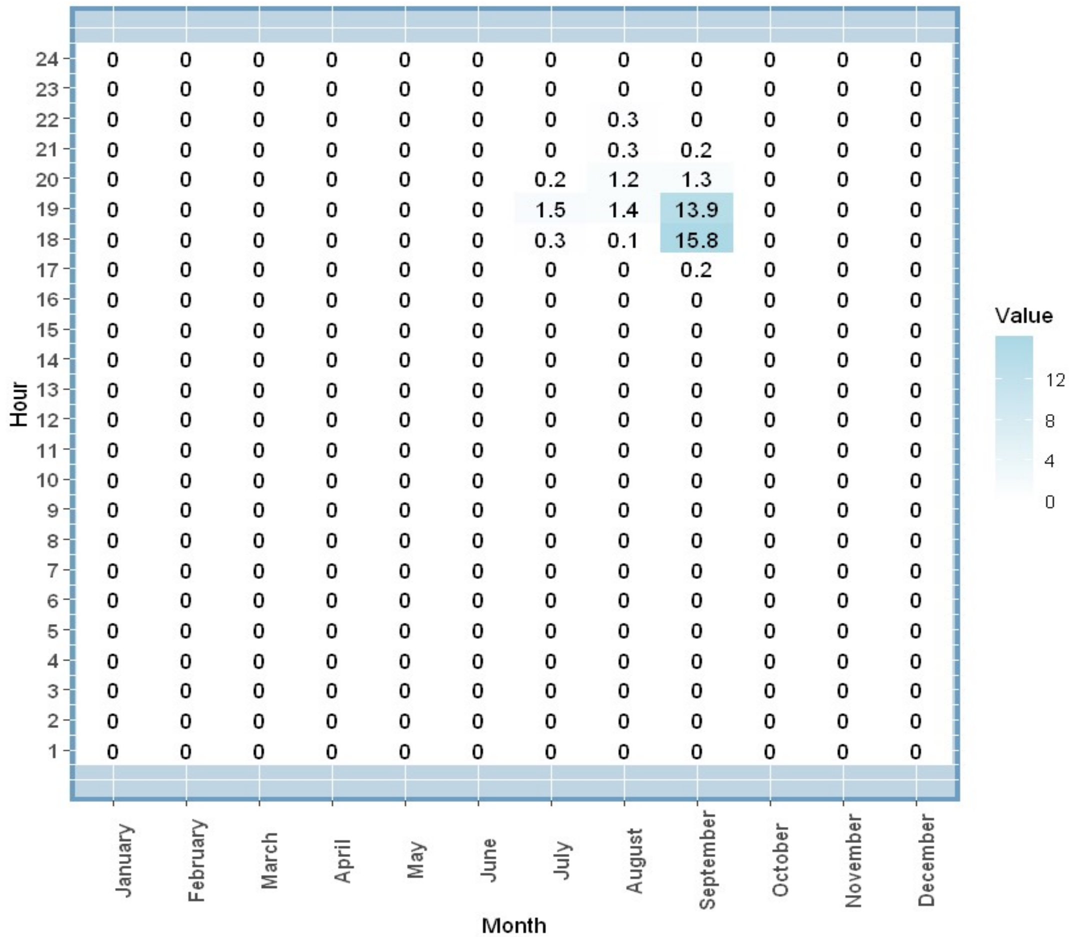
Month

Value: 15, 10, 5, 0

- Bulk of EUE occurs in September evening hours.
- the EUE hours shift later, likely due to further peak shift from solar penetration.

NOTE: The chart only shows hours with nonzero EUE in at least one month. The graded color scale shows the magnitude of the EUE in a given month-hour. Dark blue indicates the largest EUE, followed by light blue ,and white.

SDGE: EUE (MWh) by Hour and Month



- Bulk of EUE occurs in September evening hours.
- the EUE hours shift later, likely due to further peak shift from solar penetration.

NOTE: The chart only shows hours with nonzero EUE in at least one month. The graded color scale shows the magnitude of the EUE in a given month-hour. Dark blue indicates the largest EUE, followed by light blue ,and white.

General Framework of Slice of Day Tool

1) Determine desired portfolio in IRP via LOLE analysis, then the IRP portfolio should inform the PRM used in RA program

2) Convert Portfolio to PRM Requirements using Slice-of-Day

3) Apply PRM to Compliance Requirement

Convert Portfolio to PRM Requirements Using Slice-of-Day

- The Slice of Day is using a portfolio that has been assessed as reliable through a Loss of Load Expectation (LOLE) study for the year 2024.
- The portfolio constraints the Path 26 to 4750 MW and Import to 3500MW.
- The objective of SOD tool is to create system-level 24-Hourly-Slice RA that achieves the maximum PRM possible on the highest load day (Worst Day) while satisfying the capacity sufficiency constraint and storage constraints:
- The objective function for SOD tool is: Maximize $\sum_{m=1}^{12} PRMm$
- -Decision Variable is: Monthly $PRMm$
- -Constraints:
  - Hourly Capacity (MW) > Hourly Load + PRM (MW)
  - Daily Storage Discharge + Roundtrip Efficiency Losses (MWh) < Daily Excess Energy (MWh)
  - Hourly Storage Dispatch (MW) < Installed Storage (MW)
  - Daily Storage Dispatch (MWh) < Installed Storage (MWh)

Slice of Day Demonstration

- This method compares the total capacity of the 0.1 LOLE compliant portfolio, adjusted for hourly availability for renewable resources, to managed load scaled by a single multiplier for every hour in a month.
- The size of the multiplier (PRM) is determined such that the scaled load matches the capacity of the portfolio.
- SOD demonstrates that before considering weather variability, forced outages, or operating reserve requirements, the capacity of the 0.1 LOLE compliant portfolio would be able to serve the managed load from the median peak day scaled up by the PRM.
- The SOD method also considers energy constraints and ensures that the energy used by the pumped storage and battery fleet does not exceed what is available

Demonstration of Translation Into SOD Tool

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,789	52,313	52,218	52,815	53,442	54,884	55,856	55,102	54,421	52,446	52,179	52,096
SERVM Worst Day Managed Peak	31,909	30,873	34,591	37,530	43,090	45,852	52,011	49,196	52,289	44,736	35,200	34,318
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
Draft SOD PRM, SERVM Worst Day Managed Peak	168.3%	179.6%	160.3%	149.1%	134.1%	130.3%	115.9%	116.4%	108.9%	125.6%	151.5%	156.9%
Draft SOD PRM, using Worst Day CEC Managed Demand	170.0%	179.0%	182.5%	168.7%	154.2%	139.6%	133.3%	126.4%	120.4%	144.8%	163.4%	159.6%

