PUBLIC UTILITIES COMMISSION
STATE OF CALIFORNIA

FILED
02/24/23
12:57 PM
R2110002

ATTACHMENT

CALIFORNIA
ENERGY COMMISSION

CALIFORNIA
NATURAL
RESOURCES
AGENCY

February 22, 2023

Honorable Members:

The California Energy Commission (CEC) is pleased to submit the recently adopted commission report, *Qualifying Capacity of Supply-Side Demand Response Working Group Final Report* (Report) and related materials. This submission replaces the previously served report, which erroneously contained the draft report. The following documents are included in this submission:

1. **Report:** The *Qualifying Capacity of Supply-Side Demand Response Working Group Final Report,* adopted by the CEC at the January 25, 2023, Business Meeting. The Report provides the CEC's final findings and recommendations from the CEC's working group on supply-side demand response to the California Public Utilities Commission (CPUC), as originally requested by the CPUC in Decision 21-06-029 and most recently requested by the CPUC in Decision 22-06-050. In these decisions the CPUC requested the CEC launch a stakeholder working group including demand response providers, utilities, industry associations, and others and make recommendations to address capacity counting issues associated with supply-side demand response.
2. **Adoption Resolution:** Confirming the report was adopted by the CEC at its January 25, 2023, business meeting.
3. **Stakeholder Proposals.** These were not formally adopted by the CEC but are summarized in the Report and attached here as requested by CPUC staff to enable further discussion and consideration in the CPUC's proceeding.
    a. **CLECA Proposal.** This proposal was submitted by the California Large Energy Consumers Association.
    b. **DSA Proposal:** This proposal was submitted by Demand Side Analytics in coordination with San Diego Gas & Electric.
    c. **OhmConnect Proposal:** This proposal was submitted by OhmConnect.
    d. **CEDMC Proposal:** This proposal was submitted by the California Efficiency + Demand Management Council.
    e. **CEC Staff Proposal:** This proposal was submitted by California Energy Commission staff. The recommended approach is in large part based on this proposal, but it is superseded by the Implementation Guide (see below).
4. **Implementation Guide:** A supplemental document based on the original CEC Staff Proposal that reflects the final Report

recommendations and includes additional technical detail on implementation. This was not formally adopted by the CEC but is attached here as requested by CPUC staff to enable further discussion and consideration in the CPUC's proceeding.

We would be happy to discuss the contents of the Report with CPUC commissioners and Energy Division staff and to continue to collaborate as necessary. The Report is also available on the Energy Commission's website at Qualifying Capacity of Supply Side Demand Response Working Group Final Report.
Sincerely,
CEC Energy Assessments Division Staff

DOCKETED	
Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	248493
Document Title:	Qualifying Capacity of Supply Side Demand Response Working Group Final Report
Description:	Citation for this report: Lyon, Erik, Tom Flynn, and Daniel Hills-Bunnell. 2022. Qualifying Capacity of Supply-Side Demand Response Working Group Draft Final Report. California Energy Commission. Publication Number: CEC-200-2022-001-F
Filer:	Jann Mitchell
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/23/2023 2:30:11 PM
Docketed Date:	1/23/2023

CALIFORNIA
ENERGY COMMISSION

California Energy Commission

COMMISSION REPORT

Qualifying Capacity of Supply-Side Demand Response Working Group Final Report

Gavin Newsom, Governor
December 2022 | CEC-200-2022-001-F

California Energy Commission

David Hochschild
Chair

Commissioners
Siva Gunda
J. Andrew McAllister, Ph.D.
Patty Monahan
Kourtney Vaccaro

Erik Lyon
Tom Flynn
Daniel Hills-Bunnell
Primary Authors

David Erne
Deputy Director
ENERGY ASSESSMENTS DIVISION

Aleecia Gutierrez
Director
ENERGY ASSESSMENTS DIVISION

Drew Bohan
Executive Director

DISCLAIMER

Staff members of the California Energy Commission (CEC) prepared this report. As such, it does not necessarily represent the views of the CEC, its employees, or the State of California. The CEC, the State of California, its employees, contractors, and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the CEC nor has the Commission passed upon the accuracy or adequacy of the information in this report.

ABSTRACT

This report provides the California Energy Commission's (CEC) final findings and recommendations from the CEC's working group on supply-side demand response to the California Public Utilities Commission (CPUC). The CPUC requested these findings and recommendations in Decision 21-06-029 and last year in Decision 22-06-050. In these decisions, the CPUC requested the CEC launch a stakeholder working group process and make recommendations to improve the method for determining the qualifying capacity of supply-side demand response, which are values based on what the resource can produce during periods of peak electricity demand. This is the final report published by the CEC to make recommendations on improving the method for determining the qualifying capacity of demand response.

Demand response provides California with benefits that include providing greater grid reliability and helping prevent rotating outages. Improving the counting conventions for the qualifying capacity of supply-side demand response can support a robust demand response market, allowing demand response to further support reliability in California.

Today's method for determining the capacity of a demand response resource, eligible to be counted toward meeting the CPUC's resource adequacy requirement, is the CPUC's load impact protocols. The load impact protocols rely heavily on measurements of the historical performance of demand response resources as a basis for forecasting anticipated performance. In this report, CEC staff recommends that the CPUC move away from the load impact protocol approach and adopt an incentive-based qualifying capacity approach.

Keywords: Supply-side demand response, resource adequacy, qualifying capacity, reliability

Please use the following citation for this report:

Lyon, Erik, Tom Flynn, and Daniel Hills-Bunnell. 2022. *Qualifying Capacity of Supply-Side Demand Response Working Group Draft Final Report*. California Energy Commission. Publication Number: CEC-200-2022-001-F.

TABLE OF CONTENTS

ABSTRACT i

TABLE OF CONTENTS ii

EXECUTIVE SUMMARY 1

CHAPTER 1: Introduction 2

- Existing Qualifying Capacity Method for Demand Response 2
  - 2022 LIP Process 3
- CEC Interim Report 3
  - LIP-Informed ELCC Proposal 5
  - Incentive-Based Proposal 5
  - LOLP-Weighted LIP Proposal 5
  - CPUC Decision 22-06-050 6
- Development of a Long-Term Methodology 7

CHAPTER 2: Proposals for Qualifying Capacity of Supply-Side Demand Response 8

- Proposal Summaries 8
  - CLECA Proposal 8
  - DSA Proposal 11
  - OhmConnect Proposal 12
  - CEDMC Proposal 13
  - CEC Staff Proposal 14
- Proposal Comparisons 15
  - Mitigating Capacity Overestimation Risk 17
  - Demand Response Characteristics 18
  - Reporting Requirements and Timeline 19
  - Role of State Agencies and California ISO 20
- Additional Items 21
  - Alignment of Operational and Planning Spaces 21
  - Intracycle Updates 22
  - Demand Response Adders 23

CHAPTER 3: Stakeholder Positions 24

  - Mitigating Capacity Overestimation Risk 24
  - Characteristics of DR 31

  - Reporting Requirements and Timeline 34
  - Role of State Agencies and California ISO 38
  - Alignment of Operational and Planning Spaces 39
  - Intracycle Updates 41
  - DR Adders 43

CHAPTER 4: CEC Recommendations 47

APPENDIX A: Principles 1

APPENDIX B: Capacity Shortfall Penalty 1

APPENDIX C: Acronyms and Abbreviations 1

APPENDIX D: Glossary 1

EXECUTIVE SUMMARY

This report provides the California Energy Commission's (CEC) final findings and recommendations from the CEC's working group on supply-side demand response to the California Public Utilities Commission (CPUC), as requested by the CPUC in Decision 21-06-029 and most recently requested by the CPUC in Decision 22-06-050. In these decisions, the CPUC requested the CEC launch a stakeholder working group including demand response providers, utilities, industry associations, and others, and make recommendations to address capacity counting issues associated with supply-side demand response. This is the final CEC report, which makes recommendations on improving the method for determining the qualifying capacity of demand response.

Demand response provides customers with incentives to reduce or shift electricity use from peak demand periods. Demand response provides California with benefits that include providing greater reliability to the grid and helping prevent rotating outages. Improving the counting conventions for the qualifying capacity[1] of supply-side demand response, which are values based on what the resource can produce during periods of peak electricity demand, may help demand response better support reliability in California.

The current method for determining the capacity of demand response resources, eligible to be counted toward meeting the CPUC's resource adequacy requirement, is the CPUC's load impact protocols. The load impact protocols rely heavily on measurements of actual historical performance of demand response resources as a basis for forecasting anticipated performance.

In this final report, CEC staff makes its recommendations primarily based on consideration of the five stakeholder proposals produced in the working group and stakeholder comments on the proposals. The recommendations are guided by CEC staff's experience this year applying the status quo approach in support of CPUC staff's review and analysis of the filings submitted by demand response providers through the load impact protocols.

CEC staff recommends that the CPUC move away from the load impact protocol approach and adopt an incentive-based qualifying capacity approach. Staff also recommends a framework that closely resembles its own proposal submitted through the working group. Replacing the upfront forecasting approach with an incentive-based framework can prompt DR providers to commit to achievable capacity contributions and to meet those commitments while streamlining the process for both DR providers and agency staff. Staff included components of other proposals and incorporated stakeholder feedback into its final recommendations. The recommendations in this report describe the suggested features of the incentive-based approach.

---

[1] The maximum capacity that an electricity resource may be eligible to provide to the California ISO to meet customer demand at all hours within a study period. The criteria and methodology for calculating the qualifying capacity of resources are established by the CPUC or other applicable local regulatory authority.

CHAPTER 1: Introduction

This report provides the California Energy Commission's (CEC) final findings and recommendations from the CEC's working group on supply-side demand response (DR) to the California Public Utilities Commission (CPUC), as requested by the CPUC in Decision (D.) 21-06-029 and most recently requested by the CPUC in D.22-06-050. These decisions requested that the CEC launch a stakeholder working group[2] process and make recommendations to address electricity capacity counting issues associated with supply-side demand response.

This report is the second in a series of reports published by the CEC to recommend methods for determining qualifying capacity (QC) of DR eligible to be counted toward meeting the CPUC's resource adequacy (RA) requirement. The first interim report was published in early 2022. This is the CEC's final report on the topic.

Existing Qualifying Capacity Method for Demand Response

To determine the capacity of each resource eligible to be counted toward the CPUC's RA requirement, the CPUC develops QC values based on the load impacts of a resource during peak electricity demand periods (typically between 4 and 9 p.m. on the year's hottest days). The CPUC-adopted QC counting conventions vary by resource type. For DR, the QC values are set based on historical performance using load impact protocols (LIPs).

Currently, the process to determine the QC of a DR resource portfolio requires following the CPUC's LIPs. The LIPs rely heavily on measurements of historical performance of DR resources as a basis for forecasting anticipated future performance. For background, the status quo LIPs are summarized below.

The LIPs were adopted by the CPUC in D.08-04-050 in 2008. These protocols established guidelines for measuring historical performance of DR resources, forecasting anticipated performance under varying conditions, and reporting the results. However, they did not specify how load impacts should be applied for RA.

DR providers calculate resource capacity based on the expected load reduction capabilities of DR resources under typical expected peak grid needs. In essence, the LIPs generate a model to estimate the load reduction of a DR resource under varying conditions. This model might account for ambient temperature, day of the week, hour of the day, and month of the year,

---

[2] CEC staff formed a stakeholder working group for this purpose in Summer 2021. Participation was open to all interested stakeholders. Stakeholder organizations represented include Sunrun, California ISO, Enel X North America, Recurve, Olivine, OhmConnect, CPUC Energy Division, CPUC Public Advocates Office, Hy Power Salton Sea, SCD Energy Solutions, Grounded Analytics, Southern California Edison, Pacific Gas and Electric, Barkovich & Yap, Inc. for the California Large Energy Consumers Association (CLECA), California Efficiency + Demand Management Council (CEDMC), CPower, SDG&E, Middle River Power, Leap, CalCCA, Powerflex, NRG Curtailment Solutions, Jay Luboff Consulting, Demand Side Analytics, Opinion Dynamics, California Energy Storage Alliance, Verdant Associates, Enchanted Rock, ecobee, and EnergyHub.

depending on the nature of the resources. To generate a QC value, this model is applied to a set of conditions expected to reflect the peak grid need. These planning assumptions include the median peak temperature expected for each month on a weekday over the hours with the highest net demand. DR resources made of aggregations of small customers, such as residential "smart thermostat" programs, may be modeled as a demand reduction per customer, and the total capacity value is adjusted by the expected future participation.

Finally, the capacity value adopted as the QC for a given resource is provided by CPUC Energy Division staff. CPUC staff reviews LIP reports with estimated capacity values and makes a "reasonableness determination" for each resource. For capacity values found unreasonable, CPUC staff may change assumptions regarding the expected load impacts or participation based on professional judgment. The resulting value is adopted as the QC and represents the maximum capacity a DR resource can provide in an RA capacity contract.

2022 LIP Process

In 2022, CEC staff and CPUC Energy Division staff collaborated on the LIP reviews for the first time. Together, staff from the two agencies reviewed and analyzed the LIP submissions of third-party DR providers and developed consensus determinations. CEC staff did not review investor-owned utility LIP filings. This provided CEC staff with an opportunity to acquire first-hand knowledge of LIP filings, the LIP process, and the role of Energy Division staff in the LIP process. Through this experience CEC staff gained an appreciation for the extensive undertaking that the preparation of LIP reports by DR providers represents and the workload of Energy Division staff in reviewing those reports and developing QC determinations.

CEC Interim Report

On June 25, 2021, the CPUC issued Decision 21-06-029, which asked the CEC to launch a stakeholder working group process and make "recommendations for a comprehensive and consistent [measurement and verification] strategy, including a new capacity counting method for [DR] addressing *ex post* and *ex ante* load impacts for implementation as early as practicable. (35)"[3] The CPUC specifically requested the CEC "make actionable recommendations" on the following issues:

1. "Whether the [California ISO's] ELCC [effective load carrying capability] proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered;
2. Whether the LIP-informed ELCC proposal is reasonable and appropriate to determine DR QC and/or what modifications, if any, should be considered;
3. Whether other proposals that may be presented in the CEC's stakeholder process are reasonable and appropriate to determine DR QC;

---

[3] *Ex ante* refers to values that are based on forecasts rather than actual results. *Ex post* refers to values that are based on actual results rather than forecasts.

4. Whether and to what extent alignment of DR M&V [measurement and verification[4]] methods in the operational space for California ISO market settlement purposes with methods to determine resource adequacy QC in the planning space should be achieved, and if so, how;
5. Whether, and if so what, enhancements to intra-cycle adjustments to DR QC during the RA compliance year, as adopted in D.20-06-031, are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space;
6. Whether implementation of any elements of DR QC methodology modifications that might be adopted by the Commission should be phased in over time;
7. Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology." (35–36).

The CPUC requested that the CEC submit its recommendations for implementation in the 2023 RA compliance year,[5] no later than March 18, 2022.

In response to the request in Decision 21-06-029, the CEC launched a stakeholder working group process in July 2021. By October 2021, it was clear that there was insufficient time to develop a permanent QC methodology for the 2023 RA compliance year. The stakeholders believed that the working group should await the outcome of the CPUC reform track process in its RA proceeding before making its recommendations. As a result, the CEC submitted its report to the CPUC on February 18, 2022.

The interim report recommended several proposed approaches on an interim basis for 2023: the LIP-informed ELCC for IOU resources, the incentive-based approach for third-party Demand Response Providers (DRPs), the LOLP-weighted LIPs as a back-up option for IOUs and third-party DRPs, and the status quo LIP methodology. The CEC interim report recommended the CPUC request California ISO grant a resource adequacy availability incentive mechanism (RAAIM)[6] exemption for DR resources that choose to use LIP-informed ELCC and the CPUC direct IOUs to move DR portfolios onto California ISO supply plans. Lastly, the CEC interim report recommended the CPUC extend the working group process beyond February 2022 to develop long-term recommendations beginning with the 2024 RA compliance year.

The three approaches proposed in the interim report are summarized below. The status quo LIP method was summarized earlier in this chapter.

---

[4] *Measurement and verification (M&V)* for demand response means the determination of the demand reduction quantities.

[5] The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. The program ensures that CPUC jurisdictional load-serving entities have sufficient capacity to meet their peak load with a 15 percent reserve margin. The RA program began implementation in 2006 and is intended to provide the energy market with adequate forward capacity to meet peak demand and integrate renewables. Each October, the RA program requires load-serving entities to make compliance showings for the coming year.

[6] The RA Availability Incentive Mechanism (RAAIM) is a mechanism for California ISO to assess nonavailability charges and provides availability incentive payments to RA resources based on whether the performance of these resources falls below or above defined performance thresholds.

LIP-Informed ELCC Proposal

Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) proposed using the LIP analysis to inform the QC of the effective load carrying capability (ELCC) methodology, referred to as *LIP-informed ELCC.* The method proposed to apply the same logic and principles as bid-informed ELCC but would use LIP profiles as the input for the ELCC model. The proposal assumed that CPUC staff would calculate the ELCC values.

CEC staff recommended that for the 2023 RA compliance year, the proposal should be adopted on an interim basis for investor-owned utility resources. Because of time constraints, CEC staff noted it was unlikely CPUC staff could perform the modeling for third-party DRPs.

The California ISO, PG&E, and SCE supported the proposal as an interim approach for the 2023 RA compliance year. OhmConnect suggested that the method should be available to third-party DRPs, as well as IOUs. California Large Energy Consumers Association (CLECA) and SDG&E opposed the proposal.

Incentive-Based Proposal

The California Efficiency + Demand Management Council (CEDMC) proposed an incentive-based approach modeled in part by approaches used by the PJM Interconnection and the New York Independent System Operator. On a quarterly basis, DRPs would estimate the capability of their resources and claim a corresponding QC value using any proprietary analytical tool. DRPs would submit claimed QC values and supporting documentation to the CPUC for review, after which CPUC staff would determine the approved amount. Each DR provider would provide a $2,500/MW-year collateral payment to the CPUC Energy Division to be held in escrow based on the amount of NQC contracted. The performance of a resource would be evaluated against the provider's monthly supply plan to determine underperformance. A financial penalty structure would be based on PG&E's Capacity Bidding Program, where penalties are issued if providers deliver less than 75 percent of the contracted amount.

CEC staff recommended the proposal be adopted on an interim basis for third-party DRPs for the 2023 RA compliance year. Staff recommended a penalty structure based on PG&E's Capacity Bidding Program structure and the Demand Response Auction Mechanism penalty structure, where penalties would be triggered if a DR resource performs below 90 percent of contracted capacity.

OhmConnect, CESA, and a coalition of DR providers supported CEDMC's proposal as an interim solution. Several stakeholders opposed the proposal, including Cal Advocates, the California ISO, PG&E, and SCE.

LOLP-Weighted LIP Proposal

CLECA proposed to use relative loss of load probability (LOLP) as hourly weights to apply to the LIPs (rather than using a simple average), referred to as the *LOLP-weighted LIP proposal.*

CEC staff recommended that for the 2023 RA compliance year, the LOLP-weighted LIP proposal should be adopted as an interim back-up option for third-party DRPs and IOUs. Staff believed the proposal provided an incremental improvement to reflecting contribution to reliability relative to unweighted LIP results.

The California ISO, CESA, and a coalition of DR providers supported the LOLP-weighted LIP proposal as an interim solution for 2023. PG&E believed it was not robust enough for an interim solution but recommended that the working group develop the proposal as a potential long-term solution. SCE suggested that the proposal did not evaluate contribution to grid reliability in the context of other types of capacity on the grid, such as wind, solar, and storage, and did not consider the order through which DR resources are dispatched or the related interactive effects.

CPUC Decision 22-06-050

After considering the CEC recommendations in its interim report and taking comments from stakeholders, the CPUC issued Decision 22-06-050 in Rulemaking 21-10-002 on June 24, 2022.[7]

The CPUC observed that to implement new QC methods for DR resources for the 2023 RA compliance year, even on an interim basis, there would be significant timing and resource constraints for the proposed methods. The CPUC found insufficient record to adopt a DR QC counting proposal for the 2023 RA compliance year. Consequently, the CPUC determined that the status quo LIP method would remain in effect unless superseded by a future decision.

The CPUC agreed that the CEC working group should continue to develop long-term recommendations, consistent with the adopted reform track framework. The CPUC found that to adopt a new DR QC method for the 2024 RA compliance year, in advance of the load impact protocol process that begins in December, a working group recommendation would need to be submitted by August 2022. The CPUC found that given the short time remaining, it would be unlikely that the working group would have sufficient time to develop an implementable proposal for 2024 and more realistic to submit recommendations for the 2025 RA compliance year and beyond.

Thus, the CPUC requested that the CEC working group develop recommendations that consider the following issues for 2025 RA compliance year:

1. “Whether the proposals that are presented in the CEC’s stakeholder process are reasonable and appropriate to determine the QC of DR resources;
2. Whether the DR QC methodology reflects the contributions of DR resources to reliability;
3. Whether the DR QC methodology is compatible with the new RA framework for the 2025 RA year and beyond;
4. Whether the DR QC methodology is transparent and how it could be implemented in a time-efficient manner;
5. Whether and to what extent alignment of DR M&V [measurement and verification] methods in the operational space for CAISO market settlement purposes with methods to determine DR QC in the planning space should be achieved, and if so, how;

---

[7] See Section 3.4.1 (pages 27-41) of the decision for more detail. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

6. Whether, and if so what, enhancements to intra-cycle adjustments to DR QC during the RA compliance year, as adopted in CPUC Decision 20-06-031,[8] are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space;
7. Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology." (40-41).

The Commission requested that the CEC working group submit recommendations into Rulemaking 21-10-002 by February 1, 2023.

Development of a Long-Term Methodology

Prior to CPUC Decision 22-06-050, the CEC recommenced the working group on April 7, 2022. The working group began with the assumption that the status quo load impact protocol methodology would remain in effect unless superseded by a future CPUC decision and that the working group should focus on recommendations for the 2025 RA compliance year and beyond. Those assumptions were confirmed by CPUC Decision 22-06-050. The decision also confirmed that the working group should develop recommendations consistent with the slice-of-day framework adopted by the CPUC. This meant that the development of a long-term solution by the working group would need to be done in parallel with the development of the slice-of-day framework by the CPUC. The working group began its work on a durable solution following the decision. Since CPUC Decision 22-06-050 gave the working group a deadline of February 1, 2023, the working group developed a workplan and timeline that would achieve this goal. The working group also revisited the principles it had developed in 2021 and further refined them in preparation for using them to help evaluate proposals. The final set of nine principles were posted to docket 21-DR-01 on May 2, 2022.[9]

The working group also began the development of a range of proposals for QC of supply-side DR for the 2025 RA compliance year and beyond. Ultimately, five proposals were developed and submitted to the working group by participants. The CEC posted the five written proposals to Docket 21-DR-01 on September 28, 2022. Chapter 2 summarizes and compares the five proposals.

The CEC received written stakeholder comments during the week of October 17, 2022, and posted those to Docket 21-DR-01. Chapter 3 summarizes the stakeholder comments received. The CEC provides its recommendations in Chapter 4 based on its consideration of the five proposals, stakeholder written comments, and CEC staff's experience this year in supporting CPUC staff review and analysis of the 2022 LIP filings submitted by DR providers.

---

[8] See page 45 of CPUC Decision 20-06-031 issued in CPUC Rulemaking 19-11-009 on June 30, 2020. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF

[9] California Energy Commission staff. 2022. *DR QC Counting Methodology Principles.* California Energy Commission, https://efiling.energy.ca.gov/GetDocument.aspx?tn=242909&DocumentContentId=76492

CHAPTER 2:
Proposals for Qualifying Capacity of Supply-Side Demand Response

Following the submittal of the interim report to the CPUC on February 18, 2022, the CEC moved the working group's focus away from an interim solution and on to the development of a long-term solution for RA compliance year 2025 and beyond. Five proposals were developed and sponsored by several stakeholder participants in the working group and final written descriptions of these were submitted to CEC in September 2022 and posted to Docket 21-DR-01.[10]

The chapter begins with a section summarizing each proposal in brief, followed by a section comparing the different proposals across four key attributes. For summaries of stakeholder positions on these proposals based on written comments solicited by CEC staff, see Chapter 3.

Proposal Summaries

This section introduces the five proposals submitted through the DR QC working group process from the CLECA, Demand Side Analytics (DSA), OhmConnect, CEDMC, and CEC staff.

CLECA Proposal

The CLECA proposes adapting the status quo LIP-based methodology to the slice-of-day framework. CLECA notes the LIPs "already produce hourly expected load reductions" that are averaged under the current process; under slice-of-day, they simply do not need to be averaged. CLECA's emphasis is more on the flexibility in *when* DR providers can provide capacity and requirements for counting capacity across hours than on the specific method used to calculate the values.

Specifically, CLECA observes that "under the 24-hourly proposal, the requirement that DR must be available from 4 to 9 p.m. may no longer be necessary. That change would allow an LSE to develop DR programs to meet its load requirement shape." However, the CLECA proposal does maintain other elements of the status quo RA requirements, including a minimum four-hour dispatch and minimum availability of 24 hours per month from May to September.

Under the slice-of-day framework, CLECA proposes to require DR providers to account for "any significant spillover impacts which increase [or decrease] load before or after the event." This element is included for consistency with storage under slice-of-day, which requires load-serving entities to "show the resources providing energy used for charging as part of their capacity requirements." CLECA notes the specific requirements may need to be revisited based on future reliability studies.

---

[10] See California Energy Commission Docket Log 21-DR-01.
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-DR-01.

The CLECA proposal also includes guidance on a method to determine the monthly QC value for the California ISO need determination and on the "additional items" presented later in this report. The need determination method is being addressed in the reform track of CPUC Rulemaking 21-10-002 and out of scope for this report. The CLECA perspective on additional items is presented later in the "Reporting Requirements and Timeline

The five proposals submitted all recognize the requirement for developing hourly capacity values by month, though they differ by how directly and explicitly that process is described. Some proposals focused on new reporting requirements for the slice-of-day framework, while others focused on unnecessary reporting requirements under the status quo that can be eliminated and the extent to which this streamlining can allow for QC values to be finalized earlier.

The DSA proposal focused on the format of QC reporting for the slice-of-day framework. Specifically, DSA proposes a reporting format referred to as the *24-slice-of-day table* with months as columns and hours of the day as rows that is filled in with the capacity value for that hour of the "worst day" of that month. For weather-sensitive resources, DSA also proposes a time-temperature matrix that includes temperature, dispatch start time, and hours into event in addition to month and hour.

The incentive-based proposals from CEDMC and CEC staff both included requirements for reporting *ex ante* claimed capacity. For CEDMC, the claimed capacity values would be a single megawatt value for each hour of each month for which a DR provider is seeking RA capacity. The CEDMC proposal requires a single value because the methodology does not include weather normalization. In contrast, the CEC staff proposal also requires a "capability profile" that represents the minimum capacity the DR provider is willing to commit to over a range of temperatures. The monthly/hourly capacity values are determined by applying the planning temperature for each month and hour to the capability profile, resulting in a single value much like the CEDMC proposal. Both proposals are ultimately compatible with the slice-of-day table.

CEDMC and OhmConnect focused on eliminating excess *ex ante* reporting requirements. OhmConnect began with the list of protocols enumerated in the LIPs and removed or amended those found to be unnecessary. (See OhmConnect Proposal for details.) CEDMC took the opposite approach and proposed a new list of "supporting data," including:

a. Current and projected number of service accounts.
b. Customer class, size, and technology type, if applicable.
c. Projected aggregated load.
d. Projected percentage of load impact or reduction.
e. Nature of load being aggregated.
f. Dispatch method.
g. Historical performance data.

CEDMC and OhmConnect proposed reducing the timeline for finalizing QC values such that DR providers can contract with load-serving entities earlier in the year-ahead process. Under the proposed timelines, final QC values would be available by June 1 and July 1, respectively, prior to the RA compliance year.

The CEDMC and DSA proposals also included *ex post* performance reporting requirements. For CEDMC, the main purpose of *ex post* reporting is to provide a measurement of delivered capacity for the CPUC to complete its assessment of performance relative to commitments and, if necessary, enforce penalties. In the CEC staff proposal, *ex post* capacity measurement is assumed to be completed by a state agency or the California ISO.

DSA proposes two novel measurements of *ex post* performance, the "bid alignment metric" and "performance alignment metric." The bid alignment metric "is a ratio between historic[al] bidding values and the capability forecasted by the historic[al] [*ex ante*] model." The performance alignment metric "is a ratio between the historic[al] performance … and the planning values developed from the historic[al] *ex ante* model for the same weather and dispatch conditions." According to DSA, these metrics "can let implementers, planners, and [the California ISO] know if there needs to be an adjustment to the planning model in the long term so that there is greater alignment between actual performance and the forecasted performance" or bids.

Role of State Agencies and California ISO

Under the current processes, CPUC Energy Division staff reviews LIP reports and makes a finding as to whether claimed QC values are reasonable. The three LIP-based proposals from OhmConnect, CLECA, and DSA would maintain this role. CEDMC proposes to preserve the prerogative of the CPUC to conduct the same level of detailed review, but because of the "penalty structure in place to provide after-the-fact rigor, … it will not be necessary that the Energy Division apply the same degree of up-front rigor it uses under the LIP process." The CEC proposal takes a similar approach and suggests specific criteria under which CPUC staff waives the prerogative and approve claimed QC values. These criteria include the following:

- "[*Ex post*] capacity value is at least 90 percent of the committed capacity."
- "Requested [*ex ante*] capacity is no more than 25 percent above the [*ex post*] delivered capacity in the previous year."

CEC staff states that together, these criteria "will reduce administrative burden on both DR providers and CPUC staff, while still retaining oversight abilities in cases where a DR provider underperformed in the previous year or a significant increase in QC is requested."

The DSA proposal also included a new *ex ante* role for a central agency. DSA suggests the CPUC, CEC, or California ISO produce a "reliability risk heatmap" ahead of the RA compliance year. The heatmap would guide development of DR resources by quantifying reliability risk (for example, loss of load probability or expected unserved energy) by month and hour of day over the RA compliance year. The heatmap would be provided roughly 18 months ahead of the RA compliance year.

CEDMC recommends "the Energy Division [to] assess the monthly Demonstrated Capacity reports of each [investor-owned utility] and DR provider." CEC staff does not specify which entity would implement the penalty structure.

Additional Items" section of this chapter.

For more information, see the CLECA proposal posted to CEC Docket 21-DR-01.[11]

DSA Proposal

DSA proposal is fundamentally an application of the LIPs to the new slice-of-day framework. The first element of the proposal states: "The [LIPs] should be retained but modified to address the 24-hour slice-of-day framework." Such modifications include updating planning temperatures to the "worst day" as defined in the RA program, allowing DR resources the flexibility to provide capacity value based on need (in contrast to the static availability assessment hours), and accounting for spillover in nonevent hours (including negative load impacts or takeback).

Much of the DSA proposal focuses on standardization of reporting requirements and outputs. For all resources, a *24-slice-of-day table* would show hourly load impacts for the worst day in each month. Each load impact estimate in the table would be the hourly capacity value eligible for RA in that hour and month. For weather-sensitive resources, DSA proposes production of a time-temperature matrix of load impacts as an upon-request output. The time-temperature matrix could also disaggregate load impacts by event start time or hours into event, if needed.

The proposal includes supplemental components apparently for informational purposes. DSA proposes that a central planning authority produce a "reliability risk heatmap" for each compliance year that will help DR providers align resources and programs with system need but does not directly affect either *ex ante* or *ex post* capacity valuation.

The proposal also includes two *ex post* performance metrics:

- The **bid alignment metric** measures the extent to which resources bid as expected based on the associated 24-slice-of-day table or time-temperature matrix or both.
- The **performance alignment metric** measures the extent to which resources perform as expected when dispatched.

Like the risk heatmap, these metrics do not appear to directly impact *ex ante* or *ex post* capacity valuation. DSA writes of both metrics: "we recognize that stakeholders may want additional discussion and the opportunity to test it in practice before it is adopted," suggesting it may be integrated into the QC methodology, but a description of how it would do so is not provided.

DSA also included suggestions for aligning evaluation of load impacts in the planning space with evaluation used for settlement. These elements of the proposal are included in the section "Alignment of Operational and Planning Spaces" of this report.

For more information, see the DSA proposal posted to CEC Docket 21-DR-01.[12]

---

[11] Nelson, Paul. 2022. *Proposal for Demand Response Resource Counting for Slice of Day*. CLECA, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246242&DocumentContentId=80425

[12] Demand Side Analytics Staff. 2022. *Demand Response Qualifying Capacity Working Group Proposal.* San Diego Gas & Electric, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246240&DocumentContentId=80424

OhmConnect Proposal

OhmConnect proposes using the same underlying methods used in the current LIP-based status quo and focuses instead on removing or otherwise streamlining the LIP reporting requirements not directly applicable to QC. OhmConnect argues that current protocols regarding *ex ante* evaluation of a resource are both "burdensome and inefficient" for DR providers and CPUC Energy Division staff. OhmConnect notes that streamlining reporting requirements is "compatible with any number of approaches to modify the LIP outputs for the slice-of-day RA program" but "does not opine on any individual proposal here." While OhmConnect uses the status quo LIP-based methodology as a sensible default, it signals openness to alternative methodologies so long as the reporting requirements are simplified sufficiently "to *just* those that are necessary for the determination of RA QC."

Reporting changes proposed by OhmConnect include the following:

- **Streamline evaluation plan requirements:** OhmConnect proposes a standardized tabular or spreadsheet template that would reduce burden on DR providers and CPUC Energy Division staff (Protocol 1). To further reduce the reporting burden, OhmConnect proposes that only first-time DR providers or providers making "material changes" to their program or evaluation approach should be required to submit an evaluation plan to the CPUC Energy Division staff for approval (Protocol 1) or respond to questions/issues regarding the evaluation plan (Protocol 3).
- **Eliminate *ex post* and *ex ante* impact estimates not relevant to QC valuation:** OhmConnect proposes eliminating reporting requirements including average and total resource impact (Protocol 5), estimates for typical and average day events (within Protocol 8), change in monthly/annual energy use (Protocol 19), non-RA-relevant *ex ante* event estimates, such as the 1-in-10 peak (within Protocol 22), and capacity projections beyond the RA compliance year for which the DR provider is seeking QC.
- **Eliminate all non-event-based DR protocols:** The LIPs include a suite of protocols (Protocols 11 through 16) specific to load-modifying and other non-event-based DR that can be eliminated for supply-side DR.
- **Streamline evaluation report, especially public review:** OhmConnect proposes eliminating the "comparison to prior year's study in *ex ante*" because it introduces confusion (within Protocol 26). However, OhmConnect places greater emphasis on shortening the evaluation review process and eliminating the public review component that was designed for oversight of IOU DR programs (Protocol 27). According to OhmConnect, public review requires considerable time and effort, and redaction of proprietary data renders the value of public oversight "questionable." OhmConnect notes that full, unredacted evaluation reports can still be provided to the CPUC, CEC, California ISO, or the CPUC Public Advocate's Office, or a combination, as appropriate.

For the comprehensive list of proposed changes, see the OhmConnect proposal posted to CEC Docket 21-DR-01.[13] Between these changes, OhmConnect proposes the LIP timeline be

---

[13] OhmConnect staff. 2022. *"Simplified LIPs" Proposal*. OhmConnect, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246232&DocumentContentId=80415

shortened so DR providers can receive QC values for the following year by July 1, rather than mid-September.

CEDMC Proposal

CEDMC proposes an *ex post* incentive structure that levies a penalty on underperformance to ensure delivered capacity. This proposal is largely aimed at reducing the burden and risk for DR providers, who bear compliance costs of participation and uncertainty of awarded QC, and oversight for CPUC Energy Division staff, who is responsible for auditing submissions and approving final awarded QC.

Central to the CEDMC proposal is the penalty structure, which determines the financial incentives faced by DR providers. This penalty structure is adapted from PG&E’s Capacity Bidding Program. When demonstrated capacity is 50 to 100 percent of committed capacity, the payment is adjusted to the demonstrated capacity but does not face an incremental penalty. Below 50 percent, the DR provider loses the entirety of its capacity payment *and* is penalized by the value of the committed capacity.

Along with shifting from an analytical forecasting or predictive approach (that is, a LIP-based approach) to an incentive-based one, the proposal includes several specific elements to further streamline the process for DR providers and CPUC Energy Division staff. To avoid complex analytics, *ex post* capacity “would be assessed based on a resource’s performance during the best hour.” In the absence of market dispatches, *ex post* capacity could be based on a test event or bids. Neither approach would apply weather normalization.

The penalty structure itself is selected to accommodate the streamlined *ex post* capacity valuation. According to CEDMC, “The 50 percent ‘tolerance band’ may appear substantial but … [w]ithout weather normalization, performance of a given weather-dependent DR resource would be lower under cooler conditions.” For weather-sensitive resources, the simplified *ex post* valuation methodology is a rough measure of capacity that requires a high tolerance band to avoid improperly penalizing DR providers.

The incentive-based approach is intended to reduce the burden on CPUC Energy Division staff in addition to DR providers. The proposal specifies a minimum amount of data to document *ex ante* capacity values and retains CPUC Energy Division staff’s role in assessing claimed QC values, but notes that “there would be a penalty structure to provide after-the-fact rigor, so it will not be necessary that the [CPUC] Energy Division [staff] apply the same degree of up-front rigor it uses under the LIP process.” An incentive-based approach shifts the risk of incorrect or overinflated *ex ante* assessment from CPUC Energy Division staff to DR providers.

Based on the proposed methodology and process, CEDMC proposes shortening the timeline so that QC values are awarded by June 1 preceding the RA compliance year.

For more information, see the CEDMC proposal posted to CEC Docket 21-DR-01.[14]

---

[14] California Efficiency + Demand Management Council staff. 2022. *California Efficiency + Demand Management Council Incentive-Based Method DR Counting Proposal.* CEDMC, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246235&DocumentContentId=80417

CEC Staff Proposal

CEC staff proposes an incentive-based approach to minimize shortfalls in delivered capacity from DR providers. To account for different weather-sensitive resources, DR providers define a temperature sensitivity profile for each resource in each hour of the day and month (or group of months). Critically, the DR provider must define a series of temperature change points for weather-sensitive resources capability profiles that will be used in *ex post* capacity calculation. The *ex ante* capacity value for each month is determined by the intersection of the capability profile with the planning temperature (the assumed temperature for the "worst day"), which can be audited by CPUC Energy Division staff. Energy Division staff may review requested QC if the DR provider has not met performance criteria or is projecting drastic resource growth and approve QC values.

After the period for which RA capacity was shown, *ex post* load impacts of events are calculated. Simple, non-weather-sensitive resources are directed to use the results from settlement in the California ISO market, when possible. For other resources, particularly those that are weather sensitive, an alternative baseline may be used if it can produce better results but cannot reasonably be implemented for settlement.

Load impacts are normalized to the amount bid to account for the reality that DR load impacts may be low for some events simply because the full resource was not called, not because of underperformance of the DR resource. These bid-normalized load impacts (BNLI) are calculated by the following formula:

$$\mathrm{BNLI} = \mathrm{Max}\left(Bid\left(\frac{\mathrm{Min}(Delivered, Dispatch)}{Dispatch}\right), Delivered\right)$$

A simple linear regression determines the *ex post* demonstrated capabilities of the resource, analogous to the capability profile submitted in the *ex ante* phase. The regression applies the temperature change points previously submitted to measure the capacity value of the resource under hot or cold temperatures. The *ex post* demonstrated capacity is the intersection of the *ex post* capacity regression line with the same planning temperature used in the *ex ante* process. For resources without weather sensitivity, the *ex post* capacity value can be generated simply from average hourly bid-normalized load impacts.

CEC staff proposes a penalty mechanism as a function of the shortfall in demonstrated capacity relative to committed capacity (the portion of QC that was contracted for and included in an RA showing). The penalty is levied if a resource meets less than 94.5 percent of the committed capacity. Below this threshold, a resource is compensated for the delivered capacity minus the shortfall amount. CEC staff notes that load-serving entities and DR providers can develop contracts that compensate DR providers for exceeding capacity commitments, but these provisions are outside the scope of determining QC.

For more information, see the CEC staff proposal posted to CEC Docket 21-DR-01.[15]

---

[15] Lyon, Erik. 2022. *Hourly Regression Capacity Counting Methodology for Supply-Side Demand Response*. California Energy Commission, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246244&DocumentContentId=80427

Proposal Comparisons

Table 1 below compares the five proposals with respect to how each address four key attributes: mitigating capacity overestimation risk, DR characteristics, reporting requirements and timeline, and role of state agencies and the California ISO.

Table 1: Comparison of Proposals

	Mitigating Capacity Overestimation Risk	DR Characteristics	Reporting Requirements and Timeline	State and ISO Role
CLECA	NC (*ex ante* analysis similar to status quo)	Account for spillover and takeback (pre-cooling, snapback)	Encourages flexibility outside the 4 to 9 p.m. window for when DRPs can supply capacity	NC
DSA		Account for spillover and takeback (pre-cooling, snapback)	*Ex ante*: Slice-of-day capacity table and time-temperature matrix for weather-sensitive resources. *Ex post*: Calculate Bid Alignment Metric and Performance Alignment Metric.	CEC, CPUC, or ISO produce reliability risk heatmap.
OhmConnect		NA	Eliminates many LIP reporting requirements QC finalized July 1	NC
CEDMC	Penalty Mechanism: Adapted from PG&E Capacity Bidding Program	Capacity based on maximum ("best") dispatch.	Claimed monthly/hourly capacity value along with specified supporting data QC finalized June 1	CPUC implements penalty
CEC	Penalty Mechanism: Capacity Shortfall Penalty	Calculate *ex ante* hourly capacity value with availability profile and monthly planning temperature	Claimed monthly/hourly capability profiles over varying temperature conditions.	CPUC expedites approval of QC for providers with proven track record. CPUC or ISO implements penalty.

