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Proposal for Demand Response Resource Counting for Slice of Day

September 2022

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The 24-Hourly Slice-of-Day Framework

The California Public Utilities Commission (CPUC) in D.21-07-014 adopted the Slice-of-Day framework developed by Pacific Gas and Electric (PG&E). In D.22-06-050, the CPUC adopted the 24-hourly Slice-of-Day framework refinement developed by Southern California Edison (SCE). No longer would parties submit a resource stack to meet just the peak load, but they would have to show resources to cover the load throughout the day. In addition, parties using storage would show the resources providing energy used for charging as part of their capacity requirements. The following chart depicts an illustrative load serving entity (LSE) resource showing under the Slice-of-Day proposal, where the green line represents the LSE's 24-hour requirement (load profile plus PRM), and the stacked bars represent the LSE's portfolio by resource type.[2] Here, the LSE passes the showing because it has satisfied its requirement in all 24 hours.

In addition to hourly capacity contributions, all resources will still have a single monthly qualifying capacity value (QC) approved by the CPUC for the California Independent System Operator's (CAISO's) need determination process.[3] The monthly QC value "for wind and solar

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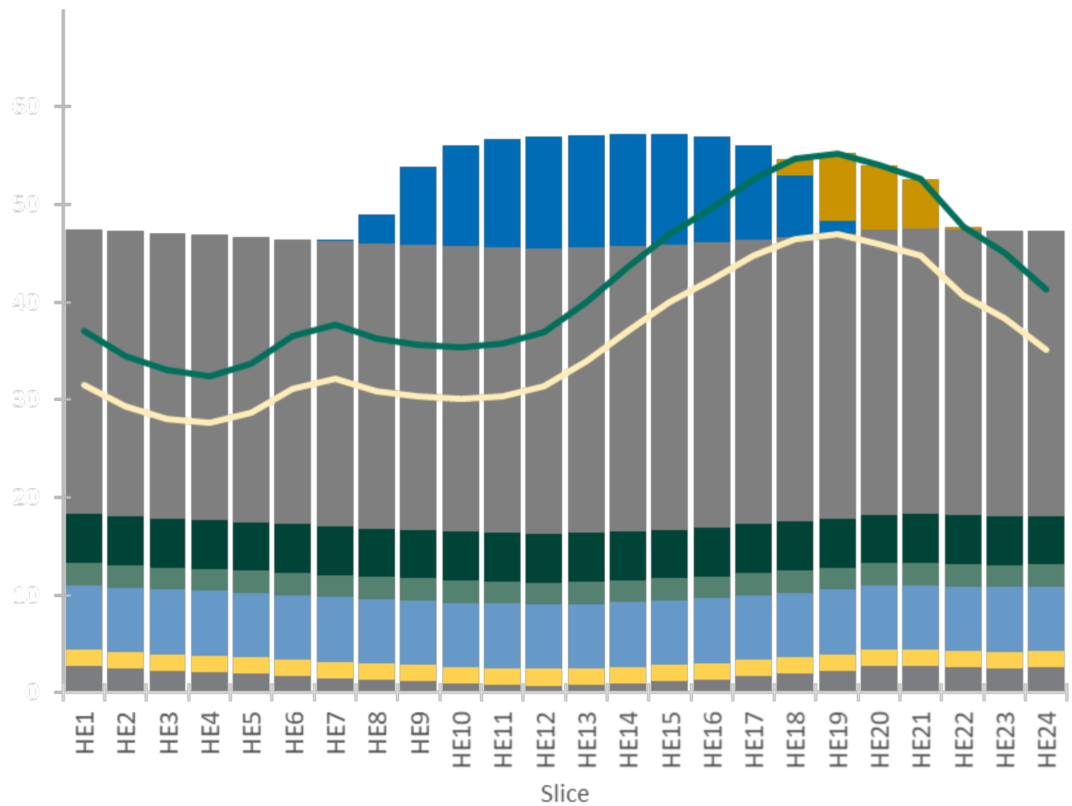
[1] CLECA is an organization of large, high load factor industrial customers located throughout the state; the members are in the cement, steel, industrial gas, medical gas, pipeline, beverage, cold storage, and minerals processing industries, and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite renewable generation. CLECA has been an active participant in Commission regulatory proceedings since the mid-1980s, and all CLECA members engage in Demand Response (DR) programs to both promote grid reliability and help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing. CLECA members have participated in the Base Interruptible Program (BIP) and its predecessor interruptible and non-firm programs since the early 1980s.

[2] The beige line is the load.

[3] D.22-06-050 Appendix A at 3.

will be based on peak hour deliverable capacity based on their profile for that hour".[4] This should provide guidance for the monthly QC for DR, as many DR programs also have a profile that varies by hour.