Summary of Findings

- LOLE results show that 2024 portfolio BASELINE requires no additional capacity to be reliable (meet 0.1 LOLE standard)
- Chosen scenario: Import limited to 3500 MW and PGE>SCE constraint at 4,750MW – provides more balanced LOLE across the CAISO
- Due to significant retirements, in 2024 CAISO will rely heavily on large amounts of storage, solar and other hybrid generators currently under development
- A delay for 4000MW of "in development" capacity for 2024 will result of high LOLE for CAISO (about 0.29 LOLE)
- A PRM of 118% to 120% for all 12 months is proposed for the 2024 RA compliance year

Questions and Comments

Loss of Load Expectation Studies and PRM proposal for 2024 RA Compliance Year Demonstration of Slice-of-Day Implementation of PRM results

PRM and Effective PRM

11:50 a.m. – 12:05 p.m.

Simone Brant, Electric Market Design Section, Energy Division

Background

- D.04-01-050 adopted a 15-17% PRM. Implemented as 15% through 2022
- Summer reliability proceeding determined additional resources needed for reliability during extreme events but given tightness of market adopted ‘effective PRM’ where IOUs procure contingency resources on behalf of all customers
  - Target set at 2,000-3,000 MW, equivalent of 20-22.5% effective PRM for summers of 2022-2023
  - No penalties if IOUs unable to meet target
- D.22-06-050 increased PRM to 16% for 2023 and minimum of 17% for 2024 Additional increase for 2024 to be considered pending updated LOLE modeling
- During this time, load forecast has increased substantially

Load Forecast	August 2023	September 2023	August 2024	September 2024
2019 IEPR	44,616	45,447	44,750	45,610
2020 IEPR	44,891	45,826	45,300	46,451
2021 IEPR	46,060	46,727	46,500	47,325
2022 IEPR (draft)	46,074	46,829	46,569	47,445

Year	CPUC YA Sept Load Forecast (+increase from 2021)
2021	40,363 (+0)
2022	40,585 (+222)
2023	42,192 (+1,829)
2024 (estimate)	42,700 (2,961)

Proposal

- LOLE modeling recommends 18-20% PRM
- Modeled portfolio includes ~5,800 MW nameplate capacity of resources that are under development
- Over past few years significant project development delays
- May not be possible to meet increased PRM if new resources are delayed particularly since PRM increases with load forecast increase

Options for 2024

- ED staff have identified four options for the 2024 PRM:
  - Status quo (17%) - Maintain the already adopted 17% PRM and do not raise it further
  - Retain at 2023 level (16%) - Reduce the PRM to 16% for 2024 RA year
  - Increase to modeled level (19-20%) proposed in LOLE study- Adopt a PRM for 2024 of 18-20%
  - An intermediate level between 16% and 20%
- Effective PRM
  - Status quo (ends after 2023)
  - Extend effective PRM (difference between modeled PRM and adopted?)

Lunch Break

12:05 – 12:35 p.m.

PRM and LOCAL RA

12:35 p.m.– 12:50 p.m.

Cathleen Colbert, VISTRA

CPUC Rulemaking 21-10-002
Implementation Track
Vistra Phase 3 Proposals

Cathleen Colbert
Senior Director, Western Markets Policy
Regulatory Affairs, Vistra Corp.
cathleen.colbert@vistracorp.com
412-720-7016

Issue 3. Consider modifications to the Planning Reserve Margin (PRM) for the 2024 RA year and beyond, including Energy Division's recent loss of load expectation (LOLE) study in the Integrated Resource Planning (IRP) proceeding, or a future LOLE study for RA to be submitted into this proceeding no later than January 2023

Background

- In D.04-01-050, Commission first adopted the requirement that LSEs procure system RA capacity based on an LSE's share of the monthly peak load plus a PRM of 15 to 17 percent

- In D.21-12-015, Commission adopted "effective PRM" of 20 to 22.5 percent for summers 2022 and 2023 for IOUs to procure RA to meet "effective PRM"

- In D.22-06-050, Commission balanced the need to increase the binding PRM for all LSEs while acknowledging that PRM proposals including additional Loss of Load Expectation ("LOLE") modeling still need to be submitted
  - Commission increased PRM for 2023 to 16% and for 2024 to a minimum of 17% at levels that would fall within the 15 to 17 percent PRM range
  - Commission noted that the 2024 PRM may be further revised

- Implementation Track Phase 3 is the procedural mechanism to do so
  - It should include proposals for establishing PRM for 2024 and beyond, where the discussion on how to convert that PRM once established to a slice of day is out of scope of the Phase 3 proposals.

Proposal for 2024 and beyond

- Commission should establish system RA requirements through a bi-annual probabilistic LOLE study
  - Regularly updated LOLE study that incorporates uncertainty risks
  - Ensures reliability and results in more equitable outcome for ratepayers than continuing to rely on a fixed, predetermined deterministic PRM

- LOLE established PRM to vary across two seasons: “summer” and “non-summer” months* to cover generation needed to ensure sufficient capacity and energy in each season
  - “Summer”: June – September
  - “Non-Summer”: October - May

- Perform the LOLE study to identify total generation capacity needed to meet at least a one-day-in-ten-years reliability threshold and adopt requirements for specific methods

- No changes to system RA requirements allocation approach

*Vistra is using summer and non-summer loosely to define the PRM seasons, and these months do not align with summer and non-summer for penalties. We believe this is appropriate for PRM purposes and are not proposing changes to CPUC use of these terms in its penalties.

Should require meeting a one day in ten year reliability standard at a minimum

- Adopt a defined reliability threshold that meets a one-day-in-ten-years threshold at a minimum, although a stricter standard could be considered by the Commission

- Allow CPUC to recommend additional MW needed to maintain reliability under any sensitivities performed with more conservative uncertainty scenarios, including a limited charging sensitivity

- Commission should use its discretion to determine whether any additional margin should be included in a binding PRM or an effective PRM

Should identify seasonal Reserve Margins

- Establish seasonal PRM as a ratio of the LOLE's generation requirement relative to CEC's Managed 1 in 2 monthly CAISO coincident peak forecasts

- PRM is the ratio of the LOLE's output for monthly total generation capacity needed to meet a specified reliability threshold (Step 5 above) to the CEC Managed 1 in 2 Monthly CAISO Coincident Peak forecast

$$PRM_s = \max_m \left(\frac{LOLE\ Capacity\ to\ Meet\ One - Day - in - Ten - Years\ Standard_m}{Managed\ 1in2\ Monthly\ CAISO\ Coincident\ Peak_m} \right)$$

Where s is the season and m is the month within that season's set of months.

