

ATTACHMENT 1:
RULEMAKING 20-11-003 GUIDANCE

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1. Flex Alert

A Statewide Flex Alert Paid Media campaign shall be funded by the ratepayers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). The following is the guidance on the implementation of this program, to be available by the summer of 2021.

SCE shall develop a new contract with the existing time-of use Statewide Marketing, Education and Outreach (ME&O) vendor DDB San Francisco (ME&O vendor).

SCE shall create a 2-year contract, shall do a performance assessment during year two (2022) covering both process and impact, and shall provide the assessment to stakeholders through the service list and to Energy Division directly. SCE shall execute a contract with the ME&O vendor within 30 days of the effective date of this decision to allow for adequate program implementation for the 2021 summer months.

SCE shall coordinate with Energy Division staff to receive direction on the scope of the contract and budget and during the implementation and administration of the contract. The contract shall terminate on December 31, 2022.

Stakeholders shall have input into the evaluation's scope of work through regular stakeholder May through October meetings presented by the ME&O vendor in coordination with Energy Division. SCE shall direct the ME&O vendor, through the contract, to provide Energy Division staff with campaign evaluation reports in the fall of 2021 and 2022. This evaluation is distinct from the performance assessment SCE will conduct.

PG&E, SCE, and SDG&E shall fund the paid-media Flex Alert campaign with funds collected from all benefitting customers (i.e., bundled investor-owned utility (IOU), community choice aggregator (CCA), and Direct Access customers) using Public Purpose Program (PPP) balancing accounts. Each IOU will collect its share of the authorized Flex Alert campaign PPP funds from all benefitting customers in its service territory.

This decision authorizes a budget of \$12 million per year, for two years, to support the Statewide Flex Alert Paid Media campaign. The decision also authorizes IOUs up to 3% of the annual Flex Alert budget to cover IOU administration costs.

SCE, PG&E, and SDG&E shall collect the authorized funds for the statewide paid-media Flex Alert campaign from all customers in their service territories (i.e., bundled customers and customers of CCAs and Electric Service Providers (ESPs)) based on each IOUs' portion of the CPUC jurisdictional share of CAISO peak load: 45% for SCE, 45% for PG&E, and 10% for SDG&E.

2. Critical Peak Pricing

The following are directed modifications to the Critical Peak Pricing (CPP) rate design programs of PG&E, SCE, and SDG&E. Additionally, contained in this section is guidance for the three large electric IOUs regarding expanding CPP rate design programs to non-IOU Load Serving Entities (LSEs).

PG&E

PG&E shall modify its CPP event window for both residential and non-residential customers to the hours of 4:00 PM to 9:00 PM, no later than June 1, 2022. PG&E is directed to spend, and authorized to recover, up to \$2 million to implement the new event hours of 4:00 pm to 9:00 pm, including information technology, billing, and administrative costs.

PG&E is directed to spend, and authorized to recover, up to \$635,000 associated with customer education with the focus on improving performance on the CPP rate.

SDG&E

SDG&E shall modify its CPP event window for both residential and non-residential customers to the hours of 4:00 PM to 9:00 PM, no later than June 1, 2022.

SCE

SCE shall increase the maximum number of events for CPP from 12 to 15 per year.

SCE shall include weekends and holidays as potential call days for its CPP program no later than June 1, 2022. SCE is directed to use the memorandum account authorized in this decision to track expenses associated with this change.

SCE is directed to spend, and authorized to recover, up to \$1,000,000 (\$500,000 annually for 2021 and 2022) associated with customer education with the focus on improving performance on the rate.

PG&E, SCE, and SDG&E

PG&E, SCE, and SDG&E are directed to coordinate to host a virtual workshop on the voluntary expansion and establishment of non-IOU LSEs' CPP rate design programs. The IOUs shall consult with Energy Division staff on the content for the workshop, which shall be held no later than April 7, 2021.

The IOUs are directed to cover the following topics at the workshop:

- CCA and IOU best practices around developing and implementing CPP programs, including rate structures, marketing/outreach and billing;
- Barriers to non-IOU LSE CPP program expansion;
- Potential CPP program benefits for non-IOU LSEs, including the potential to obtain a resource adequacy (RA) credit through load impact reports (LIPs), and other potential incentive mechanisms;
- Improving IOU hourly interval data transfers to non-IOU LSEs for purposes of CPP; and
- Options for evaluating CPP programs, including load impact studies and cost effectiveness studies.
- Alternative approaches for CCA to promote load shedding, including how the CCAs should coordinate with IOUs on programs such as the Emergency Load Reduction Program.

3. Emergency Load Reduction Program (ELRP)

PG&E, SCE, and SDG&E are each directed to develop and administer an Emergency Load Reduction Program (ELRP) pilot with the attributes described in the following sections. ELRP shall be effective by May 1, 2021, for both Group A and B participants, as defined below.

Pilot Program Duration

ELRP duration will be five years (2021-2025), with years 2023-2025 subject to revision in the Demand Response (DR) Application proceeding expected to be initiated November 2021. ELRP design aspects that are subject to review and revision include minimizing use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals. To this end,

PG&E, SCE, and SDG&E should collect data on backup generator participation in ELRP, including as location, type of fuel used, and the capacity of the generator, for years 2021 and 2022.