NC = No change from status quo; NA = Not directly addressed

Source: CEC Staff Analysis of DR QC Proposals

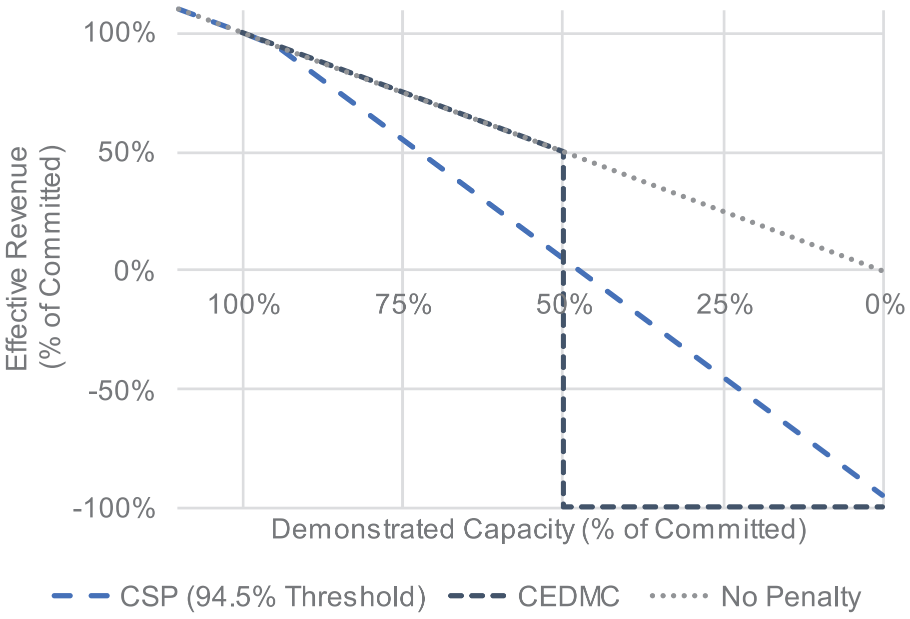
Mitigating Capacity Overestimation Risk

Fundamentally, the QC proposals fell into two categories based on the strategy for reducing the risk of overstating the *ex ante* capacity value of DR resources. The first category rests upon a detailed *ex ante* analytical method that seeks to forecast the capacity value of resources based on a mix of past performance and projected changes in the resource, such as enrollment and customer composition. This approach is consistent with the LIP-based current practice. The CLECA, DSA, and OhmConnect proposals fall into this category.

The second category of QC proposals relies on a penalty for underperformance relative to commitments to ensure DR providers face an incentive not to overestimate resource capacity values. The CEDMC and CEC staff proposals fall in this category. The CEDMC penalty structure is less severe at low to moderate levels of performance but becomes extremely severe after reaching a threshold underperformance level. The CEC "capacity shortfall penalty" structure, by contrast, increases slowly but steadily under increasing levels of underperformance.

Figure 1 illustrates the differences between the two proposed penalty structures. The graph shows the amount of capacity the DR provider would be compensated for based on varying levels of performance relative to its commitment. For reference, the reference case of no penalty (gray dots) represents a case wherein the DR provider is compensated for its demonstrated capacity, regardless of its committed capacity. As demonstrated capacity falls from 100 percent to 0 percent of committed capacity, the revenue falls proportionally.

Figure 1: Comparison of CEC Capacity Shortfall Penalty and CEDMC Penalty Adopted From the PG&E Capacity Bidding Program



Source: CEC staff analysis.

Both incentive structures recognize that the RA framework requires an *ex ante* commitment and reliability may be threatened if these commitments are not met, justifying additional penalties. These penalties are represented graphically by falling below the reference case. The

CEDMC proposal tracks the no-penalty case until the DR provider falls below half of committed capacity, at which point the DR provider loses the entire value of its contract *and* must pay the contract amount in penalties. In contrast, the CEC capacity shortfall penalty takes effect at higher levels of performance in small amounts and grows rapidly with underperformance. The DR provider loses its entire contract value just below half of its committed capacity and faces a net penalty beyond that point. The CEC capacity shortfall penalty is more severe for moderate underperformance, and the CEDMC capacity bidding program-based penalty is more severe for extreme underperformance.

CEDMC proposes its penalty be assessed "at the program level for each [investor-owned utility] and at the contract level for DR providers," as opposed to at the resource level. Similarly, CEC staff proposes allowing "capacity aggregation," or applying penalties to the aggregated portfolio of a DR provider rather than individual resources, to reduce underperformance risk.

Demand Response Characteristics

Stakeholders in the working group generally agreed that a robust QC methodology must account for the diverse characteristics of DR resources. These characteristics include use and availability limitations and weather sensitivity, among others.

The LIPs allow for normalizing DR load impacts for variable weather conditions, and capacity values are based on a 1-in-2 (median) forecast peak temperature. OhmConnect, CLECA, and DSA all carry forward the weather-normalization process from the LIPs while noting the planning temperatures will need to be updated to match the slice-of-day framework. OhmConnect proposes to "align required 'day type(s)' with the adopted [slice-of-day] program," and DSA proposes "aligning weather conditions with the worst day of the month as defined in [RA]." CLECA also references the worst day in its summary of SCE's 24-hourly slice proposal. Effectively, all three proposals adapt the status quo process to the new slice-of-day framework with varying levels of specificity.

CEC proposes a weather normalization process that is largely influenced by the LIPs but imposes consistency across resources. The CEC proposal comprises related but distinct processes for *ex ante* QC valuation and *ex post* capacity measurement. These processes are:

- ***Ex ante* capability profile and QC:** The capability profile shows the minimum load impacts a DR provider expects of a resource under varying temperature conditions, as described in Reporting Requirements and Timeline below. The profile includes regions where a resource can show responsiveness to temperature, such as an increase in capacity under hotter temperatures (smart thermostat programs, for example). The QC value is the intersection of the capability profile and the planning temperature. Like in the CEDMC proposal, the *ex ante* submission is primarily the responsibility of the DR provider.
- ***Ex post* performance regression:** The *ex post* performance regression measures actual bid-normalized load impacts as a function of temperature during a given compliance period. Weather sensitivity is measured only in the regions specified in the *ex ante* capability profile, making the *ex ante* profile and *ex post* regression directly

comparable. The *ex post* demonstrated capacity, like in the capability profile, is the intersection of the regression line and the planning temperature.

Relative to the other approaches to weather normalization, the CEDMC proposal is an outlier. Instead of applying weather normalization, CEDMC proposes, "Demonstrated Capacity would be assessed based on a resource's performance during the best hour." Applying the maximum load impact is an accommodation for the lack of explicit weather normalization. CEDMC explains, "[I]f Demonstrated Capacity from a market dispatch was instead based on average performance, then there might be a motivation not to dispatch a DR resource … if the first dispatch resulted in a [high value]."

DSA and CLECA both propose including positive and negative load impacts outside the dispatch window. These impacts are collectively referred to as "spillover effects" in both proposals and include both increases (for example, precooling and snapback) and decreases in load. CLECA writes, "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." DSA similarly calls for updating the LIPs to include "spillover effects such as snapback, pre-cooling, or persistence of load reductions beyond the event window." CLECA notes this approach is consistent with the approach used for battery storage, whereby load-serving entities "would show the resources providing energy used for charging as part of their capacity requirements." CEC staff proposes including only negative load impacts (increases in load) within two hours of a dispatch and suggest including all positive load impacts in hourly capacity values.

Reporting Requirements and Timeline

The five proposals submitted all recognize the requirement for developing hourly capacity values by month, though they differ by how directly and explicitly that process is described. Some proposals focused on new reporting requirements for the slice-of-day framework, while others focused on unnecessary reporting requirements under the status quo that can be eliminated and the extent to which this streamlining can allow for QC values to be finalized earlier.

The DSA proposal focused on the format of QC reporting for the slice-of-day framework. Specifically, DSA proposes a reporting format referred to as the *24-slice-of-day table* with months as columns and hours of the day as rows that is filled in with the capacity value for that hour of the "worst day" of that month. For weather-sensitive resources, DSA also proposes a time-temperature matrix that includes temperature, dispatch start time, and hours into event in addition to month and hour.

The incentive-based proposals from CEDMC and CEC staff both included requirements for reporting *ex ante* claimed capacity. For CEDMC, the claimed capacity values would be a single megawatt value for each hour of each month for which a DR provider is seeking RA capacity. The CEDMC proposal requires a single value because the methodology does not include weather normalization. In contrast, the CEC staff proposal also requires a "capability profile" that represents the minimum capacity the DR provider is willing to commit to over a range of temperatures. The monthly/hourly capacity values are determined by applying the planning temperature for each month and hour to the capability profile, resulting in a single value much like the CEDMC proposal. Both proposals are ultimately compatible with the slice-of-day table.

CEDMC and OhmConnect focused on eliminating excess *ex ante* reporting requirements. OhmConnect began with the list of protocols enumerated in the LIPs and removed or amended those found to be unnecessary. (See OhmConnect Proposal for details.) CEDMC took the opposite approach and proposed a new list of "supporting data," including:

h. Current and projected number of service accounts.
i. Customer class, size, and technology type, if applicable.
j. Projected aggregated load.
k. Projected percentage of load impact or reduction.
l. Nature of load being aggregated.
m. Dispatch method.
n. Historical performance data.

CEDMC and OhmConnect proposed reducing the timeline for finalizing QC values such that DR providers can contract with load-serving entities earlier in the year-ahead process. Under the proposed timelines, final QC values would be available by June 1 and July 1, respectively, prior to the RA compliance year.

The CEDMC and DSA proposals also included *ex post* performance reporting requirements. For CEDMC, the main purpose of *ex post* reporting is to provide a measurement of delivered capacity for the CPUC to complete its assessment of performance relative to commitments and, if necessary, enforce penalties. In the CEC staff proposal, *ex post* capacity measurement is assumed to be completed by a state agency or the California ISO.

DSA proposes two novel measurements of *ex post* performance, the "bid alignment metric" and "performance alignment metric." The bid alignment metric "is a ratio between historic[al] bidding values and the capability forecasted by the historic[al] [*ex ante*] model." The performance alignment metric "is a ratio between the historic[al] performance … and the planning values developed from the historic[al] *ex ante* model for the same weather and dispatch conditions." According to DSA, these metrics "can let implementers, planners, and [the California ISO] know if there needs to be an adjustment to the planning model in the long term so that there is greater alignment between actual performance and the forecasted performance" or bids.

Role of State Agencies and California ISO

Under the current processes, CPUC Energy Division staff reviews LIP reports and makes a finding as to whether claimed QC values are reasonable. The three LIP-based proposals from OhmConnect, CLECA, and DSA would maintain this role. CEDMC proposes to preserve the prerogative of the CPUC to conduct the same level of detailed review, but because of the "penalty structure in place to provide after-the-fact rigor, … it will not be necessary that the Energy Division apply the same degree of up-front rigor it uses under the LIP process." The CEC proposal takes a similar approach and suggests specific criteria under which CPUC staff waives the prerogative and approve claimed QC values. These criteria include the following:

- "[*Ex post*] capacity value is at least 90 percent of the committed capacity."
- "Requested [*ex ante*] capacity is no more than 25 percent above the [*ex post*] delivered capacity in the previous year."

CEC staff states that together, these criteria "will reduce administrative burden on both DR providers and CPUC staff, while still retaining oversight abilities in cases where a DR provider underperformed in the previous year or a significant increase in QC is requested."

The DSA proposal also included a new *ex ante* role for a central agency. DSA suggests the CPUC, CEC, or California ISO produce a "reliability risk heatmap" ahead of the RA compliance year. The heatmap would guide development of DR resources by quantifying reliability risk (for example, loss of load probability or expected unserved energy) by month and hour of day over the RA compliance year. The heatmap would be provided roughly 18 months ahead of the RA compliance year.

CEDMC recommends "the Energy Division [to] assess the monthly Demonstrated Capacity reports of each [investor-owned utility] and DR provider." CEC staff does not specify which entity would implement the penalty structure.

Additional Items

CPUC Decisions 21-06-029 and 22-06-050 asked that the CEC working group address several additional items related to supply-side DR: operational and planning space alignment, intracycle updates, and DR adders. The extent to which each of the five proposals address these items is discussed below.

Alignment of Operational and Planning Spaces

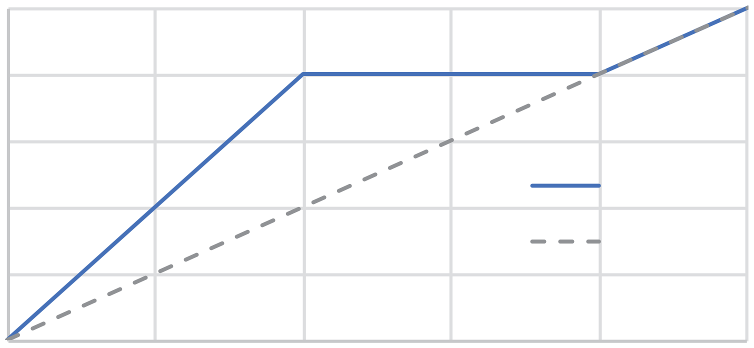
Three of the five proposals directly addressed alignment between measurement of DR events for energy market settlement and *ex ante* and *ex post* capacity valuation. These proposals included guidelines for how and when measurement baselines can and cannot differ between settlement and *ex post* analysis. Summaries of the three alignment proposals follow.

- **CEDMC** proposes that the DR provider must use the same baseline for energy settlement as the baseline used to measure demonstrated capacity.
- **DSA** proposes that the California ISO allow alternative baselines used in capacity evaluation to be allowed for settlement if they are (1) included in an evaluation plan, (2) able to be produced within the settlement period, and (3) accompanied by any code used to produce the results.
- **CEC staff** proposes using the same baseline for California ISO settlement as for capacity counting where possible but grants an exception for cases where an alternative baseline is superior but unable to be implemented within the settlement period.

CEC staff also proposed an adjustment to measured load impacts to account for the amount made available to the market through bids called *bid-normalized load impact*. This adjustment is an attempt to align planning and operations in cases where the capability of DR resources is greater than the delivered load impact simply because the resource received a partial dispatch.

Under a full dispatch, the bid-normalized load impact is equal to the delivered load impacts. Under a partial dispatch, the bid amount is adjusted by the ratio of delivered load impacts to the bid amount. The only time bid-normalized load impact can exceed the bid is when load impacts exceed the bid, regardless of the dispatch amount. Figure 2 illustrates how bid-normalized load impact would be calculated over various levels of performance under a partial dispatch of 50 MW relative to a total bid of 100 MW.

Figure 2: Graphical Illustration of Bid-Normalized Load Impact (BNLI)



Source: CEC staff analysis.

Under the CEC staff proposal, bid-normalized load impacts would be used in *ex post* regressions to calculate delivered capacity, rather than unadjusted load impacts. Bid-normalized load impacts can exceed the bid only when load impacts do. This affordance serves to balance out instances of underperformance (because DR is a resource with inherent randomness) and allow DR providers to demonstrate *overperformance* that can be used to justify larger future QC values, enabling DR growth.

Intracycle Updates

Stakeholders were asked to respond to the need for intracycle updates to DR QC values in written comments prior to the final proposals. SCE was the only stakeholder to respond, stating: "Like other third-party [DR] providers, SCE currently conducts [biannual] checks of any updates to supply-side DR QC, based on changes in enrollments for the current RA compliance year. This process should be made available for the IOU to update its supply-side DR QC values."[16]

In addition, the CEDMC proposal explicitly addressed intracycle updates. CEDMC proposes allowing DR providers to "seek QC values for up to three years in advance … to allow … [multiyear] RA contracts." That is, the "cycle" could be extended to three years, and intracycle updates could occur annually. CEDMC also proposes the timeline for such intracycle updates

---

[16] Southern California Edison. August 11, 2022. *Intra-Cycle Updates — Southern California Edison Response*, https://efiling.energy.ca.gov/GetDocument.aspx?tn=244562&DocumentContentId=78647.

overlap with new or updated QC requests "such that the Energy Division would perform one round of assessments rather than two."

Demand Response Adders

Stakeholders also separately submitted comments on the appropriateness of two categories of adders: the planning reserve margin (PRM) adders and the transmission and distribution loss factor adders. The first category, which collectively comprise the PRM adder, sum to the 15 percent historical planning reserve margin. The PRM adder includes 6 percent for operating reserves and ancillary services that has since been eliminated by CPUC Decision 21-06-029 for RA compliance year 2022, with the remainder (9 percent) split between load forecast error and forced outage rate. In the same decision, the CPUC found the load forecast error adder inappropriate to credit to DR resources but maintained the 9 percent remainder of the PRM because there was no appropriate method to distribute the remainder between load forecast error and forced outage rate. In D.21-06-029, the CPUC agreed with the Energy Division's rationale that the component associated with load forecast error should be removed. However, the CPUC stated it is unclear how the 9 percent should be divided and so opted to retain the full 9 percent portion of the PRM adder. In this same decision, the CPUC asked the CEC-led working group to provide recommendations on the PRM adder.

The second category of adders relates to reductions in losses in the transmission and distribution system attributable to a decrease in demand on the grid rather than an increase in generation. The distribution loss factor (DLF) adder is added directly to QC values, whereas the transmission loss factor (TLF) adder is grossed up and included as a credit to the California ISO. In Decision 21-06-029, the CPUC opted to retain the transmission and distribution adders but agreed with Energy Division that the CEC working group process should consider whether it is appropriate to retain the transmission adder beyond 2022.

Working group stakeholders provided input on the adders through a survey. Positions on the adders were not requested in QC proposals (though some authors included them). Results from the survey are included under the heading "DR Adders" below.

CHAPTER 3: Stakeholder Positions

Once the five written proposals were posted to Docket 21-DR-01 on September 28, 2022, the CEC requested stakeholders submit their written comments on each of the proposals. The CEC received written stakeholder comments during the week of October 17 and posted those to Docket 21-DR-01. This chapter summarizes the positions of stakeholders on each proposal based on the written comments submitted. This summary has been organized into the following key attributes: mitigating capacity overestimation risk, characteristics of DR, reporting requirements and timeline, and role of state agencies (and the ISO). The summary also examines the additional issues including alignment of operational and planning spaces, intracycle updates, and DR adders. CEC staff findings are presented in a discussion following a summary of stakeholder comments and positions on each attribute.

Mitigating Capacity Overestimation Risk

Stakeholder support for analytical *ex ante* forecasting and incentive-based approaches is largely split between third-party and investor-owned utility DR providers. Third-party representatives tended to back incentive-based approaches that reduce the difficulty, uncertainty, and cost of compliance, whereas representatives of investor-owned utilities and their customers supported analytic approaches that more closely resemble the status quo. PG&E, SCE, SDG&E, and CLECA all support the CLECA and DSA proposals, at least in general. All these stakeholders but SCE support streamlining the LIPs per OhmConnect's proposal, though there is some disagreement on how to do so. In contrast, Leap, CEDMC, and CESA support a mix of elements from the CEDMC and CEC incentive-based proposals. The California ISO "has longstanding concerns"[17] with the LIPs but also expresses some caution about an incentive-based approach.

Opponents of incentive-based approaches note they put significant responsibility on DR providers to estimate the capacity of their resources, which is an untested break from the approach taken historically. SDG&E summarizes this concern: "Outside of penalties, there is no mechanism to ensure the capability profiles submitted by DR providers are realistic. It is premature to move toward penalties."[18]

In contrast, CESA and Leap suggest that replacing extensive forecasting analysis with back-end rigor and penalties is consistent with proven methods in other ISO markets like the New

---

[17] California ISO staff. 2022. CAISO Comments on DR Working Group Proposals, page 2. https://efiling.energy.ca.gov/GetDocument.aspx?tn=246608&DocumentContentId=80867.

[18] San Diego Gas & Electric staff. 2022. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 9. https://efiling.energy.ca.gov/GetDocument.aspx?tn=246630&DocumentContentId=80926.

York ISO, PJM,[19] and ISO New England. CESA summarizes the idea behind the incentive-based approach, writing "the penalties … faced by DRPs will incentivize rational creation of proposed QC values."[20]

The DR providers that support the CEDMC proposal also found the proposed penalty structure to provide a sufficient incentive to support reliability. OhmConnect writes, "The penalty structure should be sufficiently punitive to encourage reliability, while not so severe as to exceed the value of the contract for modest under-delivery"[21] and ultimately support the penalty structure proposed by CEDMC.

However, other stakeholders found the CEDMC penalty structure to be insufficient to support reliability. SCE suggests that "full compensation for 50% performance seems too lenient, thus rendering the penalty structure largely ineffective for promoting accountability and grid reliability" and that this mechanism could simultaneously act as a barrier for "any DR provider who cannot provide up to 50% of its awarded QC."[22]The California ISO asserts "penalties under the CEDMC proposal are simply inadequate incentives for [DR providers] to perform to their QC values in real-time"[23]. Similarly, PG&E states "the proposed penalty structure is too lenient for underperformance."[24] While the CEDMC penalty was modeled on that of the PG&E capacity bidding program, PG&E notes the distinction between applying the penalty to a single program and DR resources across the board: "the [capacity bidding program] is not exempt from the LIP process in determining the QC. PG&E's proposed [capacity bidding program] penalty structure has no direct bearing on the program's QC value."[25]

At low levels of performance, however, some stakeholders found the CEDMC penalty mechanism too severe. Leap, while generally supportive of the CEDMC proposal, suggests a modification: "Instead of…dropping to a full penalty for performance below 50 [percent], the penalty should continue to scale linearly."[26] SCE argues that for new DR providers, the penalty "could act as a market-entry barrier by creating disincentives for new third-party DR providers,

---

[19] PJM is a regional transmission organization that coordinates the movement of wholesale electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

[20] CESA. 2022. *CESA's Comments on SSDR QC Working Group Proposals*, page 3, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246614&DocumentContentId=80871.

[21] OhmConnect staff. 2022. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders*, page 2, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246629&DocumentContentId=80925.

[22] Southern California Edison staff. 2022. *SCE Comments on CEC Working Group Proposals for DR QC Counting*, page 7, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246619&DocumentContentId=80876

[23] California ISO. *CAISO Comments on DR Working Group Proposals*, page 6-7

[24] Pacific Gas and Electric staff. 2022. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 2, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246609&DocumentContentId=80869.

[25] PG&E. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 2

[26] Leap staff. 2022. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*. Leapfrog Power, Inc., page 6-7, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246610&DocumentContentId=80868.

who could take quite some time to demonstrate their Claimed QC and perform up to their Awarded QC."

The California ISO signals openness to the CEC's more stringent capacity shortfall penalty, writing "the Energy Commission staff's proposed penalty proposal may be more effective to incentivize reasonable capacity valuation up front." DR providers, in contrast, tended to feel it is too severe. OhmConnect described the capacity shortfall penalty as "severely punitive,"[27] and CEDMC writes that 94.5 percent "is far too soon for a penalty to take effect because there will always be a certain degree of variability to DR performance."[28] Even CESA, which states the organization is "open to a more stringent penalty mechanism"[29] references examples that are less stringent than the proposed capacity shortfall penalty. Leap appears to believe either of the proposed penalties "would act as a sufficient deterrent to poor performance,"[30] but supports the modified CEDMC penalty described above, the most lenient of any proposal.

Mitigating Risk Discussion

Third-party DR providers have made it clear throughout the working group process that the analytical LIP-based approach is difficult, opaque, and unpredictable. CEC staff finds these concerns valid and views the current approach as untenable and unable to support a robust and sustainable market for DR in California. Furthermore, CEC observes that the working group was formed in response to the shortcomings of the status quo; the initial CPUC decision forming the working group requested CEC "to develop recommendations for a comprehensive and consistent [measurement and verification] strategy, including a new capacity counting methodology for DR addressing *ex post* and *ex ante* load impacts."[31] Other approaches and frameworks may be appropriate for valuing capacity contributions of DR. In the view of CEC staff, incentive-based approaches were the only alternatives to adaptations to the LIP-based status quo put forth in the working group process that sufficiently address these shortcomings.

Based on experience supporting CPUC Energy Division staff review third-party LIP filings and assigning QC values, CEC staff has also observed that the current process makes Energy Division staff accountable for correctly assessing DR capacity, rather than the DR providers themselves. CEC staff believes that DR providers, rather than state agency staff, should be accountable for correctly forecasting the capacity values of their own resources. Accordingly, CEC staff finds an incentive-based approach is more appropriate for ensuring credible and attainable QC values for DR resources.

---

27 OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 4

28 CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 6-7

29 CESA. *CESA's Comments on SSDR QC Working Group Proposals*, page 3

30 Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 9

31 CPUC. 2021. Decision 21-06-029. *DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2022-2024, FLEXIBLE CAPACITY OBLIGATIONS FOR 2022, AND REFINEMENTS TO THE RESOURCE ADEQUACY PROGRAM*. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

Staff notes that the idea for a performance-based penalty for DR as an alternative to the existing Resource Adequacy Availability Incentive Mechanism did not originate with CEC staff but has been recommended independently by CPUC Energy Division staff and California ISO Department of Market Monitoring staff. Department of Market Monitoring staff summarizes the reasoning:

> *A performance-based penalty or incentive mechanism could be particularly relevant for [DR] resources because of the difficulty of determining in advance whether…a new [DR] resource — or an existing provider that is selling additional new capacity — is capable of delivering load curtailment in critical hours equal to the quantity of [RA] capacity that the resource has been paid to provide.*[32]

In other words, DR capacity valuation faces an asymmetric information problem; the entity with the best knowledge of the resource capability also has an incentive to overstate that value. CPUC Energy Division staff made a similar recommendation in their DR proposals submitted under Rulemaking 19-11-009: "[The California ISO] is encouraged to explore an alternate mechanism [to RAAIM] to hold DR bidders accountable for the DR resource market bids accurately reflecting the capacity available under the applicable operating conditions associated with the specific day and hour."[33]

The main distinction between the prior penalty recommendations and CEC staff's proposal is that the proposal explicitly links the penalty mechanism to QC (or contracted and committed fraction thereof). While CPUC and California ISO staff did not explicitly recommend an incentive-based approach for *determining* QC, CEC staff finds careful definition of *ex ante* QC and *ex post* capacity measurement to be prerequisite to enforcing any performance mechanism.

CEC staff suggests that the CPUC should implement the incentive mechanism rather than the California ISO to keep *ex ante* QC determination and *ex post* capacity measurement and verification under a single central entity. As proposed, the penalty requires visibility into the contract price of DR capacity to implement. This format is appropriate for resources for which CPUC has visibility into contract prices, such as the DR Auction Mechanism. Equivalently, the penalty can be recast in terms of the amount of contracted capacity for which a DR provider is compensated in cases where the CPUC does not have and cannot gain visibility into contract prices.

As a less desirable alternative, CPUC may set a fixed penalty price per MW of capacity based on available RA contract cost data to be applied to all DR resources. However, CEC staff observes that implementing a penalty in this way would be equivalent to reducing the penalty for resources with capacity prices higher than the penalty price and increasing the penalty for lower capacity prices. This unintended effect may lead to DR contract price increases and

---

[32] California ISO. 2022. *Demand Response Issues and Performance.* http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf#search=demand%20response%20report.

[33] California Public Utilities Energy Division. 2021. *Energy Division Demand Response Proposals for Proceeding R.19-11-009,* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M378/K737/378737761.PDF.

overinflation of capacity values. While a fixed penalty price would simplify implementation and may deserve consideration, additional study is required to understand its potential consequences more fully.

Opponents of incentive-based approaches argue that that there would be no mechanism to ensure *ex ante* estimates are reasonable and that a penalty-based method is untested. However, the CEC DR QC working group was initiated in large part because of historical evidence showing that DR has not met expectations; the status quo process itself does not deliver satisfactory results. CEC staff believes an incentive mechanism is a *more* effective approach to "ensure the capability profiles submitted by DR providers are realistic,"[34] as SDG&E put it.

CEC staff also recognizes it is true that an incentive-based approach is untested in California. However, CEC staff agrees with CEDMC that an incentive-based approach is "generally consistent with that used by the PJM, ISO-New England, and New York [ISO] capacity markets in which each DR provider provides its proposed QC values."[35] Furthermore, if novel proposals are dismissed simply because they have yet to be tested, the available options are limited to those that closely resemble the current LIP process, as other proposals do.

Between the two incentive-based proposals, CEC staff finds the CEC proposed penalty structure to be more appropriate and reasonable. The CEDMC penalty, in contrast, appears insufficient to incentivize performance enough to support reliability. DR providers and their representatives strongly preferred the less stringent CEDMC penalty mechanism. The lenience of the CEDMC penalty is justified by the variability in weather and variability inherent to DR. CEDMC writes of the CEC staff penalty that "94.5 [percent] of the committed QC value…is far too soon for a penalty to take effect" because it "would very likely result in penalties for all DR providers."[36] While true, the objective of a penalty is to incentivize the desired performance, not to minimize the extent to which it is imposed on DR providers. Instead of weakening the penalty mechanism, CEC suggests more precisely accounting for differences in capabilities under varying temperature conditions to avoid penalizing DR providers for natural variability in weather (as described in Characteristics of DR below).

The primary purpose of the incentive mechanism is to ensure DR performance under critical conditions. Meeting just over half of commitments is poor performance and should be subject to a penalty beyond simply prorating the capacity payment to the delivered amount. From the perspective of policy makers, any underperformance relative to a capacity value is a failure to meet commitments to support reliability. The intent of the penalty mechanism is not to penalize DR providers, but to encourage them through incentives to forecast their capabilities accurately and deliver on their commitments.

---

[34] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 9

[35] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 2

[36] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 7

CEC staff also agrees with stakeholders that it is important to avoid the edge effect observed by Leap: "While performance of 49 [percent] and 9 [percent] are both poor, a penalty structure should be more severe for worse performance."[37] However, Leap suggests making the CEDMC penalty structure *less* stringent to reduce this effect by scaling the penalty linearly below 50 percent, rather than dropping precipitously. Instead, CEC staff finds it reasonable for the penalty to take effect at lower levels of underperformance and linearly scale such that the penalty is more severe for worse performance — precisely as the capacity shortfall mechanism proposed by CEC staff does — to eliminate edge effects and retain a robust incentive.

Relatedly, SCE similarly suggested "step-wise or incremental incentives that would incentivize DR providers to maximize the performance of their resources or portfolio."[38] Such increments appear to represent a middle ground between the linearly increasing capacity shortfall penalty and the threshold-based CEDMC penalty. However, no evidence is presented that such a structure would produce the incentives to maximize performance any better than the capacity shortfall penalty as proposed.

SDG&E argued it is "premature to assign the same penalty structure for residential and non-residential customers."[39] It is not clear to CEC staff whether SDG&E is arguing it is permanently or only temporarily inappropriate to apply the same penalty structure to both customer classes. However, CEC staff views DR capacity as a product that should be as standardized as possible, despite the diversity in underlying resources, and a single penalty structure should apply to all supply-side DR resources to create a level playing field.

However, CEC staff realizes it is important to build understanding and confidence in the approach and leave room to make modifications as necessary. DR providers can construct the *ex post* regressions with the bid, dispatch, and load impact data already available to them to begin understanding the implications of this methodology on their resources. Based on the outcomes of *ex post* analysis of prior years, DR providers can understand the likely impacts of the new methodology and process on their resources.

CEC staff initially proposed applying the penalty to all underperformance under 100 percent but added the 94.5 percent threshold both in response to stakeholder feedback and for consistency with RAAIM. SCE and CLECA noted in their comments on adders that the forced outage adder is similarly intended to create equity between DR and other resources by setting comparable standards for availability. (See DR Adder Discussion below.) Accordingly, CEC staff conducted additional analysis to understand whether one approach is preferable to the other or whether applying both approaches is appropriate (see Appendix B for detailed analysis). CEC staff concluded that replacing the 94.5 percent threshold with a 5.8 percent adder applied to effective capacity is the superior approach.

---

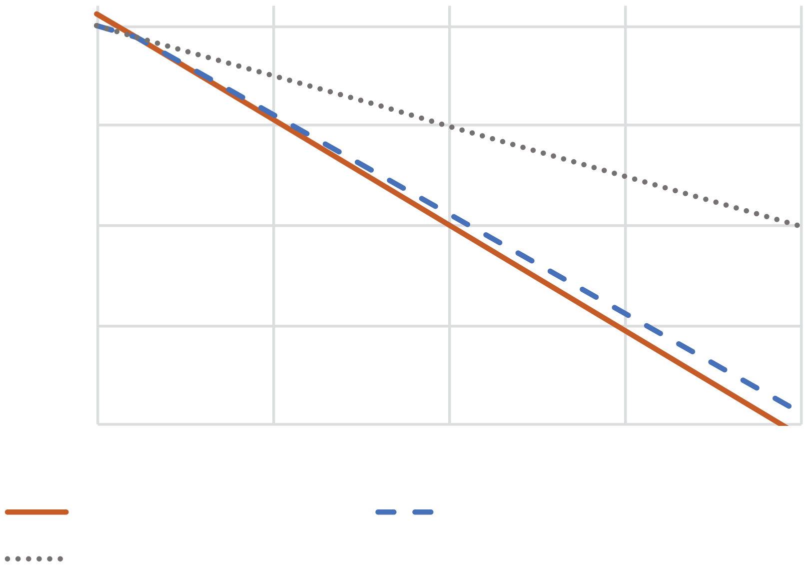
[37] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 7

[38] SCE, *SCE Comments on CEC Working Group Proposals for DR QC Counting*, page 13

[39] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 6

Figure 3 compares the capacity shortfall with the threshold as originally proposed by CEC staff and the updated version with a 5.8 percent forced outage adder proposed here. The updated capacity shortfall penalty results in a steeper line that exceeds 100 percent of demonstrated capacity.

Figure 3: Capacity Shortfall Penalty (CSP) With 94.5 Percent Application Threshold (Original Proposal) and 5.8 Percent Forced Outage Adder (Updated Proposal)



Source: CEC staff analysis.

Overall, CEC staff finds that the CSP with a 5.8 percent forced outage adder — rather than an application threshold as described in the CEC staff proposal — elegantly addresses multiple issues. First and most important, it preserves the incentive for DRPs to commit the expected capacity of their resources and no more. In contrast, the application threshold introduces an unintended incentive to overcommit. Second, the forced outage adder allows DRPs to earn the full expected capacity of their resources, so long as they can forecast the capacity value with reasonable certainty. In the absence of the adder, DRPs need perfect accuracy to be compensated for the full expected capacity of their resource.

Moreover, the forced outage adder derived from the RAAIM cutoff provides a defensible answer to the question of what value to apply. An adder of 5.8 percent is consistent with the application threshold proposed by CEC staff and less than 9 percent, the collective sum of the forced outage and forecast error adders. Finally, the adder can be embedded in the calculation of effective capacity as shown in this analysis, avoiding the need for any grossing up of QC values as credits to the California ISO.

CEC staff finds its proposal of applying the capacity shortfall penalty to the aggregation of all resources of a given DR provider and capacity product (that is, for system capacity and for local capacity in each local area) to be reasonable. For providers with multiple contracts for a given capacity product, DR resource commitments and shortfalls can be aggregated and attributed on a pro rata basis across contracts. However, the proposal can easily be applied to more granular geographic units if desired, such as to investor-owned utility service area, load aggregation point (LAP), or sub-LAP. A tradeoff exists between the need for geographic specificity in the locational marginal pricing system of the California ISO and the benefits of aggregating many, small resources, which diminishes under increasing geographic granularity. At this point, CEC staff declines to recommend more granular geographic application of the penalty, but recognizes this issue may need to be addressed by the CPUC and California ISO.

Characteristics of DR

Overall, working group members agreed on the need for variable DR capacity profiles to meet the needs of the slice-of-day framework. CLECA explains, "Both [CLECA and DSA] proposals can develop hourly shapes for DR programs, which is necessary for RA Reform."[40] The California ISO notes that even under the LIPs, which is not its preferred approach, "using hourly LIP profiles as the basis for [DR] QC values is preferable to static QC values because the former capture resource variability across the day."[41] All proposals submitted through the working group process allowed for such variability.

Nearly all stakeholders supported taking weather sensitivity into account when measuring capacity, which four of the five proposals included in some way. Stakeholders generally found the weather normalization in the LIP process acceptable and typically not the objectionable aspect of the program. For example, PG&E finds CLECA's LIP-based process for estimating hourly expected DR load reduction reasonable because it incorporates "DR performance history and weather conditions."[42]

Of the incentive-based approaches, stakeholders supported the weather normalization in the CEC proposal. OhmConnect stated that "[o]f the two proposals that combine up-front flexibility with back-end penalties, OhmConnect prefers CEC's proposal."[43] The California ISO notes the CEC proposal "expressly accounts for weather variability by treating both the *ex ante* stated capability and *ex post* performance as temperature-dependent."[44] In contrast, SDG&E notes "the [CEDMC] proposal does not address weather sensitivity of [DR] resources and is not well suited for them."

CEDMC acknowledges "weather-adjusting DR performance to account for the variable performance of weather-sensitive DR is beneficial to ensure that DR performance can be compared to a weather-normalized QC value on an apples-to-apples basis," and "sees [the CEC] approach as a reasonable alternative to its own Demonstrated Capacity proposal." However, it also argued that the CEC's "weather-adjustment element would eliminate any

---

[40] California Large Energy Consumers Association. 2022 *CLECA Comments on Supply Side Demand Response QC Methodologies*, https://efiling.energy.ca.gov/GetDocument.aspx?tn=246605&DocumentContentId=80862

[41] California ISO. *CAISO Comments on DR Working Group Proposals*, page 7

[42] PG&E. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 2

[43] OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 5

[44] California ISO. *CAISO Comments on DR Working Group Proposals*, page 6

direct connection between DR performance in the [California ISO] market and committed QC value."[45]

Similarly, CESA, which represents battery providers, supports CEDMC's proposal because weather sensitivity is a "smaller factor" for storage-backed resources. However, CESA acknowledges other resources do display weather sensitivity and "supports CEC's proposed methodologies for [*ex ante*] and [*ex post*] analysis."[46]

Furthermore, stakeholders wanted the methodology to go beyond simply accounting for temperature. After noting the treatment of weather sensitivity in the CEC proposal, the California ISO continues: "However, the Energy Commission staff's proposal does not expressly account for use and availability limitations; it instead relies on a penalty mechanism to incentivize availability."[47] Similarly, SDG&E notes, "The [CEC] proposal addresses weather sensitivity and hour of day but does clearly address how other characteristics of DR are incorporated."[48]

DR Characteristics Discussion

Accounting for weather sensitivity and measuring resource capabilities under temperatures where reliability concerns are likely to arise is critical to valuing the contribution of DR to reliability. While not all DR resources display weather sensitivity, a viable DR QC method must have the *ability* to take weather sensitivity into account.

The CEDMC proposals attempts to avoid the weather normalization issue by taking the best performance by hour, which will likely occur under the hottest (or possibly coldest) conditions for weather-sensitive resources. CEC staff agrees with the assessment of PG&E that the approach is "highly upward biased and inconsistent with other QC methodologies."[49] Maximum performance is not the same as typical performance, even after adjusting for temperature. Accordingly, the CEC staff finds the CEDMC proposal of defining *ex post* hourly capacity by the best day or maximum performance unreasonable.

The weather normalization process implied in the LIPs is generally appropriate, but the application is opaque and difficult to reproduce, leaving policy makers largely reliant on the attestation of DR providers to certify QC values. In its proposal, CEC staff attempted to formalize and make explicit this process for weather normalization included in the LIPs. Stakeholders have observed that the proposal is consistent with the status quo. This similarity is a deliberate attempt to carry forward elements of the LIPs that are appropriate rather than fully reinvent the process.

---

[45] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 6

[46] CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 5

[47] California ISO. *CAISO Comments on DR Working Group Proposals*, page 6

[48] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 13

[49] PG&E. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 2

CEC staff attempted to include a significant amount of flexibility for resources that show weather sensitivity to higher temperatures, lower temperatures, both, or neither, with more complexity required to model resources with more weather sensitivity. However, some stakeholders such as PG&E believe the proposal is overly prescriptive. SDG&E similarly observed the proposal does not account for characteristics such as decay over the course of a dispatch. CEC staff is open to incorporating additional capability profile specifications to accommodate a greater diversity of DR resources. However, defining *in advance* how such specifications will be implemented and translated into hourly *ex post* capacity values consistent with the *ex ante* "worst day" is critical to the functioning of the CEC staff proposal.

Accordingly, CEC staff finds it reasonable to include a process to adopt new capability profile types for use in the RA program. New capability profiles should be incremental to those included in the CEC staff proposal and should be shown to account for resource characteristics not accounted for in the default set. Decay over multihour dispatches is a reasonable example to include, particularly for resources with large first-hour effects such as those backed by smart thermostats or other air-conditioning controls.

A note of caution on new capability profile specifications is warranted, however. More complex model specifications require more data simply to run, let alone to generate valid results. For a simple weather-dependent resource, Leap notes that if "in the month of January there were only 2 events, the *ex ante* projection for January would be based on little actual event data."[50] For specifications with additional variables, decisions must be made to handle instances when there are insufficient data to run the full model.

For example, CEC staff specified handling weather-sensitive resources with a single *ex post* data point by assigning that load impact value as the *ex post* capacity. Consider a model specification for weather-sensitive resources with first-hour effects (described above). If adopted, an additional decision must be made regarding whether to model load impacts as a function of temperature or dispatch hour when there is insufficient data to do both, and whether it is reasonable for the DR provider to choose. With additional variables, the number of such decisions grows. CEC staff sought to minimize such decisions in its proposal but recognizes it may be appropriate to include additional flexibility.

CEC staff also affirms stakeholders' recommendation to include negative load reductions such as precooling and snapback (collectively, "takeback"). SDG&E writes that "[p]recooling and [snapback] effects should be accounted for"[51] in the QC method and included in showings only if they occur within the "RA window" (that is, the availability assessment hours). The California ISO characterizes the DSA and CLECA proposals as "incremental enhancements to *status quo* LIPs by accounting for load pre-cooling and snapback effects."[52] The CEC staff proposal

---

[50] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 4

[51] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 18

[52] California ISO. *CAISO Comments on DR Working Group Proposals*, page 1

includes showing precooling and snapback effects two hours before and after the call period by default.

CLECA and SDG&E request including "call limitations" and "max event duration," respectively. CEC staff believes these concerns are addressed simply by showing a resource no longer than the associated maximum dispatch duration. For example, a resource with a 4-hour maximum dispatch within a 9-hour call window should only be shown for the four hours it is likeliest to be dispatched on the worst day (and include takeback effects before and after, where appropriate). Accordingly, CEC staff believes the CEC proposal accounts for these DR characteristics.

Reporting Requirements and Timeline

Nearly all stakeholders support simplification of the current LIP process to improve transparency and shorten the QC timeline. OhmConnect, having authored the proposal for streamlining the LIPs, "strongly opposes increasing the time, cost, and complexity of an already burdensome process."[53]

However, not all agreed on exactly how or to what extent to streamline the LIPs. SCE opposed OhmConnect's streamlined LIP proposal altogether, and SDG&E and PG&E opposed the elimination of protocols pertaining to *ex post* metrics for non-event-based DR. CLECA advocated more generally for a review from the Energy Division on which LIP elements are essential. SCE suggested that DR providers could request exemptions as opposed to eliminating protocols in the current LIPs.

