Demand Response ELCC

CAISO ESDER Stakeholder Meeting

5.27.20

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Overview

Background

+ California has a unique approach to capacity procurement, where the CPUC administers a Resource Adequacy (RA) program to ensure sufficient resources to maintain an acceptable standard of reliability, but the CAISO retains ultimate responsibility for the reliable operation of the electricity system

+ The CAISO wants to ensure DR is properly valued in the Resource Adequacy program

Project

+ The CAISO retained E3 to investigate the reliability contribution of DR relative to its capacity value in the CPUC administered RA program

+ To the extent that DR is overvalued, the CAISO asked E3 to suggest solutions to issue

+ E3 provided technical analysis to support the CAISO in this effort
This report has been prepared by E3 for the California Independent System Operator (CAISO). This report is separate from and unrelated to any work E3 is doing for the California Public Utilities Commission. While E3 provided technical support to CAISO preparation of this presentation, E3 does not endorse any specific policy or regulatory measures as a result of this analysis. The California Public Utilities Commission did not participate in this project and does not endorse the conclusions presented in this report.
Outline

- Refresher on March 3 CAISO stakeholder meeting presentation
- Background on ELCC
- Performance of Existing DR
- Characteristics of DR Needed for ELCC
  - Time availability
  - # of calls / duration of calls
  - Penetration of DR
- Incorporating DR ELCC into Existing CPUC RA Framework
- Questions
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Name</th>
<th>Description</th>
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<tr>
<td>API</td>
<td>Agricultural and Pumping Interruptible</td>
<td>DR program to suspend agricultural pumping</td>
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<td>BIP</td>
<td>Base Interruptible Program</td>
<td>Participants are offered capacity credits for reducing their demand up to a pre-determined level in response to an event call</td>
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<td>CBP</td>
<td>Capacity Bidding Program</td>
<td>DR program where aggregators work on behalf of utilities to enroll customers, arrange for load reduction, receive and transfer notices and payments</td>
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<td>DR</td>
<td>Demand Response</td>
<td>Reductions in customer load that serve to reduce the need for traditional resources</td>
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<td>ELCC</td>
<td>Effective Load Carrying Capability</td>
<td>Equivalent perfect capacity measurement of an intermittent or energy-limited resource, such as DR</td>
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<td>LCA</td>
<td>Local Capacity Area</td>
<td>Transmission constrained load pocket for which minimum capacity needs are identified for reliability</td>
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<td>LIP</td>
<td>Load Impact Protocol</td>
<td>Protocols prescribed by the CPUC for accurate and consistent measuring (and forecasting) of DR program performance</td>
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<td>LOLP</td>
<td>Loss of Load Probability</td>
<td>Probability of a load shedding event due to insufficient generation to meet load + reserve requirements</td>
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<td>NQC</td>
<td>Net Qualifying Capacity</td>
<td>A resource’s contribution toward meeting RA after testing, verification, and accounting for performance and deliverability restrictions</td>
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<td>PDR</td>
<td>Proxy Demand Response</td>
<td>Resources that can be bid into the CAISO market as both economic day-ahead and real-time markets providing energy, spin, non-spin, and residual unit commitment services</td>
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<td>PRM</td>
<td>Planning Reserve Margin</td>
<td>Capacity in excess of median peak load forecast needed for reliability</td>
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<td>RA</td>
<td>Resource Adequacy</td>
<td>Resource capacity needed for reliability</td>
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<td>RDRR</td>
<td>Reliability Demand Response Resource</td>
<td>Resources that can be bid into CAISO market as supply in both economic day-ahead and real-time markets dispatched for reliability services</td>
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<td>SAC</td>
<td>Smart AC Cycling</td>
<td>Direct air conditioner load control program offered by PG&amp;E</td>
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<td>SDP</td>
<td>Summer Discount Plan</td>
<td>Direct air conditioner load control program offered by SCE</td>
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<td>SubLAP</td>
<td>Sub-Load Aggregation Point</td>
<td>Defined by CAISO as relatively continuous geographical areas that do not include significant transmission constraints within the area</td>
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Established disconnect between ELCC and NQC

Provided E3 thoughts on how to match CAISO and utility DR bid data as well as techniques to extend this data over multiple historic weather years. Both points were addressed with the 2019 data.
1) How are demand response programs performing today, relative to what they are being credited for?