Out of Market Framework

ELRP load reduction capacity will be excluded from the Resource Adequacy (RA) / California Energy Commission (CEC) peak forecast framework with no CAISO market obligations.

Program Parameters

- Program availability: May – October; seven days a week; 4 pm – 9 pm
- Event duration: 1-hour minimum; 5-hour maximum
- Annual dispatch limit: Up to 60 hours
- Consecutive day dispatches: No constraints

Eligible Customers

Eligible participants for ELRP are divided into two groups with several subgroups:

- Group A: Select non-residential customers and aggregators not participating in DR programs
 - A.1. Non-Residential, Non-DR Customers
 - A.2. Base Interruptible Program (BIP) Aggregators
 - A.3. Rule 21 Exporting Distributed Energy Resources (DERs)
 - A.4. Virtual Power Plants (VPP)
- Group B: Market-integrated proxy demand response (PDR) resources
 - B.1. Third-party DR Providers (DRPs)
 - B.2. IOU Capacity Bidding Programs (CBPs)

Eligibility criteria for each group are defined below.

GROUP A

At the time of enrollment, or at designated times during the ELRP pilot, Group A participants will nominate an estimated target load reduction quantity to be achieved during an ELRP event. Participation during an ELRP event is entirely voluntary, and no financial penalties will result from not meeting or exceeding the nominated target load reduction during the event.

If a customer qualifies for the ELRP under both A.1. and A.3. criteria described below, the customer will make an election for participating in the ELRP as part of one or the other subgroup at the time of enrollment, or at designated times during the ELRP pilot.

A.1. Non-Residential, Non-DR Customers

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- Customer meets the “Minimum Size Threshold” specified further below, and
- Customer is not currently taking service on a CPP or real time pricing (RTP)-equivalent tariff, and
- Customer is not simultaneously enrolled in another DR program offered by an IOU, demand response provider (DRP), or CCA, with the exception that dual enrollment in an IOU’s BIP or SCE’s Agricultural and Pumping Interruptible (AP-I) program is permitted.

The Minimum Size Threshold parameter for each IOU is as follows:

- For PG&E, the customer must be able to reduce load by a minimum one kilowatt (kW) during an ELRP event.
- For SCE, the non-residential service account must have a peak demand of greater than or equal to 200 kW with an SCE approved interval meter.
- For SDG&E, the customer agrees to drop a minimum of 100 kW during an ELRP event.

A.2. BIP Aggregators

BIP aggregators are eligible to participate in ELRP. If a BIP aggregator chooses not to participate, its customers may independently participate in ELRP under A.1, subject to the applicable criteria and requirements.

For SCE, participating aggregators may add and nominate only non-residential customers eligible under A.1. in their ELRP portfolio.

SDG&E may elect to defer the effective date of Group A.2 eligibility to a date no later than May 1, 2022 by filing a Tier 1 AL.

A.3. Rule 21 Exporting DER

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- Customer is not simultaneously enrolled in any market-integrated DR program offered by an IOU, DRP, or CCA, and
- Customer possesses a behind-the-meter (BTM) Rule 21-interconnected device (including Prohibited Resources) with an existing Rule 21 export permit, and
- Customer's BTM Rule 21 interconnected device is able to meet the "Minimum Export Threshold" specified further below for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event.

The Minimum Export Threshold is set at 25 kW based on the physical interconnected capacity.

For situations in which electric vehicles owned by a government agency and their associated charging equipment are located on a service that is electrically contiguous to a facility also owned by that agency, with the electrically contiguous facility possessing continuous export permission to operate, it may be necessary for an IOU to consider and grant a limited deviation to facilitate the agency's participation in ELRP under the A.3 sub-group. The IOU is instructed to provide a deviation¹ to its electric Rule 21, with its scope limited to the duration of an ELRP event, for an agency that wishes to export energy from its electric vehicles and can utilize that portion of the previously approved continuous export permission to operate that is unutilized during the ELRP event. This potential interconnection pathway for government fleets to use an existing Rule 21 Permission to Operate, where available, does not limit a government fleet from using any other approved Rule 21 interconnection pathway. A Tier 1 AL filed either prior or subsequent to the deviation being granted shall be served on parties for both this and the R.17-07-007 proceedings. Any deviation shall be added to the listing of contracts and deviations² maintained by the IOU.

An IOU may elect to defer the effective date of ELRP eligibility for A.3 participants to a date no later than May 1, 2022 by filing a Tier 1 AL.

A.4. Virtual Power Plants

An aggregator managing a BTM hybrid VPP consisting of storage paired with net energy metering (NEM) solar deployed with residential (bundled or unbundled) or non-residential

¹ Deviations for the benefit of Government Agencies are addressed in section 9.2.3 of General Order 96b.

² Listing of contracts and deviations are addressed in section 9.5.6 of General Order 96b.

(bundled or unbundled) customers, whose VPP meet the following criteria, is eligible participate in ELRP:

- The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by an IOU, DRP, or CCA, and
- A customer site within the aggregation is not currently taking service on a CPP or RTP-equivalent tariff, and
- All sites within the VPP aggregation are located within the distribution service area of a single IOU, and
- The aggregated BTM storage capacity of the VPP is able to meet the “Minimum VPP Size Threshold”, where the VPP size is determined by summing the Rule 21 interconnected capacity of the individual storage devices comprising the aggregation, and
- Each site within the VPP aggregation has a Rule 21 export permit.