CEDMC's proposal affords DR providers the most flexibility in reporting, which Leap suggests "would shorten the timeline from when DRPs submit estimates of Year Ahead QC …[and] allow DRPs to confidently, and accurately, contract with LSEs throughout the summer months when most bilateral contracts are signed."[54]

CEC staff's proposed hourly capability profile is more complex than the single hourly values proposed by others. PG&E found "that the methodology is overly prescriptive and generates a large amount of output not critical to the QC."[55] Stakeholders provided relatively little commentary on the reporting format required to implement the capability profile; CEC staff understands stakeholders may have been confused on the capability profile. SDG&E observed that "making the proposal more concise and clear would help make it more understandable."[56]

However, CEC staff attempted to address the increase in reporting requirements by allowing flexibility in how capacity is aggregated across resources and across the year into groups of months referred to as "seasons." Leap "agree[s] that aggregating by season is a good

---

[53] OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 4

[54] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 6

[55] PG&E. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 3

[56] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 12

[workaround,] and we would recommend this approach be included under any proposal that requires fine toothed *ex ante* projections."[57]

Stakeholders expressed some interest in the bid and performance alignment metrics proposed by DSA, but nearly all were unclear on how these metrics would be incorporated into QC and RA processes. The California ISO wrote that "[a]lthough such metrics could indicate how availability and use-limitations impact the resource's availability, DSA does not propose that parties use these new metrics to inform QC values."[58] Similarly, Leap notes, "DSA's proposal would increase the complexity and cost of the analysis without speaking to the implementation of the new information."[59] CLECA is similarly "concerned about additional cost related to the performance metrics … since they are not necessary for QC determination."[60] CESA emphasizes: "[U]nless the … [metrics] will be used … in a formal venue …, CESA cautions against requiring excessive analysis that is not used for planning."[61] SCE explains the issue in additional detail:

> *Methodologies to quantify any difference between either the historical bids or recent* [*ex post*] *and historical* [*ex ante*] *used to inform RA planning do not align DR measurement and verification methods in the operational space for [California ISO] market settlements with methods of determining DR QC for RA planning purposes. The metrics simply demonstrate whether there has been alignment between either the historical bids or recent Ex Post and the historical Ex Ante (p. 6).*

The California ISO expressed interest in having the additional data outlined in DSA's proposal but found it "unclear how this additional data [would] be used to inform QC values"[62] regarding the time-temperature matrix. OhmConnect describes the time-temperature matrix (and the metrics described above) as "add[ing] too much complexity and cost to an already burdensome exercise."[63]

Many working group stakeholders expressed concern with the complex reporting requirements that effectively require outsourcing LIP analysis to external contractors. CEDMC expressed this concern for whichever methodology is ultimately selected: "[I]f consultants are required to implement the new methodology, then the DR providers … may be hesitant to incur the cost until observations can be made with regard to the [investor-owned utilities'] experiences with

---

[57] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 8

[58] California ISO. *CAISO Comments on DR Working Group Proposals*, page 5

[59] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 5

[60] CLECA. *CLECA Comments on Supply Side Demand Response QC Methodologies*, page 6

[61] CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 6

[62] California ISO. *CAISO Comments on DR Working Group Proposals*, page 7

[63] OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 4

it."[64] CESA similarly notes that "[g]iven the amount of analysis and limited number of consultants that can conduct a LIP, the entire process for QC determination typically lasts over nine months and costs hundreds of thousands of dollars."[65]

Accordingly, stakeholders expressed the desire for a methodology requiring little or no external support from consultants. Stakeholders generally agreed that the CEDMC proposal would not require consultants and the three LIP-based proposals would. Stakeholders were less clear on whether they would be required under the CEC staff proposal. CEDMC argues that "all of the other proposals [not submitted by CEDMC] utilize a temperature-dependent adjustment to QC values which makes the *ex post* analysis process far more complicated and expensive due to the resulting need to retain consultants to perform the associated analysis."[66] CLECA writes the CEC staff proposal "would also require the use of consultants, which is a complaint of the third-party DR providers. It is also unclear if the cost to perform the regressions would be more or less expensive than the current LIP."[67] Leap, in contrast, found the CEC staff proposal "substantially simpler and more flexible than the LIPs, [but] it is unclear at this time if it is something that Leap can do internally, or if an external consultant will still need to be retained."[68]

Reporting Requirements Discussion

CEC staff recognizes that the reporting requirements of the LIPs have been a burden and a barrier, particularly to third-party DR providers who are not compensated for costs associated with the process and who tend to have more dynamic customer portfolios.

At the same time, the minimum possible reporting requirements will necessarily increase under the slice-of-day framework from single monthly values to up to 24 monthly values. The slice-of-day table proposed by DSA is an appropriate and reasonable format to convey these values. Moreover, CEC recognizes its proposal would require additional parameters that define the capability profile (specifically, any change points).

The CEC staff proposal addresses the increase in reporting requirements by allowing one capability profile to apply to multiple months as defined by a DR provider. CEC staff notes that CEDMC refers to this flexibility as "to-be-determined 'seasons' comprised of a handful of months,"[69] apparently implying these seasons will be prescriptively determined for all DR

---

[64] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 10

[65] CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 2

[66] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 9

[67] CLECA. *CLECA Comments on Supply Side Demand Response QC Methodologies*, page 7

[68] Leap. *LEAPFROG POWER, INC COMMENTS ON THE DEMAND RESPONSE QUALIFYING CAPACITY COUNTING PROPOSALS*, page 8

[69] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 7

providers. Instead, the intent of the CEC staff proposal is to allow DR providers to define any set of months as a "season."

Accordingly, CEC staff finds it reasonable to reduce supporting data reporting requirements. However, stakeholders have argued that some *ex ante* documentation should still be required, and no proposal eliminated such supporting information completely, especially during the transition to an incentive-based process. CEC staff finds the reporting requirements outlined by CEDMC and OhmConnect reasonable. However, given the proposed move away from the LIPs, the supporting information proposed by CEDMC is a more appropriate starting point. CEC staff does not propose eliminating the LIPs for purposes unrelated to QC of supply-side DR, such as for long-term IOU resource planning and for load-modifying DR.

CEDMC recommends requiring the following supporting information, all of which CEC staff finds reasonable to include:

- Current and projected number of service accounts.
- Customer class, size, and technology type, if applicable.
- Projected aggregated load.
- Projected percentage of load impact or reduction.
- Nature of load being aggregated.
- Dispatch method.
- Historical performance data.

CEC staff defers to CPUC on the refinement and definition of these requirements. In addition to the information listed above, CEC staff recommend also requiring a customer energy baseline measurement plan for DR providers that use a different baseline than for wholesale market settlement. Borrowing from the LIPs (Protocols 9–10), these DR providers should include error metrics for day matching, regression method, or other baseline method as appropriate from historical or non-event data (particularly for new resources) to support the use of the alternative baseline. The plan would be subject to approval by CPUC Energy Division staff and, upon approval, be considered binding for *ex post* measurement.

Other proposed reporting requirements are extraneous and should not be adopted. The time-temperature matrix proposed by DSA largely accomplishes the same objective as the capability profile proposed by CEC staff. However, CEC staff proposed the form of a continuous function rather than a stepwise table to avoid gamesmanship in how resources are shown to respond to temperatures. Furthermore, characteristics such as event decay can be incorporated into capability profiles (as proposed in DR Characteristics Discussion). A time-temperature matrix can easily be derived from a capability profile if a DR provider finds it helpful, but a capability profile cannot necessarily be derived from a time-temperature matrix.

Similarly, the bid alignment metric and performance alignment metric proposed by DSA are sensible and may be appropriate components of a viable alternative QC methodology. DSA recognizes that "stakeholders may want additional discussion and the opportunity to test [the metrics] in practice before [they are] adopted."[70] However, DSA did not specify what adoption

---

[70] Demand Side Analytics. *Demand Response Qualifying Capacity Working Group Proposal.*, page 15

of these metrics would entail other than calculating them for reference. CEC staff does not oppose exploring inclusion of these metrics into a QC method, but as written they would not affect *ex ante* or *ex post* capacity counting in a meaningful way.

CEC staff believes the overall timeline can be shortened to meet the QC finalization milestones proposed by stakeholders. Earlier in the year is preferable to enable planning and contracting, so planning for June 1 is ideal, but July 1 is reasonable if the earlier date is not possible, especially in the first few years of implementation.

In the view of CEC staff, there are three main reasons consultants are required in the current process. Consultants possess technical expertise required to produce results, they have experience completing LIP reporting requirements, and they act at arm's length to DR providers to reduce the conflict of interest inherent in requesting QC values. CEC staff believes an incentive-based approach can reduce much of the reporting requirements and is a more resilient method of addressing conflict of interest, eliminating the latter two needs. However, it is not clear whether DR providers wish to eliminate the need for technical expertise. CEC staff views statistics, economics, and data science as fundamental to operating a robust DR market. Accordingly, DR providers should be expected to compensate individuals with that expertise, but CEC staff takes no position on whether that expertise should be held by in-house employees or contracted consultants.

Role of State Agencies and California ISO

Stakeholders that addressed the CEC staff proposal to adopt criteria for streamlined QC approval supported the change. SDG&E "also agree[s] with the recommendation for a streamlined approval for DR providers and resources that have a proven track record."[71] CESA similarly "agrees with the CEC that this streamlining will likely significantly reduce the administrative burden associated with reviewing any [*ex ante*] QC analysis."[72]

CESA also supported the DSA recommendation of "the release of risk allocation (*e.g.*, loss of load probability) for the state so that DRPs can be better informed as to where their resources may be most needed."[73]

Stakeholders expressed desire for more clarity on who will implement a proposed penalty if one is adopted. The California ISO writes that the CEDMC proposal "fails to specify who will be responsible for administering any penalties," and the CEC staff proposal "does not clearly define who will be responsible for administering the proposed penalty structure."[74] OhmConnect also urged the CEC to "recommend that any penalty structure be centrally administered,"[75] rather than be enforced by load-serving entities.

---

71 SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 8

72 CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 7

73 CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 8

74 California ISO. *CAISO Comments on DR Working Group Proposals*, page. 6-7

75 OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 2

Role of State Agencies and ISO Discussion

CEC staff observes that while few stakeholders directly addressed the streamlined QC approval criteria in the CEC staff proposal, no stakeholders registered opposition or suggested alternate criteria. CESA observed that while the streamlining criteria reduce administrative burden, "underperforming DRPs and large changes to QCs can be appropriately assessed by Energy Division."[76] CEC staff agrees with this assessment and finds the streamlined QC approval reasonable.

CEC staff finds the publication of a risk allocation heatmap for the state to be a potentially useful exercise, but one that is not critical to developing QC values under the slice-of-day framework. Similar studies are completed in other planning and reliability exercises; these studies can guide DR resource design.

CEDMC specified in its proposal that "Energy Division would assess" demonstrated capacity and implies Energy Division would accordingly administer the penalty. CEC staff agrees with OhmConnect's observation that "[m]any [load-serving entities] are small and do not have the resources to administer a penalty structure. Placing such a burden on these entities will raise the cost of doing business with DR providers."[77] CEC staff agrees that central administration of the penalty mechanism is preferable and that the CPUC is the appropriate entity to approve QC values and administer the penalty.

Alignment of Operational and Planning Spaces

Stakeholders provided relatively little feedback on proposal elements intended to align DR counting in the planning and operational spaces, other than by stakeholders that reiterated positions in their proposals. CESA expresses support for "the use of the [California ISO] settlement methodology to evaluate QC performance given that it increases transparency, aligns market performance, and represents a methodology familiar to [DR providers]."[78]

SDG&E opposes the bid-normalized load impact adjustment proposed by CEC staff, asserting the "metric introduces an asymmetric, downward bias in assessing performance."[79] SCE opposes any use of bids for the opposite reason, arguing that "[a] bid is not necessarily reflective of the maximum capacity of a weather-sensitive resource during the first hour of an event; nor do bids account for the actual decline of load impacts delivered over subsequent hours of an event."[80]

Operational and Planning Alignment Discussion

The CEC staff proposal for alignment is intended to be a reasonable middle ground between the proposals to use California ISO settlement baselines in *ex post* analysis (CEDMC) and vice

---

[76] CESA. CESA's Comments on SSDR QC Working Group Proposals,, page 5

[77] OhmConnect. Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders, page 2

[78] CESA. CESA's Comments on SSDR QC Working Group Proposals,, page 4

[79] SDG&E. Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group, page 12

[80] SCE, SCE Comments on CEC Working Group Proposals for DR QC Counting, page 11

versa (DSA). CEC staff recognizes that while consistency between settlement and capacity valuation is desirable, California ISO baselines in regular use are “heuristics” that are “not well suited” for weather-sensitive resources, as described by SDG&E. On the other hand, any baselines used for California ISO settlement must be shown to be tariff-compliant, so simply submitting methods documentation and code ahead of time is insufficient to allow the baseline to be used in settlement. CEC staff observes that if a desired baseline method is submitted to the California ISO and approved as tariff compliant, using that baseline for settlement and *ex post* evaluation would be consistent with all three alignment proposals.

More important, the DSA proposal adds an element of inequity between third-party and utility DR providers. SCE comments highlight this potential inequity when rightly observing that comparison groups are often preferable to other common baselines:

> *For [investor-owned utilities], which can identify non-participants, the option of establishing a [comparison] group baseline to assess performance of its DR program should still be present, especially if it can produce more robust results of performance for weather-sensitive residential DR programs (p. 9).*[81]

The utilities themselves have access to nonparticipant data; third-party DR providers do not. CEC staff hopes to make comparison group baselines available to third-party DR providers eventually but is unlikely to be able to do so within the settlement period, at least within the next few years.

The CEC proposal attempts to clarify the existing logic for when different baselines may be used for settlement and *ex post* evaluation, rather than inventing a new process. Under CEC staff’s proposal, a third-party DR provider would be able to use a day-matching or weather-matching baseline for settlement and *ex post* evaluation. They would *also* be able to use a comparison group or similar method for *ex post* evaluation, even if it requires waiting longer than the settlement period for the CEC or other entity to generate the baselines. If the utilities can apply comparison group baselines for both settlement and *ex post* evaluation, they should do so for consistency in measurement.

CEC staff disagrees with the assertion by SDG&E that the bid-normalized load impact metric produces a “downward bias” on load impacts. SDG&E explains its position with an example: “If a DR resource is called for 60 MW, but delivers 80 MW, the overperformance is ignored.”[82] However, SDG&E does not specify the amount bid. Consider the bid-normalized load impacts of SDG&E’s example under two bid amounts:

- 70 MW bid: The maximum function takes the 80 MW delivered, resulting in 80 MW of bid-normalized load impacts.

---

[81] SCE refers to nonparticipant group baselines as “control groups.” CEC staff refers to these groups as “comparison groups” to distinguish them from control groups, which consist of enrolled participants who are withheld from participation for the purposes of developing a baseline.

[82] SDG&E. Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group, page 9

- 90 MW bid: The function recognizes that while the resource was only called for 60 MW, it exceeded its obligations, resulting in bid-normalized load impacts of 90 MW, its full bid amount.

In both cases, bid-normalized load impacts are greater than or equal to the actual load impacts. Indeed, CEC staff is more sensitive to SCE's argument that the bid-normalized load impact metric produces an *upward* bias on load impacts, particularly for partial dispatches. This concern appears to stem from a current issue for DR that DR resources have a must-offer obligation to bid the entire QC. To avoid dispatch of the full must-offer obligation, DR providers bid most of this capacity at or near the bid cap under conditions when that capacity is unlikely to be available (for example, on temperate days). While the proposal may *allow* DR providers to continue this practice, it will not *require* them to do so to avoid financial penalties.

A second reason to include bid normalization is equity between economic proxy demand response (PDR) and emergency reliability demand response resources (RDRR). High-bidding PDR functions like RDRR in that it is dispatched when there is an insufficiency or near insufficiency of bids in the market to serve load. While RDRR may bid economically in the market, it is not required to do so. Failing to account for the PDR capacity made available to the market through bids would improperly penalize PDR relative to RDRR, particularly for resources that bid across a range of prices, for being more regularly available to the market.

However, CEC recognizes that, as proposed, the bid-normalized load impact metric is generous in its evaluation of DR load impacts, particularly for underperformance in partial dispatches. Accordingly, CEC recommends an additional prerequisite for calculating bid-normalized load impacts: bid-normalized load impacts will be calculated and included in the *ex post* regression only if the dispatch amount is 20 percent or more of the bid amount.

This cutoff will require DR providers dispatch a significant portion of resource capability into the market to develop data points for the *ex post* regression. It also caps the ratio of actual load impacts to bid-normalized load impacts to one to five, preventing extremely high bid-normalized load impacts from being generated by extremely small dispatches. This feature provides some protection against overinflation of *ex post* capacity values from both bidding gamesmanship and fundamental statistical properties of small populations of dispatched customers.

CEC staff further clarifies that only customers in dispatched resources would be counted toward bid-normalized load impacts. That is, customers that are not dispatched by the California ISO, such as those in other sub-LAPs, but deliver load impacts cannot compensate for underperformance by customers in dispatched resources.

Intracycle Updates

In general, stakeholders found a single midyear intracycle update to be sufficient. For example, SDG&E writes, "[T]he proposed QC methodology should be able to produce a mid-year QC updated value."[83] CESA expressed support for the timeline proposed by CEDMC that

---

[83] SDG&E. *Comments on Demand Response Qualifying Capacity Proposals Submitted to the Working Group*, page 15

would allow for midyear updates: "The Council proposes that claimed QC or [intrayear] updates be submitted to the CPUC by April 1 of each year and that Energy Division would provide a final QC value by June 1 of each year."[84] PG&E similarly recommended, "[T]he load impact filing in April 2023 should be used to inform the QC updates in the 2023 RA compliance year."[85]

The investor-owned utilities requested the update process be available to them, not just third-party DR providers. For example, SCE commented the intracycle update "process should also be made available for the IOU[s],"[86] consistent with the intracycle update proposal submitted by the utility.

Stakeholders also recommended revisiting the criteria for updating QC values (greater of 10 MW or 20 percent) during the RA compliance year. CEDMC expressed "strong concerns about the … unreasonably high threshold to trigger an update."[87] SCE notes these criteria apply to the "program level rather than portfolio level," so "[d]epending on the capacity (MW) provided by the supply-side DR resource, the net change due to enrollment at the portfolio level may not meet or exceed the [threshold]."[88] CEDMC recommended lowering the thresholds to the greater of 10 percent or 5 MW.

OhmConnect recommends deferring this issue to the RA proceeding. It notes that the topic of intracycle updates "was discussed only very briefly" and that appropriate recommendations for intracycle updates "depend heavily on the type of QC methodology that is ultimately adopted."[89]

Intracycle Updates Discussion

CEC staff agrees with the near-consensus that one midyear update is sufficient. If a new QC methodology and process shorten reporting QC finalization timelines as proposed by OhmConnect and CEDMC, updated QC values should be available to include in RA showings for July or August at the latest, consistent with the timing of California's critical peak needs. Midyear updates should be accessible to IOUs and third parties to provide equity between providers.

CEC staff believes it is reasonable to relax the threshold required to complete a midyear update. Presumably, applying the *maximum* of capacity or percentage was intended to reduce the number of midyear updates that CPUC Energy Division staff was required to review because the process was difficult and time-consuming. Ideally, under a faster, more streamlined approach, such limitations will not be necessary. The threshold can be decreased

---

[84] CESA. *CESA's Comments on SSDR QC Working Group Proposals*,, page 5

[85] PG&E. *PG&E Comments on the final Supply Side Demand Response QC Proposals*, page 5

[86] SCE, *SCE Comments on CEC Working Group Proposals for DR QC Counting*, page 12

[87] CEDMC. *California Efficiency + Demand Management Council Comments on Supply Side Demand Response Working Group Phase 2 Proposals*, page 10

[88] SCE, *SCE Comments on CEC Working Group Proposals for DR QC Counting*, page 12

[89] OhmConnect. *Informal Comments of OhmConnect on Demand Response ("DR") Qualifying Capacity ("QC") Proposed Methodology, Intra-Cycle QC Updates, and Adders,* page 5

by changing the maximum of the two criteria to the minimum. For example, a 10 MW resource would be eligible for an updated value with a change of 2 MW, and a 100 MW resource would be for a change of 10 MW. CPUC may also consider decreasing one or both criteria as suggested by CEDMC.

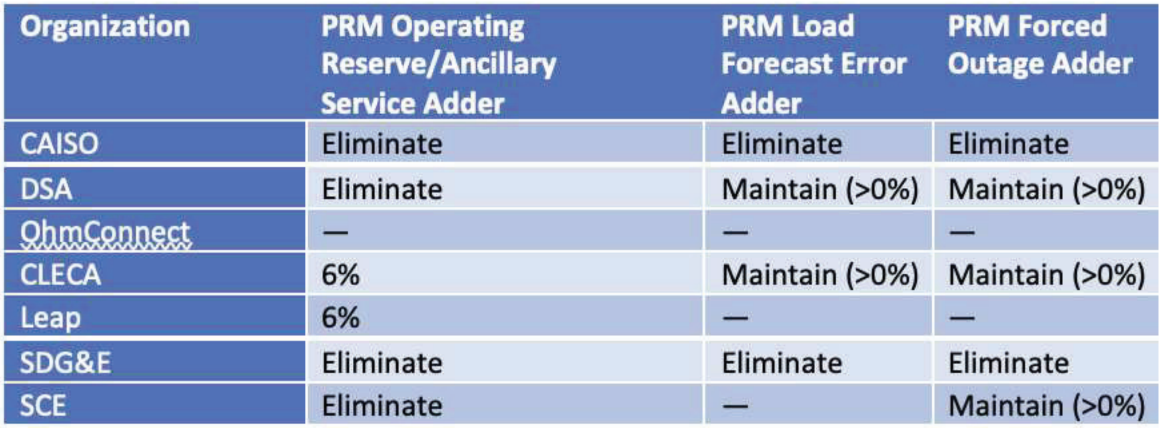
CEC staff recognizes OhmConnect's concerns and suggests the preceding changes as sensible defaults. They may be reexamined and updated within the RA proceeding of the CPUC. However, no stakeholders expressed strong desire or need for intracycle updates beyond the single midyear update.

DR Adders

Working group members provided feedback on the adders included in QC values or as an additional credit to the California ISO by survey. Not all stakeholders responded to the survey, and not all those that did provided a position on every question.

Table 2 summarizes stakeholder positions on the PRM adders. A slim majority of respondents supported eliminating the adder for operating reserves and ancillary services, consistent with CPUC Decision 21-06-029. Respondents appeared most ambivalent on the load forecast error adder, with respondents split and nearly half declining to comment. Responses to the forced outage rate were similar, with one more respondent in favor of maintaining the adder than eliminating it.

Table 2: Stakeholder Positions on PRM Adders



Organization	PRM Operating Reserve/Ancillary Service Adder	PRM Load Forecast Error Adder	PRM Forced Outage Adder
CAISO	Eliminate	Eliminate	Eliminate
DSA	Eliminate	Maintain (>0%)	Maintain (>0%)
OhmConnect	—	—	—
CLECA	6%	Maintain (>0%)	Maintain (>0%)
Leap	6%	—	—
SDG&E	Eliminate	Eliminate	Eliminate
SCE	Eliminate	—	Maintain (>0%)

Source: Survey of DR QC working group participants

CLECA offered the only arguments in support of retaining the PRM adder in its entirety "on the grounds that capacity requirements are determined as peak load plus the PRM." In its view, supply-side and load-modifying DR should be treated the same as they both "effectively create an additional capacity margin by reducing load." In support of including the forced outage component, CLECA writes, "DR's QC is based upon historical performance, which include non-performance."[90]

The California ISO argues that it is inappropriate to include any component of the PRM adder because "[t]he presence of supply side [DR] does *not* reduce the [California ISO's] reserve requirements day to day." Rather, "the PRM adder inappropriately assumes [DR] would reduce procurement for load forecast error," and "there is no evidence…demonstrating that…[DR] reduces generator forced outages, or the amount of capacity [load-serving entities] must procure to account for those outages."[91]

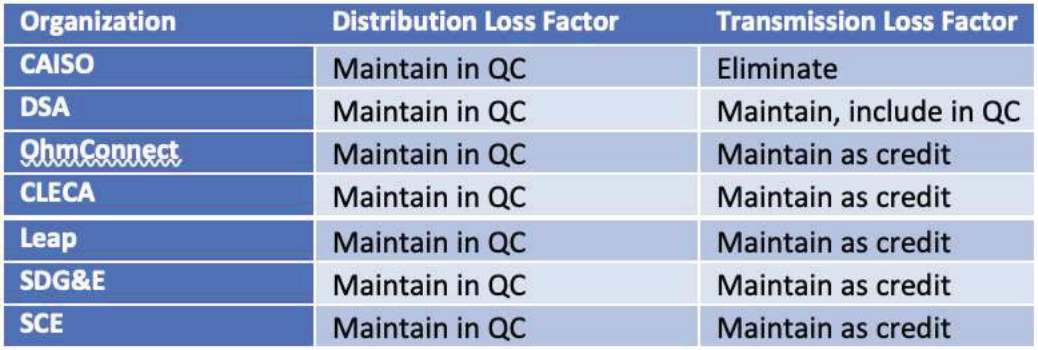
Stakeholders more nearly reached consensus on the transmission and distribution loss factor adders, as summarized in Table 3. All stakeholders found the DLF reasonable and appropriate to include directly in QC values.

---

[90] CLECA. *CLECA Comments on Supply Side Demand Response QC Methodologies*, page 9

[91] California ISO. *CAISO Comments on DR Working Group Proposals*, page 3

Table 3: Stakeholder Positions on Transmission and Distribution Loss Factor Adders



Organization	Distribution Loss Factor	Transmission Loss Factor
CAISO	Maintain in QC	Eliminate
DSA	Maintain in QC	Maintain, include in QC
OhmConnect	Maintain in QC	Maintain as credit
CLECA	Maintain in QC	Maintain as credit
Leap	Maintain in QC	Maintain as credit
SDG&E	Maintain in QC	Maintain as credit
SCE	Maintain in QC	Maintain as credit

Source: Survey of DR QC working group participants

All but the California ISO found the TLF reasonable and appropriate to include as a gross-up credit to the California ISO. CLECA argued that TLF adder should be retained because "[t]he load forecast is at the transmission level, so the load impact at the meter should be grossed up for distribution losses to calculate [QC] losses."[92] The California ISO, the only stakeholder in favor of eliminating the TLF adder, suggests "other distribution-side resources do not receive a transmission adder … [and] [t]he loss factor adder for [DR] is unduly preferential." The California ISO argues that "a single, static avoided transmission loss factor does not accurately represent node-specific and dynamic congestion benefits across the year." Perhaps even more important, the record establishing the TLF adder values is insufficient; according to the California ISO, "[The attachment] to the Ruling [establishing the TLFs] lists avoided transmission and distribution loss factors 'supplied by the CEC,' but there is neither reference to the specific [CEC] study nor explanation how these factors were calculated."[93]

DR Adder Discussion

CPUC has previously found in Decision 21-06-029 that the components of the PRM adder associated with operating reserves and load forecast error are inappropriate to include for DR QC values. CEC staff finds the arguments for removing these adders reiterated by stakeholders, including the California ISO, persuasive.

CEC staff also finds it reasonable to include the PRM adder component associated with forced outages. SCE provides an argument similar to CLECA's for maintaining the forced outage component:

> *The LIP process accounts for forced outages (or non-performance) by looking at actual historical performance ([ex post]). If the historical performance was impacted by an outage (or non-performance) affecting the ability to curtail load, then the LIP will forecast a lower response rate. In other words, the LIP methodology already includes and de-rates DR for forced outages. To not apply*

---

[92] CLECA. *CLECA Comments on Supply Side Demand Response QC Methodologies*, page 8

[93] California ISO. *CAISO Comments on DR Working Group Proposals*, page 4-5

> *the forced outage adder of PRM, when LIP is used to estimate DR QC, would be de-rating the DR capacity twice and valuing it unfairly. (p. 15)*

CEC staff's experience reviewing QC requests and LIP filings is inconsistent with the view of SCE and CLECA that nonperformance is included in QC values. For example, at least one LIP filing reviewed by the CEC team dropped events from its *ex ante* analysis where technical or communication errors prevented end-use customers from responding to dispatches from the ISO. It may have been appropriate to drop such points for *ex ante* valuation for the following year if the technical issue had been resolved, but the *ex ante* analysis did *not* reflect those outages.

CEC staff finds it reasonable to maintain the forced outage rate adder because under the framework recommended in this report, SCE's statement *would* be correct. The CEC staff proposal includes an explicit comparison of actual (*ex post*) performance with *ex ante* commitments that would incorporate the kinds of outages described above. Furthermore, based on this observation, CEC staff finds the adder a *more* appropriate adjustment to the capacity shortfall penalty than the 94.5 percent threshold as originally proposed by CEC staff, but it is inappropriate to include both. (See Appendix B.)

If the forced outage rate adder is found appropriate, the issue remains of how much of that amount to attribute to the forced outage rate. The forced outage rate and forecast error components collectively comprise the remaining 9 percent of the PRM adder. CPUC previously declined to apportion the adder between the two components and instead maintained the entire 9 percent. CEC staff finds it reasonable to apply a 5.8 percent adder for forced outages (implemented as a multiplier of 1.058). This value is derived from the reciprocal of 94.5 percent (105.8 percent), implying an adder of 5.8 percent. (See Appendix B.)

CEC staff finds the transmission and distribution loss factor adders reasonable to maintain, as supported by nearly all stakeholders. While the California ISO cautions against including the TLF because it results in inequitable treatment between DR and other distributed resources, CEC staff suggests that it may be appropriate to include a TLF adder to other distributed resources rather than remove it from DR. However, CEC staff is sensitive to the concern that the record on the TLF values themselves is insufficient. A new study of avoided transmission losses from DR — and perhaps other distributed resources such as solar or storage or both — is warranted. Until such a study has been completed, CEC staff does not opine on whether to maintain the TLF, or at what value, in the interim.

CHAPTER 4: CEC Recommendations

The CEC's final findings and recommendations provided here consider the proposals received (Chapter 2) and stakeholder comments on the proposals (Chapter 3). These recommendations are informed by staff's experience reviewing and analyzing the 2022 LIP filings, which were submitted by DR providers.

CEC staff has served in a collaborative, advisory role with CPUC staff in all RA proceedings as designated by CPUC decisions. CEC recommends the continuation of its role to support the implementation of these recommendations.

1. **Apply a consistent QC framework and methodology across DR resources.** Create consistency among investor-owned utility programs, third-party DR contracts, and DR Auction Mechanism resources by applying these recommendations broadly to DR resources.
2. **Adopt an incentive-based approach.** CEC staff recommends moving away from the analytical forecast approach represented by the LIP process and finds the status quo approach unsustainable. Fundamental to the LIP format, QC results are variable in interpretation, time consuming, and difficult for both DR providers to produce and CPUC staff to review. The lengthy timeline of the LIP process makes securing contracts and making QC improvements difficult for DR providers. Since producing LIP filings will likely remain an expensive undertaking, many DR providers have no guarantee of recouping that cost. Under the status quo approach, CPUC Energy Division staff — rather than DR providers— is accountable for the DR provider results with no recourse when DR resources underperform. CEC staff believes that an incentive-based approach is the only viable alternative that addresses issues with the status quo LIP-based approach. A performance-based incentive mechanism for DR has been recommended by CPUC Energy Division staff and the California ISO Department of Market Monitoring.
3. **Adopt the capacity shortfall penalty incentive mechanism with forced outage adder.** Of the two incentive-based proposals considered by the working group — the CEDMC proposal and the CEC staff proposal — CEC staff recommends the capacity shortfall mechanism proposed by CEC staff as the most viable and capable of delivering high performance to support reliability. The proposed penalty increases steadily with underperformance, avoiding the edge effect present in the CEDMC proposal.
   The capacity shortfall penalty was developed under a theoretical framework to encourage DR providers with incentives to accurately forecast the actual expected capacity of their resources. The penalty design accounts for the fundamental variability of DR and provides the same affordances for forced outages and other forms of underperformance granted to all resources under the RAAIM while preserving the incentive for DR providers to accurately value and reliably operate their resources.

   The capacity shortfall penalty can be implemented in terms of cost ($) where contract prices are known, such as for the DR Auction Mechanism, or in terms of capacity (MW) where they are not. As a less desirable but simpler alternative, a single reference shortfall penalty price applied across all DR resources may be considered.

4. **Adopt the *ex ante* capability profile and *ex post* regression approach proposed by CEC staff.** The temperature-dependent regression approach accounts for temperature variability during the compliance year and allows more accurate adjustment for weather-sensitive resources. The CEC recommends the adoption of the temperature-dependent regression-based approach, which represents weather-sensitive resources and provides an incentive for consistent performance better than simpler proposals such as the "best hour" approach recommended by CEDMC. The CEC approach also allows DR providers to use simpler methods when modeling weather sensitivity is unnecessary.

   CEC staff recognizes the diversity of DR resources and considerations specific to different DR providers and recommends adopting the profile types proposed by CEC staff and continuing a stakeholder process to adopt additional parameters as needed.
5. **Require resources to show takeback.** Showing takeback affords DR similar treatment to other resource types such as battery storage. A requirement to show negative impacts outside a dispatch window should also be incorporated as outlined by CLECA and DSA.

   CEC staff does not believe additional changes are required to distinguish between dispatches and spillover of load reduction as proposed by CLECA and DSA. Rather, these load reductions can be shown as part of the hourly capacity values of the resource, rendering the distinction unnecessary.
6. **Require DR providers to submit capability profiles and "slice-of-day" table to summarize QC values.** DR providers submit a capability profile that applies to every combination of month and hour for which they are seeking a QC value. Capabilities may include sensitivity to hot temperatures, cold temperatures, both, or neither, as well as a first-hour effect.
   The slice-of-day table proposed by DSA conveniently summarizes *ex ante* QC values by hour and month. These QC values, plus takeback in surrounding hours, should be directly derived from *ex ante* capability profiles.
7. **Reduce reporting requirements for QC determination.** Require submission of information needed to determine QC values, including the DR resource IDs submitted for QC approval, specifications for how they will be aggregated, capability profiles for each aggregation including seasons, change points, and first-hour effects.
   CEC staff recognizes that some documentation of ex ante forecasts and assumptions is reasonable to require, particularly during the transition to an incentive-based framework. Also require the supporting information outlined by CEDMC, as well as a customer energy baseline measurement plan for DR resources that do not use the same baseline for California ISO market settlement and *ex post* measurement.
8. **Plan to produce final QC numbers by June 1 preceding the RA compliance year.** CEC staff appreciates the need for a shorter timeline for DR providers to receive final QC valuation to facilitate year-ahead planning and contracting. Based on the recommended reporting and process changes, target completion of the QC valuation process by June 1. However, allow flexibility if needed to produce values by July 1, particularly during the first few years of transition.

9. **Adopt streamlined QC approval criteria.** Approve QC values for all months and hours that the DR provider has demonstrated at least 90 percent of its committed capacity and is requesting no more than a 25 percent increase from its demonstrated capacity for that hour and month in the previous year. CEC staff recognizes that CPUC Energy Division staff always retain the prerogative to conduct detailed analysis of submissions, but these are reasonable thresholds to waive that prerogative for DR providers that have a consistent performance record and reasonable growth values.
10. **The CPUC should implement the proposed penalty mechanism and the California ISO should exempt DR from the RAAIM.** The CPUC should administer the capacity shortfall penalty for DR. The CPUC can implement the methodology for the DR Auction Mechanism resources and utility DR programs.

    With the capacity shortfall penalty in place, the CEC recommends the California ISO exempt supply-side DR from the RAAIM. RAAIM exemption is consistent with treatment of other variable resources such as wind and solar but was not feasible in the absence of an appropriate incentive mechanism.
11. **Phase in the incentive-based approach over time.** CEC staff finds it reasonable to reduce or waive the penalty in the first year of implementation (RA compliance year 2025) to allow DR providers to gain experience with the new framework. CPUC Energy Division staff should ensure all aspects of the proposal are implemented in the first year, including calculating *ex post* capacity and determining prospective penalties. During the phase-in period, CPUC may require elements of the LIPs, such as those enumerated in OhmConnect's proposal. CEC staff recommends the CPUC maintain the discretion to extend the phase-in period based on the success and acceptance of the new approach.

    CEC staff also recommends that CPUC Energy Division staff continue to collaborate with CEC and California ISO staff on implementation details and to host one or more workshops to discuss the proposed approach in more detail so DR providers can prepare for and transition into the new process.
12. **Require DR providers to use the same baseline for settlement and *ex post* evaluation unless an alternative is more accurate but unable to be used for settlement.** Measurement consistency between settlement and *ex post* evaluation should be preferred by default. However, CEC staff realizes that feasible ISO-approved baselines are often insufficient, particularly for weather-sensitive resources. More accurate methods may require longer to implement, especially when additional data is required.
    This recommendation is framed as a qualitative guideline rather than a prescriptive standard because proving whether these criteria are met is difficult. However, CEC staff believes it is important for policy makers to articulate implementation preferences.
13. **Adopt bid normalization for load impacts in *ex post* capacity valuation.** For calculating delivered capacity, apply the bid-normalized load impact metric proposed by CEC staff to avoid penalizing DR providers for partial dispatches, to preserve equity between economic and reliability DR, and to reduce opportunities for gamesmanship. Apply bid normalization to dispatches of 20 percent or more of the amount bid and discard dispatches of less than 20 percent from the *ex post* capacity valuation process.

14. **Reduce the threshold required for midyear QC update.** Rather than require a change of the greater of 10 MW or 20 percent, allow midyear QC updates for DR resources or portfolios with changes of *either* 10 MW or 20 percent. The current threshold is a barrier to updates for large and small resources alike. Additional intracycle updates appear unnecessary but can be explored in the RA proceeding, if desired.
15. **Eliminate the components of the PRM adder associated with operating reserves and load forecast error.** CEC staff generally agrees with the conclusion in D.21-06-029 that these components are inappropriate to include.
16. **Convert the forced outage adder to a multiplier applied in the capacity shortfall penalty.** CEC staff recommends the equivalent of a 5.8 percent adder for forced outages consistent with other RA resources. However, the forced outage adder can be converted to a multiplier of 1.058 included in the effective capacity formula of the capacity shortfall penalty rather than as a credit sent to the California ISO.
17. **Maintain the distribution loss factor adder in QC values.** CEC staff supports the unanimous view of working group stakeholders that distribution loss factors are appropriate to include in DR QC values.
18. **Update transmission loss factors and include the adder as a credit.** CEC staff supports the near-unanimous view that transmission loss factors are appropriate to gross up as a credit to the California ISO. DR is typically deployed when grid usage and attendant transmission losses are high, and this characteristic should be valued.

    Conduct a follow-up transmission loss factor study including factors for other distributed energy resources such as battery storage to allow equity between distributed resources. CEC staff declines to take a position on whether the current values should be maintained or eliminated until a study is completed.

APPENDIX A: Principles

Introduction

As an additional means of evaluating proposals, the working group developed a set of principles that a qualifying capacity method should meet. A final set of nine principles developed by the working group were posted to Docket 21-DR-01 on May 2, 2022.[94]

The principles are listed in the next section. A subsequent section presents the results of a principles survey provided to working group participants.

Principles

The following nine principles represent the final set adopted by the CEC's demand response qualifying capacity working group. These principles are intended to provide an additional means of evaluating QC methodology proposals. Each principle should be considered independently of all others when applied to a given QC methodology proposal. A proposal may score highly by some principles and poorly by others, which helps make tradeoffs between the various options visible.

1. The QC methodology should be transparent and understandable.
2. The QC methodology should use best available information regarding resource capabilities, including recent historical performance and participant enrollment and composition projections.
3. The QC methodology should allow DR providers to quickly determine or update QC values.
4. The QC methodology should be consistent and compatible with the resource adequacy program.[95]
5. The QC methodology should account for any use limitations, availability limitations, and variability in output of DR resources.
6. The QC methodology should translate a DR resource's load reduction capabilities into its reliability value.
7. The QC methodology should include methods to determine delivered capacity (*ex post*) that are compatible with the determination of qualifying capacity (*ex ante*).
8. The QC methodology should not present a substantial barrier to participation in the RA program.
9. The QC methodology should account for a resource's capacity when reliability needs are highest.

---

[94] California Energy Commission staff. 2022, *DR QC Counting Methodology Principles*, https://efiling.energy.ca.gov/GetDocument.aspx?tn=242909&DocumentContentId=76492

[95] CEC planned to accommodate multiple possible slice-of-day proposals. By the time the working group completed this exercise, however, the 24 slice-of-day framework had been selected by the CPUC and working group members rated proposals relative only to this framework.