2) What characteristics of demand response are needed today and in the future?

3) How should a resource adequacy program be designed to allocate and credit both DR in aggregate and individual DR programs?
Background on ELCC
Effective Load Carrying Capability (ELCC) is a measure of the amount of equivalent perfect capacity that can be provided by an intermittent or energy-limited resource.

- **Intermittent resources**: wind, solar
- **Energy-limited resources**: storage, demand response

Industry has begun to shift toward ELCC as best practice, and the CPUC has been at the leading edge of this trend.

A resource’s ELCC is equal to the amount of perfect capacity removed from the system in Step 3.
There are multiple approaches to measuring the ELCC of a resource(s)

- **Portfolio ELCC**: measures the combined ELCC of all intermittent and energy-limited resources on the system
- **First-In ELCC**: measures the marginal ELCC of a resource as if it were the only intermittent or energy-limited resource on the system, thus ignoring interactive effects
- **Last-In ELCC**: measures the marginal ELCC of a resource after all other intermittent or energy-limited resources have been added to the system, capturing all interactive effects with other resources
“First-In” ELCC

- First-in ELCC measures the ability of a resource to provide capacity, absent any other resource on the system.
- This measures the ability of a resource to “clip the peak” and is often analogous to how many industry participants imagine capacity resources being utilized.

![Diagram of load vs. perfect capacity with DR highlighted.](Image)
"Last-In" ELCC

- Last-in ELCC can be higher or lower than first in ELCC
  - Higher last-in ELCC means there are positive synergies with the other resources that yield a diversity benefit.
  - Lower last-in means the resource is similar to other resources and competes to provide the same services, yielding a diversity penalty.

- Last-in ELCC measures the ability of a resource to provide capacity, assuming all other resources are on the system.
E3 analyzed the value of DR to the CAISO system today (2019) and the future (2030) to assess how coming changes to the electricity system might impact value.

Primary changes are on the resource side (shown below) with modest changes to loads (49 GW 2019 peak load vs 53 GW 2030 peak load)

2019 and 2030 CAISO Resource Portfolio

- 5,000+ MW retirement of thermal resources
- 24,000+ MW increase in solar
- 11,000+ MW increase in storage
- Small increase in DR

Source: CPUC Integrated Resource Plan (IRP) Reference System Plan (RSP)
Demand response (DR) resource adequacy qualifying capacity is currently calculated using the load impact protocols (LIP), which are performed by the utilities under the oversight of the CPUC.

- LIP uses regression and other techniques to estimate the availability of demand response during peak load hours.

E3 has analysis suggests that LIP overvalues the capacity contribution DR relative to ELCC by 40%+ for two reasons:

1. DR does not bid into the CAISO market, in aggregate, at levels equal to its NQC value.
2. The times when DR is bid are either not at optimal times or not for long enough to earn full ELCC value.

Load impacts are grossed up for transmission and distribution losses, as also the 15% PRM, owing to demand response being a demand reduction measure:

\[
NQC = LI \times 1.15 \text{ (PRM)} \times T&D \text{ loss factor}^{[1]}
\]

Load impacts for the year 2019 are referenced from the CPUC’s RA Compliance documents\(^{[2]}\).

Load impacts are defined on an LCA level from 1 pm to 6 pm, Apr to Oct, and from 4 pm to 9 pm in the rest of the year, both with and without line losses.
First-in ELCC of PG&E and SCE Programs

PG&E

0% ELCC for BIP and CBP Humboldt is a result of the program size being too small.

These results just focus on utility event-based DR, not DRAM programs.

Pmax is max bid placed in the given month.