Supply-Side Demand Response Resources

The CPUC currently uses the Load Impact Protocols (LIP) to provide capacity values for DR for the Resource Adequacy (RA) program. The output of the LIP is a value for each DR program for each of 12 months (in MW). Each value is an average of the hourly load reductions from an assumed call from 4pm–9pm. The load assumption is a monthly peak with a 1-in-2 weather assumption. Since the Slice-of-Day methodology will no longer use a single monthly load target, but have multiple load targets, the status quo of a single MW value is not compatible with the Slice-of-Day framework.

[4] D.22-06-050 Appendix A at 3.

An expected load reduction for demand response is required for each hour

Under the 24-hourly slice (by month) proposal, the expected load reduction of a DR program during those hours is required to build up an accurate resource stack to meet the forecasted load and planning reserve margin requirement.[5]

The expected load reduction in an hour should incorporate DR performance history and, if applicable, the weather conditions. The regressions and supporting data from the existing LIP already produce hourly expected load reductions that can be utilized. For example, the table below shows the hourly load impacts for a load reduction from 4pm–9pm from the LIP for Southern California Edison's Summer Discount Plan, which is an air conditioner (A/C) cycling program.[6] While this example is from 4pm–9pm, a better fit for the DR program could be 5pm-9pm or 5pm-10pm. Other methods can be used, provided they can produce hourly expected values with sufficient accuracy and granularity for the 24-hourly Slice-of-Day proposals.

SCE-SDP-Commercial		
	Load Impact	
HE	MW	
16	0	
17	28.95	
18	23.72	
19	18.78	
20	14.90	
21	12.61	
22	-2.81	
23	-1.21	

For the 24-hourly Slice-of-Day proposal, the hourly values for the assumed DR call period, including any significant spillover impacts which increase load before or after the event, would be used in the resource stack. Spillover can occur for programs that rely on pre-cooling or when snap back occurs, such as increasing load after air conditioners that have been turned off are turned on again. This type of spillover is an increase in load due to the DR event (either before or after it) that is a result of the load interruption, which otherwise would not have

[5] Since the load forecast is at the CAISO level, the current practice is to gross up the hourly load impacts at the customer delivery point to yield the impact at the CAISO grid. In addition, the customer load impacts are grossed up for the avoidance of the planning reserve margin.

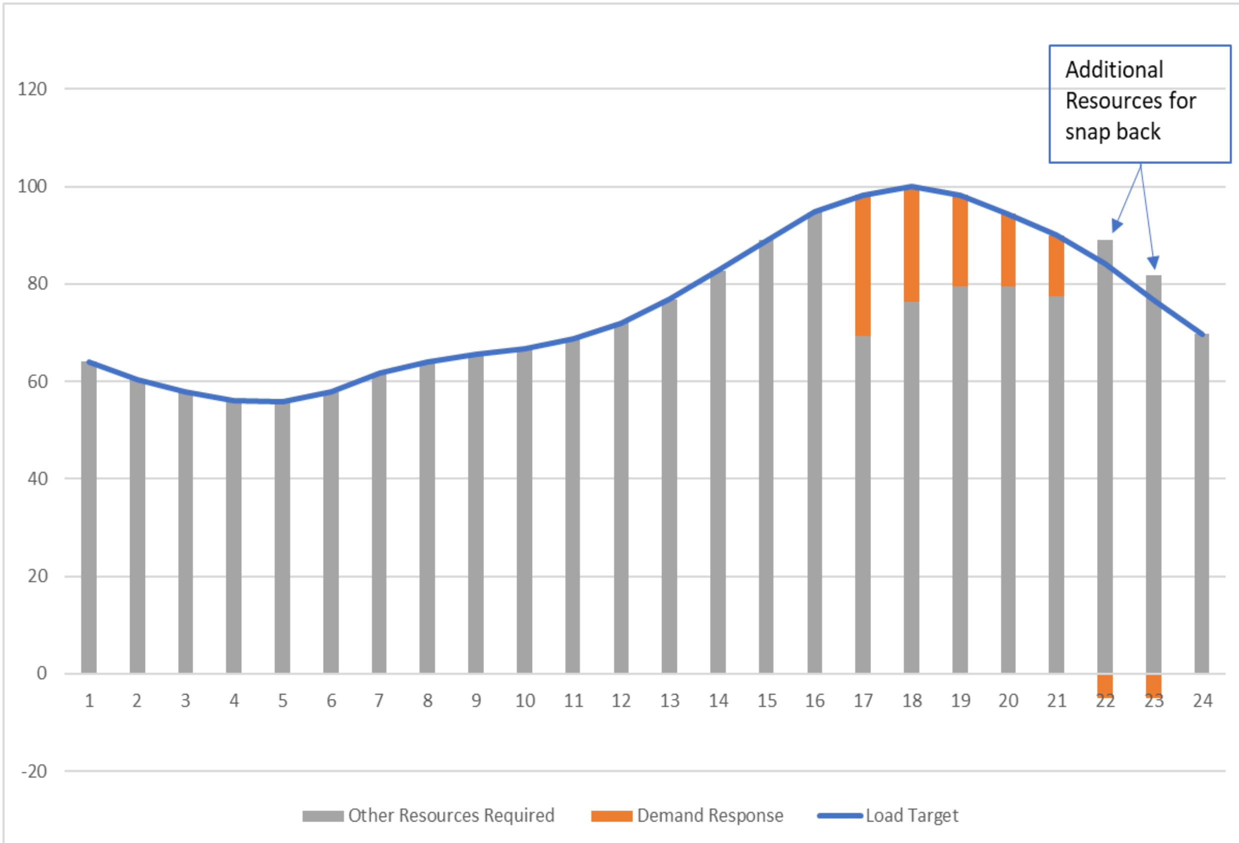
[6] The program is available for a 6-hour duration, and other call hours are possible. The negative values represent snap back impacts due to increased load after the DR event that otherwise would not have occurred.