- Multiply the PRM for the applicable season to the monthly CEC's Managed 1 in 2 CAISO coincident peak demand forecast.

- Maintain existing (allocated to LSEs on a peak load share basis)

Should identify seasonal reserve margins cont.

- By analyzing CAISO production data of average net load and average load levels for weekdays, weekend days, and all days by month in 2022, it appears there are two logical seasons

- June – September experience meaningfully different net load and load patterns than other months, providing basis to produce a PRM for this season and another PRM for the remaining months

	All		Weekday		Weekend		
	Average of Net Load	Average of Load	Average of Net Load	Average of Load	Average of Net Load	Average of Load	
Jan	19,363	23,417	19,894	24,078	18,250	22,030	
Feb	17,683	22,796	18,081	23,522	16,687	20,981	
Mar	16,067	22,215	16,641	22,810	14,408	20,496	Non-Summer
Apr	14,474	22,139	15,250	22,948	12,662	20,254	
May	14,907	23,449	15,580	24,198	13,264	21,618	
Jun	19,484	28,020	20,479	28,910	16,750	25,572	
Jul	21,696	29,659	22,272	30,327	20,485	28,256	Summer
Aug	25,026	32,058	26,094	32,950	21,955	29,492	
Sep	24,931	30,961	25,405	31,536	23,626	29,379	
Oct	19,852	25,143	20,862	26,006	17,731	23,332	
Nov	17,863	23,287	18,473	23,835	16,195	21,789	Non-Summer
Dec	20,271	24,537	20,739	25,118	19,127	23,114	

Source: CAISO production data 2022

Should ensure generation dispatch assumption accuracy

- CPUC should structure model to include specified dispatch assumptions for specific resource types being modelled:
  - Includes stochastic resource availability for variable resources
  - Ensures forced outage rates modeled are consistent with those reported to the CAISO

- It is critical forced outage rates used are consistent with those being reported to CAISO
  - CAISO forced outage rates higher than GADS derived EFORd[1]
    - Due to CAISO rules where planned outages that must be taken where the seller cannot provide substitute capacity are converted to forced outages for reporting purposes
  - CPUC Energy Division presentation on August 17, 2022 EFORd was used and that “Equivalent Forced Outage Rate demand (EFORd) is a SERVM output characterizing class average forced outage rates using generator performance data”[2]

2 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf
1 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_ed_220817.pdf, slides 29 and 11.

Should ensure generation dispatch assumption accuracy cont.

For example in the month of June, the monthly average historical forced outage rate submitted to CAISO went from 7.98% in 2020 to 12.65% in 2021.[1]

Comparing that to the CPUC EFORd that ranged between 0-11.2% where Combined Cycles were at roughly 7.7%, these values may not be best method of availability because they will not be as consistent with operational availability as seen by CAISO.

Monthly Average Hourly Outage Rate

	2018	2019	2020	2021	3-year avg.
January		5.20	5.99	5.48	5.56
February		6.88	4.53	6.27	5.89
March		4.73	5.76	5.88	5.46
April		7.35	8.34	10.01	8.57
May		7.01	7.38	8.61	7.67
June		8.14	7.98	12.65	9.59
July		5.57	6.74	8.92	7.08
August		6.33	7.90	7.57	7.27
September		5.91	10.33	6.85	7.70
October		5.31	8.93	7.24	7.16
November	6.22	7.39	5.63		6.41
December	6.98	8.54	7.95		7.82
Yearly Avg.	6.60	6.53	7.29	7.95	7.18

Table 8: EFOR and EFORd used in SERVM

CAISO Unit Category	EFOR (%)	EFORd (%)	Startup probability (%)
Battery Storage	5.4	0.0	97.9
Combined Cycle	9.1	7.7	98.6
Combustion Turbine	22.1	11.2	99.5

1 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf, slide 9
2 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M452/K750/452750851.PDF, Page 18

Should incorporate operational risks by producing distributions of outcomes for those risks

- Demand variation,
- Forced outage risks from outages that are unforeseen,
- Substitution risk for planned outages where a resource cannot find substitute capacity,
- Resource availability risks (e.g., solar, wind, hydro, qualifying facilities, imports etc.) that affect the ability to deliver sufficient energy to serve load, and
- Conservative resource availability risk scenario (i.e. limited charging sensitivity) that is designed to limit the energy needed to directly serve load including the energy needed to charge the storage fleet to be able to directly serve load.

Issue 1. Consider 2024-2026 Local Capacity Requirements (LCR)

Background

- CPUC adopts local capacity requirements (LCR) proposed by CAISO

- CAISO identifies:
  - Minimum local capacity area MW for each local capacity area needs
    - Does not identify minimum continuous energy need, but assume a conventional resource
  - Available units within local capacity area that can meet need
  - Amount of resource deficiency within each local capacity area

- CAISO revises its final LCR proposals to reduce need in each area by the resource deficiency even in the forward years under multi-year RA
  - Does not maintain LCR in forward years when new resources can achieve commercial operations in future and cure the deficiency

Proposal

- CPUC should modify local RA rules to better reflect:
  - Changes made to local California RA framework to require local RA for three-year forward from both existing and new resources
  - Changing CA system's needs given growing share of fleet coming from non-conventional or energy limited resources

- Specifically, LCRs should be set to avoid creating near-term demand that can not be met by existing resources and to create medium-term demand that can be met by new resources:
  - Binding year 2024 LCR requirements should be reduced to recognize binding year requirements will be met by existing or under construction resources only
  - 2025 and 2026 LCR requirements should not be reduced in areas with resource deficiency and instead the multi-year local RA requirements should be met by new resources if available
  - Forward local RA requirements specify both capacity and energy

Example – 2023 Stockton area procurement in forward years improved to include deficiency

- Stockton area had:
  - NQC of 579 MW, 24 MW in Lockeford and 555 MW in Tesla-Bellota
  - Requirement/need of 27 MW and 965 MW
  - Deficiency of 3 MW in Lockeford and 410 MW in Tesla-Bellota

- Today, LCR reduced to 579 MW for all years 2023-2025

- Vistra proposes that the LCR be established as follows:

Local Area Name	2024	2025	2026
Stockton	579*	992**	992**

*CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

*****Resource deficient areas and sub-area in forward years***

- Proposal to apply consistently to all local areas with deficiencies.