SCE
Time Window Availability Needs for DR in 2019 & 2030

+ Month/hour (12x24) loss of load probability heat maps provide a quick overview of “high risk” hours

+ Key findings from this project are showing that strong interactions between storage and DR may elongate the peak period by 2030

**LOLP in 2019**

Historical LOLP hours driven by gross peak load during summer afternoons, but an abundance of solar energy has now reduced the LOLP in these hours

Current LOLP hours have been shifted later into the evening and later in summer due to solar

**LOLP in 2030**

LOLP hours will continue to shift later into the evening as solar and storage increase

LOLP hours may elongate back into the afternoon as storage proliferates and market signals encourage it to wait to discharge during later hours
DR Interaction with Storage

- Historically, DR is dispatched as a resource of “last resort” which is how RECAP dispatched DR.
- A system with high penetrations of storage require much more coordination in the dispatch of DR and storage in order to achieve maximum reliability.

**E3 RECAP Model Methodology**

1. **Step 1**: Calculate Hourly Load
2. **Step 2**: Calculate Renewable Profiles
3. **Step 3**: Calculate Available Dispatchable Generation
4. **Step 4**: Hydro Dispatch
5. **Step 5**: Calculate Available Transmission
6. **Step 6**: Dispatch Storage
7. **Step 7**: Dispatch Demand Response
8. **Step 8**: Calculate Loss of Load

*Coordination required*
When DR is dispatched as the resource of last resort, there is **loss of load**

Preemptively dispatching DR to delay storage discharge eliminates loss of load event

**Key takeaway:** DR should be dispatched to delay storage discharge on days with potential loss of load
### Call and Duration ELCC Results

#### First-in ELCC

<table>
<thead>
<tr>
<th>ELCC (% of nameplate)</th>
<th>Max annual calls</th>
<th>Max call duration (hrs)</th>
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<td>1 2 4 5 10 15 20</td>
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<td>2019</td>
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<td>1</td>
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<td>2</td>
<td>63% 73% 78% 78% 78% 78% 78%</td>
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<td>4</td>
<td>70% 81% 94% 95% 95% 95% 95%</td>
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<td>6</td>
<td>70% 81% 94% 95% 95% 95% 95%</td>
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<tr>
<td>8</td>
<td>70% 81% 94% 95% 95% 95% 95%</td>
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<tr>
<td><strong>No interactions with storage – therefore no expected significant differences</strong></td>
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#### Last-in ELCC

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<th>ELCC (% of nameplate)</th>
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<td>2030</td>
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<td>1</td>
<td>59% 73% 73% 73% 73% 73% 73%</td>
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<td>2</td>
<td>74% 90% 94% 94% 94% 94% 94%</td>
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<td>4</td>
<td>77% 98% 100% 100% 100% 100% 100%</td>
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<td>77% 98% 100% 100% 100% 100% 100%</td>
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<td>8</td>
<td>77% 98% 100% 100% 100% 100% 100%</td>
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<tr>
<td><strong>Significant degradation in last-in ELCC in 2030 is driven by saturation of energy-limited resources, primarily storage</strong></td>
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Average ELCC = Total Effective Capacity / Total Installed Capacity

Incremental ELCC = \( \Delta \) Effective Capacity / \( \Delta \) Installed Capacity

ELCC generally decreases as DR capacity on the system increases:

- Similarity in hours of operation and characteristics limits the incremental value that more of the exact same resource type can add to the system.
- Degradation gets more severe as call constraints become more stringent.
ELCC generally decreases as DR capacity on the system increases:

- Similarity in hours of operation and characteristics limits the incremental value that more of the exact same resource type can add to the system.
- For a given DR capacity on the system, ELCC in 2030 is lower than that in 2019 owing to saturation of energy-limited resources on the system in 2030, particularly storage.
The CPUC has been a leader in North America through the incorporation of intermittent and energy-limited resources into RA frameworks