The Minimum VPP Size Threshold is set at 500 kW.

An IOU may elect to defer the effective date of ELRP eligibility for A.4 participants to a date no later than May 1, 2022 by filing a Tier 1 AL.

GROUP B

B.1. Third-party DRPs

A third-party DRP with a market-integrated PDR resource is eligible to participate in ELRP.

B.2. Capacity Bidding Program PDR Resources

An IOU’s CBP PDR resources are eligible to participate in ELRP.

Program Event Triggers

ELRP will utilize a day-ahead (DA) trigger.

Day-Ahead (DA) Trigger

The ELRP DA trigger for Group B resources is activated when a DA Alert, per the “Alert, Warning, Emergency (AWE)” process defined by the CAISO Operating Procedure 4420, is declared by the CAISO. The start time and duration specified in the DA Alert defines the Group B ELRP event window.

Following a DA Alert declaration by the CAISO, the IOUs will exercise discretion to activate the DA trigger for Group A participants, either selectively staggered over time or all DA participants at the same time. The start time and duration specified by the IOU defines the ELRP event window for the Group A participants called by the IOU.

Day-Of (DO) Trigger

There is no ELRP Day-Of trigger for Group A or Group B defined at this time.

Other Trigger Related Guidelines

An ELRP event cannot be triggered by an IOU for a localized transmission or distribution emergency.

For coordination among and guidance to the IOUs in the exercise of discretion for Group A trigger activation, the IOUs shall form a “Joint ELRP Operations Board,” with representatives from each IOU’s grid operations group and an invited representative from the CAISO’s grid operations group. Following an AWE declaration by the CAISO, the Board will periodically assess the current and forecasted grid conditions and provide guidance on target load reductions to be sought by the IOUs from Group A participants.

The IOUs are directed to coordinate with the CAISO in providing timely information on the status and expected load reduction under ELRP from Group A.

Future AWE Declarations

In the future, when the CAISO completes the transition from the current AWE process to the North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) standards, then the AWE declarations shall be replaced by the equivalent CAISO issued day-ahead EEA level notices in the above guidelines, per the following table:

AWE Levels	NERC EEA Levels	Comments
Restricted Maintenance Operations		Issued in real time or in advance
Transmission Emergency		Issued in real time
Notifications of forecasted reserve deficiencies		

Alert	EEA-1	Issued in advance – day ahead by 1500
Warning	EEA-1	Issued in real time
Warning – triggering DR programs	EEA-2	Issued in real time
Stage 1	EEA-2	Issued in real time
Stage 2	EEA-3	Issued in real time
Stage 3	EEA-3	Issued in real time

Compensation

Incremental load reduction (ILR) is defined as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and any other existing commitment. Only ILR is eligible for compensation under ELRP.

Any load reduction technology may be used during an ELRP event to achieve ILR. Prohibited resources³ may be used in compliance with Rule 21 and other applicable regulations and permits during an ELRP event to achieve ILR, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (e.g., under a dual-enrolled DR program).

General ELRP compensation parameters for all customers include the following:

- After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate applied to ILR.
- There are no “capacity-like” payments or enrollment incentive.
- There are no penalties for non- or under-performance.

The ELRP Compensation Rate (ECR) for Group A is set at \$1 / kilowatt-hour (kWh) (or \$1000 / megawatt-hour (MWh)).

The ECR for Group B PDRs is also set at \$1 / kWh (or \$1000 / MWh).

³ As directed in Resolution E-4906 (see Ordering Paragraphs 45 and 47 at 104), customers previously using a prohibited resource fuel may switch the resource to a renewable fuel that has met CARB certification. Allowable fuels are those that have met the agency’s [Low Carbon Fuel Standard \(LCFS\) Tier 2 Pathway](#). Customers may update their required attestations upon making this operational change.

GROUP A

For Group A eligible participants, the compensation for load reduction delivered during an ELRP event is determined by calculating the product of ILR and ECR.

ELRP compensation for an event is bounded for Group A participants between 50 percent and 200 percent of pre-nominated load shed or exported energy quantity.

An IOU may choose to defer the effective date of counting export energy in ILR, as described below, to a date no later than May 1, 2022 by filing a Tier 1 AL.

A.1. Non-Residential, Non-DR Customers

Baseline

The ELRP baseline will be constructed by all IOUs according to the method described below.

1. A customer's Adjusted Energy Baseline (AEB) for an ELRP event is calculated by multiplying the energy baseline (EB) by the optional day-off (DO) adjustment.
2. The EB will be calculated on an hourly basis using the average of either 1) the previous 10 calendar days, or 2) the previous 10 similar days.
3. The days selected in step 2 above shall exclude days when a) the customer was subject to an ELRP event or an event in a dual-enrolled DR program, or b) there was a grid outage during similar hours.
4. The DO adjustment value shall be either 1) not less than 1.00 or greater than 1.40, or 2) not less than 0.60 or greater than 1.40. The DO adjustment is a ratio of (a) the average load of the first three hours of the four hours prior to the event to (b) the average load of the same hours from the last 10 days selected in accordance with step 2 above.