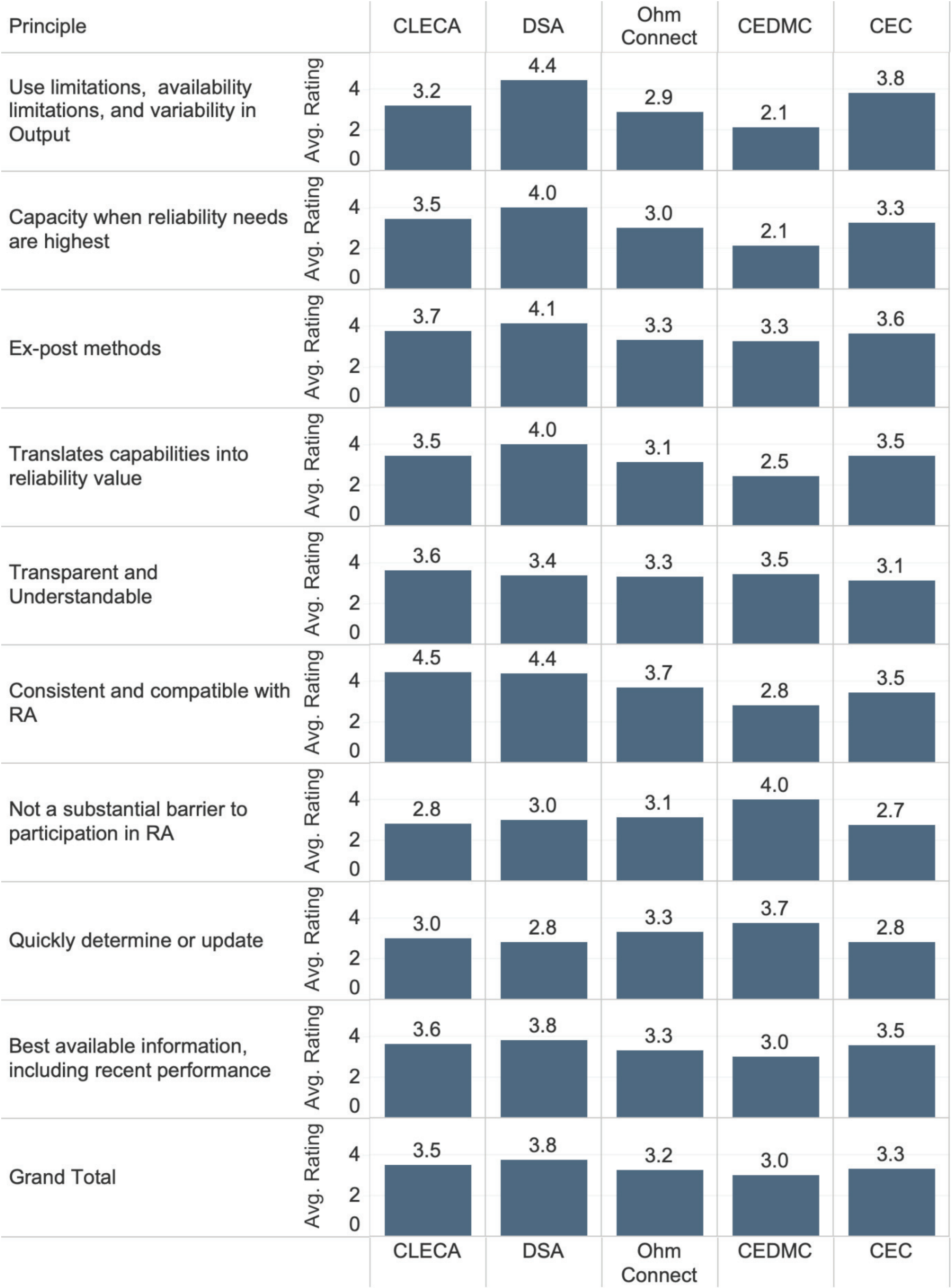
Survey Results

Once the five proposals were submitted by stakeholders and posted to Docket 21-DR-01, CEC staff provided a survey to working group participants on September 28, 2022. CEC staff requested that respondents rate how much they agree (or disagree) that each proposal meets or aligns with each of the nine principles on a five-point scale. The survey closed October 4, 2022, and the results were discussed during a meeting of the working group October 6, 2022. The results were aggregated so that no respondent is identified.

The results are only intended to be a guide for stakeholder discussion and should not be considered conclusive for several reasons. First, only a subset of working group participants responded to the survey, and the respondents were not necessarily representative of the working group. Respondents included Sunrun, SCE, CEC staff, SDG&E, California ISO, Leap, DSA, PG&E, CEDMC, Olivine, and CLECA. Of these 11, 5 were directly or indirectly involved with at least one of the two LIP-based proposals that scored highest overall (DSA and CLECA). Second, some respondents did not rate all five proposals.

Additionally, some respondents may have misinterpreted some of the principles. OhmConnect observes that "the final set of principles appears to be interpreted differently by different entities." CEDMC similarly concluded "that stakeholders applied far different interpretations to most of the principles." CLECA also "noted that parties had different interpretations on what a principle meant and how it should be applied to a proposal." With these caveats in mind, the results are provided in Figure 1 on the following page.

Figure 1: Aggregated Survey Results



Source: Principles survey of working group participants

APPENDIX B: Capacity Shortfall Penalty

An incentive mechanism known as the Capacity Shortfall Penalty (CSP) is put forth as an alternative to the current incentive mechanism in the California ISO markets, the Resource Adequacy Availability Incentive Mechanism (RAAIM). The RAAIM is assessed based on bids under must-offer obligation (MOO) hours, currently the availability assessment hours (AAH). However, the RAAIM requires resources to bid their shown QC in each AAH. This incentive mechanism generally appears sufficient for traditional dispatchable generation resources that can produce a constant output over many hours; if a natural gas power plant bids 100 MW for five consecutive hours, it is highly likely to deliver that power if called upon to do so.

DR resources are fundamentally different and only some types of DR can deliver sustained constant load impacts over many consecutive hours. Even so, variable DR resources can provide significant capacity contributions. The incentive mechanism differs from the RAAIM by applying to the *ex post* measured capacity relative to the shown or otherwise committed capacity, which is in turn limited by the *ex ante* qualifying capacity. In doing so, it accounts for actual performance where applicable. This feature is critical to ensure DR providers cannot avoid penalties under a RAAIM-style system by bidding the contracted capacity value and purchasing the difference in the spot market.

Theoretical Framework

The CSP is defined as the product of any shortfall in demonstrated capacity relative to the contracted capacity, the market price for capacity, and a penalty parameter. The shortfall *S* is defined as:

$$S = \max\left(Cap_{Com} - Cap_{Dem}, 0\right)$$

Where Cap_{Com} is the committed capacity (typically, the shown capacity), and Cap_{Dem} is demonstrated capacity. Note the maximum function ensures DR providers face a penalty for delivering below the capacity award, but do not receive a bonus for surpassing it. The overall CSP is defined as the product of the shortfall (*S*), the price of capacity (*P*), and a multiplier (λ) that adjusts the relative intensity of the penalty:

$$\begin{aligned} CSP &= \lambda\, P\, S \\ &= \lambda\, P \max\left(Cap_{Com} - Cap_{Dem}, 0\right) \end{aligned}$$

Under this proposal, the capacity revenue for a DRP is given as the demonstrated capacity less the CSP:

$$\begin{aligned} Revenue &= P\, Cap_{Dem} - \ CSP \\ &= P\, Cap_{Dem} - \lambda P \max(Cap_{Com} - Cap_{Dem}, 0) \end{aligned}$$

Demonstrated capacity can be rewritten as the committed capacity minus the shortfall, which simplifies as follows:

$$Revenue = P\, (Cap_{Com} - \max(Cap_{Com} - Cap_{Dem}, 0)) - \ \lambda P \max(Cap_{Com} - Cap_{Dem}, 0)$$

$$= P\,(Cap_{Com} - \max(Cap_{Com} - Cap_{Dem}, 0) - \lambda \max(Cap_{Com} - Cap_{Dem}, 0))$$

$$= P\,(Cap_{Com} - (1 + \lambda) \max(Cap_{Com} - Cap_{Dem}, 0))$$

That is, revenue is the price of the committed capacity times a large factor that represents committed capacity less the shortfall once for adjusting for demonstrated capacity (the 1 component of 1+ λ) and an *incremental* penalty for the shortfall (λ).

The objective of the DRP is to maximize revenue. Note that because the capacity price P_{Cap} is constant, the DRP will maximize revenue if it maximizes the large term, deemed "effective capacity," which is defined as the contracted capacity less the product of λ and the amount by which, if any, the DRP fails to meet the capacity award:

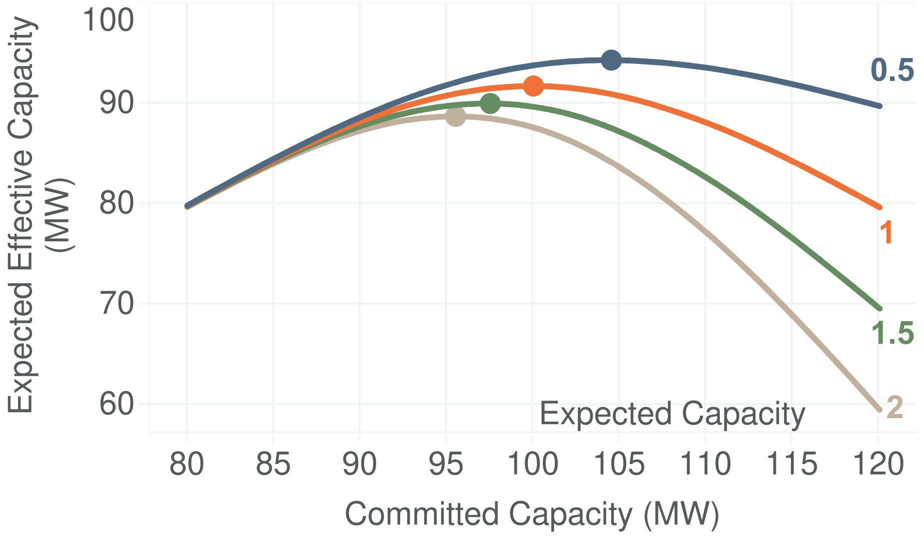
$$Cap_{Eff} = Cap_{Com} - (1 + \lambda)\ \max(Cap_{Com} - Cap_{Dem}, 0)$$

In other words, effective capacity is the equivalent amount of capacity for which the resource is compensated after applying the penalty. When λ = 0, the effective capacity is equal to demonstrated capacity for resources that underperform relative to their contracts, so only values of λ > 0 are considered to truly be considered a penalty.

A critical challenge of DR resources is that the demonstrated capacity is subject to future uncertainty and cannot be known precisely ahead of time. To account for this uncertainty, demonstrated capacity can be represented by random values from a normal distribution with known mean and standard deviation. CEC staff modeled a DR resource with mean 100 MW and standard deviation 10 MW to find the DR provider's optimal commitment for the resource under varying penalty parameter values to understand its impact.

Figure B- shows the expected effective capacity as a function of awarded capacity for each value of λ, with the mean value (vertical line) shown for reference. Expected capacity tends to increase with awarded capacity at low levels when there is little risk of not meeting the obligation. Expected capacity begins to decrease as the penalty begins to outweigh the increased award.

Figure B-1: Optimal Capacity Commitment by Penalty Parameter



Source: CEC staff analysis.

When λ < 1, the optimal capacity award exceeds the expected value of the, as the top line (blue) does for λ = 0.5. When λ = 1 (orange), the optimal award amount is equal to the median and expected value. When λ > 1 (green and gray), the optimal award amount is less than the median and expected value. A penalty parameter of 1 is therefore recommended because it provides the incentive to contract as much as but no more than a resource is expected to provide.

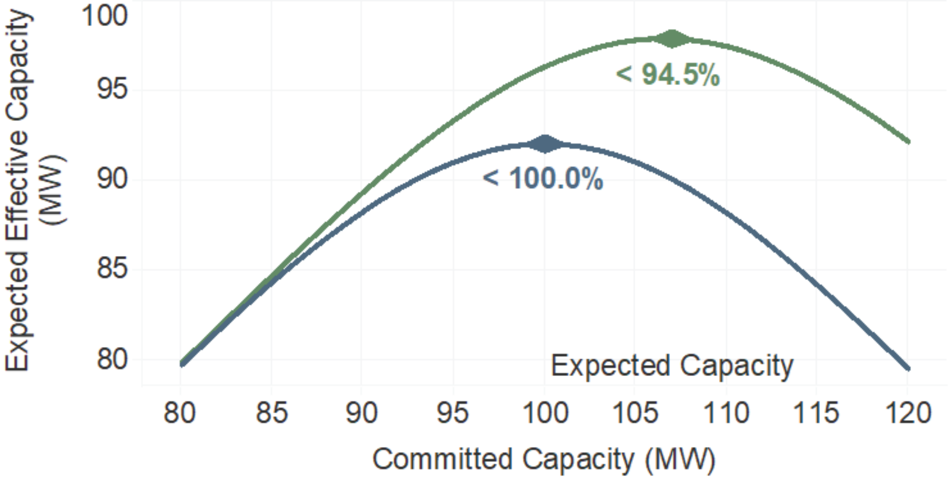
Forced Outages and Consistency with RAAIM

Unlike the penalty mechanism demonstrated above, the RAAIM applies only below 94.5 percent of shown capacity. This feature acknowledges the impossibility of perfect availability and sets a target for reasonable availability that penalizes or rewards resources for being less or more available. Accordingly, CEC staff included the 94.5 percent cutoff for consistency in the final CSP proposal (no cutoff was included in the draft proposal). However, stakeholders that advocated for including a forced outage adder remarked that the forced outage adder largely fulfills the same role of accounting for a reasonable rate of forced outages. This is particularly important when forced outages (or parallel forms of underperformance) are embedded in the QC methodology.

This section explores the impacts of adopting a penalty application threshold and/or a forced outage adder within the CSP construct.

Figure B-2 shows the optimal capacity commitment behavior with and without the application threshold of 94.5% of committed capacity under the penalty parameter of λ = 1. Including the application threshold has the effect of increasing the optimal committed capacity for DRPs to claim, similar to decreasing the penalty parameter. However, it also increases the effective revenue to closer to the expected capacity of the resource.

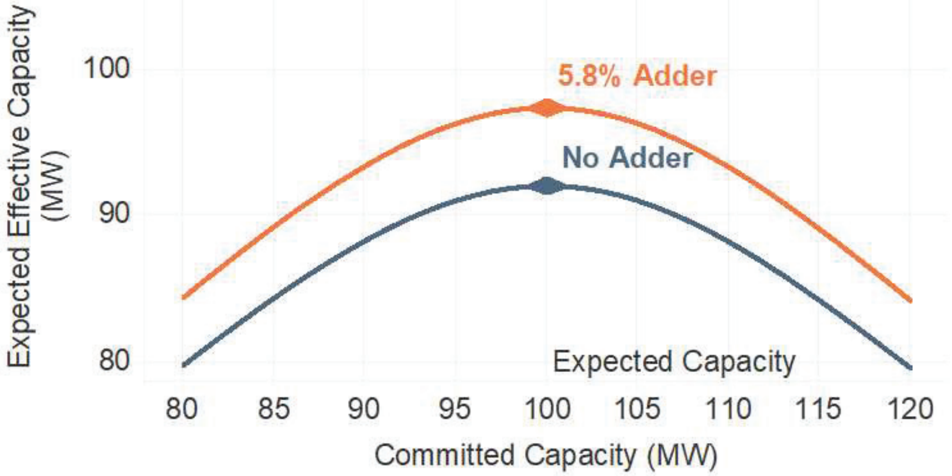
Figure B-2: CSP with and without 94.5% application threshold



Source: CEC staff analysis

A forced outage error is modeled as a multiplier to the effective capacity based on the draft CSP (with no application threshold). Figure B-3 shows optimal capacity commitment behavior with and without a forced outage. For consistency with RAAIM, the forced outage adder is set to 5.8%, the reciprocal of the 94.5% cutoff (minus one).[96] Under an adder, the optimal committed capacity remains at the expected capacity and the expected effective capacity (the amount the DRP will be compensated for) increases closer to the expected capacity.

Figure B-3: CSP with and without 5.8% forced outage adder



Source: CEC staff analysis

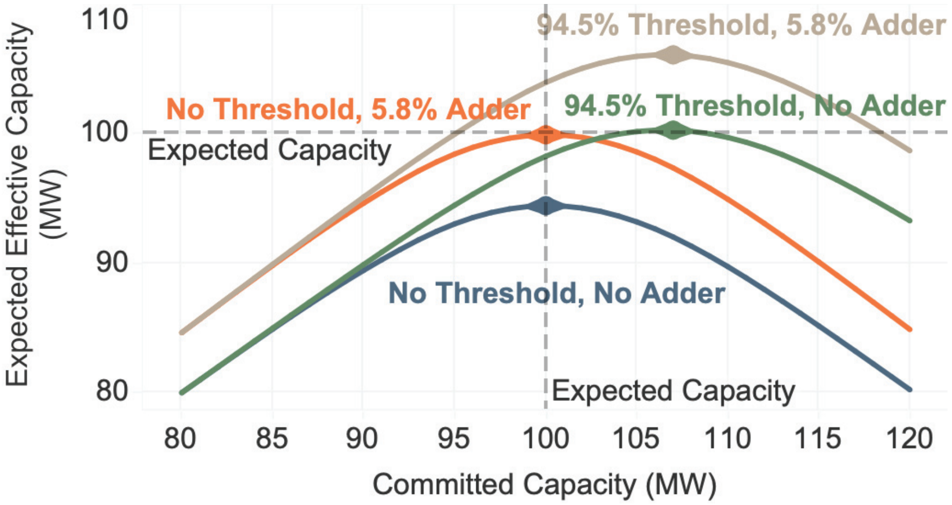
The amount by which the expected *effective* capacity (that is, the capacity value after taking the penalty into account) differs from the expected capacity of the resource depends on the amount of variability in the resource. In this analysis, the variability is modeled as the standard deviation of the distribution of possible capacity outcomes. The expected effective capacity of the resource modeled up until this point (standard deviation of 10 MW) does not quite reach its expected capacity (100 MW).

DR resources with less variability will have higher effective capacity under the CSP. The case of a 100 MW DR resource with standard deviation of 7 MW is instructive. Figure B-4 shows the optimal capacity commitment of this resource under the CSP with no adjustments, with the 94.5% threshold (as proposed), with a 5.8% forced outage rate adder applied, and with both. In all cases, the penalty parameter λ = 1.

---

[96] (1/0.945)–1 = 0.058 = 5.8%

Figure B-4: CSP variations with DR resource of standard deviation 7 MW



Source: CEC staff analysis

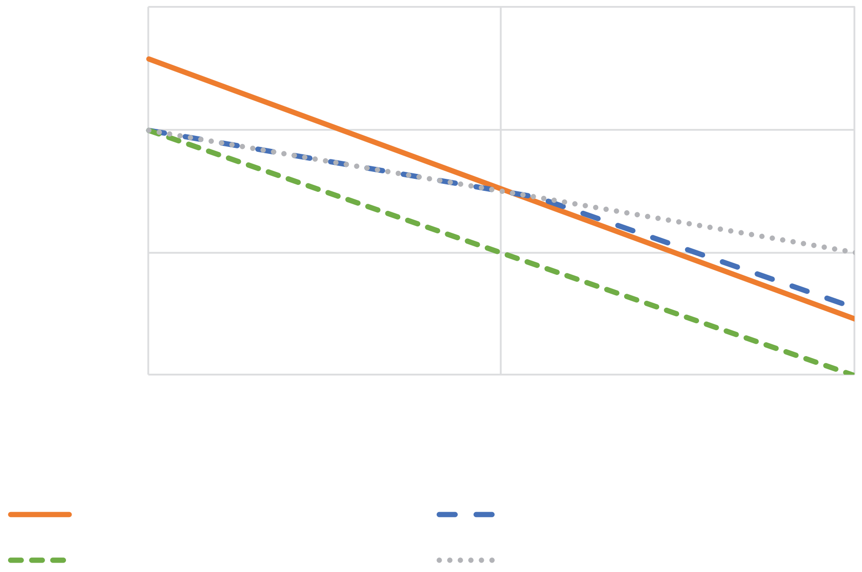
At this reduced level of variability, the DR resource will have an expected effective capacity of almost exactly 100 MW under either penalty design. However, the optimal capacity commitment under the threshold increases to 107 MW, compared to 100 MW under the adder — precisely the expected capacity of the resource. While the expected *effective* capacity changes with resource uncertainty, the optimal capacity commitment is always 100 MW, avoiding the distortionary effect caused by the threshold and incentivizing DRPs to commit no more than their expected capacity. Under both the threshold and the adder, the DRP both incentivized to overcommit and financially overcompensated for doing so. Accordingly, including both accommodations for forced outages is inappropriate and can be ruled out.

Note the expected effective capacity of the resource without adder or threshold is 94.5 MW, the amount initially targeted by the threshold (94.5% of 100 MW). That is, the DR resource will be compensated for 100% of its committed capacity so long as it meets 94.5% of its commitment, the desired outcome.

Another small difference from the threshold approach is that under the adder, a resource with even less uncertainty relative to its expected capacity will be earn an expected effective capacity *greater* than its expected capacity (over 100 MW in this example). This feature is consistent in motivation with RAAIM, which allows RA providers to be rewarded for overperformance relative to a standard.

The adder approach is more generous in response to minor underperformance than either the draft CSP or the proposed CSP with threshold. Figure B-5 shows the three variations of the CSP — with a forced outage adder, an application threshold, and neither (the draft version) — from 90–100% of committed capacity. The draft CSP, which does not take forced outages into consideration at all, is the most stringent of the three in this range. From 94.5–100%, the adder approach is the most generous, but below 94.5% becomes slightly more stringent than the CSP with penalty. Only under severe underperformance (<50% of committed) does the CSP with adder become the more stringent of the three.

Figure B-5: Comparison of CSP variations at low levels of underperformance



Source: CEC staff analysis

Overall, CEC staff find that the CSP with a 5.8% forced outage adder — rather than an application threshold as described in the CEC staff proposal — elegantly solves multiple issues. First and most importantly, it preserves the incentive for DRPs to commit the expected capacity of their resources and no more. In contrast, the application threshold introduces an unintended incentive to overcommit. Second, the forced outage adder allows DRPs to earn the full expected capacity of their resources, so long as they can forecast the capacity value with reasonable certainty. In the absence of the adder, DRPs need perfect accuracy to be compensated for the full expected capacity of their resource.

Additionally, the forced outage adder derived from the RAAIM cutoff provides a defensible answer to the question of what value to use. An adder of 5.8% is consistent with the application threshold proposed by CEC Staff and less than 9%, the collective sum of the forced outage and forecast error adders. Finally, the adder can be embedded in the calculation of effective capacity as shown in this analysis, avoiding the need for any grossing up of QC values as credits to the California ISO.

APPENDIX C: Acronyms and Abbreviations

Acronym	Term
CBP	Capacity Bidding Program
CEDMC	California Energy + Demand Management Council
CLECA	California Large Energy Consumers Association
DR	Demand Response
DRAM	Demand Response Auction Mechanism
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
ISO	Independent System Operator
LIP(s)	Load Impact Protocols
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRA	Local Regulatory Authority
LSE	Load-Serving Entity
PDR	Proxy Demand Resource
QC	Qualifying Capacity
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource

APPENDIX D: Glossary

CAPACITY BIDDING PROGRAM – An investor-owned utility DR program that is managed by third-party aggregators responsible for designing their own DR program as well as customer acquisition, marketing sales, retention, support, and event notification tactics.

CALIFORNIA ENERGY + DEMAND MANAGEMENT COUNCIL – A statewide trade association of non-utility companies that provide energy efficiency, DR and data analytics products and services in California.

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION – An organization of large electricity customers located in California who all participate in the Base Interruptible Program.

DEMAND RESPONSE – Providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use, particularly during peak demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues.

DEMAND RESPONSE AUCTION MECHANISM – Aggregated DR solicited by investor-owned utilities from third-party aggregators and bid directly into the California ISO market by third-party aggregators, typically as Proxy Demand Resources.

EFFECTIVE LOAD CARRYING CAPABILITY – A metric used to assess the capacity value or reliability contribution of electricity resources.

EXPECTED UNSERVED ENERGY – A measure of the amount of customer demand that cannot be supplied due to a shortage of electricity generation.

INDEPENDENT SYSTEM OPERATOR – An entity regulated by the Federal Energy Regulatory Authority that operates transmission facilities and dispatches electricity resources, but has no financial interest in these facilities or resources.

INTEGRATED ENERGY POLICY REPORT – A California Energy Commission report that contains an integrated assessment of major energy trends and issues facing California’s electricity, natural gas, and transportation fuel sectors. The report provides policy recommendations to conserve resources, protect the environment, ensure reliable, secure, and diverse energy supplies, enhance the state’s economy, and protect public health and safety.

INVESTOR-OWNED UTILITY – A private company that provides a utility, such as water, natural gas, or electricity, to a specific service area. The investor-owned utility is regulated by the California Public Utilities Commission (CPUC).

LOAD IMPACT PROTOCOLS – A set of guidelines comprised of 27 protocols that are used to estimate the aggregate load drop impacts of DR programs. The Load Impact Protocols provide guidance on how to measure the historical (*ex post*) performance of DR programs which informs the future (*ex ante*) performance of DR programs.

LOAD SERVING ENTITY – Any entity that has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-use consumers of electric power.

LOCAL REGULATORY AUTHORITY – The state or local governmental authority, or the board of an electric cooperative, responsible for the regulation or oversight of a utility.

LOSS OF LOAD EXPECTATION – The expected number of hours per year that available generation capacity will be inadequate to supply customer demand.

LOSS OF LOAD PROBABILITY – The likelihood (probability) that system demand will exceed the generating capacity during a given period.

MEASUREMENT & VERIFICATION - Measurement and verification for DR means the determination of the demand reduction quantities.

PROXY DEMAND RESOURCE – Economic DR comprised of a load or aggregation of loads that bid into the California ISO market under normal operating conditions.

QUALIFYING CAPACITY – The maximum Resource Adequacy capacity that an electricity resource may be eligible to provide to the California ISO. The criteria and methodology for calculating the Qualifying Capacity of resources are established by the CPUC or other applicable Local Regulatory Authority.

RELIABILITY DEMAND RESPONSE RESOURCE – Emergency DR comprised of a load or aggregation of loads that bid into the California ISO market during supply-shortage conditions.

RESOURCE ADEQUACY – The ability of electricity resources (supply) to meet the customers' energy or system loads (demands) at all hours within a study period.

RESOURCE ADEQUACY AVAILABILITY INCENTIVE MECHANISM – A mechanism through which the California ISO assesses nonavailability charges and provides availability incentive payments to Resource Adequacy resources based on whether the performance of these resources falls below or above, respectively, defined performance thresholds.

RESOLUTION NO: 23-0125-10

STATE OF CALIFORNIA

STATE ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

RESOLUTION ADOPTING QUALIFYING CAPACITY OF SUPPLY-SIDE DEMAND RESPONSE WORKING GROUP FINAL REPORT

WHEREAS, the CPUC issued Decision 21-06-029, in Rulemaking 19-11-009 concerning resource adequacy on June 25, 2021, which requested the CEC to launch a stakeholder working group process and make recommendations for a new capacity counting method for supply-side demand response; and

WHEREAS, the CEC launched a stakeholder working group process in July 2021 and engaged with stakeholders throughout 2021 and early 2022 to develop interim recommendations; and

WHEREAS, the CEC adopted the Qualifying Capacity of Supply-Side Demand Response Working Group Interim Report on February 16, 2022, and CEC staff served the report on the CPUC's Rulemaking 21-10-002 service list; and

WHEREAS, after considering the CEC interim recommendations and taking comments from stakeholders, the CPUC issued Decision 22-06-050 in Rulemaking 21-10-002 on June 24, 2022, which requested the CEC to submit its final recommendations to the CPUC by February 1, 2023; and

WHEREAS, the CEC continued the stakeholder working group process throughout 2022 to develop final recommendations; and

WHEREAS, the CEC made a draft of the Qualifying Capacity of Supply-Side Demand Response Working Group Final Report, including proposed final recommendations to the CPUC, available to the public on December 6, 2022, and requested written stakeholder comments by December 20, 2022; and

WHEREAS, the CEC considered the written stakeholder comments received, made appropriate revisions, and published the revised version of the Qualifying Capacity of Supply-Side Demand Response Working Group Final Report on January 23, 2023, for consideration by the CEC at its January 25, 2023, Business Meeting.

THEREFORE BE IT RESOLVED, the CEC hereby adopts the Qualifying Capacity of Supply-Side Demand Response Working Group Final Report along with any changes identified in the January 25, 2023 Business Meeting, and directs CEC staff to serve the report on the CPUC's R21-10-002 service list and take any other action necessary to submit these recommendations into that proceeding.

CERTIFICATION

The undersigned Secretariat to the CEC does hereby certify that the foregoing is a full, true, and correct copy of a resolution duly and regularly adopted at a meeting of the CEC held on January 25, 2023.

AYE: Hochschild, Gunda, McAllister, Monahan
NAY: NONE
ABSENT: NONE
ABSTAIN: NONE

Dated: January 30, 2023

SIGNED BY:

____
Liza Lopez
Secretariat

DOCKETED

Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	246242
Document Title:	CLECA Proposal for Demand Response Resource Counting for Slice of Day
Description:	N/A
Filer:	Courtney Wagner
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/28/2022 2:08:48 PM
Docketed Date:	9/28/2022

Proposal for Demand Response Resource Counting for Slice of Day

September 2022

Drafted by Paul Nelson for the California Large Energy Consumers Association[1] (CLECA)

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

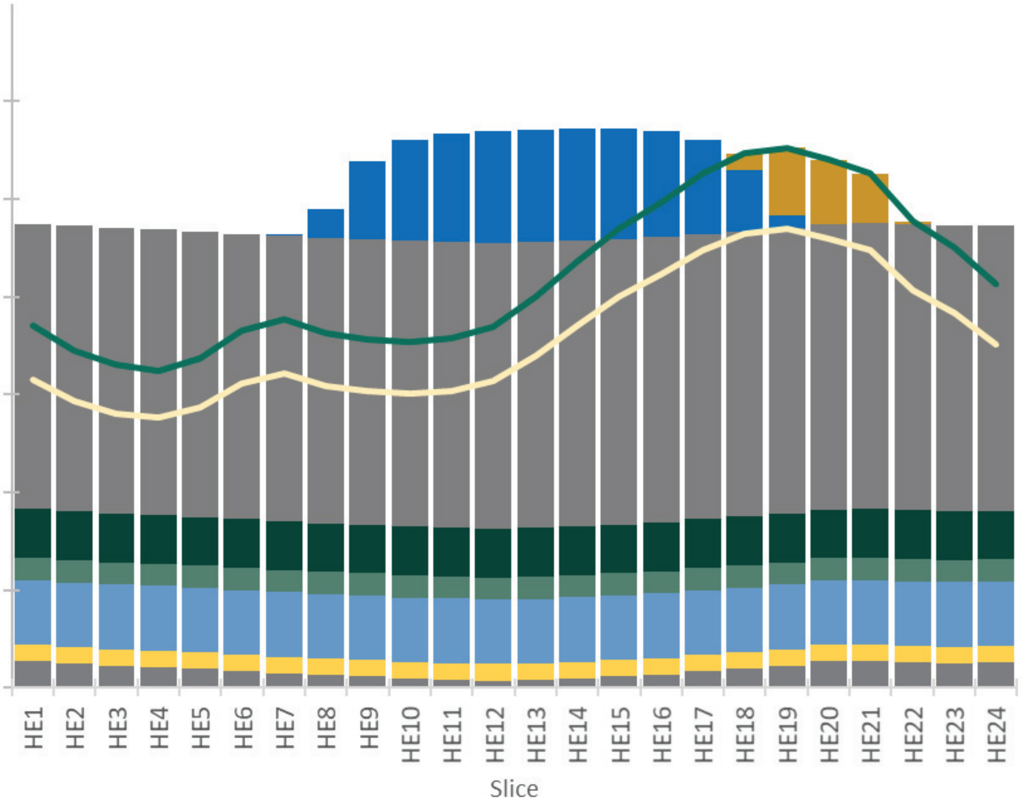
---

[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.

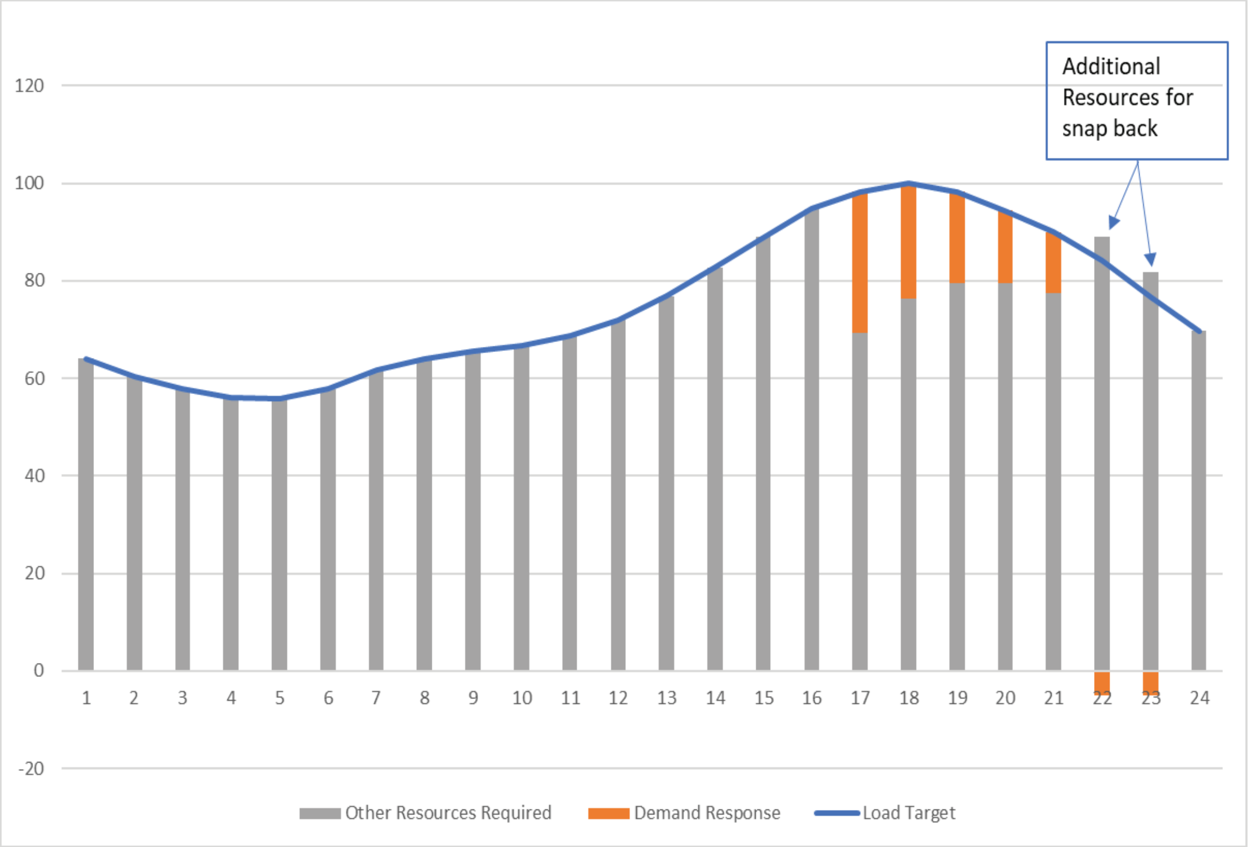
occurred if use of demand response was not necessary.[7] Another type of spillover occurs when there is a delay in load being restored after a DR event, due to the need to turn facilities back on slowly or sequentially, as at an industrial facility.

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.

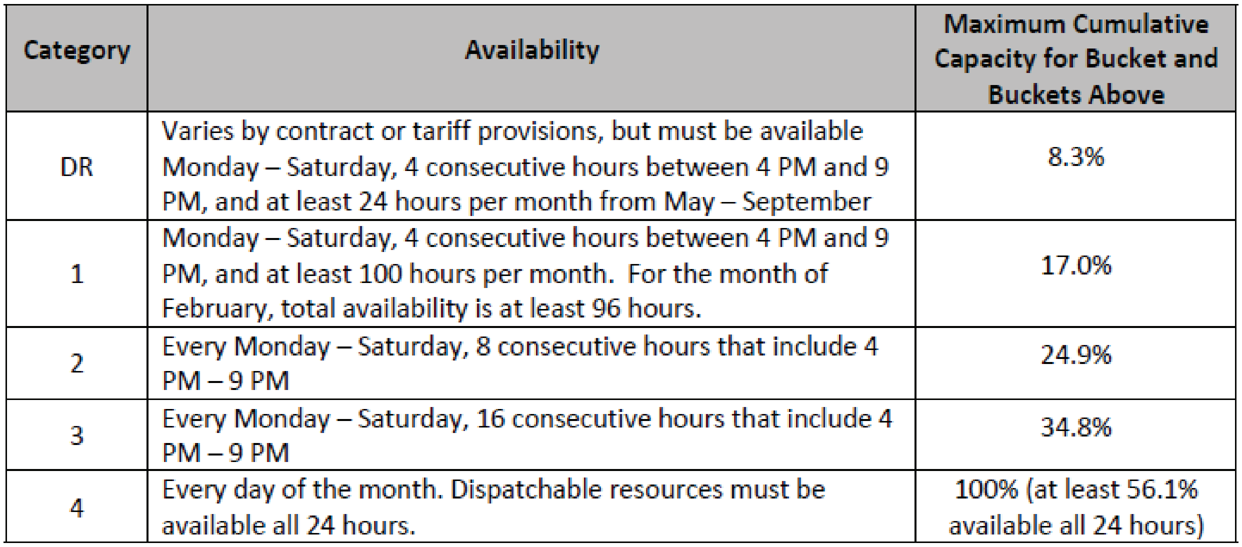


Minimum Demand Response Program Requirements

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.

---

[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.

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

DOCKETED

Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	246240
Document Title:	Demand Side Analytics - Final Draft Proposal
Description:	N/A
Filer:	Courtney Wagner
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/28/2022 1:19:24 PM
Docketed Date:	9/28/2022

FINAL DRAFT PROPOSAL

Demand Response Qualifying Capacity Working Group Proposal

Prepared by:
Demand Side Analytics
San Diego Gas & Electric

TABLE OF CONTENTS

1 Introduction 3
2 California Context and Motivation 5
  2.1 DEMAND RESPONSE RESOURCES AND CAISO PEAKING PATTERNS 6
  2.2 SHORTCOMINGS OF THE CURRENT FRAMEWORK 9
3 Proposal 12
Appendix A: Producing the Slice of Day Table 16
Appendix B: Slice of Day Applied Example 20
Appendix C: Producing a Time Temperature Matrix 21
Appendix D: Time Temperature Matrix Example 25
Appendix E: Performance Alignment Metric 26
Appendix F: Bid Alignment Metric 30

1 INTRODUCTION

This report is prepared for consideration by members of the California Energy Commission (CEC) working group on the Qualifying Capacity (QC) of demand response (DR) resources. The proposal supersedes the draft proposal submitted on April 28, 2022. Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Demand Side Analytics (DSA) met for over 12 work sessions. The group met to formulate workable solutions, develop models, run applied tests, and gather feedback from specific entities. In this process, SCE asked questions and provided feedback. PG&E cannot endorse the proposal at this time because they need more time to vet it with multiple organizational units. After additional discussion, PG&E will determine whether to support the proposal in whole or in part. In addition, the team gathered feedback from CAISO, CPUC, and CLECA to ensure we understood their concerns and to identify areas that needed further refinement.

As the resource mix in California is changing to meet de-carbonization goals, the need for flexible resources has increased. As such, it is now more important than ever that we accurately estimate the capability of DR resources for planning and operations. However, the process for developing the qualifying capacity value of DR resources is complex. DR resources include a wide range of technologies and customer segments. They can vary in shape, weather sensitivity, and operating limitations such as the maximum event duration, annual hours of dispatch, and the number of consecutive dispatch days. While there are many aspects of developing the value of DR resources that will continue to be discussed, we seek to answer three main questions in this proposal:

1) **How do we determine the ex-ante DR capability under different conditions?** Specifically, how can we develop ex-ante values that can be used for planning and also reflect how DR is expected to perform under a range of operating conditions?
2) **How are the characteristics of DR accounted for in determining the slice of day values by month and day?** Specifically, how does the approach account for the coincidence of DR with resource needs and for its limitations on availability, event duration, and frequency of dispatch?
3) **How do we measure DR performance?** How can we measure whether the ex-ante values used for planning align with bids and actual event performance?

In addition to answering these questions, our proposal has a few overarching goals:

- Provide greater transparency
- Produce a framework that accounts for the characteristics of each resource, including coincidence with reliability risk, weather sensitivity, resource availability, maximum event duration, and limitation on the annual hours, monthly hours, and consecutive days of dispatch
- Generate greater alignment between DR planning and operations;
- Produce estimates of DR capability that align with the slice of day framework;

- Ensure accurate measurement of the demand reductions delivered
- Ensure accurate estimation of resource capabilities under planning conditions
- Develop standardized metrics for measuring if bids and actual event performance align with the ex-ante values

The proposal focuses on technical aspects of how to align the DR outputs to fit the 24-Slice of day resource adequacy framework. It does not discuss how and where to simplify the Load Impact Protocols, or how and where to simplify the process and shorten the timelines. However, we are open to both simplifying the Load Impact Protocols and process improvements to reduce the burden on DR providers, the CPUC, and other stakeholders.

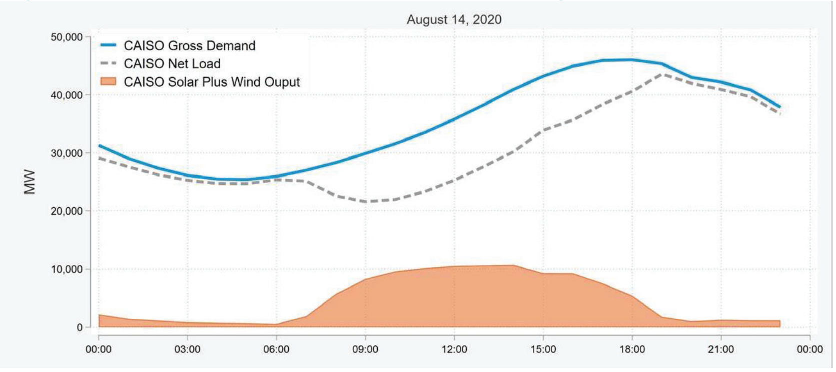
The remainder of the proposal is divided into two main sections and six technical appendices. Section 2 presents the California context and motivation. Section 3 contains the proposal, which we have intentionally kept concise. The appendices include technical detail. Appendices A and B describe how to produce the slice day table and the workbook used to test the process. Appendices C describes how to produce a time-temperature matrix, and Appendix D contains an applied example. Appendices E and F provide examples of a performance alignment metric and a bid alignment metric for illustrative purposes.

2 CALIFORNIA CONTEXT AND MOTIVATION

The fundamental nature of how electricity is generated, transmitted, distributed, and used in California changed substantially in the past ten years and will continue to evolve in the next decade. The single largest change affecting California's electric grid is the de-carbonization goals. The penetration of intermittent utility-scale renewable generation, mostly in the form of large solar power facilities and wind farms, has grown substantially in the past decade. In 2021, solar resources delivered up to 13,000 MW and wind resources exceeded 6,000 MW.[1] In addition, residential households and businesses are installing behind-the-meter solar, installing battery storage, and increasingly adopting electric vehicles.

Historically, the electric grid infrastructure has been sized to meet the aggregate peak demand of end users with a reserve margin for extreme weather or unforeseen outages. The electric system is unique in that it is necessary to balance supply and demand at all times. An imbalance can lead to cascading outages and compromise the reliability of the entire grid. Because electricity storage was prohibitively expensive in the past, enough supply capacity and flexibility had to be built to accommodate peak demands, and enough reserves had to be maintained to withstand unforecasted changes in the supply-demand balance (e.g., generator and transmission outages). However, the technology for energy storage has evolved, and the costs are declining. California's generation interconnection queue includes a large amount of battery storage.