- One of the first to adopt and implement ELCC framework to value wind and solar
- Currently the only jurisdiction that recognizes and accounts for interactive effects of resources through allocation of a “diversity benefit” to wind and solar

The CPUC has recognized that the concept of “interactive effects” applies not only to renewables but to storage and other resources, but has not yet established an approach for allocation that incorporates them all

Establishing a more generalized, durable framework for ELCC (capable of accounting for renewables, storage, and DR) will require a reexamination of the methods used to allocate ELCC and the “diversity benefit”

This section examines alternative options for allocating ELCC among resources that could improve upon existing methods currently in use
Allocating Portfolio ELCC is necessary with a centralized or bilateral capacity market framework where individual resources must be assigned a capacity contribution for compensation purposes

- Directly impacts billions of dollars of market clearing transactions within California and other organized capacity markets

Allocating Portfolio ELCC can impact planning and procurement in California to the extent that entities procure based on the economic signal they receive in the RA program

- An allocation exercise is not necessary in vertically integrated jurisdictions or in systems with a centralized procurement process

There are an infinite number of methods to allocate Portfolio ELCC to individual resources and no single correct or scientific method, similar to rate design

Sample ELCC Allocation Method Options

1. Allocate proportionally to First-In ELCC
2. Allocate proportionally to Last-In ELCC
3. Allocate adjustment to First-In ELCC proportionally to differences between First-in and Last-In ELCC
4. Vintaging approach where each resource permanently receives Last-In ELCC at the time it was constructed
5. More
This section presents a framework as one option for attributing capacity value to DR within the current resource adequacy framework administered by the CPUC.

This framework relies on several key principles:

1) **Reliability**: The ELCC allocated to each project/program should sum to the portfolio ELCC for all resources.

2) **Fairness**: ELCC calculations should be technology neutral, properly reward resources for the capacity characteristics they provide, and not unduly differentiate among similar resources.

3) **Efficiency**: ELCC values should send accurate signals to encourage an economically efficient outcome to maximize societal resources.

4) **Customer Acceptability**: ELCC calculations should be transparent, tractable understandable, and implementable.
Overview of Framework

1. Calculate portfolio ELCC

2. Calculate “first-in” and “last-in” ELCC for each resource category

3. Allocate portfolio ELCC to each resource category

4. Allocate resource category ELCC to each project/program using tractable heuristic
1) Calculate Portfolio ELCC

The first step should calculate the portfolio ELCC of all variable and energy-limited resources

- Wind
- Solar
- Storage
- Demand Response

\[ \text{Portfolio ELCC} = \text{Solar} + \text{Wind} + \text{Storage} + \text{Demand Response} \]
The second step calculates the “first-in” and “last-in” ELCC for each resource category as a necessary input for allocation of the portfolio ELCC.

2) Calculation First-In and Last-In Resource Category ELCCs

DR First-In ELCC

DR Last-In ELCC

Repeat first-in and last-in calculations for all resource categories.
3) Allocate Portfolio ELCC to Each Resource Category

Calculate **diversity impact** as the difference between portfolio ELCC and sum of first-in ELCCs

1. Calculate diversity impact for each resource category

2. Allocate diversity impact in proportion to the difference between first-in and last-in ELCC for each resource category

3. Scale individual resource category diversity impacts to match portfolio diversity impact

Repeat calculation of positive or negative allocator for each resource category.
Benefits of this Approach

There are several options to allocate Portfolio ELCC to each technology category, two examples of which are shown below:

**First-In ELCC Allocation Option**

- Wind
- Solar
- Storage
- DR

**Wind**

**Solar**

**Storage**

**DR**

Scale up to match Portfolio ELCC

**Portfolio ELCC**

**Last-In ELCC Allocation Option**

- Wind
- Solar
- Storage
- DR

**Wind**

**Solar**

**Storage**

**DR**

Scale down to match Portfolio ELCC

**Portfolio ELCC**

Both of these options can lead to final ELCC allocations that fall outside the bounds of the first-in or last-in ELCC:

- For example, in the case of a “perfect” resource (e.g. ultra-long duration storage, always available DR, baseload renewables, etc.), this should be counted at 100% ELCC and should not be unduly scaled up or down based on the synergistic or antagonistic impacts of other resource interactions.
- Scaling the first-in or last-in ELCC in any way would result in an ELCC of either >100% or <100% for this perfect resource.