Special Considerations

1. In the case of overlapping BIP and ELRP events, only the incremental reduction below the customer's pre-committed firm service level (FSL) is counted in ILR.
 - a. Load reduction by dual-enrolled BIP customers during an ELRP event outside of a BIP event is excluded from ILR (and not eligible for ELRP compensation).
 - b. Load reduction by dual-enrolled BIP customers during an ELRP event on a day with no BIP event is excluded from ILR (and not eligible for ELRP compensation).

2. If the customer has a Rule 21 interconnected device with export capability and permit, the customer may choose to count exported energy in ILR. In that case, the applicable ELRP baseline is modified to account for exported energy during non-event days and count exported energy in ILR.

For SCE, the effective date of compensation for ILR during overlapping BIP and ELRP events is deferred to May 1, 2022.

An IOU may choose to defer the effective date of excluding grid outages from an ELRP baseline to a date no later than May 1, 2022 by filing a Tier 1 AL.

An IOU may choose to implement the ELRP baseline with only one option for the ten-day selection or one option for the DO adjustment by filing a Tier 1 AL.

A.2. BIP Aggregators

Same guidelines as A.1 apply.

A.3. Rule 21 Exporting DER

For a customer on a CPP or RTP equivalent tariff, the ELRP baseline is deemed to be zero and only exported energy is counted in ILR.

For a customer not on a CPP or RTP equivalent tariff, the ELRP baseline defined under A.1 is utilized and modified to account for exported energy during non-event days and exported energy is counted in ILR.

A.4. Virtual Power Plants

The aggregator selected CPUC approved baseline for IOU's CBP is utilized and modified to account for exported energy during non-event days and count exported energy in ILR.

GROUP B

ELRP Baseline for Group B

To construct the ELRP baseline for measuring a Group B PDR's ILR contribution during an ELRP event, the applicable CAISO baseline will be modified to account for the following:

- 1) Count net exports to the distribution grid by customer locations within the PDR aggregation that comply with Rule 21 and other applicable permits,
- 2) Exclude prior days with other ELRP events when selecting the set of “non-event, but similar” days when calculating the baseline,
- 3) Exclude applicable preceding hours with either CAISO market awards or another ELRP event on the day of the ELRP event when calculating the same-day adjustment (SDA) to the calculated baseline in step 2, and
- 4) Allow the SDA in step 3 to be no greater than 100%.

ELRP Settlement for Group B

For participation in ELRP under Group B, a DRP must construct a PDR Portfolio consisting of only 1) PDRs with RA assignment or PDRs without RA assignment (but not both) and 2) PDRs limited to the service area of one IOU (thus, a DRP may have up to six PDR portfolios participating in ELRP).

The CAISO settled aggregated load during an ELRP event is modified to count net energy exported to the distribution grid by any customer location within the PDR aggregation.

Following an ELRP event, the DRP’s scheduling coordinator is responsible for determining the following:

1. ELRP Event Performance (total load reduction during the ELRP event) of each PDR in the DRP’s PDR Portfolio by applying the applicable ELRP modified baseline to the PDR’s modified aggregated load settled during the ELRP event.
2. ILR of each PDR by subtracting the CAISO scheduled award quantities, inclusive of day-ahead market (DAM) and real-time market (RTM), from the PDR’s ELRP Event Performance. If the total market award for the PDR during the ELRP event is zero, then ILR of the PDR equals the ELRP Event Performance.
3. The ELRP Event Compensation due for each PDR by adding all interval-specific ELRP Compensations across all applicable intervals of the ELRP event, subject to the following:
 - a. The interval-specific ELRP Compensation in each applicable interval of the ELRP event is obtained by subtracting 1) any CAISO market payments for any portion of the load reduction counted in the interval-specific ILR and 2) the interval-specific CAISO Opportunistic Revenue (COR), defined below, from 3) the interval-specific Product of the ECR and the interval-specific ILR (see illustration below).

If the interval-specific ILR is negative, then the interval-specific ELRP Compensation is set to zero in that interval.

If the interval-specific COR is greater than the interval-specific Product, then the interval-specific ELRP Compensation is set to zero in that interval.

- b. The interval-specific COR is the product of the interval-specific Market Eligible Capacity (MEC), defined below based on the interval-specific CAISO Market Event Performance (MEP) determined under applicable CAISO market baseline, and the interval-specific CAISO Clearing Price Delta (CCPD), defined below.
 - i. MEC:
 - 1. If the total CAISO scheduled award quantity in an interval is non-zero and the interval-specific MEP is less than or equal to the total CAISO scheduled award quantity in the interval, then the interval-specific MEC is set to zero.
 - 2. If the total CAISO scheduled award quantity in an interval is non-zero and if the interval-specific MEP is greater than the total CAISO scheduled award quantity in the interval and less than or equal to the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific MEP minus the interval-specific total CAISO scheduled award quantity.
 - 3. If the total CAISO scheduled award quantity in an interval is non-zero and if the interval-specific MEP is greater than the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific QC of the PDR minus the interval-specific total CAISO scheduled award quantity.