Figure 1: CAISO Gross versus Net Loads on August 14,2020



The introduction of large-scale solar and wind has led to fundamental changes in planning the electric grid. The focus has shifted from planning for gross peak demand to net peak demand – electricity demand minus large-scale solar and wind. The grid must now focus on having sufficient dispatchable resources to meet the demand that cannot be met using solar and wind resources. Figure 1 illustrates the concept of net loads versus gross demand. It shows the electric demand and the wind and solar production on August 14, 2020, a day when California had experienced a shortage in resources. While gross demand peaks in the late afternoon, net loads peak a couple of hours later, when solar production declines as the sun sets. The ongoing changes lead to a cleaner supply mix, but also affect the magnitude and type of resources and grid services required to maintain

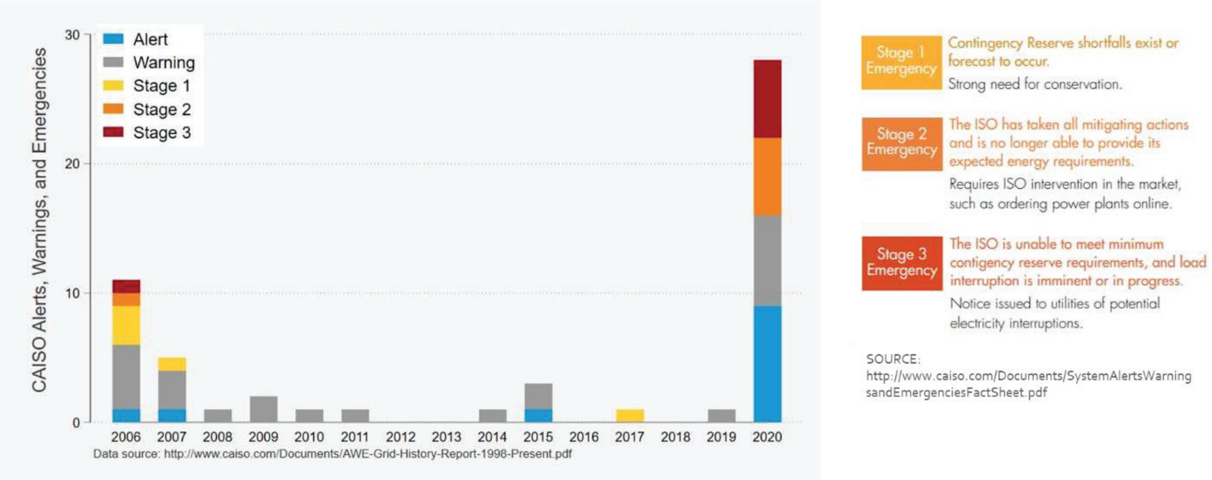
---

[1] CAISO press release. http://www.caiso.com/Documents/California-ISO-Hits-All-Time-Peak-of-More-Than-97-Percent-Renewables.pdf

reliability. They place a premium on flexible resources: enough flexibility is needed to adjust supply to meet fluctuations in demand and fill gaps when solar and wind power are unavailable.

In 2020, California experienced a confluence of extreme weather and widespread fires, leading to a historic number of CAISO emergency events, including rolling blackouts. The emergencies occurred due to a mix of high demand, unusual weather conditions, lower than forecasted solar output, operator forecasting error, and planning paradigms focused on gross demand rather than net loads. Demand response played a critical role in helping reduce demand when resources were needed. In 2020, the resources shortages did not occur when gross peak demand was at its highest but later in the evening when net loads (demand minus solar and wind) peaked.

Figure 2: Historical CAISO Alerts, Warnings, and Emergencies



Data source: http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf

Contingency Reserve shortfalls exist or forecast to occur.
Strong need for conservation.

The ISO has taken all mitigating actions and is no longer able to provide its expected energy requirements.
Requires ISO intervention in the market, such as ordering power plants online.

The ISO is unable to meet minimum contigency reserve requirements, and load interruption is imminent or in progress.
Notice issued to utilities of potential electricity interruptions.

SOURCE:
http://www.caiso.com/Documents/SystemAlertsWarningsandEmergenciesFactSheet.pdf

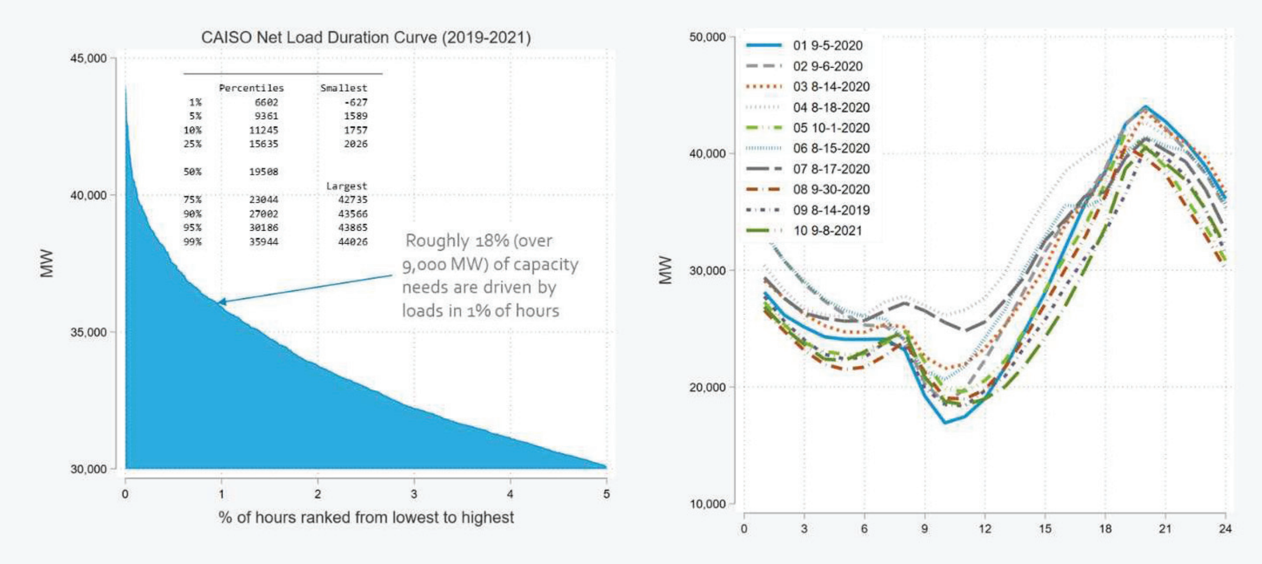
2.1 DEMAND RESPONSE RESOURCES AND CAISO PEAKING PATTERNS

Historically, demand response programs have been designed to reduce peak demand and offset the need for additional peaking capacity. When, where, how often, and for how long DR resources are needed are evolving due to the introduction of large amounts of intermittent renewable resources.

A fundamental characteristic of power system planning is that a small number of hours drive a significant share of costs. Electric prices climb sharply when the grid is strained due to high demand, generator outages, transmission outages, fluctuations in power output, or forecast error. Resource shortages typically occur due to high net load demand levels and a combination of generator outages, transmission outages, low imports, or unforecasted fluctuations in solar or wind output.

Figure 3 shows the concentration of CAISO high net load hours and days. The panel to the left is a load duration curve, which ranks the top 5% of hours based on net loads from highest to lowest. The panel to the right shows the hourly patterns on the ten days with the highest CAISO net loads. Net loads are the primary driver of resource capacity needs and are highly concentrated. The net loads in roughly 1% of the hours in the year drive the need for 18% of the capacity resources (over 9,000 MW with the reserve margin). Moreover, the timing of the high net loads is concentrated in the summer months and on specific hours. Figure 4 shows a heat map of CAISO net loads in 2020. Even in unusual years, such as 2020, the risk of resource shortages is concentrated in a limited number of hours in the summer months and driven by heatwaves.

Figure 3: CAISO Concentration of High Net Load Hours and Days



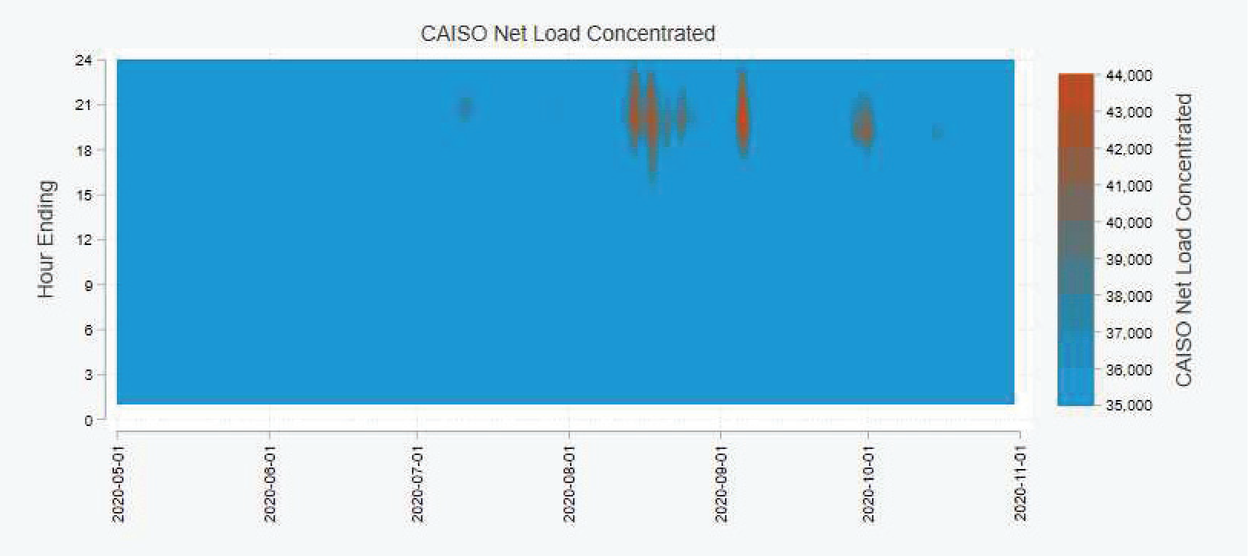
CAISO Net Load Duration Curve (2019-2021)

```
          Percentiles      Smallest
 1%           6602           -627
 5%           9361           1589
10%          11245           1757
25%          15635           2026

50%          19508
                            Largest
75%          23044          42735
90%          27002          43566
95%          30186          43865
99%          35944          44026
```

Roughly 18% (over 9,000 MW) of capacity needs are driven by loads in 1% of hours

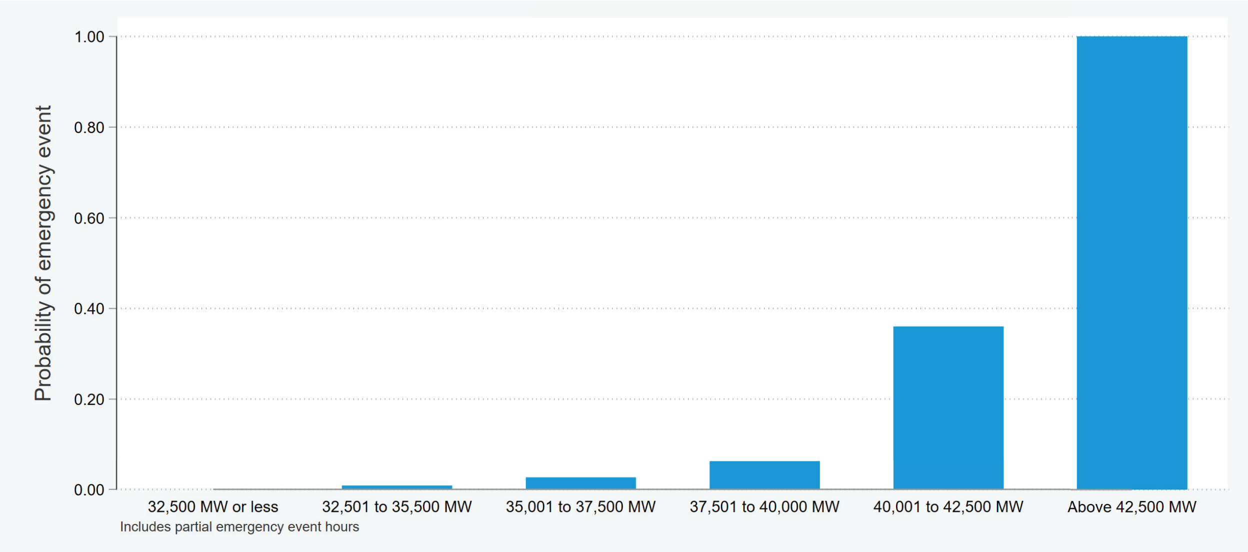
Figure 4: Heat Map of CAISO Net Load in Summer 2020



CAISO Net Load Concentrated

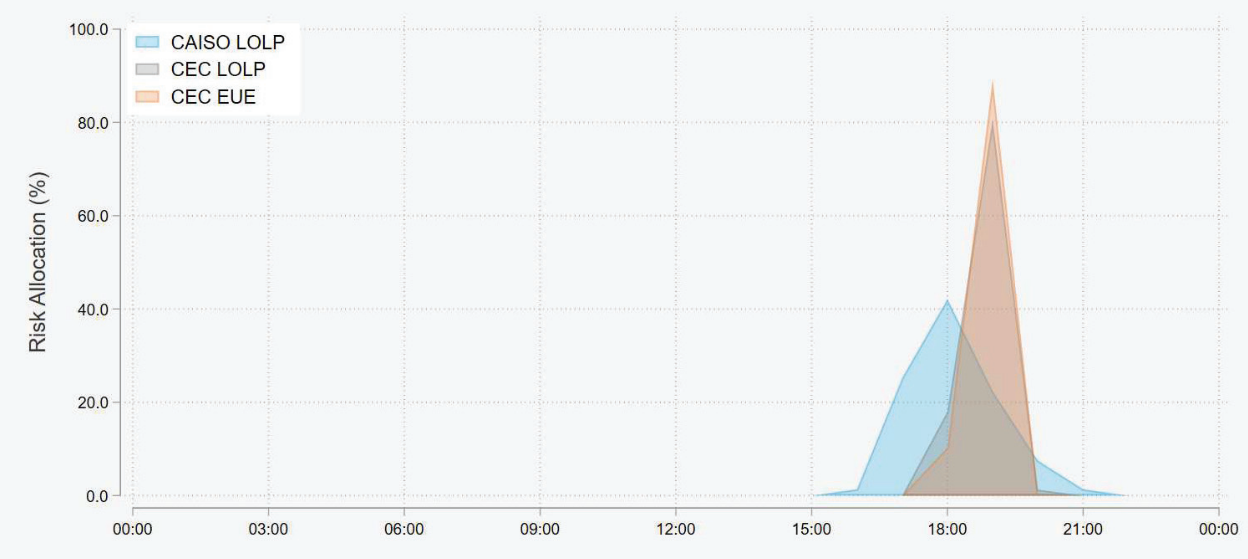
High net loads are closely related to resource shortages, as measured by CAISO emergency notices, which are directly linked to the available reserve margin. Figure 5 shows the relationship. The probability of resource shortages in 2019-2021 was directly linked to net loads. The risk of resource shortages was highest when loads exceeded 40,000 MW.

Figure 5: 2019-2021 Relationship Between Net Loads and CAISO Emergency Events



In 2021 and 2022, CAISO and the CEC, respectively, conducted reliability planning studies and quantified the risk of resource shortfalls using loss-of-load probabilities (LOLP) or expected unserved energy (EUE). The results from the studies also indicate the risk of resource adequacy shortages is highly concentrated in a limited number of hours.

Figure 6: Risk of Capacity Shortfalls is Highly Concentrated in Limited Hours



To help meet resource adequacy requirements, DR resources need to be dispatched in the right months and right hours when net loads are high. Because net loads drive planning needs, the framework of DR qualifying capacity must account for the level of solar and wind penetration. DR includes a wide range of resources ranging from residential thermostats and behind-the-meter batteries to large industrial customers, each with differing capabilities on when, how often, how long, and how much demand reduction they can deliver. It is our position that any resource adequacy and qualifying capacity framework must properly incorporate and model the use limitations of DR resources and their coincidence with resource needs. DR resources also interact with battery storage. Both resources effectively aim to shave the net load duration curve, targeting the hours when resources are needed most. Higher amounts of peak shaving resources effectively mean that the resources must be dispatched more often to shave the load duration curve.

The main takeaways are simple:

- **Planning has shifted from gross loads to net loads.** Wind and solar are effectively the base supply resource but are inherently intermittent.
- **Electricity infrastructure costs are currently driven by net loads which are highly concentrated, peaking on a limited number of hours and days.** Over 9,000 MW of capacity resources (18%) are needed due to high net loads in less than 1% of hours.
- **Empirically, high net loads are closely linked to resource shortages.** The likelihood of shortages increases as net loads grow.
- **To deliver resource adequacy, DR resources need to be dispatched in the months and hours when net loads are high**. Because net loads drive planning needs, the DR QC framework must account for the level of solar and wind penetration. DR resources are not needed for all the roughly 720 hours each month to ensure resource adequacy.
- **DR also interacts with battery storage** since both resources have use limitations; target the hours when resources are needed most; and aim to shave the net load duration curve.

2.2 SHORTCOMINGS OF THE CURRENT FRAMEWORK

The current framework is often referred to as the Load Impact Protocol (LIP) framework. The Load Impact Protocols were designed to produce standardized outputs to use to track historical performance and to inform planning and resource adequacy. The protocols themselves did not specify how load impacts should be used for resource adequacy, did not limit the ability to run updates, and did not set the timelines for approval. Subsequent decisions by the CPUC led to the use of the average hourly impact over the availability window (4-9) to produce a monthly qualifying capacity value and set forth the process and timelines for approval of qualifying capacity. At the time the LIP protocols were approved in 2008, resource adequacy was driven by system gross peak loads, while today they are driven by net loads.

Table 1: Summary of Current Process

Component	Detail
What were the actual demand reductions delivered under the conditions called (ex-post impacts)?	For simplicity, these are called ex-post impacts. The goal is to provide the most accurate estimate of the delivered demand reductions. Most evaluations conduct accuracy tournaments testing different models, and many rely on matched control groups with difference-in-differences using smart meter data. The protocols require producing hourly results for each event in a standardized format, including information about the number of participants called, event start and end times, weather conditions, and confidence intervals. It also requires validation of the accuracy of the method used to produce the load impacts. Notably, the CAISO settlement does not match the evaluation results. CAISO settlement usually relies on heuristic methods – e.g., same hour average for the past ten (10) days – which can be implemented quickly and is easier for customers to understand.
What is the magnitude of program resources available under standard planning conditions (ex-ante impacts)?	For simplicity, these are called ex-ante impacts. They rely on developing a predictive model using hourly reductions from historical events, typically the most recent three years. The objective is to model how reductions vary as a function of weather, hour-of-day, hours into the event, and other factors (e.g., cycling strategy, location, etc.). This model is then used to predict demand reduction capability for each hour under 1-in-2 and 1-in-10 weather conditions and standardized dispatch hours that align with resource adequacy planning (currently 4-9 PM). The results are hourly tables with the load reduction capability for each month for 1-in-2 and 1-in-10 weather years
What value is used to determine the qualifying capacity?	Even though the outputs are hourly, the CPUC currently uses the average for the 4–9 PM time period under 1-in-2 utility peak conditions to determine the qualifying capacity for each month. The CPUC also specifies minimums a DR resource must meet to qualify for capacity. Currently, DR resources must be available Monday through Saturday for four (4) consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May to September. The DR qualifying capacity per customer relies on the load impact evaluation from two years ago (e.g., the 2023 qualifying capacity is based on the 2021 evaluation). Demand response providers can update enrollments, but only under limited circumstances.

In practice, utilities, CAISO, planners, operators, and program managers need to understand the magnitude of resources available for different hours under various temperature conditions, for different start times, and for different event durations. Actual events reflect on-the-ground decisions and do not always align with planning values. Specifically, actual weather conditions do not frequently match the 1-in-2 and 1-in-10 weather year planning conditions, and the event start times and durations often differ from the 4-9 PM resource adequacy window. Moreover, DR events are called for multiple reasons –testing or evaluation, economic dispatch, and reliability-related alerts, warnings, and emergencies. The current process has several limitations, summarized in Table 2.

Table 2: Limitations of Current DR Qualifying Capacity Framework

Limitation	Explanation
It does not incorporate the hourly capability of the resources	The current approach uses the average hourly load impacts from 4-9 PM under 1-in-2 peaking conditions for each month. It does not reflect the hourly load reduction capability, even though ex-ante values are produced on an hourly basis.
It does not fully factor in the coincidence of the resource shape with the risk of capacity shortages	The risk of capacity shortages is highly concentrated on specific hours when net loads are high, as shown by the recent CAISO and CEC reliability studies. Many DR resources are also tied to an underlying load shape – e.g., air conditioners or C&I load – and some of those resources deliver larger demand reductions when weather and demand are more extreme. Simply put, not all hours between 4–9 PM are equal. Thus, the coincidence of the DR resources with the hours when the risk is highest should be a critical component of determining the DR qualifying capacity value.
Is difficult to assess if performance during operations and bids into CAISO and align with the planning values	Actual events reflect on-the-ground decisions and do not always align with planning conditions. The actual weather conditions often do not frequently match the 1-in-2 or 1-in-10 weather conditions, and the event start times and durations often differ from the 4-9 PM resource adequacy window. Because of the format of the outputs, it can be difficult to compare the resource capability under planning conditions to bids or to compare them to the performance during actual events. This is particularly true for weather-sensitive programs that deliver lower reductions on milder days and larger reductions on hotter days when resources are needed most. In addition, the comparisons are sometimes inconsistent about whether the behind-the-meter demand reduction are scaled up to account for transmission and distribution line losses or the planning reserve margin. Last but not least, evaluation results are often used to assess performance, which does not always match the CAISO settlement. CAISO settlement is typically conducted using heuristics – day matching baselines – which are easy to understand and easy to compute. By contrast, evaluations often use accuracy tournaments, control groups, and techniques such as difference-in-difference regression models.
It lacks the flexibility needed for the 24-hour slice of day resource adequacy framework	The existing framework aligns well with the new 24-hour slice of day resource adequacy framework in several aspects. The demand response capability is produced by month and hour for standardized 1-in-2 and 1-in-10 system peak conditions and reflects spillover effects (e.g., pre-cooling and snapback). However, DR providers will need the flexibility to target the hours that maximize value and coincide with need. A standard 4–9 PM dispatch window may not be adequate. Several DR resources can deliver reductions for more than five hours and are also available outside of 4–9 PM. Resources that experience performance decay, such as thermostat control programs, can maximize value by avoiding early dispatch and targeting the most critical hours.

3 PROPOSAL

The current method requires producing hourly results for each event in a standardized format, including information about the number of participants called, event start and end times, weather conditions and confidence intervals. It also requires DR providers to produce estimates of DR capability by month and hour for 1-in-2 and 1-in-10 planning conditions that are ground in actual event performance when possible. The core elements of the existing framework align well with the slice-of-day resource adequacy framework, which also requires estimates of resource capability by month and hour-of-day. The proposal has nine main elements.

1

The Load Impact Protocols (LIP) should be retained but modified to address the 24-hour slice-of-day framework. Specifically, the protocols should continue to:

- Require that ex-ante load impact be grounded on actual event demand reductions when possible
- Require reporting of hourly load impacts for each event in a standard hourly format
- Require reporting of resource capability under planning conditions (ex-ante impacts) on an hourly basis for each month
- Provide flexibility in methods and models for ex-post evaluation and ex-ante impacts. Based on over a decade of applied experience, it is clear that no single ex-ante model fits all programs. Rather than focus on the models, we believe the focus should be on standardized outputs and transparency.

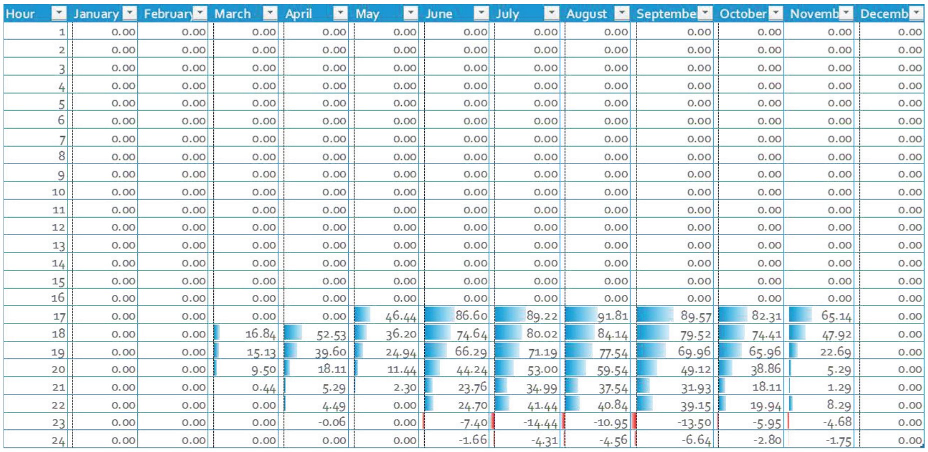
The team is open to modifications to simplify, add transparency, and further standardize outputs. The team is also open to streamlining the process to make it more concise and timely. However, modifications to the load impact protocols require technical expertise and testing – they should be done with caution.

2

Modifications to the Load Impact Protocols should include:

- Aligning weather conditions with the worst day of the month as defined in resource adequacy.
- Allowing DR providers flexibility to target the hours that maximize value and coincide with need (i.e., don't force everyone into 4–9 PM) while taking into account:
  - ✓ The coincidence of the resource with the risk of capacity shortages
  - ✓ The availability of the resource as defined by the program rules (e.g., 12–9 PM) by month, hour, and weekday/weekend conditions
  - ✓ Max event duration
  - ✓ Spillover effects such as snapback, pre-cooling, or persistence of load reductions beyond the event window (for non-residential).
  - ✓ Minimum requirements for annual maximum dispatch hours, monthly maximum dispatch hours, and maximum consecutive days

- Ensuring the load impacts for the worst day of the month is an output of the ex-ante impacts
- Produce a summary 24-slice of day table that shows impact of the resource for all 24 hours for each of the 12 months on the worst day. The table must meet the resource adequacy requirements, match the load impact protocol tables, and include all spillover effects. The below table serves as an example.



Hour	January	Februar	March	April	May	June	July	August	Septembe	October	Novemb	Decemb
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	46.44	86.60	89.22	91.81	89.57	82.31	65.14	0.00
18	0.00	0.00	16.84	52.53	36.20	74.64	80.02	84.14	79.52	74.41	47.92	0.00
19	0.00	0.00	15.13	39.60	24.94	66.29	71.19	77.54	69.96	65.96	22.69	0.00
20	0.00	0.00	9.50	18.11	11.44	44.24	53.00	59.54	49.12	38.86	5.29	0.00
21	0.00	0.00	0.44	5.29	2.30	23.76	34.99	37.54	31.93	18.11	1.29	0.00
22	0.00	0.00	0.00	4.49	0.00	24.70	41.44	40.84	39.15	19.94	8.29	0.00
23	0.00	0.00	0.00	-0.06	0.00	-7.40	-14.44	-10.95	-13.50	-5.95	-4.68	0.00
24	0.00	0.00	0.00	0.00	0.00	-1.66	-4.31	-4.56	-6.64	-2.80	-1.75	0.00

- Production of a Time-Temperature Matrix for weather-sensitive resources using a standard output format upon request. A time-temperature matrix quantifies the relationship between demand reductions, temperature conditions, the hour of the day, event start times, and hours into an event. It is based on the same model used to produce ex-ante impacts under planning conditions. Including a time-temperature matrix would better reflect the range of the resource capabilities that are not captured by a single planning value for each month (or a 24-hour profile for each month) and help bridge the gap between operations and planning

We note that the request for flexibility in choosing the event window is not without boundaries. The resource needs to fulfill the minimum resource adequacy requirements, as they are defined.Once the minimum requirements are met, the DR provider can choose additional hours to show DR impacts. However, once a DR provider has elected the hours to show reductions, it cannot modify them since it fundamentally alters the 24-hour slice of day stack. To illustrate, consider a resource that can be dispatched for six event hours and assume resource adequacy requires resource between 4 PM – 9 PM, with a four-hour duration minimum. The resource could elect to show a 3–9 PM or a 4–10 PM reduction window. In both cases, it would need to include all spillover effects, whether positive or negative, for all 24 hours (if any).

The goal of the modifications is to show the full effects of the DR, good and bad, across all 24 hours, consistent with the 24-slice-day framework.

3

The long-term DR qualifying capacity methodology should be applicable to both supply-side and load-modifying DR resources

---

4

A single entity (CPUC, CEC, CAISO) should produce the reliability risk heatmap in advance (e.g., 18 months before the RA compliance year). This enables DR providers to adjust programs and slice-of-day estimates to coincide with the hours when resource needs are greatest.

5

The ex-post load impact from evaluations should be used as the basis for performance:

- The impacts are more use the best available method and typically rely on an accuracy tournament or matched control groups with difference-in-differences
- There is a long history of load reductions in a standard template (since 2008)

6

CAISO should allow evaluation results to be used for settlement if:

- The evaluation plan is produced in advance of the season
- The results are produced within the settlement period
- The statistical analysis code to produce the results is made available to CAISO for replication

---

7

Develop a standardized performance alignment metric. The main objective of this metric is to assess if the actual performance during operations aligns with the historical forecasted capability at the meter, given the conditions actually experienced during operations and the resources dispatched. By design, the metric is centered on 1.00, with values above 1.00 indicating overperformance and values below 1.00 indicating underperformance. We introduce an applied example of calculating the metric. Still, we recognize that stakeholders may want additional discussion and the opportunity to test it in practice before it is adopted. The metric and workbook with underlying calculations would be available to the CPUC, CEC, and CAISO upon request.

8

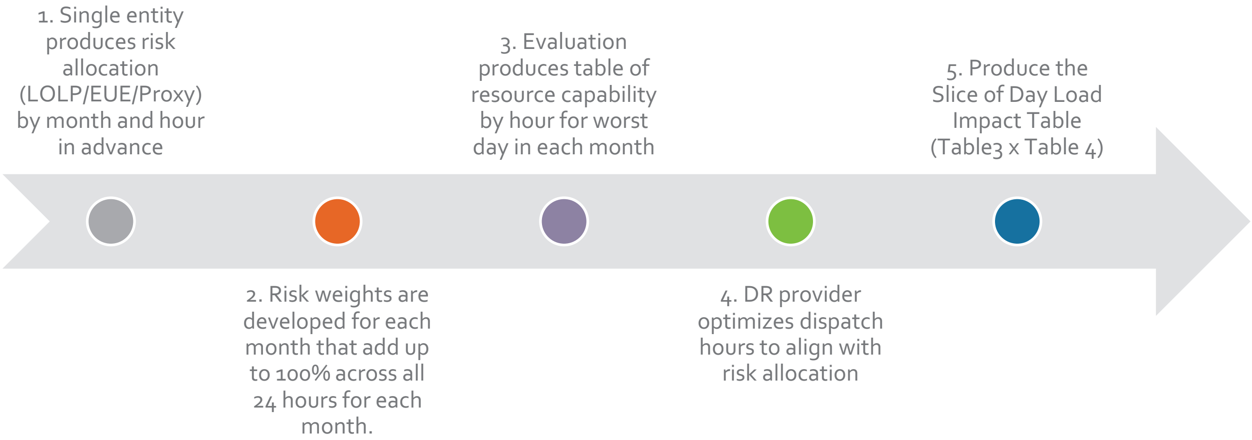
Develop a standardized bid alignment metric. The main objective of this metric is to assess if the bids align with the historical forecasted capability, given the conditions actually experienced. By design, the metric is centered on 1.00, with values above 1.00 indicating overperformance and values below 1.0 indicating underperformance. We introduce an applied example of calculating the metric. However, we recognize that stakeholders may want additional discussion and the opportunity to test it in practice before it is adopted. The metric and workbook with underlying calculations would be available to the CPUC, CEC, and CAISO upon request.

9

Work out the methodology for the monthly qualifying capacity value in the Resource Adequacy Working group, starting with the one on September 21, 2022.

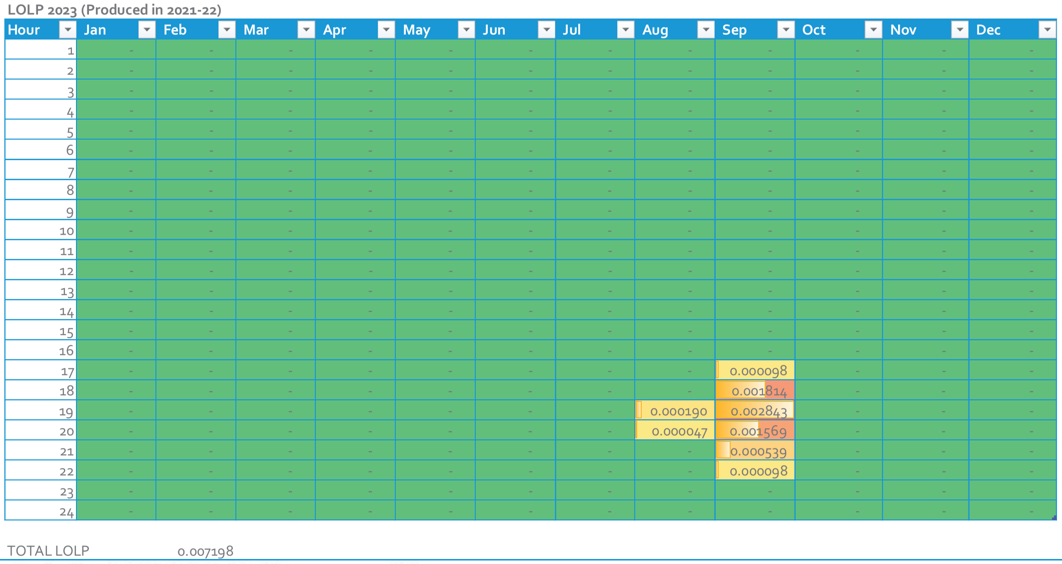
APPENDIX A: PRODUCING THE SLICE OF DAY TABLE

The figure below outlines the key steps for producing a slice of day table. Each step is outlined in greater detail with an example in the table on the following page. The process can also be used to produce monthly qualifying capacity values consistent with the slice of day framework.



Description | **Example**

1 Single entity produces risk allocation (LOLP/EUE/Proxy) by month and hour in advance
- Must be provided in advance to allow DR providers to adjust programs/rules
- Entity could be CPUC, CEC, or CAISO
- Output can be:
  - ✓ LOLP
  - ✓ EUE
  - ✓ LOLP proxy
  - ✓ EUE proxy
- Team is providing an open data, open code option as a backup.

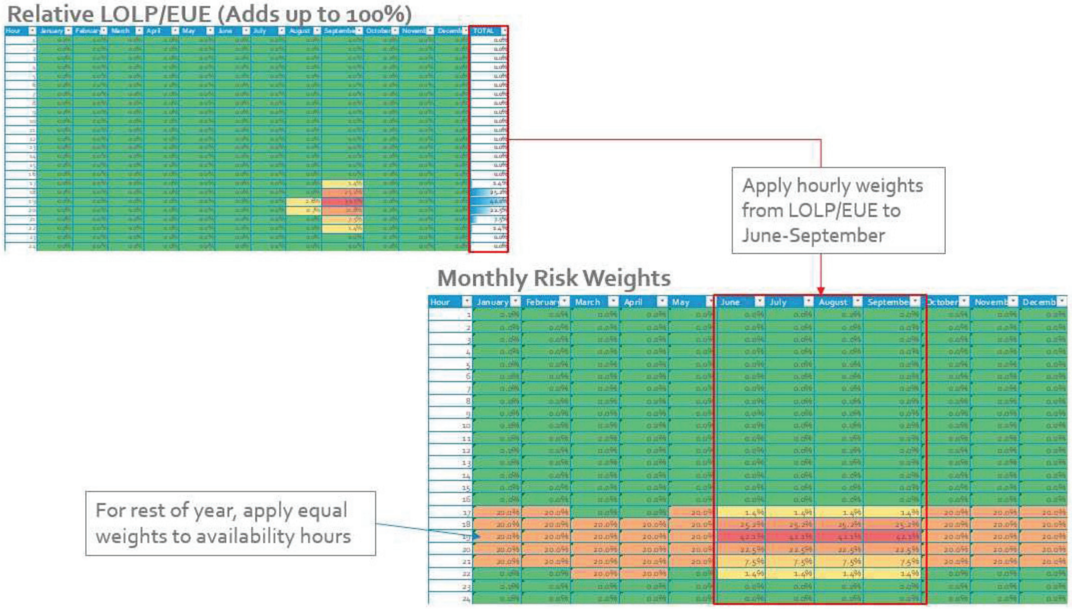


LOLP 2023 (Produced in 2021-22)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	0.000098	-	-	-
18	-	-	-	-	-	-	-	-	0.001814	-	-	-
19	-	-	-	-	-	-	-	0.000190	0.002843	-	-	-
20	-	-	-	-	-	-	-	0.000047	0.001569	-	-	-
21	-	-	-	-	-	-	-	-	0.000539	-	-	-
22	-	-	-	-	-	-	-	-	0.000098	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

TOTAL LOLP 0.007198

2 Risk weights are developed for each month that add up to 100%.
- Produce separate values for summer and winter
  - ✓ Summer value is based on LOLP
  - ✓ Winter value applies equal weights to each availability hour
- 2 values suggested because:
  - ✓ The EUE/LOLP results do not produce resource shortages each month
  - ✓ Values tend to be concentrated in 1-2 months in the outputs, which does not account for monthly variation across years



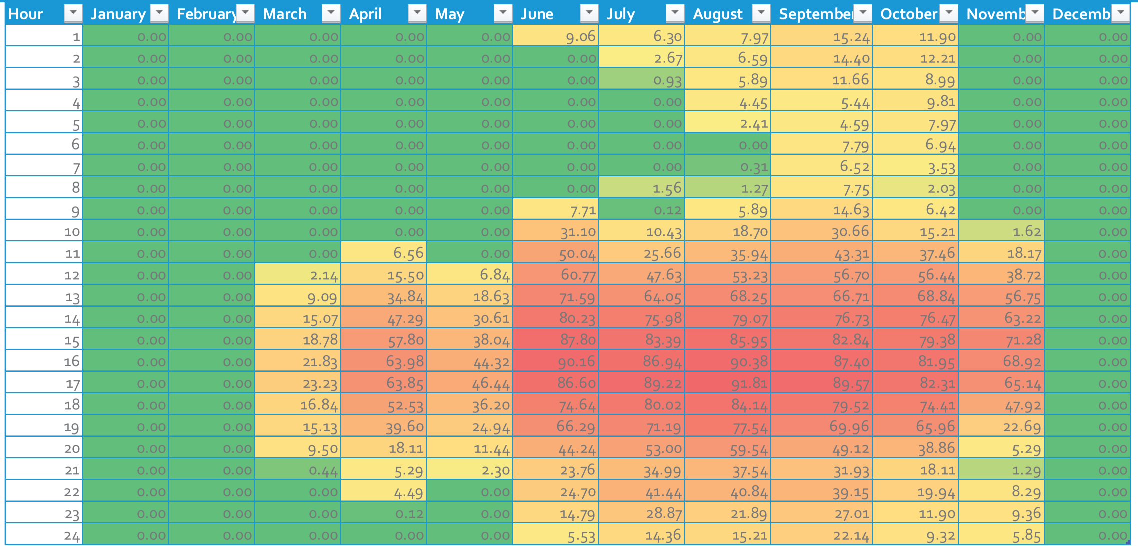
Relative LOLP/EUE (Adds up to 100%)

Apply hourly weights from LOLP/EUE to June-September

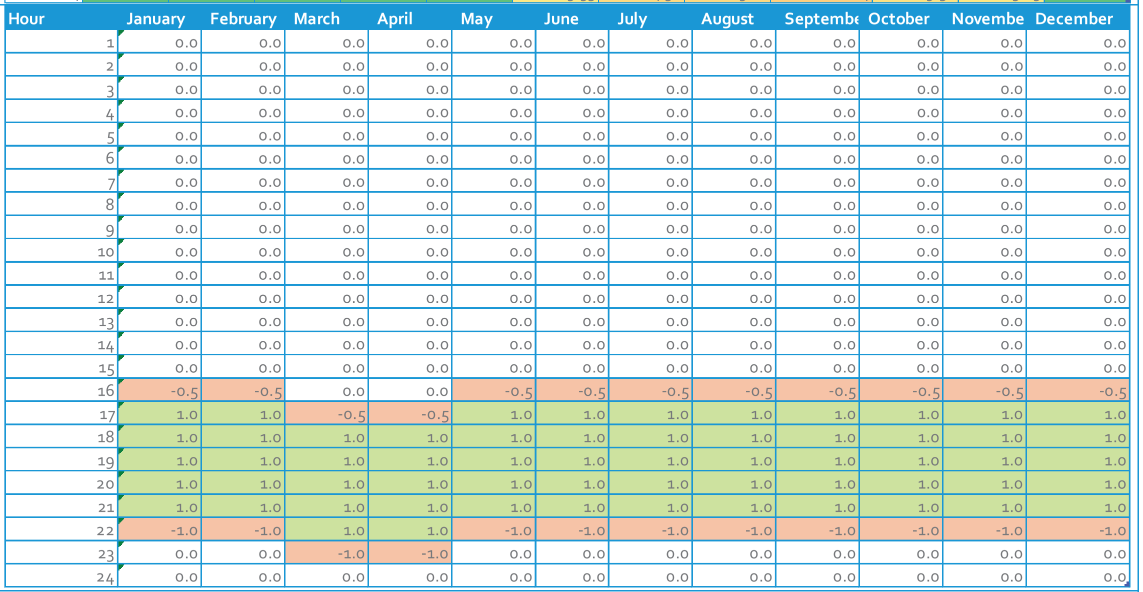
Monthly Risk Weights

For rest of year, apply equal weights to availability hours

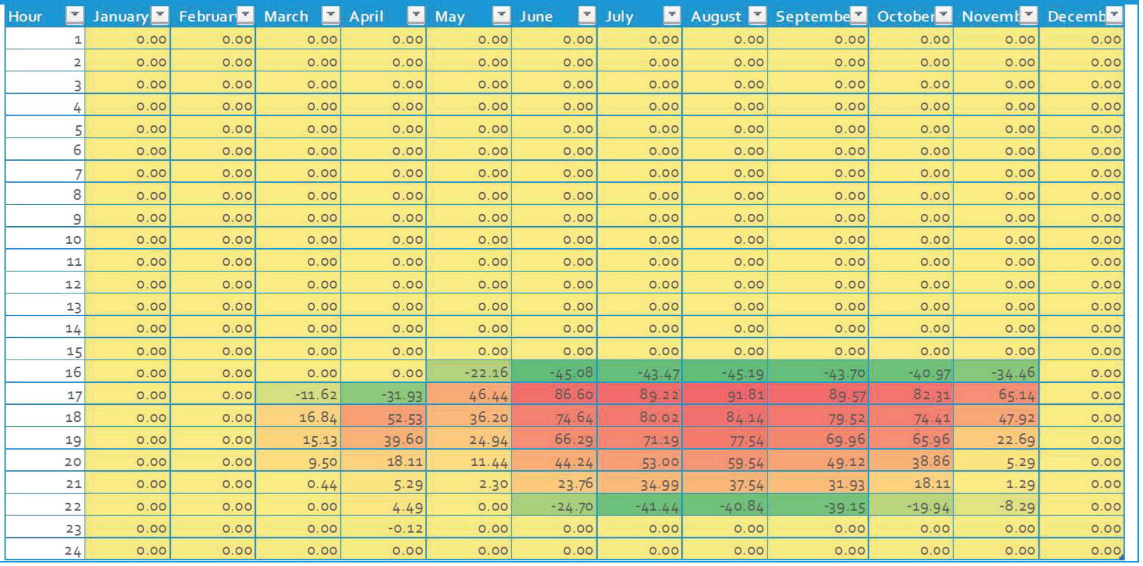
Description	Example
3 Evaluation produces a table of resource capability by hour for the worst day in each month for all hours when the resource is available and snapback/spillover and event decay multipliers (Table 3). The table reflect the value or the first hour of dispatch.	See table 3 below
4 DR provider optimizes dispatch hours to align with risk allocation (Table 4) ▪ Dispatch should include multipliers for event decay, pre-cooling, snap back, and spillover as relevant ▪ Can dispatch during availability hours or at different times depending on what is optimal for the resource	See table 4 below