The method presented in this deck scales resources based on the difference of their first-in and last-in ELCC in order to reflect their synergistic or antagonistic contributions to Portfolio ELCC:

- Negative diversity impact leads to first-in ELCC being scaled up to match Portfolio ELCC.
- Positive diversity impact leads to first-in ELCC being scaled down to match Portfolio ELCC.
- No diversity impact leads to no scaling of first-in ELCC to match Portfolio ELCC.

Perfect Resource

Perfect Resource

= 100%
4) Allocate Resource Category ELCC to Individual Resource/Programs Using Heuristics

- Each DR program submits the following information:
  - Expected output during peak period hours
  - Maximum number of calls per year
  - Maximum duration of call

- Step 1) Calculate average MW availability during peak period hours (gross and net load)

- Step 2) Multiple MW availability from step (1) by lookup table de-rating factor to account for call and duration limitations
  - DR category ELCC to individual program ELCC using first-in and last-in ELCC would work similarly to the allocation process of portfolio ELCC to resource category ELCC.
Questions
Thank You

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Zach Ming, (zachary.ming@ethree.com)
Vignesh Venugopal (vignesh.venugopal@ethree.com)
NQCs as a Basis for Comparison with ELCCs

+ NQCs are calculated using load impacts (LI), i.e. load reductions expected during peak conditions, calculated in line with the Load Impact Protocols.

+ Load impacts are grossed up for transmission and distribution losses, as also the 15% PRM, owing to demand response being a demand reduction measure.

\[ NQC = LI \times 1.15 \times (PRM) \times T&D \text{ loss factor}^{[1]} \]

+ Load impacts for the year 2019 are referenced from the CPUC’s RA Compliance documents[2]

+ Load impacts are defined on an LCA level from 1 pm to 6 pm, Apr to Oct, and from 4 pm to 9 pm in the rest of the year, both with and without line losses.

[2] CPUC 2019 IoU DR Program Totals
E3 tested how two primary constraints impact the ELCC of demand response resources

- Max # of calls per year
  - How many times can a system operator dispatch a demand response resource?
- Max duration of each call
  - How long does the demand response resource respond when called by the system operator?

Key Assumptions:

- DR portfolio is divided into 100 MW units, each of which can be dispatched independently of the other
  - In other words, 2-hour-100 MW units can be dispatched in sequence to avoid an unserved energy event 100 MW deep and 4 hours long
- Each 100 MW unit is available 24/7, at full capacity of 100 MW, subject to call constraints defined above to establish a clear baseline for ELCC %’s
- Pure Shed DR; No shifting of load; No snap-backs
### Average ELCC as a function of DR Capacity on the System

#### First-in ELCC

<table>
<thead>
<tr>
<th>Call constraints</th>
<th>DR capacity (MW)</th>
<th>2,195</th>
<th>3,000</th>
<th>4,000</th>
<th>5,000</th>
<th>10,000</th>
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<td>1 hour/call</td>
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<td>4 hours/call</td>
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<td>8 hours/call</td>
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<td>ELCC (% of DR capacity)</td>
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</table>

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*Note: The table above represents the average ELCC as a function of DR capacity on the system, considering different call constraints and DR capacity levels.*
## Incremental ELCC as a function of DR Capacity on the System