Example – 2023 Oakland area procurement improved to include deficiency

- Oakland area is a good example of how there is both a minimum capacity and minimum energy requirement possible:

- CAISO identified a minimum capacity need of 35 MW, and also identified minimum continuous energy need of ~176 MWh, however this last element was not transparent as it was not included in the proposed LCR requirements
  - 35 MW is for conventional resource assuming resource supporting it has at least 5 hours of continuous output
  - This requirement is unclear because it could be met by either:
    - 35MW with at least a ~5-hour continuous output

    OR

    - 44MW with at least a ~4-hour continuous output

- Oakland area had:
  - Requirement/need of 35 MW
  - Deficiency of 3 MW in Lockeford and 410 MW in Tesla-Bellota

CPE Proposals

12:50 p.m.– 1:30 p.m.

Cathleen Colbert, VISTRA
Lauren Carr, CalCCA
Natalie Guishar, Electric Market Design Section, Energy Division

Background

- CPE framework adopted in D.20-06-002 exempts the CPE from local RA deficiency penalties and waiver process in exchange for a “reasonable efforts” demonstration

- Commission order provides “the CPE shall have discretion to defer procurement of a local resource to the CAISO’s backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high.” (Page 100)

- Commission order also provides that this deferral is not intended to supplant the central procurement process in preference for the CAISO backstop mechanism to secure the more expensive capacity resources needed to meet local needs.

- In practice it appears that the lack of clarity on what is a reasonable basis for “unreasonably high” is undermining the effectiveness of some of the CPE solicitation processes

- With greater clarity on what the Commission would consider “unreasonably high”, the CPE would have more certainty in its negotiations with parties offering competitive offers, which should increase its confidence in awarding more offers to meet local needs and more optimally avoiding CAISO backstop risks.

Background

- CPE framework adopted in D.20-06-002 exempts the CPE from local RA deficiency penalties and waiver process in exchange for a “reasonable efforts” demonstration
- Commission order provides “the CPE shall have discretion to defer procurement of a local resource to the CAISO’s backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high.” (Page 100)
- Commission order also provides that this deferral is not intended to supplant the central procurement process in preference for the CAISO backstop mechanism to secure the more expensive capacity resources needed to meet local needs.
- In practice it appears that the lack of clarity on what is a reasonable basis for “unreasonably high” is undermining the effectiveness of some of the CPE solicitation processes
- With greater clarity on what the Commission would consider “unreasonably high”, the CPE would have more certainty in its negotiations with parties offering competitive offers, which should increase its confidence in awarding more offers to meet local needs and more optimally avoiding CAISO backstop risks.

Proposal

- Commission should adopt measures to provide CPE clear guidance on what constitutes “high pricing” that should be deferred to the CAISO backstop mechanism under the Central Procurement Entity framework for multi-year local RA program

- Commission should adopt Market Power Mitigation rules that include a CPE soft price cap in $/kw-month

- We propose the soft cap be a formulaic cap that is set at the sum of the CAISO backstop mechanism soft cap and higher of system and local RA penalties for Load Serving Entities (“LSE”) currently
  - Today that would be $15.19/kw-mo
  - If these values are changed by either CAISO or CPUC, the formulaic cap would adjust accordingly

- If the offer exceeds the price cap then,
  - CPE is not obligated to issue an award to the competitive offer
  - CPE may use its discretion if it determines the offer is in the best interest of its area subject to CPUC approval and other independent entities’ review (e.g. Independent Evaluator or a Procurement Review Group)

Basis for the formulaic soft cap

- Includes opportunity cost of failing to meet either local or system RA requirements that the bundled RA resource procured by the CPE would be used to meet and risking triggering a CPM designation
  - Currently, the soft offer cap is a single cap that represents the going forward cost of a thermal resource for an additional cost of $6.31/kw-month incurred for CPM

- Includes opportunity cost of failing to meet the Commission's requirements in its annual showing for the higher of the two penalties applied to local or system RA because failing to award bundled RA to a competitive resource in CPE would otherwise lead to both:
  - A local RA deficiency exposed to a $4.25/kw-month local penalty
  - A system RA deficiency exposed to a maximum of $8.88/kw-month because the CPE local procurement is expected to provide bundled RA that will also support system needs.

Resource Adequacy Implementation Track Phase 3 Proposals

Central Procurement Entity Enhancements

February 8, 2023

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Existing CPE Structure – The Hybrid Model

- Local RA CPEs allocated the local RA requirements (100% Y1, 100% Y2, 50% Y3)
- LSEs and generators may sell bundled local RA to the CPE
  - System and flexible attributes of bundled RA sold to the CPE allocated to all LSEs through CAM
- LSEs may self-show local RA to the CPE
  - Self-showing LSE retains system and flexible RA credit
  - LSEs self-showing new renewable or storage resources may be compensated via the Local Capacity Requirement Reduction Compensation Mechanism (LCR-RCM)
    - LCR-RCM only applies to new renewable or storage resources
    - Currently $0-$1.48 per kW-month

Hybrid CPE Introduced Significant Uncertainty

RA Year 2023 CPE Activity

1. PG&E CPE indicated it was up to 50% short of its two-year forward obligation for RA year 2023
2. Commission modified CPE timeline in D.22-03-034 to allow the CPEs to procure until mid-August 2022
3. LSEs had less than two months between receiving CPE credits and the year-ahead filings on October 31, 2022
4. PG&E CPE up to 40% short of its 2023 obligation, deferred to CAISO for potential backstop

Hybrid Structure does not Incent Selling or Self-Showing to the CPE

- LSEs may not sell because:
  - LSEs need system and flexible attributes for their own compliance obligations
  - System RA is scarce
  - LSEs not certain of the system and flexible credits they will receive

- LSEs may not self-show because:
  - The LCR-RCM is based on the delta between price of system and local RA
    - Currently, there is virtually no delta between system and local - LCR-RCM ranges from $0.00 per kW/month to $1.48 per kW/month
  - LCR-RCM only applies to new preferred or storage resources
  - If self-shown, LSE must commit to showing it each month-ahead showing for which it was shown in the year-ahead

Revise the CPE Timeline to Lock in CPE Procurement After Year Two

Current Timeline

- **Requirements Allocated** – July 2022, 2023, and 2024
- **CPE Completes Procurement** – Aug 2024
- **Credits Allocated to LSEs** – Sept 2024
- **Year Ahead RA Filings** – Oct 2024
- **Compliance Year** - 2025

CalCCA Proposed Timeline

- **Requirements Allocated** – July 2022, 2023, and 2024*
- **CPE Completes Procurement** – Aug 2023**
- **Credits Allocated to LSEs** – Sept 2023
- **Year Ahead RA Filings** – Oct 2024
- **Compliance Year** - 2025

*If there is an increase of Local RA need after Y+2, it is reasonable to allow the CPE to procure only for this incremental need.
** Could consider pushing to late September, as adopted in D.20-06-002, or December 31st of each year.