Hour	January	February	March	April	May	June	July	August	September	October	Novemb	Decemb
1	0.00	0.00	0.00	0.00	0.00	9.06	6.30	7.97	15.24	11.90	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	2.67	6.59	14.40	12.21	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.93	5.89	11.66	8.99	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.45	5.44	9.81	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.41	4.59	7.97	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.79	6.94	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31	6.52	3.53	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	1.56	1.27	7.75	2.03	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	7.71	0.12	5.89	14.63	6.42	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	31.10	10.43	18.70	30.66	15.21	1.62	0.00
11	0.00	0.00	0.00	6.56	0.00	50.04	25.66	35.94	43.31	37.46	18.17	0.00
12	0.00	0.00	2.14	15.50	6.84	60.77	47.63	53.23	56.70	56.44	38.72	0.00
13	0.00	0.00	9.09	34.84	18.63	71.59	64.05	68.25	66.71	68.84	56.75	0.00
14	0.00	0.00	15.07	47.29	30.61	80.23	75.98	79.07	76.73	76.47	63.22	0.00
15	0.00	0.00	18.78	57.80	38.04	87.80	83.39	85.95	82.84	79.38	71.28	0.00
16	0.00	0.00	21.83	63.98	44.32	90.16	86.94	90.38	87.40	81.95	68.92	0.00
17	0.00	0.00	23.23	63.85	46.44	86.60	89.22	91.81	89.57	82.31	65.14	0.00
18	0.00	0.00	16.84	52.53	36.20	74.64	80.02	84.14	79.52	74.41	47.92	0.00
19	0.00	0.00	15.13	39.60	24.94	66.29	71.19	77.54	69.96	65.96	22.69	0.00
20	0.00	0.00	9.50	18.11	11.44	44.24	53.00	59.54	49.12	38.86	5.29	0.00
21	0.00	0.00	0.44	5.29	2.30	23.76	34.99	37.54	31.93	18.11	1.29	0.00
22	0.00	0.00	0.00	4.49	0.00	24.70	41.44	40.84	39.15	19.94	8.29	0.00
23	0.00	0.00	0.00	0.12	0.00	14.79	28.87	21.89	27.01	11.90	9.36	0.00
24	0.00	0.00	0.00	0.00	0.00	5.53	14.36	15.21	22.14	9.32	5.85	0.00



Hour	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	-0.5	-0.5	0.0	0.0	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
17	1.0	1.0	-0.5	-0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
18	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
19	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
20	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
21	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
22	-1.0	-1.0	1.0	1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
23	0.0	0.0	-1.0	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Description	Example
5 Produce the Slice of Day Load Impact Table (Table 3 x Table 4)	

Hour	January	Februar	March	April	May	June	July	August	Septembe	October	Novemb	Decemb
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	-22.16	-45.08	-43.47	-45.19	-43.70	-40.97	-34.46	0.00
17	0.00	0.00	-11.62	-31.93	46.44	86.60	89.22	91.81	89.57	82.31	65.14	0.00
18	0.00	0.00	16.84	52.53	36.20	74.64	80.02	84.14	79.52	74.41	47.92	0.00
19	0.00	0.00	15.13	39.60	24.94	66.29	71.19	77.54	69.96	65.96	22.69	0.00
20	0.00	0.00	9.50	18.11	11.44	44.24	53.00	59.54	49.12	38.86	5.29	0.00
21	0.00	0.00	0.44	5.29	2.30	23.76	34.99	37.54	31.93	18.11	1.29	0.00
22	0.00	0.00	0.00	4.49	0.00	-24.70	-41.44	-40.84	-39.15	-19.94	-8.29	0.00
23	0.00	0.00	0.00	-0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

APPENDIX B: SLICE OF DAY APPLIED EXAMPLE

Slice of Day and
Monthly QC example

APPENDIX C: PRODUCING A TIME TEMPERATURE MATRIX

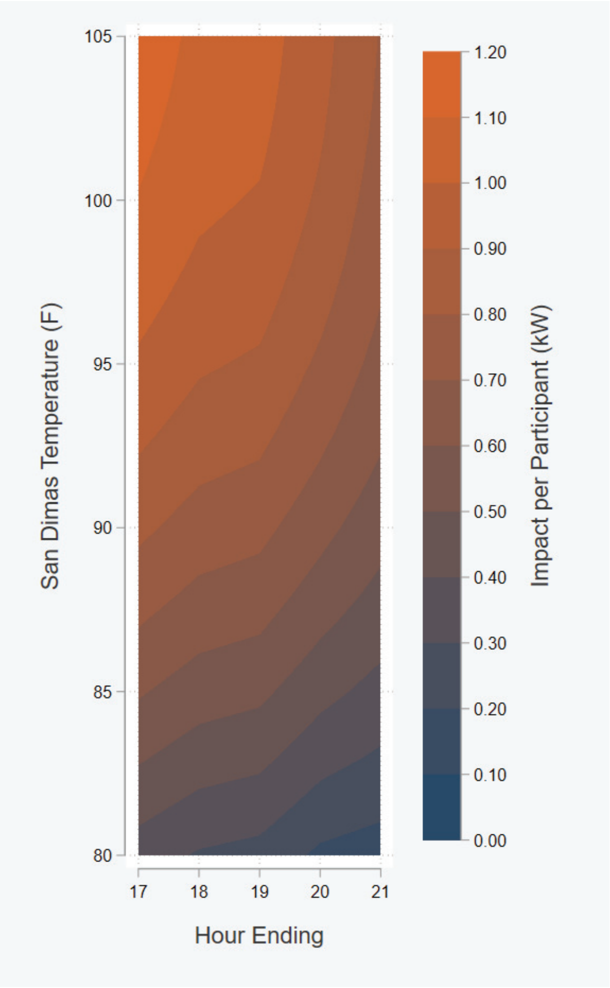
A Time-temperature quantifies the relationship between demand reductions, temperature conditions, hour of the day, event start times, and hours into an event. Importantly, a TTM is developed using the same predictive model used to produce the ex-ante planning impacts under standard conditions. Including a time-temperature matrix would better reflect the range of the resource capabilities for these different conditions that are not captured by a single planning value for each month (or a 24-hour profile for each month). A TTM has multiple uses:

- It can be used for operations and bidding.
- It can be used to compare the historical ex-ante forecasts to the bids submitted,
- It can be used to compare actual event performance to historical event forecasts, and
- It can be used to simulate the resource availability for different weather years, a common application in planning

Figure 7 shows example outputs of a simple TTM developed for SCE's Summer Discount Plan Residential (SDP-R) Program. For this program, the only independent variables used to develop the TTM were temperature (indexed to the San Dimas weather station) and hour of day. Impacts shown in the matrix are static and represent the expected participant-level impact for a territory-wide event for the given hour and temperature.

Figure 7: SDP-R Time-Temperature Matrix

Temp	Hour Ending				
	17	18	19	20	21
105	1.16	1.08	1.05	0.93	0.79
104	1.15	1.07	1.04	0.93	0.79
103	1.14	1.06	1.03	0.92	0.78
102	1.13	1.05	1.02	0.91	0.77
101	1.11	1.04	1.01	0.90	0.76
100	1.09	1.02	0.99	0.88	0.75
99	1.08	1.00	0.97	0.87	0.74
98	1.06	0.98	0.95	0.85	0.72
97	1.03	0.96	0.93	0.83	0.70
96	1.01	0.94	0.91	0.81	0.69
95	0.98	0.91	0.89	0.78	0.66
94	0.96	0.89	0.86	0.76	0.64
93	0.93	0.86	0.83	0.73	0.62
92	0.89	0.82	0.80	0.70	0.59
91	0.86	0.79	0.76	0.67	0.57
90	0.82	0.76	0.73	0.63	0.54
89	0.78	0.72	0.69	0.60	0.51
88	0.74	0.68	0.65	0.56	0.47
87	0.70	0.64	0.61	0.52	0.44
86	0.66	0.59	0.57	0.48	0.40
85	0.61	0.55	0.52	0.43	0.37
84	0.56	0.50	0.48	0.38	0.33
83	0.51	0.45	0.43	0.34	0.29
82	0.46	0.40	0.38	0.29	0.24
81	0.41	0.35	0.32	0.23	0.20
80	0.35	0.29	0.27	0.18	0.15



The method for calculating a time-temperature matrix is relatively straightforward. The first step for calculating a time-temperature matrix is to develop a model that predicts impacts for the average customer as a function of temperature. This will be the same model that is used to develop weather-normalized ex-ante impacts as a part of the annual reporting process for demand response. Below is a sample equation for modeling impacts as a function of temperature. This is the equation that was used to predict impacts for the TTM in Figure 7.

$$Impact_i = \beta_0 + \beta_1 * Temp + \beta_2 * Temp^2 + \beta_3 * hour * Temp + \varepsilon_i$$

Model Term	Description
Impact$_i$	Average impact in kW during interval i
β0	The model intercept
Temp	Temperature at San Dimas Weather Station
Temp^2	Square of Temperature at San Dimas Weather Station
Hour * Temp	Interaction term between hour and temperature
β1-β3	Regression coefficients
ε_i	Error term

Once the model has been developed, the matrix is created by predicting impacts for the expected temperature range you would expect the program to operate in (in the above example the temperature ranges from 80^{0}F - 105^{0}F) and for the expected operating hours of the program (in the above example the operating hours range from 4-9 PM). For programs where there is event decay the matrix can also include variation in impacts based on the event hour.

Due to the varied nature of DR resources, it is important to require standard formatting so that different resources can be compared to one-another. The load impact protocols currently require standardized reporting of performance during actual events (ex-post impacts) and require the standardized reporting of hourly demand reduction capability for standardized monthly system peak days conditions (ex-ante impacts). We recommend that any additional data provided also require standardized reporting.

The actual model underlying the TTM and ex-ante impacts can vary due to the diversity of programs, but the outputs need to be standardized to include the same columns and use pre-specified weather stations by Sub-LAP. Below is the recommended data structure for the model outputs. The key outputs include the resource, the location, the event start time and duration, the hour of the event, and the average daily temperature. In this output we include the per-unit impact so that the impacts can be scaled if enrollment changes.

Table 3: Time Temperature Matrix Standard Output Format

Resource Name	Location (Sub-LAP)	Hour of Day	Event Hour	Start Time	Avg. Temperature	Event Duration	Forecasted per Unit Impact (kW)
Resource A	SCEC	20	1	7 PM	90	5	1.19
Resource A	SCEC	21	2	7 PM	90	5	1.10
Resource A	SCEC	22	3	7 PM	90	5	1.06
Resource A	SCEC	23	4	7 PM	90	5	0.96
Resource A	SCEC	24	5	7 PM	90	5	0.80
Resource A	SCEC	20	1	7 PM	89	4	1.16
Resource A	SCEC	21	2	7 PM	89	4	1.07
Resource A	SCEC	22	3	7 PM	89	4	0.99
Resource A	SCEC	23	4	7 PM	89	4	0.97
Resource A	SCEC	19	1	6 PM	89	4	1.18

Resource A	SCEC	20	2	6 PM	89	4	1.09
Resource A	SCEC	21	3	6 PM	89	4	1.00
Resource A	SCEC	22	4	6 PM	89	4	0.89
Resource A	SCEC	19	1	6 PM	88	4	1.10
Resource A	SCEC	20	2	6 PM	88	4	1.03
Resource A	SCEC	21	3	6 PM	88	4	1.00
Resource A	SCEC	22	4	6 PM	88	4	0.88
Resource A	SCEC	18	1	5 PM	88	4	1.15
Resource A	SCEC	19	2	5 PM	88	4	1.03
Resource A	SCEC	20	3	5 PM	88	4	1.02
Resource A	SCEC	21	4	5 PM	88	4	0.91

APPENDIX D: TIME TEMPERATURE MATRIX EXAMPLE

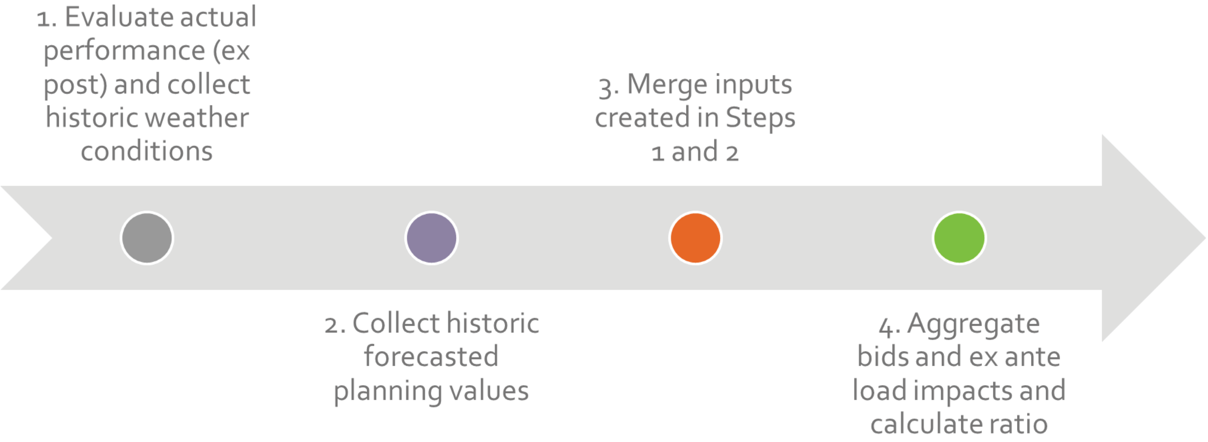
TTM Example.xlsm

APPENDIX E: PERFORMANCE ALIGNMENT METRIC

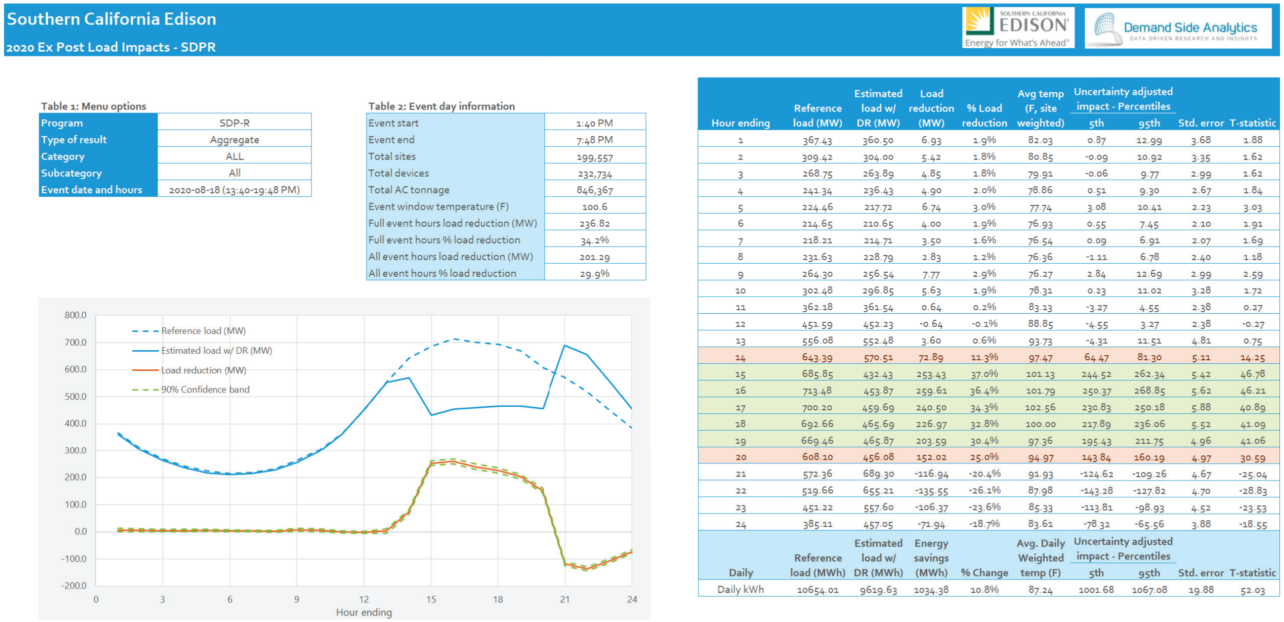
The performance alignment metric aims to determine whether actual performance during operations aligns with the forecasted capability used for planning (ex-ante impacts). The example metric is a ratio between the historic performance (ex post impacts) and the planning values developed from the historic ex ante model for the same weather and dispatch conditions. This comparison would be done for all events awarded for a given evaluation year. A ratio of 1.0 would indicate perfect alignment between performance and planning, a value greater than 1.0 would indicate that the actual performance during operations is greater than the values indicated by the planning model, and a value less than 1.0 would indicate that the actual performance for operating conditions is lower than the values indicated by the planning model.

The main concept is creating a standardized metric that is easy for all parties to understand and has a transparent calculation method. This metric can let implementers, planners, and CAISO know if there needs to be an adjustment to the planning model in the long term so that there is greater alignment between actual performance and the forecasted performance.

The figure below illustrates the key steps for developing the comparison between ex ante values and bid values. We discuss each step in greater detail in the table below.



	Step	Example
1	**Evaluate actual program performance (ex post impacts) and collect historic weather conditions.** Evaluate historic program performance for all events, as is typically done for a DR evaluation. Historic weather conditions are typically collected as a part of this process.	Below is an example of the outputs from an ex post evaluation. The results need to include the event hour, per unit impact (in kW), and weather conditions for each event.



Southern California Edison

2020 Ex Post Load Impacts - SDPR

Table 1: Menu options

Program	SDP-R
Type of result	Aggregate
Category	ALL
Subcategory	All
Event date and hours	2020-08-18 (13:40-19:48 PM)

Table 2: Event day information

Event start	1:40 PM
Event end	7:48 PM
Total sites	199,557
Total devices	232,734
Total AC tonnage	846,367
Event window temperature (F)	100.6
Full event hours load reduction (MW)	236.82
Full event hours % load reduction	34.2%
All event hours load reduction (MW)	201.29
All event hours % load reduction	29.9%

Hour ending	Reference load (MW)	Estimated load w/ DR (MW)	Load reduction (MW)	% Load reduction	Avg temp (F, site weighted)	Uncertainty adjusted impact - Percentiles		Std. error	T-statistic
						5th	95th		
1	367.43	360.50	6.93	1.9%	82.03	0.87	12.99	3.68	1.88
2	309.42	304.00	5.42	1.8%	80.85	-0.09	10.92	3.35	1.62
3	268.75	263.89	4.85	1.8%	79.91	-0.06	9.77	2.99	1.62
4	241.34	236.43	4.90	2.0%	78.86	0.51	9.30	2.67	1.84
5	224.46	217.72	6.74	3.0%	77.74	3.08	10.41	2.23	3.03
6	214.65	210.65	4.00	1.9%	76.93	0.55	7.45	2.10	1.91
7	218.21	214.71	3.50	1.6%	76.54	0.09	6.91	2.07	1.69
8	231.63	228.79	2.83	1.2%	76.36	-1.11	6.78	2.40	1.18
9	264.30	256.54	7.77	2.9%	76.27	2.84	12.69	2.99	2.59
10	302.48	296.85	5.63	1.9%	78.31	0.23	11.02	3.28	1.72
11	362.18	361.54	0.64	0.2%	83.13	-3.27	4.55	2.38	0.27
12	451.59	452.23	-0.64	-0.1%	88.85	-4.55	3.27	2.38	-0.27
13	556.08	552.48	3.60	0.6%	93.73	-4.31	11.51	4.81	0.75
14	643.39	570.51	72.89	11.3%	97.47	64.47	81.30	5.11	14.25
15	685.85	432.43	253.43	37.0%	101.13	244.52	262.34	5.42	46.78
16	713.48	453.87	259.61	36.4%	101.79	250.37	268.85	5.62	46.21
17	700.20	459.69	240.50	34.3%	102.56	230.83	250.18	5.88	40.89
18	692.66	465.69	226.97	32.8%	100.00	217.89	236.06	5.52	41.09
19	669.46	465.87	203.59	30.4%	97.36	195.43	211.75	4.96	41.06
20	608.10	456.08	152.02	25.0%	94.97	143.84	160.19	4.97	30.59
21	572.36	689.30	-116.94	-20.4%	91.93	-124.62	-109.26	4.67	-25.04
22	519.66	655.21	-135.55	-26.1%	87.98	-143.28	-127.82	4.70	-28.83
23	451.22	557.60	-106.37	-23.6%	85.33	-113.81	-98.93	4.52	-23.53
24	385.11	457.05	-71.94	-18.7%	83.61	-78.32	-65.56	3.88	-18.55
Daily	Reference load (MWh)	Estimated load w/ DR (MWh)	Energy savings (MWh)	% Change	Avg. Daily Weighted temp (F)	Uncertainty adjusted impact - Percentiles 5th	95th	Std. error	T-statistic
Daily kWh	10654.01	9619.63	1034.38	10.8%	87.24	1001.68	1067.08	19.88	52.03

	Step	Example
2	**Collect historic forecasted planning values**	At a high level, the inputs are summarized below. The data inputs are intentionally structured so they can merge with the inputs developed in step 1.

Component	Weather Sensitive Resources	Non-Weather Sensitive Resources
Forecasted per unit load reduction capability (kW)	Table by hour of day and average daily temperature bins (TTM)	Table by hour of day and month (ex ante load impact tables)

	Step	Example
3	**Merge dataset from Steps 1 and 2.**	Below is an example for 10 hours of the merged inputs for a weather-sensitive resource.

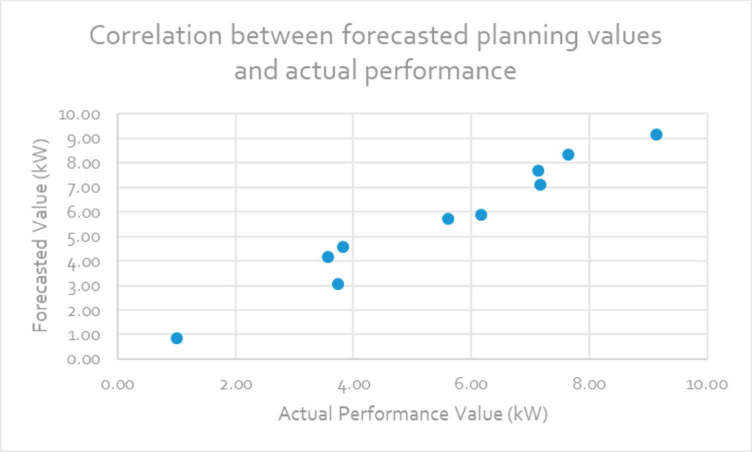
Non-weather-sensitive inputs are merged with bids for top 100 hours based on day type, month, and event hour. Weather-sensitive inputs are merged based on temperature and event hour.

Resource Name	Date	Hour	Start Time	Temp	Event Duration	Actual per Unit Performance (kW)	Forecasted Planning per Unit Value (kW)
Resource A	6/15/2021	21	6 PM	90	4	13.06	12.41
Resource A	6/16/2021	20	6 PM	81	4	88.16	74.65
Resource A	6/16/2021	21	6 PM	81	4	67.91	76.65
Resource A	6/17/2021	20	6 PM	81	4	26.19	28.83
Resource A	6/17/2021	21	6 PM	81	4	45.51	46.91
Resource A	6/17/2021	22	6 PM	81	4	37.78	37.05
Resource A	6/18/2021	20	6 PM	75	4	83.90	72.99
Resource A	6/18/2021	21	6 PM	75	4	15.65	13.78
Resource A	7/8/2021	20	6 PM	80	4	28.10	29.85
Resource A	7/8/2021	21	6 PM	80	4	91.51	93.64

5 **Aggregate bids and ex ante load impacts and calculate ratio.**

The average actual performance kW is divided by the total ex ante kW predicted to be available for all events. We use average impacts instead of aggregate MW as often the entire DR resource is not dispatched during operations. The result produces a ratio that assesses how well the actual performance aligned with the values produced by the ex-ante model.

Below is a comparison of the sample actual performance and forecasted values across all event hours for the DR season. As expected, the two are highly correlated, which indicates good alignment between the actual performance and the planning values.



Correlation between forecasted planning values and actual performance

Below is an example of the summed inputs and ratio calculation. A value of 1.0 indicates perfect alignment. A value greater than 1.0 indicates that the actual performance is greater than the values in the

$$Metric = \frac{\sum Actual\ Performance\ kW}{\sum Forecasted\ Ex\ Ante\ kW}$$

planning model. A value less than 1.0 indicates that the actual performance is lower than the values in the planning model.

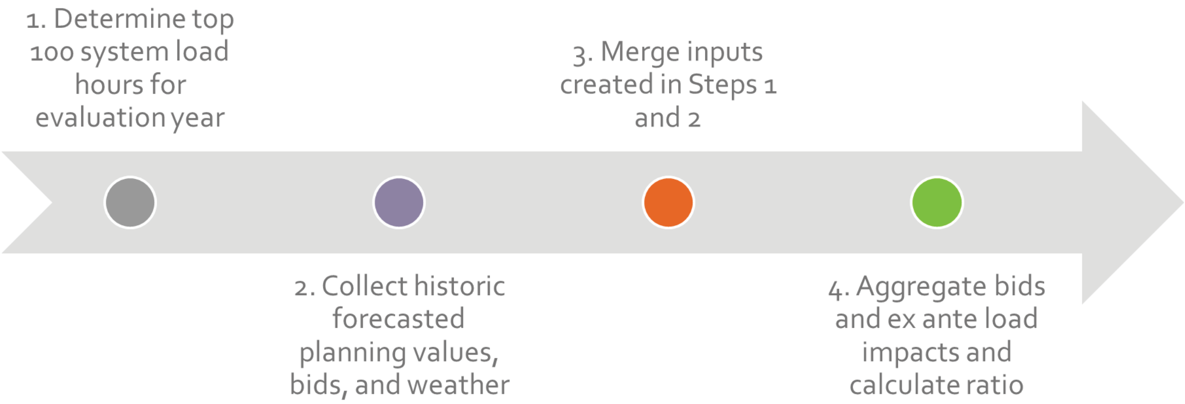
	Average Actual Performance (kW)	Average Forecasted Planning TTM Value (kW)
TOTAL	4.68	4.49
RATIO	1.04	

APPENDIX F: BID ALIGNMENT METRIC

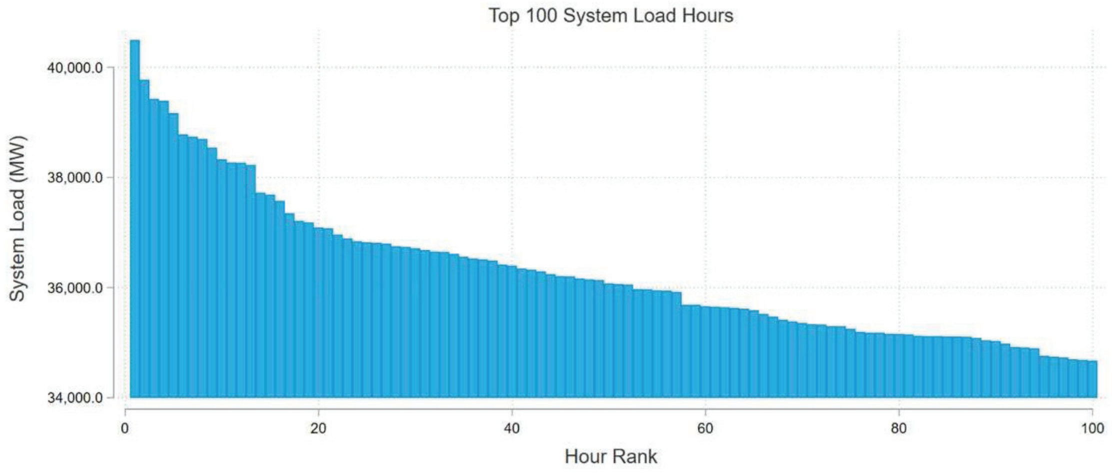
The bid alignment metric aims to determine whether historic bids align with the forecasted capability used for planning (ex-ante impacts). The example metric is a ratio between the historic bidding values and the capability forecasted by the historic ex-ante model. We recommend narrowing the comparison to the top 100 net load hours for each year for simplicity and because these hours are when DR resources are most needed. A ratio of 1.0 indicates full alignment between operations and planning, a value greater than 1.0 means that the bid values were greater than the capability forecasted by the ex-ante model, and a value less than 1.0 would indicate that the bid values are lower than the values indicated by the planning model.

The goal of the bid alignment metric is to use a standardized metric that is easy for all parties to understand and has a transparent calculation method. This metric can let implementers, planners, and CAISO know if there needs to be an adjustment to the planning model or the bidding process to improve alignment.

The figure below illustrates the key steps for developing the comparison between ex-ante values and bid values. The table below details the steps to produce the bid alignment metric.



<table>
<tr><th></th><th>Step</th><th>Example</th></tr>
<tr><td>1</td><td>Determine the Top 100 hours for the evaluation year.

Use the CAISO net system load to determine the top 100 hours for the year.</td><td>Below is a graph of the top 100 system load hours for 2021.

 </td></tr>
<tr><td>2</td><td>Collect historic forecasted planning values, bids, enrollments, and weather</td><td>At a high level, the inputs are summarized below. The data inputs are intentionally structured so they can merge with the inputs developed in step 1.
<table>
<tr><th>Component</th><th>Weather Sensitive Resources</th><th>Non-Weather Sensitive Resources</th></tr>
<tr><td>Historic forecasted planning values</td><td>Table by hour-of-day, and average daily temperature bins, event start, and hours into the event (TTM)</td><td>Table by hour-of-day and month (ex-ante load impact tables)</td></tr>
<tr><td>Historic bids for evaluation</td><td colspan="2">Table that includes date, hour, number of customers, and bid MW for CAISO. The bids should be aggregated across sub-LAPS since the goal is to assess if the capacity is being bid into the market.</td></tr>
<tr><td>Historic Weather Conditions</td><td colspan="2">Table that includes the date, hour, and temperature.</td></tr>
</table></td></tr>
<tr><td>3</td><td>Merge dataset from Steps 1 and 2.</td><td>Below is an example of 10 hours of the merged inputs for a weather-sensitive resource.</td></tr>
</table>

Non-weather-sensitive inputs are merged with bids for the top 100 hours based on day type, month, and event hour. Weather-sensitive inputs are merged based on temperature and event hour.

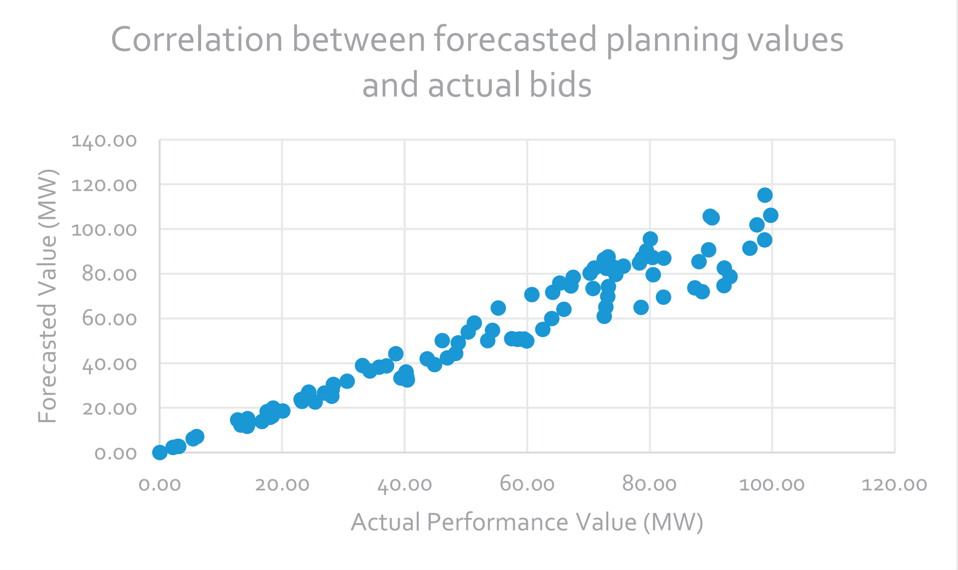
Resource Name	Date	Hour	Start Time	Temp	Event Duration	Bid Value (MW)	Forecasted Planning Value MW (Ex-Ante /TTM)
Resource A	6/15/2021	21	6 PM	90	4	15.03	12.63
Resource A	6/16/2021	20	6 PM	81	4	78.76	88.96
Resource A	6/16/2021	21	6 PM	81	4	26.96	26.56
Resource A	6/17/2021	20	6 PM	81	4	19.74	19.80
Resource A	6/17/2021	21	6 PM	81	4	39.89	42.84
Resource A	6/17/2021	22	6 PM	81	4	7.84	8.52
Resource A	6/18/2021	20	6 PM	75	4	99.25	113.17
Resource A	6/18/2021	21	6 PM	75	4	87.18	79.30
Resource A	7/8/2021	20	6 PM	80	4	54.47	62.25
Resource A	7/8/2021	21	6 PM	80	4	36.61	37.77

5 **Aggregate bids and ex-ante load impacts and calculate the ratio.**

The total bid MW available for the top 100 hours is divided by the total ex-ante MW predicted to be available for the top 100 hours. The result produces a ratio that assesses how well the bid values aligned with the values produced by the ex-ante model.

$$Metric = \frac{\sum Historic\ Bid\ MW}{\sum Forecasted\ Planning\ MW}$$

Below is a comparison of the sample bid values and forecasted values across the top 100 hours. The two are highly correlated in the example, indicating good alignment between the actual bids and the forecasted planning values.



Correlation between forecasted planning values and actual bids

Below is an example of the summed inputs and ratio calculation. A value of 1.0 indicates perfect alignment. A value greater than 1.0 indicates that the bid values were greater than the forecasted planning values. A value less than 1.0 indicates that the bid values were lower than the forecasted planning values.

	Bid Value (MW)	Ex Ante TTM Value (MW)
TOTAL	4,882	4,629
RATIO	1.05	

DOCKETED	
Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	246232
Document Title:	OhmConnect - Simplified LIPs Proposal
Description:	N/A
Filer:	Courtney Wagner
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/28/2022 11:33:45 AM
Docketed Date:	9/28/2022

“Simplified LIPs” Proposal

Prepared for: California Energy Commission DR QC Working Group

September 26, 2022

Table of Contents

Introduction......3

Summary of Proposed Changes......4

Description of Proposed Changes......6

Proposed Changes to Outputs (Protocols 1-26)......6

Proposed Changes to LIP Evaluation Process (Protocol 27)......8

Appendix A: Proposed Final Set of Revised LIPs......10

Appendix B: Evaluation Plan Template......11

Introduction

Since the California Public Utilities Commission (Commission) affirmed the applicability of the Demand Response (DR) Load Impact Protocols (LIPs) to third-party DR in Decision (D.) 19-06-026, it has become apparent that today's LIPs process is burdensome and inefficient, both for third-party DR providers (DRPs) who participate in the Resource Adequacy (RA) market, as well as Energy Division Staff. One potential way to mitigate these problems is to streamline the LIPs so that evaluations are easier to perform while ensuring they remain sufficiently robust for the Energy Division to conduct an informed assessment of each DRP's DR portfolio. To the extent that the load impact evaluations are performed for the limited purpose of determining DRPs' Qualifying Capacity (QC) value, OhmConnect proposes that:

1. Certain protocols be streamlined or eliminated;
2. the evaluation process be simplified and shortened; and
3. that transparency around the determination of QC values from ex ante estimates be increased.

Each of these is discussed further below.

Why is simplification necessary?

The purpose of this proposal is to winnow down the LIP requirements to *just* those that are necessary for the determination of RA QC. At nearly 150 pages, the current LIP Guidance document is intimidating and incredibly confusing to DRPs. Many spend considerable time and effort determining which protocols are relevant and end up producing outputs that are not useful for RA QC. In a process where the learning curve is already steep, the continued inclusion of protocols/requirements that are not applicable only serves to increase the perceived barrier to entry and causes frustration for DRPs undertaking the evaluation for the first time.

The LIP guidance document should be as simple and to-the-point as possible for DRPs undertaking the evaluation for RA QC purposes only.

Does this proposal apply to all DRPs?

This proposal is intended to apply to DRPs that are undertaking the evaluation for the purposes of receiving an RA QC only (i.e., most LIP reports done by third-party DRPs). Some protocols, while completely unnecessary for RA, may still be useful for long-term planning and other purposes. To that end, it may be necessary to retain two version of the LIP guidance document: the full document as it exists today for a broader set of applications, and a briefer document for DR RA QC.

How does this proposal apply to the 24-hour slice-of-day framework?

This proposal does not affect the methodological approaches as described in the present LIPs; it simply removes unnecessary outputs and shortens the process. To that end, it can be compatible with any number of approaches to modify the LIP outputs for the slice-of-day RA program. OhmConnect does not opine on any individual proposal here. However, the need to eliminate unnecessary analyses and processes that exist today is only amplified if the modification of the LIPs to comport with the 24-hr framework *increases* the cost and complexity of the evaluation.

Summary of Proposed Changes

Table 1. Summary of Proposed Changes

Group	Protocol	Summary	Proposed Disposition
Evaluation Plan	1	Evaluation plan is required	Replace the narrative with a standardized tabular form Mandatory only for DRPs performing evaluations for the first time or if material changes to the DR program or evaluation approach are expected
	2	Requirements beyond resource planning and additional to protocol 4-27, i.e., resource adequacy	Eliminate
	3	Questions/issues that must be addressed by the evaluation plan	Mandatory only for DRPs performing evaluations for the first time or if material changes to the DR program or evaluation approach are expected
Ex post for event-based DR	4	Hour-of-day and daily impact estimates	Keep
	5	Average and total impact	Eliminate. Not a useful reporting metric.
	6	Percentile-based uncertainties	Keep
	7	Tabular output format	Keep
	8	Reporting requirements	Keep at individual event OR representative monthly roll-up level if no of events > n: • list of events • No. of customers enrolled • No. of customers called • Event start and end times Eliminate typical and average event day
	9	Error metrics for day matching results	Keep
	10	Error metrics for regression method results	Keep
Ex post for non-event-based DR	11	Hour-of-day and daily impact estimates	Eliminate
	12	Average and total impact	Eliminate
	13	Percentile-based uncertainties	Eliminate
	14	Tabular output format	Eliminate
	15	Reporting requirements	Eliminate

	16	Error metrics for regression method results	Eliminate
Ex ante	17	Ex ante based on ex post results	Keep
	18	Hour-of-day impacts for all day types	Keep for slice-of-day purposes; Align required "day type(s)" with the adopted SOD program
	19	Change in monthly/annual energy use	Eliminate
	20	Uncertainty-adjusted impacts by percentile.	Keep
	21	Tabular reporting format	Keep but reduce “day type(s)” needed to those required for the RA program
	22	Estimates for typical event, average, and system peak day types (1-in-2 and 1-in-10)	Keep RA-relevant day type(s) only (Currently, this is monthly system peak under IOU 1-in-2 weather)
	23	Statistical tests and methods (same as 10,16 regression statistics)	Keep
Misc. technical	24	Portfolio adjustments	Eliminate
	25	Sampling requirements	Eliminate
Evaluation report	26	Evaluation report requirements	Keep as optional
		Study methodology	Keep
		Validity assessment	Keep
		Detailed study findings	Mostly keep Eliminate comparison to prior year's study in ex ante. This introduces confusion when done for third-parties that receive a QC based on a two-year old analysis and may sell only a portion of the QC.
Process and public review	27	Process and public review	Shorten process; eliminate public review unless common transparency metrics are adopted

Description of Proposed Changes

This sections below review each of the proposed changes to the outputs and process. A summary is provided in Table 1, above. The final set of proposed protocols is provided in Appendix A.

Proposed Changes to Outputs (Protocols 1-26)

- **Protocols 1, 3, and part of 26 (evaluation plan):** These protocols require the submission of an evaluation plan and specify requirements for its content.

  Proposal: In instances where a DRP has done LIP evaluations for several years, and very little has changed in terms of the program or the methodological approach, the evaluation plan loses value. To reduce time and cost—as well as the review burden placed on ED staff—evaluation plans should only be mandatory for DRPs undertaking the process for the first time, or when, per the evaluator's judgment, material changes are expected in the methodological approach. If judged valuable, the Commission may require all other DRPs to submit a brief filing stating that their evaluation approach remains unchanged from the prior year.