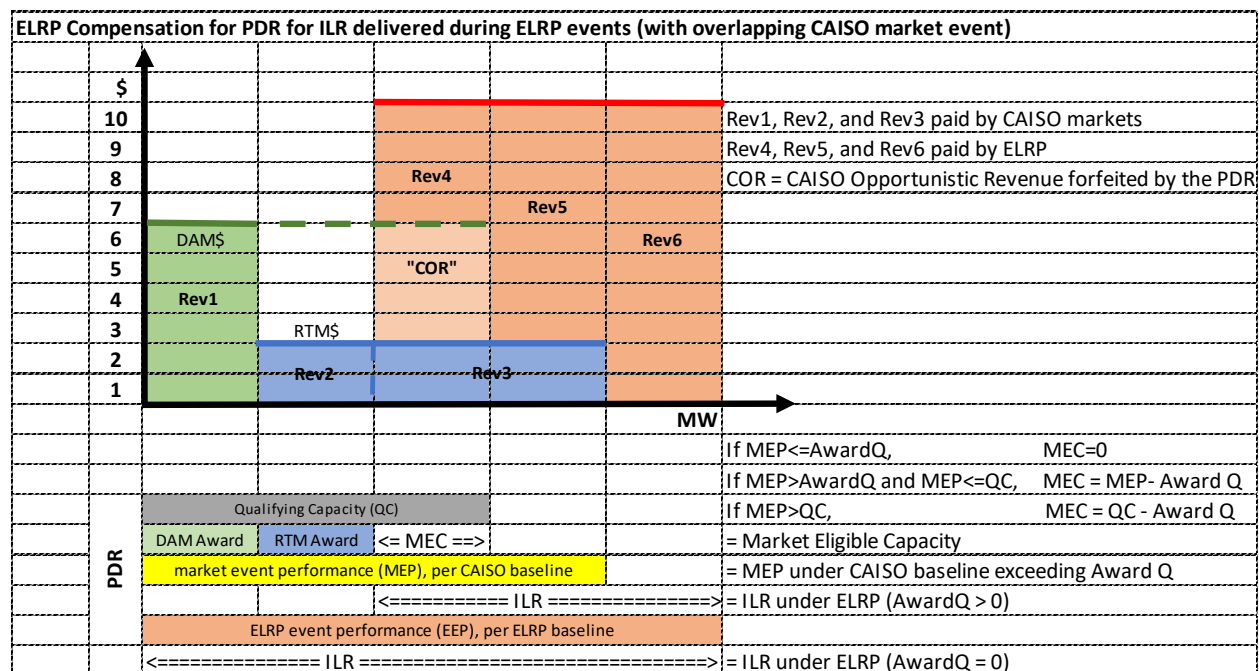
If the PDR has no assigned QC in the above cases, then the QC is replaced by the PDR's "PMin" parameter on record in the CAISO Master File applicable to the interval. Additionally, if the PMin value is less than the total CAISO scheduled award quantity in an interval, then the interval-specific MEC is set to zero.

- ii. CCPD:

For a PDR participating in the DAM only (that is, "long-start" PDR), the interval-specific CCPD is the DAM clearing price in that interval.

For a PDR participating in the RTM, the interval-specific CCPD is equal to the higher of the DAM or RTM clearing price in that interval minus the lower of the DAM or RTM clearing price in that interval.

4. PDR Portfolio Level Net Event Compensation across all PDRs in the DRP's Portfolio.



To receive ELRP compensation, the DRP shall submit an aggregate invoice for the Cumulative Portfolio Level Net Event Compensation of each PDR Portfolio for May-June-July (First Quarter) period by September 30 and for August-September-October (Second Quarter) by December 31 of the program year. for each of its PDR Portfolio to the applicable IOU's team administering Demand Response Auction Mechanism invoices. The Cumulative Portfolio Level Net Event Compensation of a PDR Portfolio over one Quarter is determined by summing the Portfolio Level Net Event Compensation across all ELRP events in that Quarter. The invoice shall be accompanied with the supporting data for each event, including but not limited to PDR-specific ELRP Event Performance, ILR, applicable market awards during the event, applicable CAISO market payments for load reductions counted in the ILR, and ELRP Event Compensation. The IOU may audit and verify the invoice as needed. The aggregate invoice amount must be equal to or larger than the ELRP Minimum Invoice Threshold to be eligible for compensation by the IOUs. The IOU shall settle the invoice within 60 days of the invoice date.

The ELRP Minimum Invoice Threshold is set at zero at this time.

Other Program Elements

The IOUs shall conduct one test event, with two-hour duration, per year for Group A participants. ELRP Group A participants, except for those relying exclusively on prohibited resources, are required to participate in the test events. Use of prohibited resources during a

test event is not permitted and will not be compensated. Incremental load reduction delivered during an ELRP test event is eligible for ELRP compensation.

The IOUs are directed to collaborate with the CAISO and the CEC in the testing process and provide data regarding ELRP response to the CAISO and the CEC to facilitate forecasting.

Within 30 days of this Decision, the IOUs shall jointly file a Tier 1 AL incorporating the ELRP terms and conditions for Group A. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, ILR measurement, and settlement.

Within 60 days of this Decision, the IOUs shall jointly file a Tier 1 AL incorporating the ELRP terms and conditions for Group B. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification, ILR measurement, and settlement and invoicing.

An IOU's Tier 1 AL filing to defer implementation of certain ELRP design elements, where permitted, shall include an explanation for why the delay is necessary or reasonable.

As experienced in ELRP is gained, the IOUs may seek to modify various aspects of ELRP design by jointly filing a Tier 2 AL before or by December 31 of each program year to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, and improve program value and reduce program cost. The change request shall be limited to technical aspects of the program design related to program participation criteria (including various minimum threshold parameters), program trigger(s), Group A baselines and settlement, and Group B baselines, settlement, and invoicing guidelines. Changes to sub-group A.1 Minimum Size Threshold parameter could be sought via an IOU-specific Tier 2 AL.