### First-in ELCC

<table>
<thead>
<tr>
<th>DR capacity (MW)</th>
<th>2019</th>
<th>Call constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELCC (%) of DR capacity</td>
<td>2,195</td>
<td>1 hour/call 1 call/year 4 hours/call 10 calls/year 6 hours/call 4 calls/year 8 hours/call</td>
</tr>
<tr>
<td>2,195</td>
<td>46%</td>
<td>51%</td>
</tr>
<tr>
<td>3,000</td>
<td>25%</td>
<td>36%</td>
</tr>
<tr>
<td>4,000</td>
<td>22%</td>
<td>29%</td>
</tr>
<tr>
<td>5,000</td>
<td>15%</td>
<td>23%</td>
</tr>
<tr>
<td>10,000</td>
<td>11%</td>
<td>22%</td>
</tr>
<tr>
<td>20,000</td>
<td>7%</td>
<td>11%</td>
</tr>
</tbody>
</table>

### Last-in ELCC

<table>
<thead>
<tr>
<th>DR capacity (MW)</th>
<th>2030</th>
<th>Call constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELCC (%) of DR capacity</td>
<td>2,195</td>
<td>1 hour/call 1 call/year 4 hours/call 10 calls/year 6 hours/call 4 calls/year 8 hours/call</td>
</tr>
<tr>
<td>2,195</td>
<td>59%</td>
<td>73%</td>
</tr>
<tr>
<td>3,000</td>
<td>33%</td>
<td>42%</td>
</tr>
<tr>
<td>4,000</td>
<td>22%</td>
<td>34%</td>
</tr>
<tr>
<td>5,000</td>
<td>16%</td>
<td>31%</td>
</tr>
<tr>
<td>10,000</td>
<td>14%</td>
<td>26%</td>
</tr>
<tr>
<td>20,000</td>
<td>11%</td>
<td>18%</td>
</tr>
</tbody>
</table>

### Energy+Environmental Economics
2019 vs 2030 Loss of Load Events

**Frequency of Event Occurrence**

- **No significant change in frequency of events**

**Distribution of Event Duration**

- Events become longer as energy-limited resources increase

**Distribution of Event Magnitude**

- Events become larger as availability of energy becomes more variable
The 2019 PG&E and SCE DR ELCC results focus on “event-based” DR programs, as opposed to passive measures like dynamic pricing applicable throughout a season/year.

- Does not consider SDG&E or Demand Response Auction Mechanism (DRAM) resources which are a significant portion of the data DR portfolio, due to data limitations.

Data sources for RECAP ELCC calculations:

1. Hourly PG&E DR bid data for 2019
   - BIP, CBP, and SAC
   - PSPS outage logs were provided by PG&E and used by E3 to identify and then fill gaps in DR bid data

2. Hourly SCE DR bid data for 2019
   - API, BIP, CBP, and SDP
+ E3 used utility data directly from PG&E and SCE for two reasons
  • CAISO does not have data by utility program
  • Wanted to ensure results were not predicated on CAISO data

+ E3 benchmarked utility data to CAISO data to ensure the veracity of the data
  • Data generally benchmarked well
  • A few inconsistencies were spotted in the RDRR data:
    – In ~1.3% of hours in the year, DR bids present in PG&E’s data are missing in CAISO’s data. Technical glitches in transmitting/recording systems may explain this.
    – DR bids in SCE data were slightly lower than bids recorded in CAISO data across significant portions of the year. Underlying reason is currently not known.
+ PDR data from the two sources are identical
+ There are a few hours (114 out of 8760) where RDRR data is inconsistent:
  • Several instances across each of the 24 hours of the day
  • These are hours where data is missing in the CAISO dataset
  • Unclear if a bid was not placed, or if it was placed but not recorded due to technical glitches

Example comparison for one of the subLAPs over the entire year and a couple of days in specific
Benchmarking of 2019 Bid Data from SCE and CAISO data

+ PDR data from the two sources are identical
+ Inconsistencies exist in RDRR data – unclear if the difference is systematic and attributable to a single factor, like treatment of line-losses

Example comparisons for 2 subLAPs across the entire year and across a couple of days in specific
In order to calculate the ELCC of a DR program or portfolio, RECAP must predict how these programs will perform over many different conditions and weather years.