Require Additional CPE Transparency

- D.22-03-034 improved transparency by requiring CPEs to include procurement information in their Annual Compliance Reports

- D.22-12-028 encouraged parties to submit proposals that would provide additional transparency on CPE procurement efforts

- The Commission should require the following additions to the Annual Compliance Report reporting requirements:
  - If any offers or self-showings were not selected by the CPE, why were they not selected (price, inability to negotiate contract terms, other)
  - Total Net Qualifying Capacity (NQC) of local RA not offered or self-shown

Enhance incentives to self-show

- Once an LSE self-shows a resource as local, the LSE must show that resource in each month-ahead showing for which it was shown in the year-ahead self-showing
  - Taking on such an obligation places constraints on an LSEs portfolio
  - Without compensation, LSEs unlikely to take on additional constraints

- The Commission should allow self-shown resources that are either not receiving the LCR-RCM or who choose to forfeit the LCR-RCM to self-show without requiring the LSE to self-show the resource in all month ahead showings

- To date, the CAISO has not performed any backstop for CPE deficiencies
  - Indicates the year-ahead showing process provided sufficient local area resources
  - The CAISO could be relying upon its ability to backstop after the month-ahead process if those resources shown in the year-ahead process are not available in the month-ahead showing

Implementation Phase Track 3 Proposals – CPE Reporting Requirements

Energy Division Proposal 4 – Natalie Guishar, Energy Division

Proposal:
- Adopt add'l data requirements for CPE mid-August compliance filings to allow LSEs to manage upfront system RA procurement and assess potential for CPM.
- Given continued tightness of system supply, increased transparency could alleviate speculation on local capacity shortfalls + facilitate certainty in the CPE process.
- Expand report to include resources that (a) did not participate in the solicitation altogether; (b) were not contracted due to unreasonable prices; (c) were offered but withdrawn; and (d) the results of outreach efforts made to those in (a) and (c).

Background:
- Commission requires CPEs to annually report solicitations, inc. details on contract terms and the criteria + method used in selecting local RA resources; subsequently requested that CPEs disclose additional information, as the Annual Compliance Report (ACR) did not provide sufficient transparency to procuring parties
- Potential gap in timing between the local capacity shown or offered to the CPE and the resources eventually shown to the CAISO
- LSEs that are dependent on allocations from CPEs to assess their system and flexible RA positions (and potential for CPM) may need *more* information and *earlier* to timely address deficiencies in their portfolios

Energy Division Demand Response Proposals

1:30 p.m.– 2:00 p.m.

Eleanor Adachi, Demand Response Section
Michele Kito, Electric Market Design Section
Natalie Guishar, Electric Market Design Section

Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2A (PDR Specific Bid Cap Below CAISO Bid Cap) – Eleanor Adachi, Energy Division

Proposal:

ED proposes to impose a bid price cap specific to PDRs.

- PDR bid price cap should be less than $949 since CAISO can insert RDRR bids at 95% of cap
  - Suggested cap: $500 (for both DAM and RTM)
- Enforced through submission of bids to ED staff
  - Violating PDRs would be treated as if capacity was not made available on Supply Plans (i.e., LSEs may receive RA deficiency)
  - Similar mechanism already exists for imports

Background + Challenges

- CAISO market prices, especially in DAM, may be less than $1000 during system emergencies, but PDRs can bid up to $1000
- PDRs, especially long-start PDRs, can be dispatched before RDRR

Implementation Track Phase 3 Proposals: DR

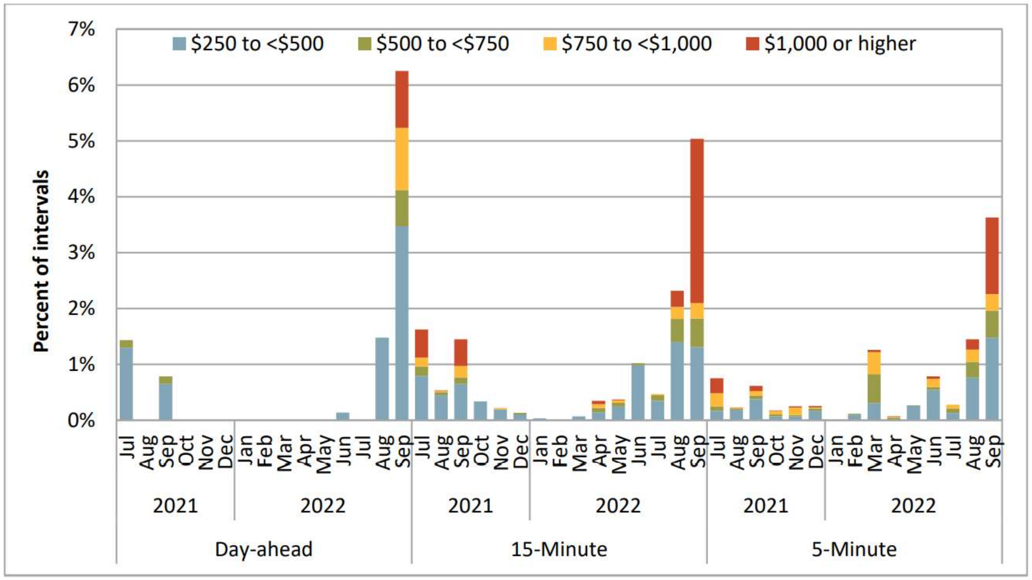
Energy Division Proposal 2A (PDR Specific Bid Cap Below CAISO Bid Cap) – Eleanor Adachi, Energy Division

Additional Background

- Suggested cap: $500
  - Equivalent to dispatch ~3% of intervals* in Sep. 2022
    - **~3%** for long-start (DAM-only) resources
    - **~3.5%** for RTM-certified resources
  - DR MCC requires min 24 hr/mo (~3.2% of intervals)
  - CBP allows max 30 hr/mo (~4.0% of intervals)

*NOTE: CAISO DMM reports prices for 3 largest default load aggregation points (DLAPs): PG&E, SCE, and SDG&E. SLAP prices may exhibit more variability.