occurred if use of demand response was not necessary.[7] Another type of spillover occurs when there is a delay in load being restored after a DR event, due to the need to turn facilities back on slowly or sequentially, as at an industrial facility.

As shown in the table below, the hourly load impacts from HE 17-23 (aka 4pm-9pm, the 5-hour call plus the two hours of spillover) are applied to each hour. For HE 22-23, the other resources required to meet the load target will increase because of the higher load due to the spillover effect. This is also shown in the figure below.

	HE	Load Target	Demand Response	Other Resources Required
	16	95	0	95
	17	98	29	69
Peak	18	100	24	76
	19	98	19	79
Net Peak	20	94	15	80
	21	90	13	77
	22	84	-5	89
	23	77	-5	82
	24	70	0	70

[7] An evaluation should occur to determine the significance of spillover for a particular DR program. If the possibility and magnitude of spillover is small, then making an estimation of spillover would needlessly increase the cost of measurement. In addition, the planning reserve margin already accounts for load forecast error.



Minimum Demand Response Program Requirements

To ensure sufficient availability, DR programs should be available a minimum number of calls per month and hours per year. Currently, to be counted for resource adequacy a DR program must be available Monday through Saturday, for 4 consecutive hours between 4pm and 9pm, and at least 24 hours per month from May through September, as shown in the table below from the most recent Commission decision establishing the maximum cumulative capacity buckets.[8]

[8] D.21-06-029 at 27.

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. For the month of February, total availability is at least 96 hours.	17.0%
2	Every Monday – Saturday, 8 consecutive hours that include 4 PM – 9 PM	24.9%
3	Every Monday – Saturday, 16 consecutive hours that include 4 PM – 9 PM	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

CLECA recommends most of the availability requirement be retained for a program to count for resource adequacy. However, under the 24-hourly proposal, the requirement that DR must be available from 4pm-9pm may no longer be necessary. That change would allow an LSE to develop DR programs to meet its load requirement shape, such as a LSE with primarily commercial load from 8am to 5pm.

Over time, the availability requirements may need revision after examining various scenarios in a reliability study in order to better understand the time period, duration, and frequency of possible loss of load events.

Monthly Qualifying Capacity

In D.22-06-050, the CPUC will still adopt monthly QC values for all resources for the CAISO need determination.[9] That decision stated QC values "for wind and solar will be based on peak hour deliverable capacity based on their profile for that hour".[10] This should provide guidance for the monthly QC for DR, as many DR programs also have a profile that varies by hour. Using the example from above, if the peak hour is HE18, then the monthly QC would be 24 MW.

It is important that the hourly value for the peak hour be consistent between the CPUC and CAISO RA programs; otherwise, inconsistent results could occur. For example, if the CPUC uses 24 MW for HE18 in the slice-of-day, but CAISO uses the HE17-21 average of 20 MW for the HE peak hour, then it is possible that the CPUC's RA program would conclude the LSE is resource-sufficient, but the CAISO's need determination could conclude there is a 4 MW shortfall. This would yield conflicting results about resource adequacy.

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[9] D.22-06-050, Appendix A at 3.
[10] D.22-06-050, Appendix A at 3.