Balancing Accounts and Cost Recovery

PG&E, SCE, and SDG&E are authorized to establish one-way balancing accounts regarding the development, implementation, and operation the program, along with incentives paid under the program. The balancing accounts shall be effective as of the date of this decision. These

three electric IOUs shall file Tier 1 advice letters within 5 days of the issuance of this decision establishing the new one-way balancing accounts.

This ELRP budget reflects projected costs for IOU program administration, including IT, evaluation, measurement, and verification costs, in addition to costs for compensating eligible customers who have contributed load reductions in response to an ELRP event. Customer compensation costs for each IOU assume a compensation rate of \$1/kilowatt-hour for both Groups A and B, for up to the 60-hour annual limit; however, if no ELRP events are called, customer compensation costs are assumed to be zero.

These balancing accounts shall have the following annual caps:

- PG&E \$3.9 million for administration and \$28.6 million for customer compensation,
- SCE \$2.9 million for administration and \$33.8 million for customer compensation, and
- SDG&E \$1.6 million for administration and \$14.8 million for customer compensation.

4. Modifications to Existing IOU Demand Response Programs

Cost-Effectiveness

The use of our traditional cost-effectiveness tools is waived for all demand response proposals that are adopted in this decision for years 2021 and 2022, under certain conditions. Regarding changes to existing demand response programs adopted in this decision, the IOUs have proposed to use their existing demand response budgets to fund many of those changes, which will help mitigate potential impacts to ratepayers. Any changes that require new incremental funding must be tracked in the memorandum accounts authorized in this decision, and requests for cost recovery will undergo reasonableness review.

Modifications to Existing DR Programs of All IOUs

1. All IOUs shall update their program tariffs to allow year-round enrollment in their BIP for the duration of the ELRP pilot. This modifies D.18-11-029, Ordering Paragraph 5, eliminating the requirement for an April lottery. A customer who enrolls by April 30 in any given calendar year must be enrolled for at least 6 months before exiting the program. A customer who enrolls after April 30 in any given calendar year must remain enrolled for at least 12 months before exiting the program. Existing unenrollment windows (i.e., during November for SCE and PG&E, and during November and April for SDG&E) are unchanged.
2. The DR reliability cap established in D.10-06-034 is temporarily raised to 3% for the duration of the ELRP pilot for all IOUs.

3. There is no restriction on utilizing the funding for the Demand Response Marketing, Education and Outreach program to actively market BIPs while there is room for new customer enrollments.

Modifications to SCE's Existing DR Programs, Pilots, and Related Support Programs

AP-I

1. SCE shall update its program tariffs to allow year-round enrollment in its AP-I program for the duration of the ELRP pilot. A customer must be enrolled for at least 12 months before exiting the program.

Base Interruptible Program

2. SCE is authorized to increase the BIP incentives by 20 percent for 2021 and 2022.

Smart Energy Program (i.e., SCE's Bring Your Own Device Program)

3. SCE is authorized to update the Smart Energy Program (SEP) tariff to modify the medical baseline exclusion and align it with the existing medical baseline exclusion language in the Summer Discount Program (SDP) tariff, and to optimize new acquisition opportunities to increase customer enrollment in SEP (e.g., integrated demand-side management, point-of-sale enrollment, etc.).
4. SCE is authorized an incremental \$3.33 million in funding through 2022 for modifying the medical baseline provision and acquisition opportunities.
5. SCE's proposal to eliminate the restriction preventing participation by customers of CCAs and ESPs by converting SEP from generation to distribution funding by 2022 is approved, and SCE is authorized \$2.87 million additional funding for labor, non-labor vendor support, participant incentives and ME&O to implement the proposal.

Summer Discount Programs

6. SCE's proposal to market and pay a sign-up bonus of \$50 to increase SDP enrollment, along with an incremental funding request for \$1.5 million for each year 2021 and 2022, is approved.
7. SCE's proposal for the purchase and installation of up to 60,000 new load control devices for new SDP enrollments, along with an incremental funding request for \$3.64 million in 2022, is approved.
8. SCE's proposal to increase SDP residential incentives by 25 percent from current levels and use the SDP contingency incentives authorized in D.17-12-003 and D.18-03-041 is approved.
9. SCE shall revise the SDP tariffs to remove the minimum dispatch requirement, while preserving the maximums of 20 economic hours and 180 emergency hours annually.

Capacity Bidding Program

10. SCE's proposal to add residential accounts to CBP instead of conducting a one-year residential CBP pilot and add a 5-in-10 baseline (with 40% day-of adjustment) for residential accounts, requiring no incremental funding, is approved.
11. SCE's proposal to increase CBP Day-Ahead and Day-Of capacity incentive rates (\$/kW-year) by 20 percent for 2021 and 2022 is approved.

Virtual Power Plant (VPP)

12. SCE's proposal to create Phase II of its VPP pilot to acquire additional vendors and customers, test dispatchable technologies, including hybrid battery energy storage, and various dispatch strategies, including grid reliability events, is approved. The pilot shall test ELRP events as well.