Figure 1.17 Frequency of high prices ($/MWh) by month



Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2B (Expand Prohibited Resource Policy) – Eleanor Adachi, Energy Division

Proposal:

ED proposes to require all RA-eligible DR resources to comply with PR policy.

- Including third-party DR procured by CCAs
- Enforce through existing mechanisms
  - Modifications to Demand Response Prohibited Resources Policy Verification Plan adopted in D.22-12-004
  - Starting in 2024 annual verification audit: Random subset of DR customers with PRs subject to data logger monitoring

Background + Challenges

Existing PR policy does not apply to CCAs

- Third-party DR did not exist when PR policy was created
- Currently, third-party DR is required to comply with PR policy if procured by IOUs, but not if procured by CCAs

Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2C (Dispatch Requirements for Emergency DR Qualifying for RA) – Michele Kito, Energy Division

- **Proposal**
  - Do not count RDRR or BIP as RA unless it is dispatched at an EEA Watch or before the operational timeframe (i.e., before an EEA2).
- **Background**
  - Intention of moving DR to the supply side was to make it more useful, but CAISO only dispatches at an EEA2, when it is too late to avoid purchases of other resources or to avoid scarcity pricing. (DR was meant to address scarcity pricing and to *avoid* costly out-of-market procurement.)
  - Moreover, the CPUC indicated that BIP should be dispatched at a Warning, which corresponds with an EEA Watch, not an EEA2.
  - Further, under CAISO's rules, BIP creates scarcity pricing in the market because it is dispatched just below the bid cap (i.e., at $950 or $1900/MWh).

Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2D (Tx Loss + PRM Adders for DR Resources) – Natalie Guishar, Energy Division

Proposal: Remove TLF and PRM adders for Demand Response resources to achieve treatment parity with other resources and to reduce outsized administrative burdens.

Background + Challenges

- Current practice of grossing up and sending both adders to the CAISO is a burden, esp. when weighed against ratio of MWs being processed. For 2023:
  - Associated System TLF adders account for ~2.5% to 3.0% of DR capacity (49 MW)
  - Associated PRM adders account for ~9% of DR capacity (105 MW)
- Burdens have multiplied to proliferation of CCAs that are procuring DR (~39) and DRPs that offer DR to these CCAs (~7)
- No other distribution-connected resources are granted TLF
- Both adders cannot be bid into the CAISO → cannot be dispatched
- Applying the PRM has *no bearing on planning reserves* because DR resources do not reduce need for operating reserves in the real-time market;
  - PRM adder contributes to overestimating actual RA value on high load days
  - CAISO DMM: 193 MW of capacity represented by the PRM adder did not materialize as physically available supply that could be called upon during 2020 heatwave

Implementation Track Phase 3 Proposals: Demand Response

Energy Division Proposal 2E (RA Availability Requirements) – Natalie Guishar, Energy Division

Proposal:
Enforce availability rules so that DR resources are available during system peak demand**.** Specifically, all resources receiving RA capacity must be:

- Available a *minimum* of four hours per day
- Available for a *minimum* of three days, *plus* additional days declared under CAISO issuance of Flex Alerts and throughout the duration of the period covered by Governor's State of Emergency proclamations
  - Available *prior* to EEA Watch (issued the day before or in the event of a sudden shortfall)
- Available on summer weekends (not just Saturdays) and holidays

Background + Challenges

- CAISO DMM: Large portion of DR RA capacity not available for dispatch during key peak net load hours of summer 2020 and 2021
  - 2020: On average across peak net load hours on high load days, only 64% of the DR committed for RA capacity was available + accessible to CAISO
  - 2021: Available + accessible MWs improved, but likely due to difference in load conditions (2021 had more days in which system warnings and emergencies were not declared)
  - 2022: Under existing requirements: Required to be available August 31-September 2, but not September 3-5.
- Increasingly + more recently, peak net load days are:
  - Longer in duration and occur more frequently, sometimes with few days separating each event
  - Not limited to weekdays and non-holidays

Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2F (Treatment of Late Requests of DR Monthly Net Qualifying Capacity) – Natalie Guishar, Energy Division

Proposal:
- Formalize by Decision the existing deadline for monthly DR NQC requests.
  - Consistent with all other resources, the NQC filings are currently due first business day of the month two months prior to the requested month. For example: The submission deadline for the August 2023 RA showing, is June 1, 2023.

Background + Challenges
- Previously there were thousands of MW of DR on the NQC list that did not exist. Consequently, the CPUC and CAISO instituted a process where the Energy Division approve NQC requests based on approved LIPs and DRAM.
  - Requests must be made by first of month so can be on NQC prior to RA showings on the 15th
- Demand Response Providers (DRPs) are more frequently submitting their filings later than the deadline as published in the RA guideline for DR NQCs
- Late filings create cascading effects and additional administrative burdens for the Energy Division to adequately review and process filings.

Implementation Track Phase 3 Proposals: DR

Energy Division Proposal 2G (Treatment of DR Resources Failing to Perform During Testing) – Natalie Guishar, Energy Division

Proposal:
The Energy Division proposes enforcing performance requirements and de-rating resources from the month-ahead supply plan for resources unable to achieve their stated capacity.

- Resources de-rated at the sub-LAP level to their test performance in the year-ahead timeframe:
  - Q1 2022 results = Q1 2023 month-ahead supply plan net qualifying capacity
- Timeline correspondence considers the weather-dependent performance of DR

Challenges + Background
Aggregated test results show that, as a percentage of their reported monthly supply plans:

- Q2 2022 test performance ranged from 27 to 35% | Q3 2022 test performance ranged from 23 to 58%
- Q3 2021 performance never reached 50%
- In D.20-06-042, the Commission was persuaded that testing requirements were required in order to determine whether new and changing resources can demonstrate reliable performance.
  - Commission sought to verify whether projected load reduction values can demonstrate typical resource performance under variety of weather + other conditions.
  - At the current performance levels, these DR resources do not meet min. operational requirements.