  The Commission may also consider replacing the current narrative format with a standardized template that asks the evaluator to respond to a prescribed set of questions. In addition to reducing the time-intensity of this exercise, an evaluation plan that solely requires responses to a simple table or form may facilitate Staff review and DRP-to-DRP comparisons. A template is provided in Appendix B.

- **Protocol 2 (evaluation plan):** This protocol requires DRPs to state whether the evaluation is intended to meet the requirements beyond long-term resource planning.

  Proposal: For third-party DRPs are undertaking this evaluation only for the purposes of receiving a QC value, this protocol is moot and can be eliminated.

- **Protocol 5 (ex post)/Protocol 19 (ex ante):** These counterpart protocols require that average mean change in energy use per year be reported for all participants and for the sum of all participants on a DR resource for the year over which the evaluation is conducted.

  Proposal: Protocols 5 and 19 should be removed in their entirety for load impact evaluations performed solely for determining the QC value of third-party DR. Annual averages are not necessary for the assignment of QC and are not telling for highly seasonal resources.

- **Protocol 8 (ex post):** This protocol describes the day types and level of aggregation for which load impacts are to be reported. It requires ex post impacts to be provided for "each day on which an event was called" and the "average event day" across the evaluation period (typically, over a year).

  Proposal: The average event day impact over the course of a year does not lend itself to the calculation of ex ante impacts for the purposes of QC because QC values are assigned monthly. Moreover, for weather-sensitive or other seasonal resources, a yearly average event day may not be very instructive. For these reasons, the requirement to calculate ex post impacts (both per customer and in aggregate) for the average event day should be eliminated.

- **Protocols 11-16:** These protocols discuss evaluation methods for non-event based DR programs.

Proposal: These protocols are not applicable to third-party DR, all of which is market-integrated, and should be removed in their entirety.

- **Protocol 22:** This protocol specifies the analyses required for each day type using CAISO and IOU 1-in-2 and 1-in-10 weather conditions

  Proposal: The day types and weather conditions should align with the requirements of the RA program. All extraneous scenarios should be eliminated.

  Currently, only the "monthly system peak day" calculated under IOU 1-in-2 weather conditions is needed to estimate the QC value for RA purposes and should be the only scenario required by the protocol. Calculating the "average weekday" and the "typical event day" under 1-in-2 weather conditions and calculating anything under 1-in-10 weather conditions is not relevant to estimating the RA QC value of a DR resource and therefore represents unnecessary costs to the DRP to produce and describe.

  Note that while the CAISO performs modeling under 1-in-10 weather conditions, *the outputs of third-party DRPs' LIP reports' 1-in-10 scenarios are not used as inputs by the CAISO in these exercises or any other agency for any purpose*. Moreover, given that approved QC often does not match the ex ante model predictions, it would be inappropriate for any external party to use the unapproved ex ante outputs for any planning purposes.

- **Protocol 26:** This protocol specifies the format and content of the load impact evaluation reports. One requirement of this protocol is that "a comparison of impact estimates derived from the analysis and those previously obtained in other studies and those previously used for reporting of impacts toward resource goals, and a detailed explanation of any significant differences in the new impacts and those previously found or used."

  Proposal: Some portions of this protocol should be eliminated because prior studies may not always be relevant. For example, studies using a methodology different from the LIPs would be like comparing apples to oranges. Even prior-year reports using the LIPs will often not be useful if a DRP's portfolio changes significantly from one year to the next in terms of number and/or type of customers, enabling technologies, and customer location. Furthermore, DRPs that are new to the California market will have no prior-year studies.

- **Define number of forward-projection years:** IOUs have traditionally forecasted ex ante impacts a decade ahead. Third-party DRPs have thus far been asked to project impacts for three years out to match the three-year forward procurement requirement of Local RA. However, QC is only approved one-year forward; the subsequent two-year modeling is not approved or used at all. Therefore, it is currently unclear what value three-year forward projections serve in third-party load impact evaluations.

  Proposal: The simplified LIPs should clarify the forward forecast requirements and how these requirements interplay with the final approved QC. If a DRP is required to provide impacts three years' forward, it should ostensibly receive QC for three years based on ED assessment of the DRP forecasts. However, if ED determines that a DRP should only receive QC values for the following RA compliance year, the purpose of three-year forecasts becomes unclear. In this case, developing and describing these forecasts is an unnecessary cost to the DRP and the forecast requirement should be reduced to one year ahead only.

Proposed Changes to LIP Evaluation Process (Protocol 27)

Public review of proprietary data should be reconsidered

The continued utility of public review for third-party DR LIP evaluations is unclear and should be reconsidered.

LIPs were developed for the purpose of long-term resource planning and determining the cost-effectiveness of regulated IOU DR programs. That environment has fundamentally changed with the proliferation of both third-party DRPs as well as non-IOU LSEs. In this new environment, DRPs are engaged in competitive activity with one another, so disclosure of market-sensitive information could cause harm to a DRP's competitive position. In response to this threat, many DRPs choose to redact large portions of their LIP reports. The public versions of the load impact evaluations submitted in recent years vary widely in their level of redactions. While some DRPs do not use redactions, others heavily redact large portions of their evaluations. At this time, there does not appear to be a uniform understanding of the data that can and cannot be redacted in a DRP's load impact evaluation.

The value of submitting heavily redacted reports to multiple listservs and requiring their presentation in public workshops is questionable. It is closer to spam than true public review and unnecessarily lengthens the timeline of the evaluation process.

One option is to determine an acceptable set of data privacy metrics and transparency requirements and continue public review. Another option is to eliminate public review for third-party DRP LIP evaluations. Continuing to require public review without common transparency requirements is a waste of resources.

For simplicity and efficiency, this proposal recommends the elimination of public review for third-party DRP LIP evaluations. Full, unredacted reports will be submitted to CPUC Energy Division Staff and CEC Staff as appropriate. They will also be available to other parties such as the Public Advocates Office and CAISO. These parties will be able to submit comments to the DRP directly by an established deadline.

QC Determination by Energy Division Should be Transparent

Energy Division Staff should continue to have discretion over final QC determination based on the available LIP evaluation. However, the QC assignment process must be significantly more transparent.

Currently, DRPs expend considerable time and resources performing rigorous evaluations. However, to the extent that ED Staff arrive at a QC valuation that is different from the ex ante model, the differences are not explained. This makes the process feel arbitrary, despite the time and expense involved, and results in a lack of trust. This status quo is both unfair and counterproductive.

Each DRP should receive, together with their QC values, a detailed explanation of any discrepancies between the ex ante modeling presented in the report and the approved QC. The explanation should identify and justify any differences between the submitted and approved customer count as well as per-customer impacts. The provided information, including any derates, should be granular enough for the DRP to reproduce the arrived at QC using the alternative set of customer enrollments and impacts.

The LIP Timeline Should be Shortened

The LIP timeline should be shortened and QC values assigned much earlier in the year.

The current timeline, which assigns QC values to third-party DRPs by mid-September is not workable. It creates a marketplace where resource-owners sell capacity well in advance of knowing the value of that capacity. While the ex ante modeling in the submitted reports should serve as a guide, the approved QC may not actually be consistent with the ex ante modeling (see discussion in next section). By the time final QC is approved, DRPs have just over a month to reconcile any differences between expected/contracted capacity and the actual QC ahead of the October 31 year-ahead showing deadline. This is not enough time and creates unnecessary risk for both the DRP and the purchasing LSE.

The below timeline reduces the LIP report production to approximately four months and results in a QC value by July 1.

Table 2. Proposed Timeline

Deliverable	**Current**	**Proposed**
Evaluation Plan	Dec 31	Jan 15 (if applicable)
>> Comments on evaluation plan	Jan 15	Jan 25 (if applicable)
Draft evaluation report	March 11	March 15
>> Comments on draft evaluation	March 25	March 30
Final evaluation report	April 1	April 20
LIP workshop	mid-May	n/a
QC values assigned	mid-Sep	July 1

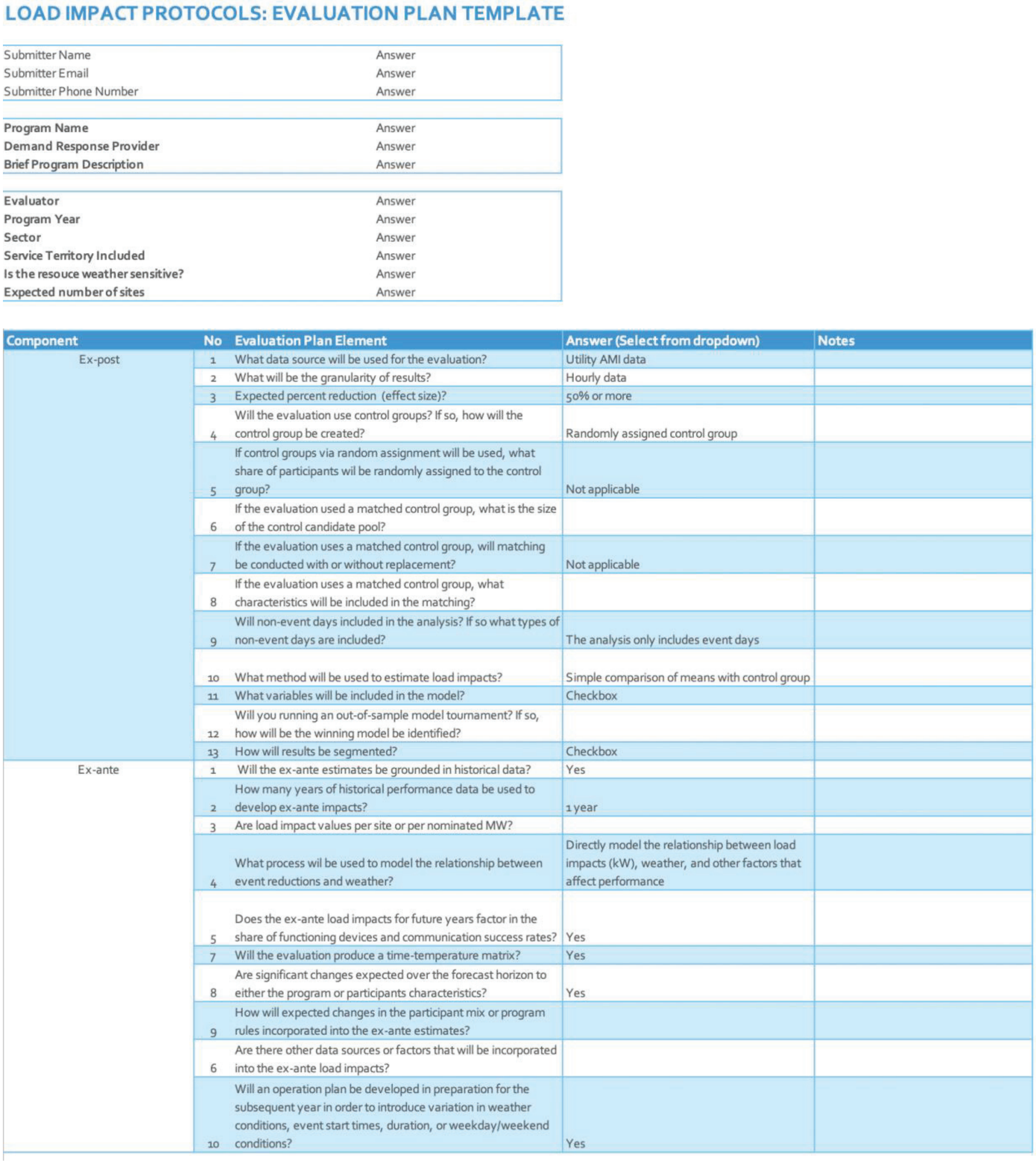
Appendix A: Proposed Final Set of Revised LIPs

The following table outlines the protocols that should be included in the LIP guidance document for third-party DRPs performing evaluations for the sole purpose of RA QC.

Group	Protocol	Summary
Evaluation Plan *(If applicable)*	1	Submit evaluation plan
	2	Questions/issues that must be addressed by the evaluation plan
Ex post	3	Hour-of-day and daily impact estimates
	4	Percentile-based uncertainties
	5	Tabular output format
	6	Reporting requirements (Required for RA relevant day types only)
	7	Error metrics for day matching results
	8	Error metrics for regression method results
Ex ante	9	Ex ante based on ex post results
	10	Hour-of-day impacts for all day types
	11	Uncertainty-adjusted impacts by percentile
	12	Tabular reporting format
	13	Estimates monthly system peak day under IOU 1-in-2 weather
	14	Statistical tests and methods
Evaluation report	15	Evaluation report requirements
		Study methodology
		Validity assessment
		Detailed study findings
Process & Timeline	16	Process and Timeline

Appendix B: Evaluation Plan Template

In the cases where an evaluation plan is required, the written narrative should be replaced by a standardized form. The following template was put together by Josh Bode, Demand Side Analytics and generously shared with OhmConnect for the purposes of this proposal. The form can be created in Microsoft Excel or a similar platform.



LOAD IMPACT PROTOCOLS: EVALUATION PLAN TEMPLATE

Submitter Name	Answer
Submitter Email	Answer
Submitter Phone Number	Answer

Program Name	Answer
Demand Response Provider	Answer
Brief Program Description	Answer

Evaluator	Answer
Program Year	Answer
Sector	Answer
Service Territory Included	Answer
Is the resouce weather sensitive?	Answer
Expected number of sites	Answer

Component	No	Evaluation Plan Element	Answer (Select from dropdown)	Notes
Ex-post	1	What data source will be used for the evaluation?	Utility AMI data	
	2	What will be the granularity of results?	Hourly data	
	3	Expected percent reduction (effect size)?	50% or more	
	4	Will the evaluation use control groups? If so, how will the control group be created?	Randomly assigned control group	
	5	If control groups via random assignment will be used, what share of participants wil be randomly assigned to the control group?	Not applicable	
	6	If the evaluation used a matched control group, what is the size of the control candidate pool?		
	7	If the evaluation uses a matched control group, will matching be conducted with or without replacement?	Not applicable	
	8	If the evaluation uses a matched control group, what characteristics will be included in the matching?		
	9	Will non-event days included in the analysis? If so what types of non-event days are included?	The analysis only includes event days	
	10	What method will be used to estimate load impacts?	Simple comparison of means with control group	
	11	What variables will be included in the model?	Checkbox	
	12	Will you running an out-of-sample model tournament? If so, how will be the winning model be identified?		
	13	How will results be segmented?	Checkbox	
Ex-ante	1	Will the ex-ante estimates be grounded in historical data?	Yes	
	2	How many years of historical performance data be used to develop ex-ante impacts?	1 year	
	3	Are load impact values per site or per nominated MW?		
	4	What process wil be used to model the relationship between event reductions and weather?	Directly model the relationship between load impacts (kW), weather, and other factors that affect performance	
	5	Does the ex-ante load impacts for future years factor in the share of functioning devices and communication success rates?	Yes	
	7	Will the evaluation produce a time-temperature matrix?	Yes	
	8	Are significant changes expected over the forecast horizon to either the program or participants characteristics?	Yes	
	9	How will expected changes in the participant mix or program rules incorporated into the ex-ante estimates?		
	6	Are there other data sources or factors that will be incorporated into the ex-ante load impacts?		
	10	Will an operation plan be developed in preparation for the subsequent year in order to introduce variation in weather conditions, event start times, duration, or weekday/weekend conditions?	Yes	

DOCKETED

Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	246235
Document Title:	CEDMC Incentive-Based Proposal
Description:	N/A
Filer:	Courtney Wagner
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/28/2022 11:38:39 AM
Docketed Date:	9/28/2022

CALIFORNIA
Efficiency
+ Demand
Management
COUNCIL

849 East Stanley Blvd. #264
Livermore, CA 94550
Tel: 925.785.2878
Email: policy@cedmc.org

September 27, 2022

California Efficiency + Demand Management Council Incentive-Based Method DR Counting Proposal

Introduction

The California Efficiency + Demand Management Council ("Council") provides its Incentive-Based Method demand response ("DR") counting methodology proposal for inclusion in the California Energy Commission's ("CEC") Phase 2 Supply Side DR Working Group ("Working Group") report as a long-term approach for determining the Qualifying Capacity ("QC") values of IOU and third-party DR. As explained in greater detail below, the Council believes that an entirely new approach to determining the QC value of DR is needed because the existing approach stifles the growth of third-party DR and is does not fit well within a paradigm of market-integrated DR.

The overriding goal of the effort to develop a new long-term DR counting methodology should be to encourage customer DR participation, attract market entry of DR providers while encouraging IOU DR program growth, and promote high quality, reliable DR. The Load Impact Protocols ("LIPs") and the associated LIP process promote none of these outcomes. For DR to grow, a new approach is needed that will accurately reflect the capabilities of each IOU and DR provider, be transparent in how a DR portfolio QC value is determined, incur a reasonable cost, and require a reasonable amount of time to implement.

The Existing LIP-Based DR Counting Process Is Problematic on Many Levels

Since the LIPs were approved in D.08-04-050, they have been utilized to determine the Resource Adequacy ("RA") value of IOU DR programs. In CPUC Decision ("D.") 19-06-026, the CPUC expanded application of the LIPs to third-party DR providers to determine their QC values beginning with the 2020 RA year.[1] Since then, it has become very apparent that the LIPs are highly problematic for DR providers for several reasons, all of which combine to act as a significant barrier to third-party DR participation in California:

1. <u>The effectiveness of the LIPs in accurately predicting QC values is unclear.</u> The LIPs rely heavily on historical DR performance to forecast future performance. This has generally been adequate for most IOU DR programs because they have historically tended to be more static or at

---

[1] D.19-06-026, at Ordering Paragraph 18.

least more predictable than third-party DR providers' portfolios. In contrast, under the current paradigm, DR provider portfolios can vary significantly in size and customer composition from year to year based on their success, or lack thereof, in gaining Demand Response Auction Mechanism ("DRAM") contracts or bilateral contracts with IOUs or other LSEs. DR providers have a financial interest in sizing their portfolios to meet their market commitments, so their customer enrollment levels often directly reflect their contractual commitments.

Further exacerbating the comparatively fluid nature of DR provider portfolios is the extended LIP process timeline which leads to performance data being used from up to two years prior to the RA Delivery Year. For example, the LIP process that kicked off in December 2021 uses data from the 2021 RA year to derive QC values for the 2023 RA year. Under a majority of circumstances, it is difficult to argue that data up to two years old is relevant to forecasting performance.

2. <u>The LIP process is very time-consuming and limits participation in solicitations.</u> The LIPs entail a ten-month process beginning in December each year that leads to a LIP report for each IOU and DR provider on April 1. The LIP reports are then assessed by the CPUC Energy Division over the following five months to determine the QC values of these DR programs in September. Receiving QC values this late in the year is problematic for DR providers because the Energy Division assigns preliminary RA requirements to IOUs and LSEs in June. This often kicks off the process by LSEs to begin contracting RA for the following year, so because DR providers do not know the exact amount of RA capacity they have available to sell until September puts them at a disadvantage. This is anti-competitive because it favors more static "steel in the ground" resources, whose QC values are generally fixed and therefore have more certainty as to their QC values from year to year.

3. <u>The LIP process is costly with no guarantee of cost recovery by DR providers.</u> The LIP process entails extensive analysis and reporting which requires the use of specialized consultants. This is very costly (typically more than $100,000), especially for comparatively small portfolios because there is typically a floor to the consultant fees, regardless of the portfolio size. IOUs are guaranteed recovery of these costs from ratepayers through their DR program budgets but DR providers do not have that luxury. This creates a clear competitive advantage for IOU DR programs versus third-party DR and reduces the motivation of IOUs to seek a less costly DR counting approach. Such a significant investment by DR providers, with no promise of cost recovery, as a cost of entry to the RA market has discouraged some DR providers from participating in the LIP process. Consequently, the quantity of third-party DR is artificially depressed for non-IOU LSEs.

4. <u>The need for consultants to perform the LIP analysis acts as a bottleneck.</u> While DR providers are permitted to perform their own LIP evaluations, many choose not to due to a lack of internal expertise and/or to avoid the perception of bias. There are a limited number of consultants who are able to perform the LIP analysis and, due to the intensive nature of this work, many consultants are limited in the number of LIP analyses they can perform for any given year. This

leads to many IOUs and DR providers chasing a limited number of consultants which can lead to DR providers being frozen out of the LIP process and unable to sell their capacity through RA contracts.

5. The Energy Division assessment of LIP reports lacks transparency. Once IOUs and DR providers submit their LIP reports on April 1, the Energy Division then determines whether to approve the QC that is claimed in each LIP report or to discount it if the claimed QC is overly optimistic. To the extent that a discount is applied to a DR provider's claimed QC, no explanation is typically provided to the DR provider as to the exact reasons for the discount. For example, the Energy Division can discount a DR provider's QC based on the per-customer load impact, enrollment forecast, or both. However, the Energy Division will not always explain the approved per-customer load impact and enrollment levels; instead, it will often simply provide the approved overall QC value with no explanation as to the underlying reasoning behind any changes to the IOU's or DR provider's claimed QC values. To the Energy Division's credit, it has developed its *Guide to CPUC's Load Impact Protocols (LIP) Process* to provide information on best practices for LIP reports, but transparency remains a significant problem.

6. There is no process for directly linking CAISO market performance with QC values. The current LIP process does not compare the QC value of an IOU DR program or third-party DR contract to CAISO market performance. The primary reason for this is that the LIPs require that ex post DR performance be normalized to peak 1-in-2 weather conditions in order to compare performance to its ex ante load impacts on an "apples to apples" basis. This prevents a direct comparison of DR performance to QC values.

A More Streamlined DR Counting Methodology with a Standardized Enforcement Mechanism Is Needed

The Council believes that most future DR growth will occur primarily through third parties because they have a commercial interest in growing their portfolios whereas IOUs do not have this motivation. To attract this third-party DR, a more streamlined DR QC methodology is needed that better suits the more dynamic nature and associated business needs of DR providers while being equally effective in determining DR QC values for IOUs and DR providers. Specifically, the new methodology should:

1. Reflect IOU and DR provider assessments of their capabilities based on the most current information possible. This will better ensure that the QC values awarded by the Energy Division reflect the most recent enrollment and per-customer load impact data.

2. Minimize the time required to receive a QC value from the Energy Division. This will better enable DR providers to participate in IOU and LSE solicitations as they come up.

3. Be as transparent as possible. It is critical that DR providers understand the reasoning behind Energy Division assessments of their QC values. Without the Energy Division's clear feedback, DR providers will have no opportunity to apply lessons learned in order to develop the optimal portfolio.

4. Minimize the cost to DR providers and ratepayers. The cost to gain a QC value should be low to attract as many DR providers and, by extension, DR capacity, as possible and reduce the cost to IOU ratepayers.

5. Eliminate the need for outside consultants. The QC methodology should be simple enough for reasonably sophisticated DR providers and all IOUs to utilize it without the need to retain a consultant, if they choose not to.

6. Reduce the Energy Division workload to determine DR QC values. The output of the QC methodology should be streamlined so as to accurately inform the Energy Division in its assessment of QC values without overwhelming them.

The Incentive-Based Method DR Counting Proposal Reduces Barriers to DR Providers While Providing More Rigor

The Council proposes its Incentive-Based Method on the basis that it meets all of the requirements discussed above. Its general approach is also consistent with that used by the PJM, ISO-New England, and New York Independent System Operator capacity markets in which each DR provider provides its proposed QC values and supporting documentation to the market operator, but with no constraints on the DR provider with regard to their method for estimating their proposed QC values. The market operator then makes a determination on the amount of capacity each DR provider is authorized to sell in the next capacity auction. To ensure that capacity sold in the capacity auction is delivered, an IOU or DR provider failing to deliver its sold capacity is subject to penalties.

From a conceptual standpoint, the approach taken with the Incentive-Based Method differs greatly from the LIPs. The LIPs utilize a great deal of quantitative up-front rigor through a set of numerous regression analyses to forecast the load impact of a DR program or resource under a specific set of weather conditions. In theory, this initial rigor is sufficient to ensure that QC values awarded by the Energy Division are accurate enough to be generally consistent with actual QC deliveries. However, the LIPs are not nimble enough to account for short-term changes to inputs that could undermine the accuracy of the associated analyses. The Incentive-Based Method takes the opposite approach and places a majority of the rigor on the actual, rather than the weather-normalized, performance of the DR programs and resources by incorporating a penalty mechanism to ensure that there are repercussions for significant performance shortfalls.

The Council stresses that its proposed penalty mechanism, explained in greater detail below, is meant to be a minimum, standardized penalty structure. As DR providers themselves, IOUs are currently not subject to penalties for failure to deliver on their committed DR QC values, yet they collect penalties from under-performing DR aggregators that participate in their Capacity Bidding Programs ("CBP") and Base Interruptible Programs ("BIP"). For third-party DR RA contracts, it is already generally standard practice by IOUs and LSEs to include penalty provisions for liquidated damages should the DR RA provider fail to deliver on its contract terms. However, the specific terms on each contract are a result of negotiations between both parties, so the Council's proposed penalty structure provides some degree of transparency and minimum protection for ratepayers. This freedom by IOUs and LSEs to negotiate additional penalty provisions with DR providers also eliminates the necessity to adopt a more rigorous penalty structure than the already-rigorous one the Council proposes.

Methodology Process

The Incentive-Based Method involves the following primary steps:

1. **IOU/DR Provider Analysis:** Once per year (with the option of a mid-year update), the IOU/DR provider would perform an analysis using its choice of analytical tools to calculate its Claimed QC (i.e., the amount of QC the IOU/DR provider forecasts that it can provide) for each hourly slice for each month of the upcoming (current, in the case of an update) RA Delivery Year based on the prevailing CPUC RA framework and DR availability requirements.

   Claimed QC values would be made at the System-level and, optionally, at the Local Capacity Area ("LCA")-level if the IOU/DR provider intends to provide Local RA. IOUs/DR providers could seek QC values for up to three years in advance for purposes of IOU planning and to allow DR providers to execute multi-year RA contracts. Even with multi-year contracts, fresh QC assessments would continue to be required no less frequently than annually to ensure a continued capability to meet commitments.

   The IOU/DR provider would then provide the Claimed QC values and specified Supporting Data to the CPUC Energy Division for review and assessment, just as is currently done under the LIP process. The Council proposes that the Supporting Data consist of those listed below but this could be adjusted in the future as greater experience is gained with this method:
   a. Current and projected number of Service Accounts
   b. Customer class, size, and technology type, if applicable
   c. Projected aggregated load (aggregated capacity in the case of behind-the-meter ("BTM") energy storage)
   d. Projected % of load impact or reduction (projected % of capacity delivered for energy storage)
   e. Nature of load being aggregated
   f. Dispatch method
   g. Historical performance data

2. **Energy Division Assessment:** The Energy Division would assess the IOU/DR provider's Claimed QC values and Supporting Data. If necessary, the Energy Division could request additional documentation or submit clarifying questions. This step is similar to the current step under the LIP process in which the Energy Division reviews LIP reports and may request additional information if necessary. The Council acknowledges concerns that allowing each IOU/DR provider to use the methodology of its choice could place a greater burden on the Energy Division. However, as discussed in detail below, there would be a penalty structure in place to provide after-the-fact rigor, so it will not be necessary that the Energy Division apply the same degree of up-front rigor it uses under the LIP process. Furthermore, the Energy Division would retain the prerogative of unilaterally discounting an IOU/DR provider's Claimed QC, but it would be required to provide a clear explanation for doing so. Once the Energy Division made a determination on the IOU/DR provider's Awarded QC values, it would post the QC values on the current CPUC NQC List for the period requested by the DR provider.

3. **Contracting and Allocating DR Capacity:** Once an IOU received its Awarded QC values, it would then be allocated to LSEs on a pro rata basis as is currently done. DR providers would be free to sell their Awarded QC through RA contracts.

4. **Demonstrated Capacity:** DR performance would be tracked through an annual Demonstrated Capacity process that would directly align CAISO market settlement with capacity performance. This would be necessary to ensure that IOUs and DR providers are bidding into the CAISO market and performing consistent with their committed QC values.

   On an annual basis, for each DR program (in the case of IOUs) or RA contract (in the case of DR providers), IOUs and DR providers would submit to the Energy Division a completed Demonstrated Capacity template comparing their monthly performance in delivering capacity consistent with their committed QC values. IOU DR programs are currently not required to be on Supply Plans so the IOU Demonstrated Capacity template would compare monthly QC values for each program to Demonstrated Capacity; conversely, third-party DR contracts must be on Supply Plans so the DR provider template would compare monthly Supply Plan values to Demonstrated Capacity. Consistent with current practice under the Demand Response Auction Mechanism ("DRAM"), in months for which the local IOU has provided less than 95% of Revenue Quality Meter Data ("RQMD") to a DR provider, the DR provider would be exempt from providing Demonstrated Capacity data and therefore not subject to a penalty. This provision is necessary because without complete RQMD, a DR provider would be at risk of under- reporting its Demonstrated Capacity through no fault of its own.

   Demonstrated Capacity would be assessed at the subLAP level for each DR program or contract and would be based on the following delivery types during the required hour(s) of availability:[1]
   1. CAISO market economic dispatch; if a DR resource is scheduled for less than its monthly QC value (for DR programs) or monthly Supply Plan value (for DR contracts), the ratio of its performance relative to its schedule would apply;
   2. Full dispatch test event (pursuant to prevailing CPUC testing rules); or
   3. CAISO market bids during the applicable Must Offer Obligation ("MOO") hours.

   Demonstrated Capacity reporting would utilize a template similar to the one currently used by DR providers under the DRAM. A draft Demonstrated Capacity template is attached as Appendix A. However, a working group process would be needed to ensure that the final template meets the needs of all parties involved.

   The following Demonstrated Capacity guidelines would apply:
   1. The current order of Demonstrated Capacity is as follows: 1) if there is a market dispatch of a resource in a month, the results must be used for Demonstrated Capacity even if the scheduled quantity is less than the monthly QC value; 2) if there is a test of a resource in a month but no market dispatch, the test results must be used for Demonstrated Capacity; and 3) only if there is no dispatch or test of a resource in a month can the bidding detail for a resource under the MOO be used for Demonstrated Capacity.
   2. For market dispatches, Demonstrated Capacity would be assessed based on a resource's performance during the best hour; i.e., the hour during which the ratio of delivered energy to scheduled energy is closest to 1.0. The Council acknowledges that there are pros and cons to this approach but the intent is to encourage IOUs and DR providers to dispatch their

---

[1] The availability requirements of DR programs and resources under the 24-Slice framework is to-be-determined. Regardless, the Demonstrated Capacity would be assessed consistent with the prevailing availability requirements of the DR program or contract.

resources more frequently without risk of depressing their Demonstrated Capacity value. If Demonstrated Capacity from a market dispatch was instead based on average performance, then there might be a motivation not to dispatch a DR resource more than once in a given month if the first dispatch resulted in a good score.

3. For market dispatches, resources located within the same subLAP but with different dispatch schedules could net out their performance. The Demonstrated Capacity of resources within a subLAP could not be netted out if they used different Demonstrated Capacity methods within a given month (e.g., one resource uses a market dispatch and another uses CAISO market bids during the MOO).
4. Each resource within a DR program or contract could provide a different ratio of full economic dispatches, test events, and market bids, subject to the prevailing DR testing rules. For example, a DR provider with a monthly Supply Plan of 4 MW of RA capacity using two 2- MW resources. Resource 1 could meet its Demonstrated Capacity requirement in a given month using an economic dispatch, whereas Resource 2 could meet its Demonstrated Capacity requirement for the same month using only market bids during its MOO hours.
5. A market dispatch need not be for the full resource monthly QC/Supply Plan value to count toward Demonstrated Capacity; however, a resource's market performance relative to its market schedule would be applied on a pro rata basis to its monthly QC/Supply Plan value.
6. To count toward Demonstrated Capacity, test events must conform with the prevailing CPUC DR testing rules.
7. Customer location movement between resources within a month would be prohibited, except under the following circumstances:
    i. Newly enrolled customers can be added to a resource.
    ii. A customer who unenrolls from a program or resource may be dropped from a resource.
    iii. If the above changes make a resource trigger the CAISO's 10 MW telemetry requirement, or have it drop below the minimum Proxy Demand Response size of 100 kw resources, resources may be split or combined mid-month to continue to meet CAISO market requirements.
8. The IOU or DR provider must avoid any potential double counting of customer performance associated with service account movement permitted by the exemptions when invoicing Demonstrated Capacity. In order to mitigate double counting of customer performance, all customers not having been dispatched through an economic dispatch must be tested within the same month.
9. The baseline method used for energy settlement at the CAISO must be the same as the baseline method used to invoice Demonstrated Capacity.

The Incentive-Based Method differs greatly from the current LIP process because the LIP process has no mechanism to directly compare the QC value of an IOU DR program or third-party DR contract to CAISO market performance. Instead, the LIPs normalize DR performance to 1-in-2 peak weather conditions to more easily compare it to its ex ante load impacts. However, the CAISO market settlement process does not allow for this weather normalization in its settlement process. Within the context of the Incentive-Based Method, in which an IOU's or DR provider's success in delivering their committed QC amount is directly measured by their performance in the CAISO market during economic dispatches, test events, and market bids, the comparison of weather normalized ex post and ante load impacts has little to no relevance. In this respect, the Incentive- Based Method is more aligned with how conventional resource performance is measured against their committed QC values.

5. Penalty Assessment: After each RA Delivery Year, the Energy Division would assess the monthly Demonstrated Capacity reports of each IOU and DR provider. The level of assessment would be at the program level for each IOU and at the contract level for DR providers. Any monthly shortfalls could lead to a penalty, depending on the magnitude of the shortfall. DR providers could also be subject to additional penalties pursuant to the terms of their bilateral contract. All penalties would be assessed based on monthly performance and aggregated to a total penalty for the year. No netting of under- and over-performance would be allowed from one month to the next. IOU penalty payments would be made as a reimbursement to ratepayers through a to-be-determined channel and DR provider penalty payments would be made to contracting LSEs. Penalty amounts for DR providers would be based on their kW-month contract price; however, additional discussion would be needed to determine an appropriate basis for IOU penalties.

The Council originally proposed to use the penalty structure used for the DRAM but elected to switch to the structure currently used by Pacific Gas and Electric Company ("PG&E") for its CBP in order to maintain comparability and equitability between IOU and third- party DR. However, in its 2024-2027 DR program application in Application (A.) 22-05-002 et al, PG&E has proposed a new CBP penalty structure which the Council proposes instead. Should the CEC or CPUC consider rejecting the Council's proposal based on its proposed penalty structure, the Council is open to consideration of alternative penalty mechanisms. As PG&E states in its testimony in support of its proposed CBP penalty structure, this revised penalty structure will "[lower] the threshold for penalties" which "ensures poor-performing aggregators will face more substantial penalties, with a penalty cap of 100 percent of the total capacity incentive."[2] If this penalty structure is deemed by PG&E to result in improved performance by DR providers participating in its CBP, then the Council presumes that PG&E and the other IOUs would support adoption of this structure, given that the same DR providers that participate in their respective CBPs may also be participating in the RA market. The Council does not believe that DR providers should be subject to more rigorous penalties when not participating in an IOU DR program.

Table 1 provides the Council's proposed penalty structure and Figure 1 provides a graphic illustration.

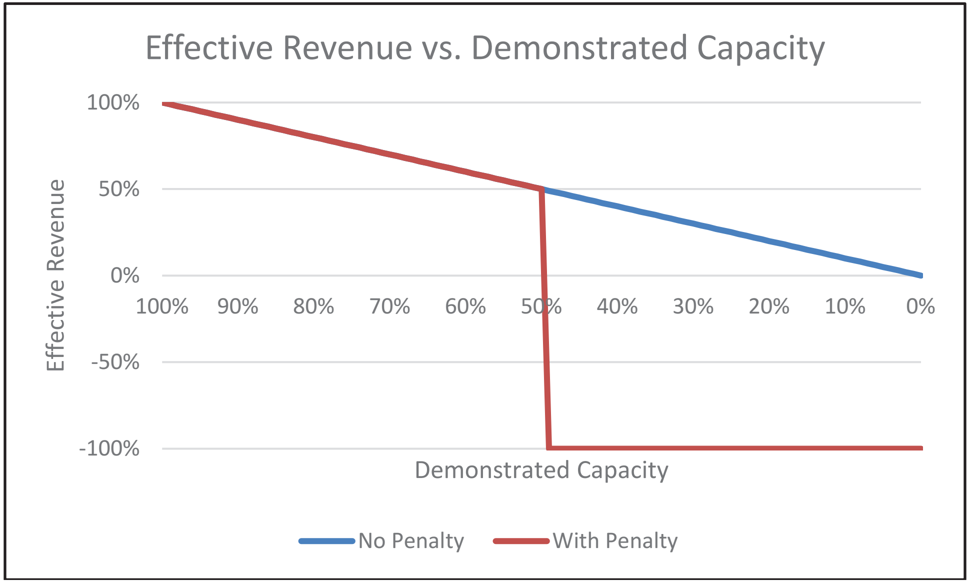
Table 1: Proposed Penalty Structure

Delivered Capacity Ratio	Payment	Penalty
>= 0.50 and <= 1.0	Unadjusted Hourly Capacity Payment; Hourly Delivered Capacity Ratio Capped at 1.0	0
>= 0 and < 0.50	0	Unadjusted Hourly Capacity Payment

---

[2] PG&E 2024-2027 DR Testimony, at p. 3-18.

Figure 1: Illustration of Proposed Penalty Structure



Applied to a DR provider, payment would be commensurate with delivered capacity; i.e., if it delivers less capacity than its committed QC down to 50 percent, then it would only be paid for what it delivered. Below 50 percent performance, a DR provider would receive no payment and would be required to pay a penalty equal to the contract value for the month being assessed. Because IOUs receive no payment for their DR capacity, any performance down to 50 percent would have no immediate repercussions but a significant shortfall could precipitate greater scrutiny and potential discounting by the Energy Division during subsequent reviews of Claimed QC values. The 50 percent "tolerance band" may appear substantial but this is balanced out by the absence of weather normalization when assessing Demonstrated Capacity. Without weather normalization, performance of a given weather-dependent DR resource would be lower under cooler conditions and higher during warmer conditions. Therefore, the tolerance band would encourage more frequent DR resource dispatch during cooler conditions because there would be a lower risk of penalties being assessed.

The tolerance band would also offset the downward bias of the current 1-in-10 (for non-residential customers) and 1-in-5 (for residential customers) wholesale DR baselines that rely on prior "like day" weather conditions even if event day temperatures are significantly higher. If the event day temperatures are higher than the prior "like day" temperatures, event day performance will be understated. This occurred during the 2020 heat storms and precipitated the CAISO to create its alternative day-of adjustment option and to commission a proof-of-concept study by Recurve to demonstrate the utility of using universal control groups as a DR baseline option.

Example:

A DR provider receives a contract to provide 10 MW of QC from HE 17-HE 22 for $5/kW-month (monthly contract value of $50,000). The capacity will be delivered through two resources (Resource A and Resource B) located in the same subLAP. Table 2 provides a hypothetical example of how the Demonstrated Capacity assessment would be applied to determine whether a penalty is warranted.

Table 2: Demonstration of Penalty Structure

[A] Month	[B] Monthly Supply Plan QC (MW)	[C] Resource A Demonstrated Capacity (MW)	[D] Resource B Demonstrated Capacity (MW)	[E] Aggregate Demonstrated Capacity (MW)	[F] Performance Ratio ([E]/[B] x 100%)	[G] Payment (If [F]>=50% (max. 100%), then = [E] x $5,000; if [F]<50%, $0])	[H] Penalty (If Applicable) ([B] x $5,000)
January	10	3	4	7	70%	$35,000	
February	10	4	4	8	80%	$40,000	
March	10	4	0	4	40%	$0	($50,000)
April	10	3	2	5	50%	$25,000	
May	10	4	3	7	70%	$35,000	
June	10	6	2	8	80%	$40,000	
July	10	7	3	10	100%	$50,000	
August	10	7	4	11	110%	$50,000	
September	10	7	4	11	110%	$50,000	
October	10	6	4	10	100%	$50,000	
November	10	5	3	8	80%	$40,000	
December	10	4	0	4	40%	$0	($50,000)
					Totals	$415,000	($100,000)
					Net Aggregate Payment	**$315,000**	

QC Process Timeline

The year-ahead QC process timeline should begin late enough in the year prior to the RA Delivery Year to maximize the quality of the data inputs to the Claimed QC values. In addition, like the current LIP process, a mid-cycle update would be allowed during the RA Delivery Year. Both timelines could overlap such that the Energy Division would perform one round of assessments rather than two staggered sets of assessments (one for year-ahead Claimed QC and another for intra-year adjusted QC). The final timeline could be adjusted based on the feedback of IOUs, DR providers, and Energy Division staff.

- Annual Year-Ahead/Intra-Year Update Cycle
    - April 1: Claimed Year-Ahead QC for the following one to three years to Energy Division or Updated Intra-Year QC
    - June 1: Awarded QC issued by Energy Division
- Annual Demonstrated Capacity Assessment
    - January 15: Prior-year Demonstrated Capacity templates due to Energy Division
    - February 15: Energy Division notifies IOU and DR providers if they incurred penalty payments
    - April 15: DR providers transfer, as applicable, penalty payments to contracting LSEs; IOU process for transferring penalty payments is TBD

Conformance with 24-Slice Resource Adequacy Framework

The Incentive-Based Method would easily conform with the 24-Slice RA framework currently being developed in the CPUC's Resource Adequacy rulemaking. The exact format used by IOUs and DR providers to present their respective hourly QC values would be determined by the Energy Division, as is it today.

Conclusion

The Council's Incentive-Based Method addresses the key requirements in a new DR QC methodology. Specifically, it 1) better reflects actual IOU and DR provider capabilities, 2) significantly reduces the timeline for QC value determination, 3) is more transparent, 4) minimizes the cost to DR providers, 5) reduces the need for outside consultants, 6) reduces Energy Division workload, and 7) provides a minimum degree of assurance that the awarded DR QC values are delivered. In addition, this method maintains the Energy Division's role as an "emergency brake" to ensure that Claimed QC values are achievable.