DR Systems and Technology:

13. SCE is authorized \$106,000 to make the following upgrades to its DR systems and technology infrastructure:
 - a. Extend the legacy Alhambra Control Platform for one additional year;
 - b. Enhance the DR Event Website and DR Mobile App; and
 - c. Create a test rack to confirm when a DR event has taken place.

Modifications to PG&E's Existing DR Programs, Pilots, and Related Support Programs

Base Interruptible Program

1. PG&E shall increase its BIP incentive rate by \$1.50/kW for 2021 and 2022 as follows:

Potential Load Reduction	Current Incentive Rate	Revised Incentive Rate
1kW to 500kW	\$8.00/kW	\$9.50/kW
501 kW to 1,000kW	\$8.50/kW	\$10.00/kW
1,001kW and greater	\$9.00/kW	\$10.50/kW

Capacity Bidding Program

2. PG&E shall modify the CBP tariff to increase the maximum number of events allowed per month from five to six, with the clarification that the foregoing takes precedence over the maximum number of 30 hours per operating month.

3. PG&E's proposal to extend the CBP operating days to seven days per week by adding a weekend option, along with a 25 percent capacity incentive adder for the weekend participation for 2021 and 2022, but no change in program hours is approved for 2021 and 2022.
4. PG&E's proposal to increase the CBP capacity incentive level for the month of October from the current \$2.27/kW to \$6.80/kW for the Day-Ahead participation option for 2021 and 2022 is approved.

Modifications to SDG&E's Existing DR Programs, Pilots, and Related Support Programs

Base Interruptible Program

1. As proposed by SDG&E, the current 100 kW minimum requirement for participation in BIP is waived, and all non-residential customers of SDG&E are eligible to enroll and participate in BIP.
2. As proposed by SDG&E, SDG&E is authorized to update the measuring hours for customers' "monthly average peak demand" to align the measuring hours for customers with "availability assessment hours" on which BIP's performance is measured.
3. As proposed by SDG&E, SDG&E is authorized to change the time period used to calculate the BIP capacity incentive from 1:00 to 6:00 pm window to 4:00 to 9:00 pm window.

Capacity Bidding Program

4. As proposed by SDG&E, SDG&E shall modify its CBP tariff to increase the maximum number of events allowed per month from six events to nine events, with the additional three events reserved for CAISO or SDG&E emergencies. Any non-performance penalties associated with the three additional monthly CBP events will be waived.
5. As proposed by SDG&E, SDG&E shall modify its CBP tariff to:
 - a. Adjust notification time to be 5:00 PM for the CBP Day-Ahead product.
 - b. Update the CBP Day-Of product notification time to 40 minutes to allow the program to be bid into the CAISO Day-Of market.
6. As proposed by SDG&E, SDG&E shall launch the CBP Residential Pilot in 2021.

AC Saver Program

7. As proposed by SDG&E, SDG&E shall modify the AC Saver tariff to allow participation by residential NEM customers.
8. As proposed by SDG&E, SDG&E shall modify the AC Saver tariff to increase the maximum number of events allowed in a year from 20 events to 25 events, with the additional 5 events reserved for CAISO or SDG&E emergencies.

9. SDG&E is authorized to a) pursue emergency agreements with device manufacturers who already have devices participating in the AC Saver program to signal existing installed thermostats that are not in an existing DR program to secure additional load reduction, and b) offer a reasonable incentive, consistent with the guidelines described by SDG&E, to these manufacturers for increasing the number of participating thermostats.

Cost Recovery

PG&E, SCE, and SDG&E shall utilize unspent funds from their existing DR budgets adopted in Decision (D.) 17-12-003, to the extent existing funds are available.

To the extent that any tariff amendments are necessary to effectuate the DR program changes ordered in this decision, those changes should be documented in a Tier 1 Advice Letter, as well as the process for transferring balances within the IOU's the Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

5. Modifications to the Planning Reserve Margin

We adopt an interim approach that will effectively increase the planning reserve margin (PRM) beginning in summer 2021 to 17.5%. This change is limited to 2021 and 2022, and subject to modification in the RA proceeding. The adopted effective 17.5 % PRM supports the goal of meeting net peak demand; we continue to require all LSEs, including the IOUs, to meet their 15% system RA PRM requirement, and the large electric IOUs are required to target a minimum of 2.5% of incremental resources that are available at net peak through the efforts authorized in this proceeding. For 2021, this results in a minimum target of 450 megawatts (MW) for PG&E, 450 MW for SCE, and 100 MW for SDG&E, based on 2.5% of the average CPUC jurisdictional share of CAISO peak load during peak summer months per the CEC's 2019 Integrated Energy Policy Report forecast for the year 2021. These minimum MW targets will also apply to 2022 unless superseded by a future Commission decision.

All of the resources being procured through this proceeding, including emergency-triggered resources that do not count towards RA like the ELRP, should be included in meeting these incremental procurement targets.

Given that a portion of the resources that make up LSEs' 15% PRM are solar resources whose generation is declining rapidly at net peak, these procurement targets represent a floor, and IOUs are encouraged to exceed their respective targets by as much as an additional 50%, which would result in approximately 1,500 MW of incremental procurement and an effective PRM of 19%. The additional 1,500 MW of resources is selected as an upper end target because it

represents the NQC of solar in September, which has been the Integrated Energy Policy Report month in recent years.