BREAK

10 Minutes

MULTI-YEAR RA PROPOSAL

2:10 - 2:25 p.m.

Mary Neal, AReM

Proposal Background

- Currently, RA program is focused on existing resources and IRP proceeding orders new resource development for reliability
- AReM's proposal seeks to avoid continued IRP procurement orders or a new IRP procurement program
  - AReM proposes a multi-year RA Program to incent new resource development AND support existing resources
- AReM's support for this proposal in the RA proceeding is linked to the changes under consideration in the IRP proceeding
  - AReM would not support multi-year RA in addition to a separate IRP procurement program for new resource development

Proposal Overview

- Multi-year system RA program with requirements four years forward
- PRM would be informed by LOLE modeling from IRP proceeding every two years
- Optional: minimum percentage of procurement four years out would be required to be from new resources
  - Minimum percentage would be informed by IRP analysis
- Penalties would apply to forward procurement requirements
- Limited role for resource-specific central procurement for long lead time or large-scale resources
  - Use existing CAM mechanism

RA Procurement Percentages

Year	System RA Obligation
Year Ahead	100%
Year +2	100%
Year +3	100%
Year +4	60% (with the option for a minimum new resource allocation if need is demonstrated by the IRP)

- Goals:
  - Allowing adequate time for new resource development
  - Balance resource assurance against technology risk

New Resource Requirement

- Optional and only triggered if shown as needed in the IRP
- Defined as a percentage of each slice in the slice-of-day framework
- Amount of procurement requirement (MW of each slice) defined four years forward
- Showing would be required in the following calendar year's showing (three years forward)
  - Gives 1+ year for LSEs to conduct procurement
- Enforced by backstop procurement and penalties
- "New" would be defined through COD and not baseline list

Implementation Schedule

- Avoid overlap with slice-of-day implementation and existing IRP procurement orders
- Original proposal:
  - Implement in calendar year 2025 for compliance years 2026 to 2029
- Revised proposal:
  - If IRP PD for 4,000 MW of procurement for 2026-2027 is approved, implement in calendar year 2027 for compliance years 2028 to 2031

RA IMPORTS

2:25 p.m.– 3:10 p.m.

Lauren Carr, CalCCA

Michele Kito, Electric Market Design Section, Energy Division

D.20-06-028 Change to Import RA Rules

The CPUC stated need:

- [RA] imports were bidding at high levels and up to the $1000/MWh cap, and had no further obligation to bid into the real-time market if not scheduled in the day-ahead market or residual unit commitment process
  - DMM stated that this type of bidding could allow a significant portion of RA to be met by imports that have limited availability and value during critical conditions (RA resource would not dispatch even if the $1000 bid price were reached)

The CPUC adopted solution:

- Require non-resource-specific imports to bid between negative $150/MWh and $0/MWh or self-schedule during the availability assessment hours (AAH)

The Opposition:

- [R]equiring energy to flow without regard to supply and demand results in inefficient dispatch and market disruption that can lead to inflexible supply, supply congestion, and negative prices
  - The requirement may reduce the pool of suppliers offering import RA to California LSEs… or may result in RA import capacity offered at higher prices

CALCCA ADVANCING LOCAL ENERGY CHOICE

Current Market Conditions Warrant a Revisit to Attract Additional RA Imports in the Near Term

- Capacity in the West is increasingly tight
  - Western Resource Adequacy Program (WRAP) made its first advisory showing in October 2022
  - Other BAAs and POUs may be procuring resources within or outside of the CAISO footprint that were previously available as RA

- CEC and CalCCA stack analyses indicate a shortfall in the near term
  - Assuming a 16% PRM, 5,500 MW of imports, and 40% project delay, the CEC projects an hourly surplus of less than 900 MW in 2023
    - Assumes no capacity is sold outside the CAISO BAA
  - With the same assumptions as the CEC above, CalCCA projects between a 96 MW surplus and nearly a 1,200 MW deficiency over July through September, given the increased demand of the IOUs procuring above the 16% PRM (D.21-12-015), thermal plant derates, and retention of supply for substitution

- RA import bidding rules that require resources to operate irrespective of their ability to recover their costs competitively disadvantages California LSEs relative to other areas that need capacity and do not have such stringent rules

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Is there a "Goldilocks" Solution?

Setting the RA Import Energy Bid Price

$0/MWh

This Price is too low

$???/MWh on an Expected Cost Basis

This Price is just right

$1,000/MWh

This Price is too high

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Providing for Reasonable Recovery of Costs

Increasing the Bid Cap

- Devise a “no higher than” bid price reflecting the costs an import resource would expect to incur
- Base the bid price on the price of typical resources on margin during the critical summer months - combustion turbine (i.e. Peaker)
  - Total Cost = Fuel + GHG + Variable O&M
    - GHG and Variable O&M are the lesser impact and are relatively stable
    - Gas price volatility can drive significant variation in the total cost

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Experience from 2022

Gas Prices in the West $/MMBTU *				
2022	June	July	August	September
Texas	$ 9.70	$ 10.59	$ 10.07	$ 9.27
Wyoming	$ 8.92	$ 7.16	No Data	$ 8.63
Colorado	$ 9.25	$ 7.96	$ 9.34	$ 9.45
Oregon	$ 6.58	$ 6.65	$ 7.08	$ 6.03
Washington	$ 10.48	$ 8.03	$ 5.61	$ 5.96
Range				
Hi	$ 10.48	$ 10.59	$ 10.07	$ 9.45
Low	$ 6.58	$ 6.65	$ 5.61	$ 5.96

Other Costs $/MWh	
VOM **	$ 5.00
GHG ***	$ 15.00

* https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_STX_m.htm

** https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf Escalated for inflation 2019 - 2023

*** https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard

CALCCA
ADVANCING LOCAL ENERGY CHOICE

Import Peaker During AAH Summer 2022

Unrecovered Costs in Many Hours

Total Cost at 12,000 MMBTU/MWh				
2022	June	July	August	September
Hi Gas Price	$ 145.76	$ 147.08	$ 140.84	$ 133.40
Low Gas Price	$ 98.96	$ 99.80	$ 87.32	$ 91.52