Transmission and Distribution (T&D) Adders

In D.21-06-029, the CPUC directed a review of the crediting of DR for certain adders as part of its QC. These adders are for transmission and distribution losses (the transmission loss factor or TLF and the distribution loss factor or DLF), and for the planning reserve margin (PRM). The decision retained the TLF and DLF, and asked the CEC Working Group to review these adders. Neither the TLF and the DLF, or the PRM adder, was addressed in the February 16, 2022 CEC Interim Working Group Report. They are being included as part of the follow-up work.

CLECA supports the retention of the TLF and DLF. Additional capacity must be available to deliver electricity to end use customers, to overcome T&D losses that are incurred when moving the power through the grid. Reducing 1 MW of load results in a greater than 1 MW reduction in need at the resource, because the T&D losses are not incurred. The CPUC acknowledged this in D.21-06-029, Ordering Paragraph 13, which states the following:

> 13. The transmission loss factor (TLF) and distribution loss factor (DLF) components of the planning reserve margin adder for demand response (DR) resources shall be retained. The DLF adder shall be incorporated into qualifying capacity (QC) values for DR beginning in the 2022 Resource Adequacy (RA) compliance year. For the TLF adder, Energy Division Staff shall continue the current practice of grossing up RA filings and sending credits to the California Independent System Operator to account for transmission losses.

The load forecast is at the transmission level, so the load impact at the meter should be grossed up for distribution losses to calculate qualifying capacity losses. Distribution losses vary among utility distribution systems and may need to be periodically updated.

Transmission losses should be a credit for the planning process, the same as today, in order to reduce capacity need.

Planning Reserve Margin Adder

D.21-06-029 adopted a reduction in the PRM adder from 15% to 9% by removing the 6% in the PRM for forced outages. However, it left open the issue of how the remaining 9% should be addressed, and asked the CEC Working Group to address this issue.

CLECA supports retention of the entire 15% PRM adder, on the grounds that capacity requirements are determined as peak load plus the PRM. Reducing load thus eliminates the incremental PRM associated with that load. For planning, DR is treated as a load modifier because it is non-firm load. Not treating supply side DR in the same way for planning purposes results in treating load modifying and supply side DR differently, despite the fact that they both effectively create an additional capacity margin by reducing load.

CLECA does not support eliminating the 6% share of the 15% PRM for operating reserves. If load is reduced, the need for operating reserves is similarly reduced. The CAISO should be able to distinguish non-firm load as DR for planning purposes. In operations, the operators should be informed of how much load is non-firm and can be shed if needed. This certainly applies to reliability demand response resources.

Attachment A: SCE's 24-Hourly Slice Proposal

Component	SCE's 24-Hourly Slices Proposal[11]
Slice Definition	24-Hourly Slices
Showings	Single monthly using a standardized template (to be developed)—LSEs must meet their load + PRM in all 24-hours and show sufficient capacity to offset battery usage to pass showing. Similar template will be used for the year-ahead showing
Resource Capacity Counting	Resource Adequacy Capacity must be deliverable **Solar and wind** will count based on their hourly expected capacity profiles—**specific methodology** *(e.g.*, exceedance, hourly ELCC, or other) **to be determined in subsequent forum** **Standalone batteries** count based on their capacity and duration as shown by the LSE; must demonstrate there is sufficient "excess capacity" in other hours to support their dispatch (plus losses) **Hybrid resources:** Requires additional stakeholder discussion due to the unique and complex issues **Use-limited resources** count based on their capacity and available duration as shown by the LSE **Other resources** will have a single counting value (e.g., NQC is eligible to be used in every slice) **Imports** must be shown in their available hours
Load Forecast	Gross
Need Allocation	Consistent with CEC proposal. Bottoms up; retain existing coincident peak process and shape based on LSEs' historical load, and adjusted by the CEC to ensure system demand is met in each hour on the monthly worst-day

[11] SCE's proposal applies to the CPUC's RA showing process, and does not govern how resources are dispatched by the CAISO.

Attachment A: SCE’s 24-Hourly Slice Proposal

Market Product	Resource attributes and capabilities are bundled (*i.e.,* no unbundling of hourly slices) but resource capacity can be split (e.g., 70% to LSE 1, 30% to LSE 2); SCE is not proposing “load trading” but does not oppose others proposing it as a potential enhancement to SCE’s 24-hourly slices framework
Energy Market Obligation	“Full capability/all-hour” must offer obligation (MOO)
Use-limitations	Use-limited 24-hour allocation; retain minimum 4-hour daily output availability requirement; eliminate flex requirements and MCC buckets
Penalties for Non-Compliance	Same principles as today: CPUC penalty for failing showing based on the hour where the LSE’s showing is the most deficient; CAISO first allocates backstop costs to LSEs who fail their showing, and remaining costs (if any) to all impacted LSEs