IOUs are to consider their respective upper end targets as “soft caps” for all resources authorized for procurement in this proceeding, but as “hard caps” for incremental supply side generation and in-front-of-meter storage resources. In other words, the total procurement under this proceeding, including RA and non-RA DR resources, could exceed the upper end targets, but generation and front-of-meter resources alone may not exceed 150% of each IOU’s target.

IOUs shall target their incremental procurement in this range during the months of most concern, including May through October but most importantly should endeavor to meet and exceed their respective minimum MW targets in July, August, and September.

The net costs associated with this procurement shall be passed through to all benefiting customers consistent with the existing cost allocation mechanism. We clarify that because this procurement is additional to LSEs’ RA requirements, there will not be RA capacity benefits to allocate to all LSEs, as is usually the case with resources procured through the cost allocation mechanism. In this instance, the benefits provided to all LSEs is increased electric reliability without requiring all LSEs to procure their share of these incremental resources under this expedited timeframe or be subject to RA program penalties for not doing so.

Some contracts may not be tailored to the months of most concern and may require year-round obligations; while IOUs should strive to layer resources to meet the most critical months, the net costs associated with this incremental procurement shall be shared by all customers in each IOU’s service territory, since all customers share the additional reliability benefits.

These incremental PRM procurement targets will remain in effect for each IOU through 2022, unless and until superseded by a future Commission decision.

All LSEs are required to provide Energy Division non-binding month-ahead RA filings for July, August, and September no later than April 15, 2021, reflecting their most recent RA positions, including any excess RA procurement (but excluding IOU procurement authorized in this proceeding).

6. Additional Capacity Procurement

PG&E, SCE, and SDG&E are ordered to continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve this effective 17.5% PRM for the months of concern.

Consistent with the guidance provided in D.21-02-028 – and consistent with the resources that have been contracted for by IOUs in response to that decision – procured resources must be available to serve load at peak and net peak, and the IOUs should give preference to storage contracts (from new solicitations, bilateral negotiations, or offering counterparties an opportunity to refresh prior IRP procurement bids), upgrades resulting in increased efficiency of existing generation resources, and contract terms that are shorter in duration. All procurement contracts should be submitted to Energy Division via a Tier 1 AL on a continuing basis, except for contracts for incremental gas generation of five years or more and incremental imports. Contracts of five years or more for incremental generation at existing gas power plants should be submitted to Energy Division via a Tier 3 AL. Contracts for fossil-fuel development at new sites or for redevelopment or repowering at existing electric generation sites will not be considered. Tier 1 advice letters are not required, but may be submitted, for incremental imports, provided the IOUs remain within the “hard cap” procurement limits for supply-side generation and storage resources established in this decision.

We understand that IOUs will be procuring to meet both their individual 15% PRM RA requirements and the additional procurement directed in this proceeding. To facilitate compliance, we clarify that IOU procurement, including RA resources procured under D.21-02-028, should first be used to meet bundled service RA requirements.

We also recognize that a combination of RA eligible and non-eligible resources will be used to meet the effective 17.5% PRM. All RA eligible resources supporting the effective PRM should be included in supply plans and IOUs’ month ahead RA showings to ensure that these resources are subject to RA obligations and incentive mechanisms, do not receive CPM double-payments, and are visible to the CAISO as RA resources not eligible for export. Of these resources, only costs associated with RA resources in excess of an IOU’s own 15% PRM should be charged to all benefiting customers in the IOU’s service territory via the CAM.

To the extent feasible, IOUs should pair imports contracted to meet the effective 17.5% PRM with maximum import capacity and include these costs in their CAM procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct an RA product, the IOU should calculate and include the average price it received for sales of its excess maximum import capacity or, if not available or representative of market value, another reasonable market benchmark.

After accounting for resources procured under D.21-02-028 and additional resources procured under the authority of this decision – including estimates of ERLP resources which will not be known until after the fact – if an IOU has not met its minimum procurement target for the months of June and October, they may use resources in their existing portfolios to meet the minimum MW procurement target at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark, in the event that they have long RA positions and have made reasonable attempts to sell this excess capacity to other LSEs to meet their 15% PRM requirements.

For the months of June through September, resources from IOUs' existing portfolios during months they are long may be used to supplement their other procurement towards such that the total resources procured – including estimated ERLP resources – reaches the soft cap set for generation and storage resources (675 MW for PG&E and SCE, and 150 MW for SDG&E). This approach ensures that the CAISO's recommended higher procurement levels than the 17.5% PRM are achieved during the three months of highest grid stress historically.

The benefit of showing these resources is that they will be subject to RA requirements and incentive/penalty mechanisms, and they will be visible to CAISO as RA resources that are not available for export or a CPM payment. This approach also avoids the unintended outcome of IOUs buying excess RA resources from one another's RA solicitations to the extent each need to do so to meet their targeted additional 17.5% PRM procurement, potentially at premiums well in excess of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark

The IOUs shall provide the monthly amounts of the excess resources they applied to the CAM and included on their monthly RA plans, as well as the calculus used to determine these amounts to Energy Division, and Energy Division is directed to post this information on its website.

Finally, to the extent that any additional adjustments to balancing accounts are needed to provide for CAM cost recovery of the procurement authorized in the decision, the IOUs are authorized to file Tier 2 advice letters with the effective date of the tariff modification to be the effective date of this decision.

(END OF ATTACHMENT 1)