Total Cost at 10,000 MMBTU/MWh				
2022	June	July	August	September
Hi Gas Price	$ 124.80	$ 125.90	$ 120.70	$ 114.50
Low Gas Price	$ 65.80	$ 66.50	$ 56.10	$ 59.60

Percent of AAH Where CAISO MCE is Less Than the Estimated Cost @ 12,000 MMBTU/MWh				
	June	July	August	September
High Gas Price	91%	91%	56%	65%
Low Gas Price	47%	48%	5%	29%

Percent of AAH Where CAISO MCE is Less Than the Estimated Cost @ 10,000 MMBTU/MWh				
	June	July	August	September
High Gas Price	76%	75%	32%	54%
Low Gas Price	11%	16%	0%	3%

CALCCA ADVANCING LOCAL ENERGY CHOICE

The “Goldilocks” Solution

Three-Tier Max Energy Bid Price

Assumptions:

- $5/MWh VOM
- $15/MWh GHG
- Variable gas price
  - Tier 1: up to $10/MMBTU = Max Energy Bid $143/MWh
  - Tier 2: above $10/MMBTU up to $20/MMBTU = Max Energy Bid $263/MWh
  - Tier 3: above $20/MMBTU = Max Energy Bid $383/MWh
    - Max Energy Bid for Tier 3 based on a gas price of $30/MMBTU
    - Additional Tiers could be added as needed

CALCCA ADVANCING LOCAL ENERGY CHOICE

Implementation Track Phase 3 Proposals: Requirements for LSEs Using Non-Specific Imports

Energy Division Proposal 7 -- Michele Kito, Energy Division

Proposal:

- Require LSEs using non-resource specific imports to be the scheduling coordinators for the resources and require that the energy flow between 4 and 9 pm, rather than specifying the bidding behavior to effectuate the "flow" to ensure compliance with CPUC decisions.

Background:

- Previously import RA was bidding at $1,000/MWh and, if selected, not delivering (called phantom or speculative RA)
- CPUC required non-resource specific RA to "flow" during the hours 4 – 9 pm, Monday – Saturday, and required that they self-schedule or bid -150 to $0/MWh to ensure that the energy is delivered (and is not speculative)
- The decision allows RA "energy" contracts, but some LSEs are using "capacity" contracts to fulfill this requirement.

Implementation Track Phase 3 Proposals: Granting RA Capacity Based on ATC and MIC

Energy Division Proposal 8 – Michele Kito, Energy Division

Proposal:
- CPUC jurisdictional LSEs should be allowed to procure ATC or acquire it through resale process, that the CPUC-jurisdictional entities be allowed to pair that ATC with RA imports to meet RA requirements.
- Alternatively, Commission could consider removing MIC requirement for RA imports, which restricts the RA imports that entities are able to buy at each of the interties, since the MIC does not convey deliverability.

Background:
- CAISO's wheeling transactions proposal: Proposes to allow external entities (non-CAISO LSEs) to reserve available transmission capability (ATC) across CAISO system based on historical RA usage in 13-month time horizon + based on actual usage in the monthly and daily timeframe at each particular intertie location (e.g., COB/Malin or NOB).
- These high priority wheels would be provided priority *equal to* CAISO load, in the event CAISO is unable to serve its own load and allow for wheeling across its Tx system. CAISO does not propose that CAISO LSEs could buy the ATC in the 13-month ahead timeframe or in the monthly timeframe *but* proposes to allow those with the high priority wheeling rights to sell those rights to others.
  - Some parties in CAISO's stakeholder process have argued that CAISO LSEs should have the right to procure the ATC, similar to external parties
  - If CAISO allows the resale of the ATC, this could be sold to a CAISO LSE. However, current Commission rules only allow Commission-jurisdictional entities to pair RA imports with MIC allocations and thus, RA imports paired with ATC would not count towards CPUC-jurisdictional RA obligations.

BREAK

5 Minutes

Proposals On: MCC Buckets; MCAM; Recoverable Costs for CAM replacement

3:15 p.m.– 3:30 p.m.

Luke Nickerman, PG&E

PG&E RA Proposals

February 8, 2023

Together, Building
a Better California

PG&E's RA Operational Proposals

1. **MCC Bucket Changes**

Issue: Significant IRP-based storage procurement is pressuring MCC Bucket 1 cap

PG&E supports SCE's proposal in RA Reform to allow storage to count as bucket 4 with sufficient charging capacity; PG&E is putting these proposals forward if that proposal is not adopted

Proposals:

A. **Updating load data to 2020-22 from 2016-18**
   - Load data is several years out of date
   - Including high loads from 2020/22 increases the size of MCC bucket 1 slightly

B. **Bucket sizes updated for all LSEs in accordance with CAM allocations**
   - IOUs currently show all CAM resources (including non-IOU portion) according to the relevant MCC bucket
   - This results in the IOUs having excess bucket 4 and bucket 1 resources
   - Details:
     - The change would result in a decrease in the bucket percentages for DA and CCA parties that aligns with the mix of CAM resources and their bucket categories
     - IOUs would no longer need to include the non-IOU portion of CAM resources in their MCC bucket showings

PG&E's RA Operational Proposals

2. Use existing CAM allocation process for MCAM allocations

Issue: Current process is a manual adjustment in each RA compliance showing that results in inconsistent showings between CPUC and CAISO; this is burdensome for both the IOUs and ED and carries compliance risk for the IOUs

Proposal: Treat the allocation of MCAM benefits the same way as CAM benefits

- A one-time RA requirement adjustment that results in a decrement (i.e., CAM credit) to the opt-out LSEs' RA requirements and an increment (i.e., CAM debit) to IOU's RA requirements (by the total amount of the opt-out LSEs' portion)

3. Use PCIA benchmark as the recoverable cost for CAM replacement cost

Issue:

- ED RA report prices are used as the recoverable cost for CAM replacement cost when a CAM resource is on outage or otherwise unable to be shown and the IOU uses a resource from its portfolio to replace the resource
- However, the PCIA benchmark is used when the IOU retains that resource for substitution
- Because RA report prices differ from the PCIA benchmark prices, cost shifts occur when PCIA benchmark prices are higher or lower than RA report prices

Proposal: Use the PCIA benchmark price as the recoverable cost for CAM replacement cost to align with the cost to IOU bundled customers to retain the resource for substitution

Q&A

Until 4:15 pm

California Public Utilities Commission

Thank you for attending today's workshop. Feedback welcome.

Host contact:
Sasha Cole – alexander.cole@cpuc.ca.gov