Therefore, E3 must extend actual 2019 data over the entire historical temperature record as a data requirement for the E3 RECAP model.

In response to stakeholder feedback from the May 3 CAISO ESDER meeting, E3 modified the backcasting approach to include temperature for temperature-dependent air conditioner DR programs.

- More details on this process and methodology can be found in the appendix.
Get daily max, min and average temperature data (1950-2019) from NOAA for every climate zone that DR program bids come from

Use weather-informed day-matching to match every day from Jan 1, 1950 - Dec 31, 2018 to the “most similar” day from Jan 1, 2019 – Dec 31, 2019

Use day-matching results to extrapolate hourly DR bids from just 2019 to 1950-2019

Aggregate extrapolated DR bids by program-LCA to allow for comparison with respective NQCs

Each aggregated shape dictates the hourly availability of the corresponding DR program-LCA combination in RECAP
As in the previous phase of this project, E3 used a simple day-matching approach for CBP, BIP and API programs.

DR bid forecasts for these programs were not as strong a function of the temperature as Smart AC.

For an individual DR program and a particular day, ‘d’ in a simulated year, pick one day out of +/- 3 calendar days, ‘d+3’ to ‘d-3’ of the same type (workday/holiday) from the actual 2019 data at random.

### Simulated Year

<table>
<thead>
<tr>
<th>Day</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mon</td>
<td>d</td>
</tr>
<tr>
<td>Tue</td>
<td>d + 1</td>
</tr>
<tr>
<td>Wed</td>
<td>d - 1</td>
</tr>
</tbody>
</table>

- Thu: d - 4
- Fri: d - 3
- Sat: d - 2
- Sun: d - 1
- Mon: d
- Tue: d + 1
- Wed: d + 2
- Thu: d + 3
- Thu: d + 4
Weather-informed Day-Matching Algorithm for AC cycling DR Programs

+ Inclusion of weather for air conditioner DR is in direct feedback to stakeholder comments from the May 3, 2020 CAISO ESDER meeting

+ For an individual DR program and a particular day in a simulated year, pick one day out of +/- 10 calendar days of the same type (workday/holiday) from actual 2019 data with the closest $T_{\text{max}}$, $T_{\text{min}}$, and $T_{\text{avg}}$

+ Applied to PG&E’s Smart AC program and SCE’s Summer Discount Plan program data to account for influence of temperature on DR availability

**Example weekday in simulated year**

**Candidate (2019) days for matching**

**Holiday/Weekend**
The Mean Absolute Percentage Error (MAPE) is defined as:

\[ \text{MAPE} = \frac{\text{Abs}(\text{Day-matched value} - \text{Actual Value}) \times 100}{\text{Actual Value}} \]

MAPE is calculated and shown below for July-September, 4 pm to 10 pm
Why Day Matching and not Regression?

Regression based on temperature, month and day-type couldn’t explain movement in DR bids. Potential reasons could be:

- Mismatch in temperature data used by E3 and IoUs.
- Not accounting for other explanatory variables that IoUs use in their forecasts.

Absence of reliable hourly temperature records going back to 1950 meant only regression for daily DR bids was doable.

DR bids are higher despite temperature being lower.
## Assumptions on DR Program Characteristics

<table>
<thead>
<tr>
<th>Utility</th>
<th>DR Program</th>
<th>Event Duration (hours/call)</th>
<th>Max. Events per Month</th>
<th>Max. Events per Year</th>
<th>Comments on RECAP Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E</td>
<td>BIP</td>
<td>6</td>
<td>10</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>CBP</td>
<td>6</td>
<td>5</td>
<td></td>
<td>30 hrs/month is interpreted as 5 events/month</td>
</tr>
<tr>
<td></td>
<td>SAC</td>
<td>6</td>
<td>17</td>
<td></td>
<td>100 hrs/year is interpreted as 17 events/year</td>
</tr>
<tr>
<td>SCE</td>
<td>API</td>
<td>6</td>
<td>7</td>
<td></td>
<td>40 hours/month is interpreted as 7 events/month</td>
</tr>
<tr>
<td></td>
<td>BIP</td>
<td>6</td>
<td>10</td>
<td></td>
<td>60 hours/month is interpreted as 10 calls/month</td>
</tr>
<tr>
<td></td>
<td>CBP</td>
<td>6</td>
<td>5</td>
<td></td>
<td>30 hours/month is interpreted as 5 calls/month</td>
</tr>
<tr>
<td></td>
<td>SDP</td>
<td>6</td>
<td>30</td>
<td></td>
<td>180 hours/year is interpreted as 30 events/year</td>
</tr>
</tbody>
</table>
Climate zones and sub-LAPs for reference
## Sub-LAPs vs. Local Capacity Areas

<table>
<thead>
<tr>
<th>Sub-LAP</th>
<th>Sub-LAP (long form)</th>
<th>Local Capacity Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>PGCC</td>
<td>PG&amp;E Central Coast</td>
<td>Bay Area</td>
</tr>
<tr>
<td>PGEB</td>
<td>PG&amp;E East Bay</td>
<td>Bay Area</td>
</tr>
<tr>
<td>PGF1</td>
<td>PG&amp;E Fresno</td>
<td>Greater Fresno</td>
</tr>
<tr>
<td>PGFG</td>
<td>PG&amp;E Fulton-Geyser</td>
<td>North Coast/North Bay</td>
</tr>
<tr>
<td>PGHB</td>
<td>PG&amp;E Humboldt</td>
<td>Humboldt</td>
</tr>
<tr>
<td>PGKN</td>
<td>PG&amp;E Kern</td>
<td>Kern</td>
</tr>
<tr>
<td>PGNB</td>
<td>PG&amp;E North Bay</td>
<td>North Coast/North Bay</td>
</tr>
<tr>
<td>PGNC</td>
<td>PG&amp;E North Coast</td>
<td>North Coast/North Bay</td>
</tr>
<tr>
<td>PGNP</td>
<td>PG&amp;E North of Path 15 - non local</td>
<td>CAISO System</td>
</tr>
<tr>
<td>PGP2</td>
<td>PG&amp;E Peninsula</td>
<td>Bay Area</td>
</tr>
<tr>
<td>PGSB</td>
<td>PG&amp;E South Bay</td>
<td>Bay Area</td>
</tr>
<tr>
<td>PGSF</td>
<td>PG&amp;E San Francisco</td>
<td>Bay Area</td>
</tr>
<tr>
<td>PSGI</td>
<td>PG&amp;E Sierra</td>
<td>Sierra</td>
</tr>
<tr>
<td>PGST</td>
<td>PG&amp;E Stockton</td>
<td>Stockton</td>
</tr>
<tr>
<td>PGZP</td>
<td>PG&amp;E ZP26 (between Path 15 and 26) -non local</td>
<td>CAISO System</td>
</tr>
<tr>
<td>SCEC</td>
<td>SCE Central</td>
<td>LA Basin</td>
</tr>
<tr>
<td>SCEN</td>
<td>SCE North (Big Creek)</td>
<td>Big Creek/Ventura</td>
</tr>
<tr>
<td>SCEW</td>
<td>SCE West</td>
<td>LA Basin</td>
</tr>
<tr>
<td>SCHD</td>
<td>SCE High Desert</td>
<td>CAISO System</td>
</tr>
<tr>
<td>SCLD</td>
<td>SCE Low Desert</td>
<td>CAISO System</td>
</tr>
<tr>
<td>SCNW</td>
<td>SCE North-West (Ventura)</td>
<td>Big Creek/Ventura</td>
</tr>
<tr>
<td>SDG1</td>
<td>SDG&amp;E</td>
<td>San Diego/Imperial Valley</td>
</tr>
<tr>
<td>VEA</td>
<td>VEA</td>
<td>CAISO System</td>
</tr>
</tbody>
</table>