Appendix A

DRAFT DEMONSTRATED CAPACITY TEMPLATE

Form of Notice of Demonstrated Capacity

Showing Month:
Seller:
Seller Contact Name:
Seller Contact Phone:
SCID:

Total Qualifying Capacity (MW):
Total Demonstrated Capacity (MW):
DC-QC Ratio:
Contract (if applicable):
DR Program (if applicable):

Proxy Demand Resources (PDR) in the Program or Contract					**Demonstrated Capacity (MW)** For each PDR, choose one demonstration method to establish monthly Demonstrated Capacity Only include results during the CAISO Availability Assessment Hours (AAH)						**Prohibited Resources Adjustment**		**Demonstrated Capacity Payment Formula**			**Local Capacity Product Delivery** (Only required if delivering Local RA)
Resource Name/IOU DR Program	CAISO Resource ID	Sub-Load Aggregation Point	Month-Ahead Supply Plan QC (MW) (if applicable)	Monthly LIP QC (if applicable)	DC Dispatch Maximum hourly load reduction from DC Dispatch(es) during Showing Month		DC Test Maximum hourly load reduction during DC Test(s) conducted by Seller's SC during Showing Month		Must Offer Obligation (MOO) Average amount of capacity Seller bid into CAISO Markets during Showing Month		Adjusted MW Claimed (Specify the MW portion used to meet the contract obligation)		DC-QC Ratio	Adjustments Due to Penalized Performance	Payment/ Penalty	Local Capacity Area (if applicable)
					Raw Demonstrated Capacity (MW)	Lesser of Monthly Supply Plan Capacity or Raw Demonstrated Capacity (MW)	Raw Demonstrated Capacity (MW)	Lesser of Monthly Supply Plan Capacity or Raw Demonstrated Capacity (MW)	Raw Demonstrated Capacity (MW)	Lesser of Monthly Supply Plan Capacity or Raw Demonstrated Capacity (MW)	Default Adjustment Value (DAV) (MW)	Net MW Claimed				

Total Demonstrated Capacity:

DOCKETED	
Docket Number:	21-DR-01
Project Title:	Supply Side Demand Response
TN #:	246244
Document Title:	CEC Proposal Hourly Regression Capacity Counting Methodology for Supply-Side DR
Description:	N/A
Filer:	Courtney Wagner
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/28/2022 2:30:20 PM
Docketed Date:	9/28/2022

CALIFORNIA
ENERGY COMMISSION

California Energy Commission

DELIBERATIVE REPORT

Hourly Regression Capacity Counting Methodology for Supply-Side Demand Response

CEC Working Group Proposal

September 2022 | CEC-XXX-XXXX-XXX

California Energy Commission

Erik Lyon

Primary Author

Tom Flynn

Project Manager

TABLE OF CONTENTS

Page

Table of Contents....i

List of Figures....i

List of Tables....ii

Executive Summary....1

CHAPTER 1: Inputs for Capacity Calculation....5
  Customer Energy Baselines....5
    Baselines for Weather-Sensitive Resources....5
  Normalizing Load Impacts for Availability....6

CHAPTER 2: Ex-post Hourly Capacity Counting Methodology....8
  Availability Regression....8
  Capacity Value by Hour and Month....9
  Additional Considerations....10
    Winter Months....10
    Economic Bidding....11
    Minimum Dispatch Requirements....12

CHAPTER 3: Ex-Ante Capacity Determination....14
  Determining the Ex-Ante Capability Profile....14
  Determining the Ex-Ante Capacity Value....16
  Review and Approval....16
    Streamlined Approval....17

CHAPTER 4: Incentive Mechanism....18
  RAAIM and the MOO....18
  Capacity Shortfall Penalty....18
    Capacity Aggregation....20

LIST OF FIGURES

Page

Figure 1. Ex-post and ex-ante capacity cycle....1

Figure 2. Diagram of Ex-ante Hourly Inputs....2

Figure 3. Graphical Illustration of Ex-Ante Capacity Determination....2

Figure 4. Effective Capacity Revenue under Capacity Shortfall Penalty....3

Figure 5. Hourly September Availability, 3:00–11:00 p.m. 9
Figure 6. Hourly September Availability with Planning Temperature and Capacity Value Superimposed 9
Figure 7. Hourly August Capacity Value Summary 10
Figure 8. December DR Availability, Availability Profile, Planning Temperature, and Capacity Value 10
Figure 9. Hourly August Availability with Economic Bidding Behavior 11
Figure 10. September Hourly Capacity Values for Economic Bidding Relative to Fixed Window 12
Figure 11. Diagram of Ex-ante Hourly Inputs 15
Figure 12. Graphical Illustration of Ex-Ante Capacity Determination 16
Figure 13. Effective Capacity Revenue under Capacity Shortfall Penalty 19

LIST OF TABLES

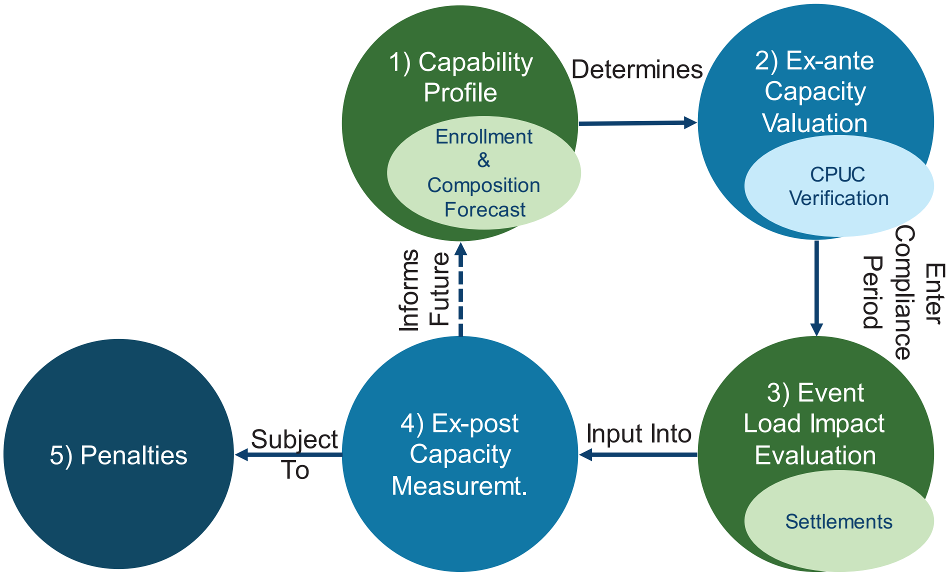
Page

Table 1. Bid-normalized Load Impact Examples 6
Table 2. Ex-Ante Profile Change Point Constraints 15
Table 3. Simulated capacity deliveries and shortfall with and without aggregation 20

EXECUTIVE SUMMARY

The hourly regression capacity counting methodology proposal is centered on a recurring cycle of ex-post capacity measurement and ex-ante capacity projection. The ex-post measurement is highly standardized such that all parties can agree in advance to the measurement procedure and outcome; the ex-ante projection is much more flexible to give DR providers the ability to account for expected changes in their resources such as enrollment and customer composition. Figure 1 summarizes this cycle.

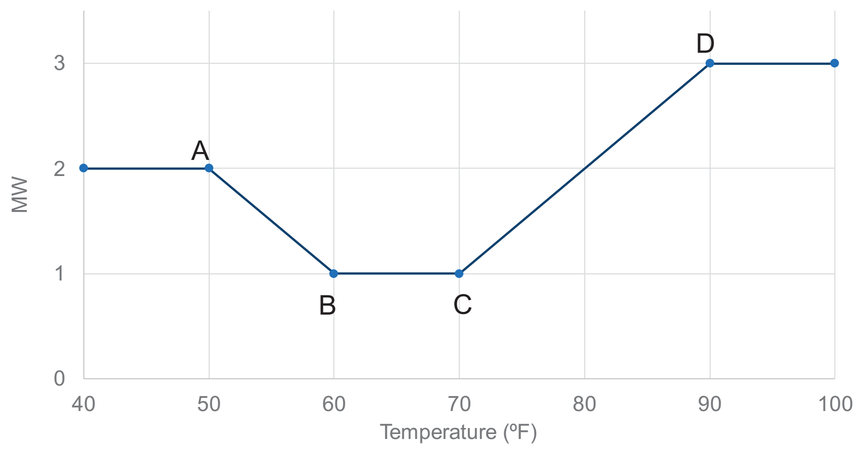
Figure 1. Ex-post and ex-ante capacity cycle



Each step in the process in additional detail below.

1. **The DR provider creates a capability profile for its resource or aggregation of resources for each hour.** The capability profile is a projection of how the resource can be expected to perform under varying temperature conditions for every hour. A profile is required for each combination of month and hour slice for which a capacity value is sought. Figure 2 shows a stylized version of a capability profile for a single hour, which can be applied to one or more months. DR providers may submit any of the points A–D to define the temperature sensitivity of a resource, but all are optional.

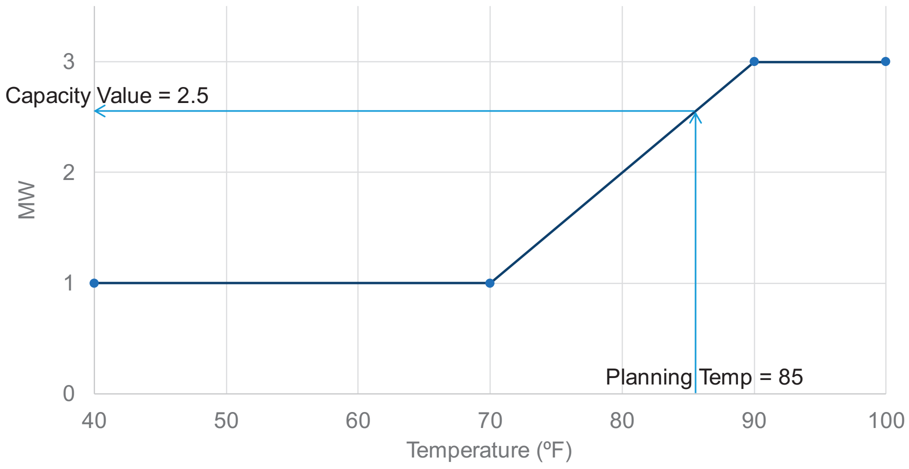
Figure 2. Diagram of Ex-ante Hourly Inputs



In general, this capability profile will be informed by the previous years' ex-post model and capacity measurement (step 4) but can be changed by the DR provider to take any changes in the resource such as enrollment or customer composition into account, or control for issues resulting in underperformance that have been resolved. New resources will be required to submit a capability profile as well.

2. **The capability profile directly determines the ex-ante capacity value of the resource, which is subject to a finding of reasonableness by CPUC Energy Division staff.** The ex-ante capacity is defined as the value of the capability profile at the planning temperature. Figure 3 shows a graphical representation of ex-ante capacity determination for a resource that shows sensitivity only to high temperatures (for example, a resource targeting air conditioning) by submitting only points C and D in the capability profile (step 1).

Figure 3. Graphical Illustration of Ex-Ante Capacity Determination



All requested capacity values no greater than 25 percent above the previous year's ex-post capacity measurement (step 4) shall be granted, so long as the resource met at least 90 percent of its committed capacity in the previous year. Resources requesting an increase of over 25 percent or that delivered less than 90 percent of committed capacity in the previous year are subject to more detailed staff review.

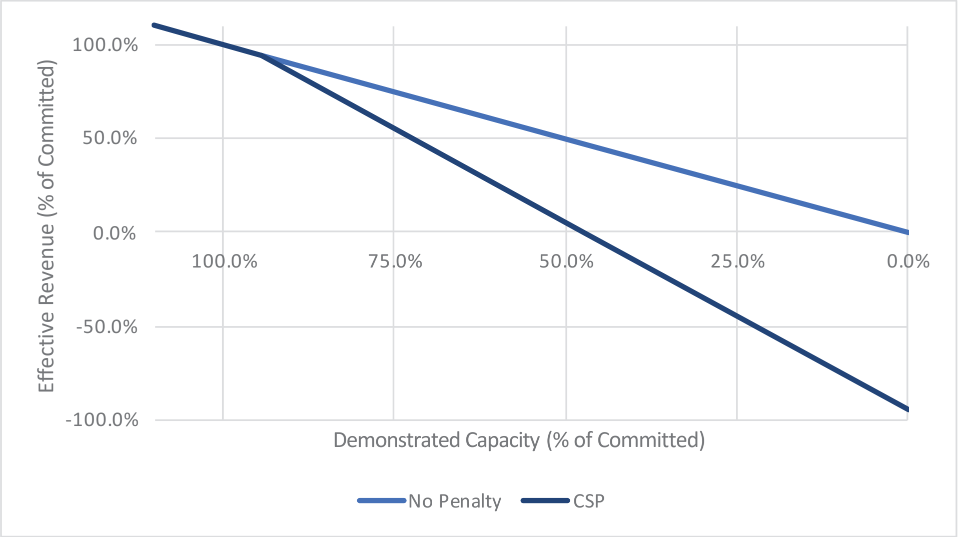
3. **Individual ex-post load impacts are calculated.** When possible, it is preferable to use the same baseline methodology used to calculate settlements in the California ISO energy market for consistency between the operational and planning space. However, an alternative method may be used when two conditions are met: 1) the alternative method can be shown to be more accurate than the settlement method, and 2) the alternative method is infeasible to implement for settlement. These load impacts will be adjusted relative to the amount bid according to the following equation:

$$\text{BNLI} = \max\left(\text{Bid}\left(\frac{\min(\text{Delivered}, \text{Dispatch})}{\text{Dispatch}}\right), \text{Delivered}\right)$$

4. **Ex-post capacity is determined.** Using individual load impacts (step 3) and any changepoints submitted in the ex-ante capability profile (step 1), a linear regression model of ex-post demonstrated capability is developed, which in turn determines the capacity value.

5. **Penalties are applied to any shortfall in delivered capacity.** Penalties are assessed on the portion of capacity to which the resource was committed but failed to demonstrate. Relative to the *committed* capacity (defined as the lesser of contracted capacity and QC), the penalty is equal to two times the shortfall below a minimum performance threshold of 94.5 percent. That is, the resource shall be compensated for its *delivered* capacity minus again the shortfall. Figure 4 shows the revenue a DR provider will receive as a proportion of its contract value as a function of the demonstrated capacity it delivers ex-post. DR providers may include contract provisions for compensation above the minimum contracted capacity, as shown up to 110 percent below.

Figure 4. Effective Capacity Revenue under Capacity Shortfall Penalty



This report is prepared for consideration by members of the CEC working group on the qualifying capacity (QC) of demand response (DR) resources, which includes representatives from DR and storage providers, evaluation consultants, utilities, as well from CEC, CPUC, and the California ISO. The report has not been formally published by the CEC and the views expressed are solely those of its author.

CHAPTER 1:
Inputs for Capacity Calculation

Building a capacity calculation model requires defining the inputs. This chapter introduces constraints on customer energy baseline for calculating individual load impacts, and how individual load impacts with be adjusted for partial dispatches. These inputs are used in step 3 of the overall process. They are described first in the report because they are foundational to the overall cycle.

Customer Energy Baselines

To measure delivered load impacts from individual dispatches relative to a counterfactual baseline, we propose a simple rule. The baseline method used to measure load impacts for the purpose of calculated ex-post capacity shall be the same baseline method used to calculate settlements in the California ISO energy market unless two conditions are met:

1) The alternative method can be shown to be more accurate than the settlement method.
2) The alternative method is infeasible to implement for settlement.

This above rule aims for consistency between the operational and planning space when possible, but allows flexibility when required.

Baselines for Weather-Sensitive Resources

One such baseline approach that would likely meet the above conditions is the use of comparison groups. DR providers have long noted that the available methods for determining DR participants' counterfactual settlement baselines are inaccurate for weather-sensitive DR resources such as air-conditioning cycling and similar programs.[1] (Sufficient baselines already exist and are in common usage for non-weather-sensitive resources.) CEC staff finds that the absence of an accurate baseline that employs transparent methods that are fixed and agreed to *before* measurement undermines policymakers' confidence in DR and is a significant barrier to allowing the DR market to reach its full potential.

Such a method has recently been tested, validated, and affirmed as tariff-compliant for the California ISO.[2] This method, a type of comparison group, satisfies the CEC's conditions above for a weather-sensitive settlement baseline.

---

1 Duesterberg, Matt. *Deep dive into OhmConnect's community response during Summer 2020.* OhmConnect. January 13, 2021. https://www.ohmconnect.com/thought-leadership/deep-dive-into-ohmconnects-community-response-during-summer-2020.

2 Glass, Joe, Stephen Suffian, Adam Scheer, and Carmen Best. Prepared by Recurve for the California ISO. November 2021. http://www.caiso.com/Documents/DemandResponseAdvancedMeasurementMethodology.pdf.

However, barriers remain to successfully implementing these baseline methods because they rely on access to nonparticipant hourly electric meter data, to which DR providers (particularly third-party providers) often do not have access. The CEC currently collects this data from the IOUs and large publicly owned utilities and intends to be the energy data hub for California. As such, CEC staff propose the CEC investigate how to take on the role of developing tariff-approved comparison group baselines for providers of weather-sensitive DR resources.

Currently, CEC plans to receive data from utilities approximately quarterly. This frequency is insufficient to clear energy market settlements on a near-daily basis. However, it may be sufficient for the purposes of calculating ex-post delivered load impacts and capacity for performance verification and RA compliance purposes.

Normalizing Load Impacts for Availability

We propose a measure of bid-normalized load impacts that a hybrid of bid, dispatch (or test), and load impact data. Bid-Normalized Load Impact (BNLI) is calculated according to the following formula for any period in which a DR resource receives a dispatch, including a partial dispatch:

$$\text{BNLI}= \max\left(\text{Bid}\left(\frac{\min(\text{Delivered, Dispatch})}{\text{Dispatch}}\right), \text{Delivered}\right)$$

Intervals in which a DR resource has RA obligations but does not bid will be assigned a BNLI of zero.

Table 1 illustrates the proposed definition of bid-normalized load impact over different scenarios. Under a full dispatch (example 1), the BNLI is equal to the delivered load impacts. Under a partial dispatch, the bid amount is adjusted by the ratio of delivered load impacts to the bid amount (example 2 and 3), but this ratio is always capped at 1 by the minimum function, limiting BNLI to the bid amount (example 4). The only time BNLI can exceed the bid is when load impacts exceed the bid, regardless of the dispatch amount (examples 5 and 6).

Table 1. Bid-normalized Load Impact Examples

Example #	Bid	Dispatch	Delivered	BNLI
1	100	100	90	90
2	100	60	30	50
3	100	60	60	100
4	100	60	80	100
5	100	100	120	120

Example #	Bid	Dispatch	Delivered	BNLI
6	100	80	120	**120**
7	[Test] 100	[Test] 100	120	**120**

DR tests can be used in the absence of ISO dispatches if necessary. In these cases, the amount bid and dispatched should be assumed to equal the entire resource. That is, the concept of a partial dispatch is not applicable to a test event. Mathematically, this implies that the amount that the DR provider believes it can provide (the "bid") and the amount it is attempting to provide (the "dispatch") are the same and these two quantities cancel out in the formula, and the result is simply the delivered load impact (example 7). In the case of a test event, the DR provider does not need to include bid or dispatch values, but the result is conceptually compatible with actual dispatch data.

The hourly ex-post capacity valuation model takes these BNLI values along with the corresponding temperatures as inputs. The recommended granularity is by sub-LAP, but the proposal could be modified to the level of granularity needed, such as by IOU service territory

CHAPTER 2:
Ex-post Hourly Capacity Counting Methodology

This chapter details the proposed ex-post hourly regression capacity counting methodology, step 4 of the overall process. While the ex-ante determination precedes the ex-post calculation chronologically, this proposal is anchored on a consistent, transparent ex-post measurement methodology and so is presented first.

For each hour in each month, the methodology includes the following steps, which are described in greater detail in the following sections:

1. **Run a regression of availability as a function of temperature:** Create a linear regression model of adjusted load impacts on temperature over each month (or grouping thereof) by hour of day. The measure of temperature may include predetermined change points if necessary to account for diminishing resource capabilities under extreme conditions. The regression line generated by this model is the resource's ex-post hourly capacity profile.
2. **Determine the hourly capacity value by the intersection of the availability profile with the monthly planning temperature.** Apply the planning temperature to the capacity profile function to generate an estimate of the resource's capacity value under planning conditions.

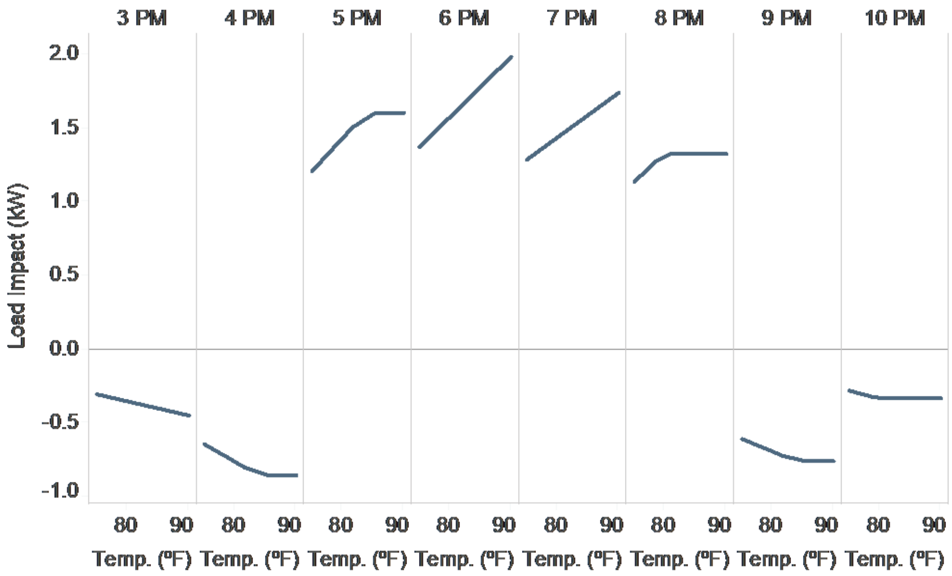
The methodology is designed to accommodate weather-sensitive resources but can be simplified further for non-weather-sensitive resources: simply take the average of adjusted load impacts by hour within each month. However, there a standardized definition of weather sensitive or non-weather sensitive is not required; any resource may use either pathway.

Availability Regression

The regression of DR adjusted load impacts on temperature serves to account for the capacity value of the resource under planning temperatures. The regression may include change points as necessary to account for DR resources with capabilities that change under warmer and cooler conditions, as well as diminishing capabilities under more extreme conditions if necessary. The changepoints must be selected by the DR provider ahead of the RA month in question. The availability regression (and associated changepoints) is not required for non-weather sensitive resources.

Consider a four-hour weather sensitive economic DR resource (PDR) with takeback in the two hours before and after event. On the "worst day," the grid need of the LSE is from 5:00–9:00 p.m. Figure 5 shows the per-meter availability of the resource from the four dispatch hours as well as the four hours with takeback. The light blue dots show the BNLI on each day, and the dark blue lines show the regression results. The DR provider has provided limiting changepoints in September for all dispatch hours, but in the 6:00 and 8:00 p.m. hours of the month the temperature never hit the changepoints during a dispatch.

Figure 5. Hourly September Availability, 3:00–11:00 p.m.

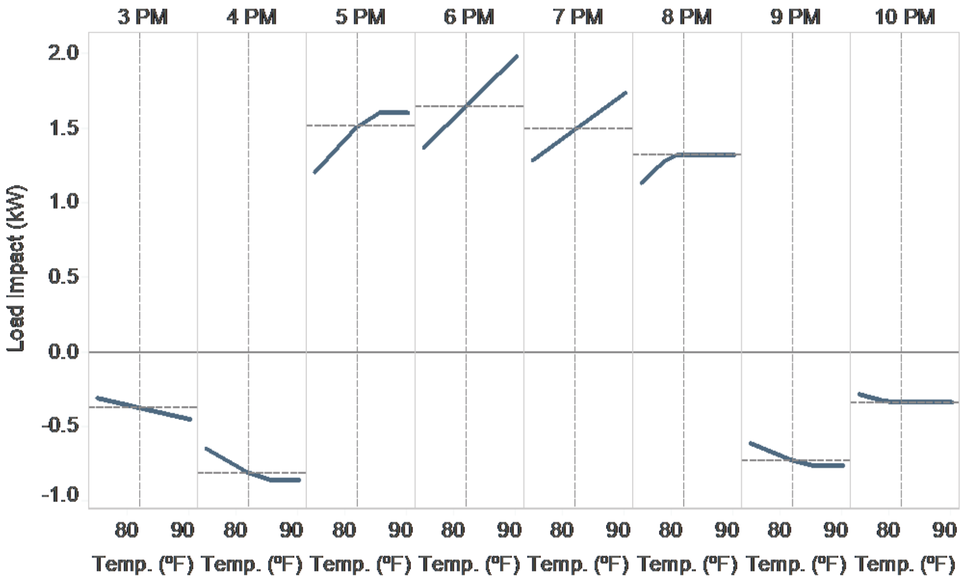


The slope of the regression lines indicates this resource is highly weather sensitive with greater positive and negative values on hotter days, both in the load impacts and in takeback.

Capacity Value by Hour and Month

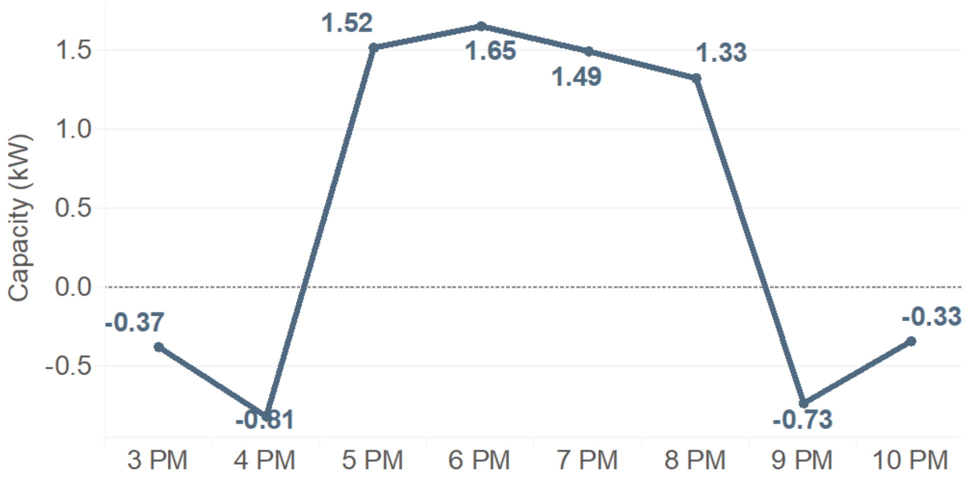
The second step is to apply the monthly planning temperatures to the regression line to determine the capacity value in each hour, including takeback hours. Figure 6 shows the same resource as in Figure 5 with planning temperature (vertical dashed lines at 81.3ºF). Where the availability profiles intersect the planning temperature are the hourly September capacity values (horizontal dashed lines).

Figure 6. Hourly September Availability with Planning Temperature and Capacity Value Superimposed



The resulting September capacity values are summarized by hour in Figure 7.

Figure 7. Hourly August Capacity Value Summary



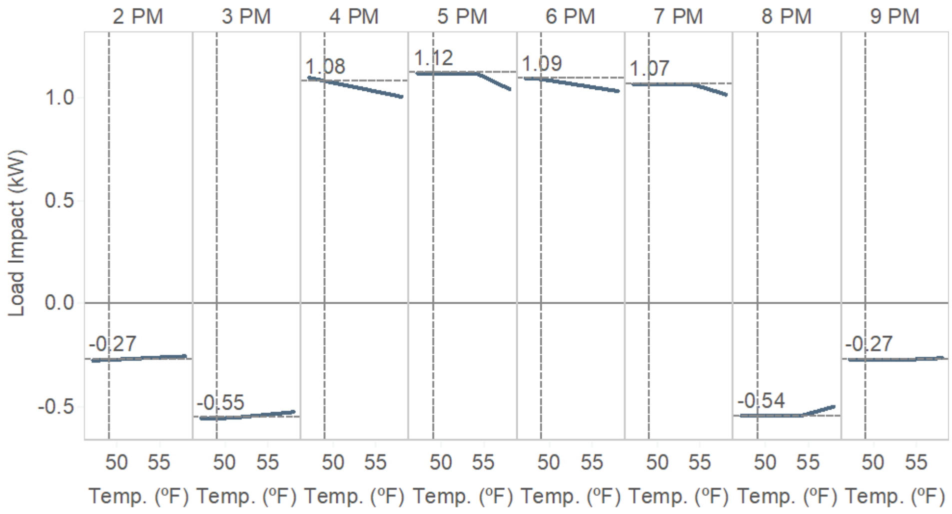
Additional Considerations

The example above is a simple representative illustration of this methodology. However, real-world circumstances may be more complicated. This section addresses some of these possibilities, as well as minimum dispatch requirements to satisfy the model.

Winter Months

During winter months (defined here as December through March), peak net load and wholesale prices tend to increase with lower temperatures. Accordingly, the 1-in-2 minimum temperature is used during these months rather than the maximum under this proposal. Figure 8 shows the same process for developing December capacity values (labeled).

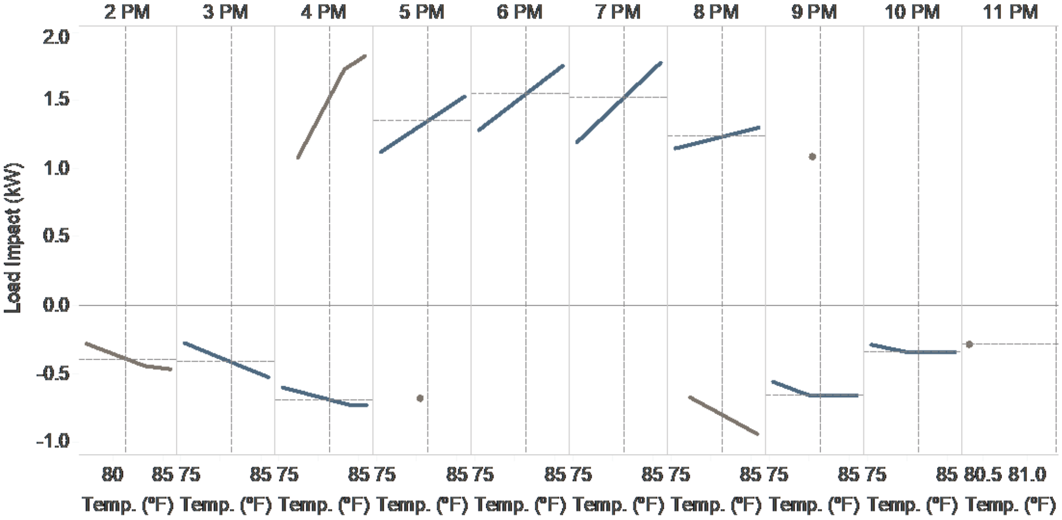
Figure 8. December DR Availability, Availability Profile, Planning Temperature, and Capacity Value



Economic Bidding

A possible challenge to a 24-slice RA paradigm is the divergence between grid needs under planning conditions and in operations. For example, a DR resource might commit to 5:00–9:00 p.m. availability based on the grid needs of the "worst day," but wholesale prices may be higher from 4:00–8:00 p.m. or 6:00–10:00 p.m. on a given day. For an economically efficient dispatch, the DR resource should be able to shift its bid window without jeopardizing its capacity valuation. Consider the case of an equivalent DR resource to that shown previously except that it bids into the four highest price hours per day rather than a fixed four-hour window. Figure 9 shows the hourly availability of this resource for August.

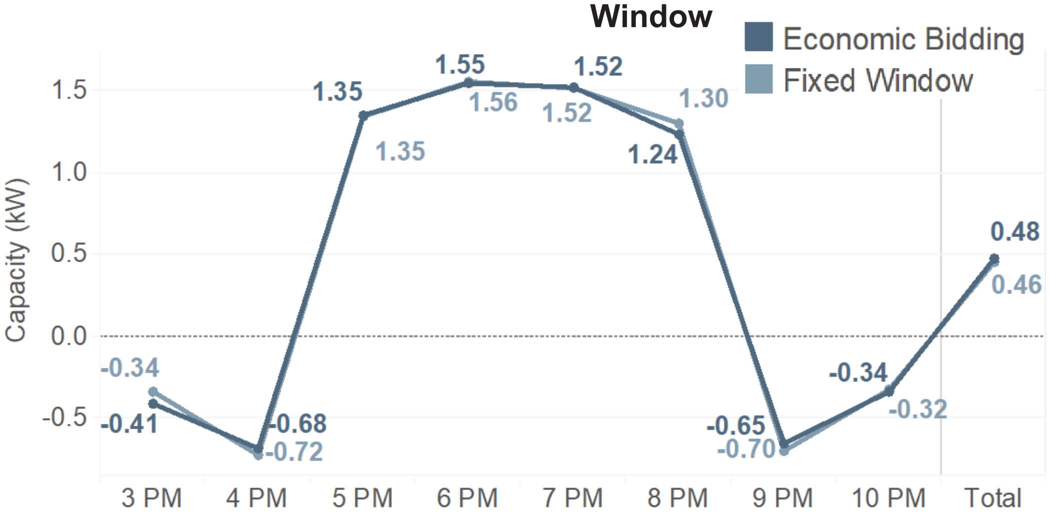
Figure 9. Hourly August Availability with Economic Bidding Behavior



To illustrate, note the 4:00 and 8:00 p.m. hours, both of which include dispatches and takeback. In those hours, the regression handles negative (takeback) and positive (load impacts/reductions) separately, so that only dispatches are considered in hours with RA commitments and only takeback is considered in hours without. As a result, the process of measuring the value of capacity regression in the committed hours produces negative load impacts in the 4:00 hour and positive values in the 8:00 hour, consistent with how the resource is expected to perform on the hottest days when reliability concerns are greatest.

Because the capacity value is measured on the "worst day" that coincides with the highest expected temperature, the methodology only picks up dispatches between 5:00–9:00 p.m. — the same hours as in the fixed window – and takeback in the adjacent hours. However, the hourly capacity values are changed slightly. Figure 10 shows the hourly capacity values for the economic bidding behavior (dark blue) relative to the fixed window (light blue).

Figure 10. September Hourly Capacity Values for Economic Bidding Relative to Fixed Window



While the positive load impacts are somewhat smaller in the 8:00 hour when the resource bids into the highest-price days, but the takeback in the surrounding hours is also less. These differences generally cancel out one another, and the average capacity value over these hours is slightly *larger* when able to adjust the bidding window. The difference between the average capacity value in the presumed bidding window on the "worst day" for which DR is awarded capacity value and the actual average capacity value may serve as a basis for evaluating performance and assessing penalties. Note that hours with takeback outside the shown hours are discarded and do not influence the final capacity valuation.

Minimum Dispatch Requirements

In order to successfully generate ex-post capacity measurements using this regression approach, multiple data points are required. This section discusses how the methodology will handle few or zero data points and how this treatment provides an incentive for DR providers to be dispatched in the market. However, there is no specific minimum dispatch requirement.

The ex-post regressions will be run based on the months or "seasons" (defined as any grouping of months defined by the DR provider) in the submitted ex-ante capability profiles described in the following chapter.

In the absence of any dispatch or test results in a season and hour, DR resources will be awarded an ex-post capacity of value of zero. In the case of a single dispatch or test, that single value will be used for capacity across all temperatures.

With a small number of data points, a regression line will still be fit. While such a regression may produce volatile results, that volatility provides an incentive for DR providers to dispatch frequently enough to generate sufficient data to develop a robust ex-post model and support their QC claims. However, there is no specific minimum requirement for what constitutes sufficient data. We also note the ability to combine months into "seasons" can allow DR providers to develop that data set over more months, if the resource behaves consistently relative to temperature across multiple months. This approach will help resources that dispatch less frequently to nonetheless develop evidence of capacity value.

As an extreme example, a non-weather sensitive RDRR resource that dispatches very infrequently may use the entire year as a season. Even if the resource is only called for its two annual test events and never dispatched under emergency conditions, those two test events may form the basis for capacity value for every month of the year.

CHAPTER 3:
Ex-Ante Capacity Determination

The ex-ante determination is made based on the DR provider's assessment of its capability to meet a capacity value determined by the ex-post capacity model described in the previous chapter. While the ex-ante process is presented as steps 1 and 2 in the overall cycle, the ex-ante portion relies on knowledge of the ex-post methodology. The process consists of two main steps, analogous to the ex-post process:

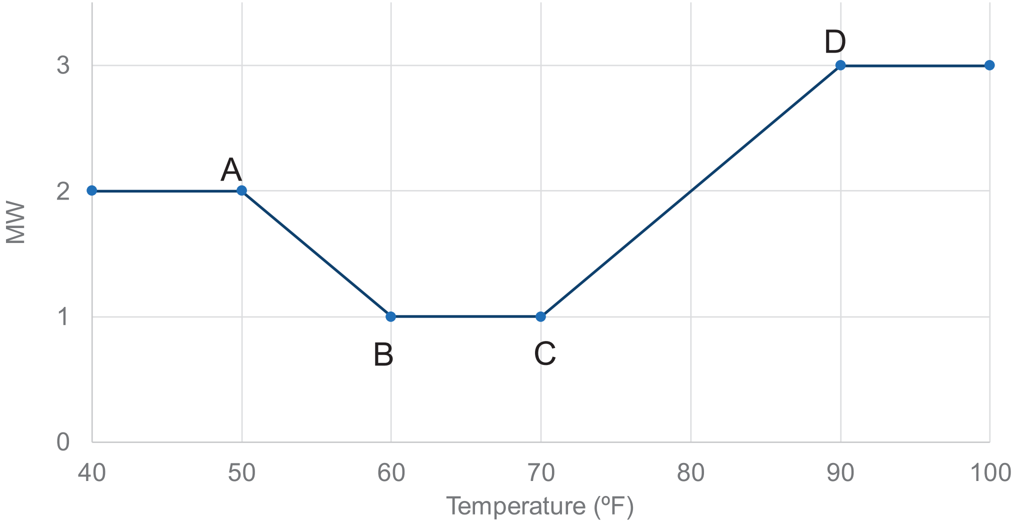
1. **Determine the ex-ante capability profile of a resource.** The DR provider submits a stepwise function estimating ex-ante capabilities under varying temperature conditions. Separate capability profiles are required by hour of the day for which the resource has RA commitments. Capability profiles may apply to one or more months.
2. **Determine the ex-ante hourly capacity value by the intersection of the availability profile with the monthly planning temperature.** Apply the planning temperature to the capability profile function to generate an estimate of the resource's capacity value under planning conditions.

Determining the Ex-Ante Capability Profile

The DR provider will be required to submit parameters defining the underlying capabilities of a resource. At its most basic, the capability profile is what the DR provider forecasts the ex-post model will be. However, the provider may make any adjustments from previous ex-post models to account for growth in enrollment, change in customer characteristics, errors and misfires from previous years that have been resolved, and any other factors deemed necessary by the provider. Critically, the ex-ante capability profile need not be a *predictive* model of the future capabilities of a resource, but a minimum threshold of capabilities that the DR provider can commit to with reasonable confidence. This reframing allows DR providers to adjust capability profiles to include factors like the probability of reaching use limitations such as maximum hours, customer fatigue over multi-day dispatches, and others.

DR providers submit the capability profile by defining parameters for one or more change points that determine a resource's capabilities at different temperatures. Figure 11 shows a schematic of the possible inputs, marked as points A–D. Points B and C represent the points below and above which the resource shows temperature sensitivity. Points A and D represent saturation change points below and above which the resource no longer shows temperature sensitivity.

Figure 11. Diagram of Ex-ante Hourly Inputs



None of these parameters are required, providing DR providers significant flexibility in defining the contours of their resource. For example, a resource targeting heat pumps used for both space heating and cooling might include all four points; a resource targeting cooling-only air conditioners might only require points C and D because it has no cool weather sensitivity.

However, there are a few constraints that must be imposed on these points. These effectively require the profile to behave similarly to the schematic shown above. In other words, points A–D must be in ascending order and points A and D must be higher than points B and C. For hours with takeback, however, the above load impact constraints are inverted to allow for greater takeback under more extreme temperatures (e.g., precooling). Constraining the *absolute value* of load impacts allows the rules to be applied to takeback hours as well. These constraints are summarized in Table 2.

Table 2. Ex-Ante Profile Change Point Constraints

Point	Required?	Temperature Constraint	Load Impact Constraint
A	No	A<B	|A|>|B|
B	Only if A submitted	A<B≤C	B=C
C	Only if D submitted	B≤C<D	C=B
D	No	D>C	|D|>|C|

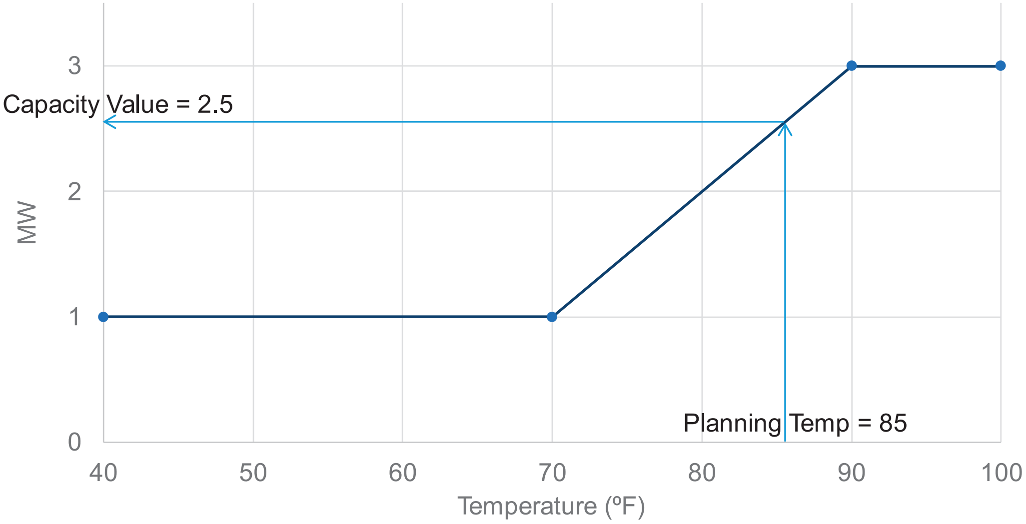
Capability profiles must be submitted for every hour of every month for which a resource is seeking an hourly QC value, plus any hours in which takeback is expected on the worst day. However, a single capability profile may be used for multiple months and/or hours as appropriate. For example, one profile for a given hour might be used for all months in the summer rate period, and a second would be used for non-summer months. Takeback profiles are optional. However, profiles of zero takeback will be imputed in the two hours before and after QC awards if not provided to ensure DR providers are not simply ignoring takeback.

Critically, the temperature values of the changepoints must be committed to ex-ante and applied when evaluating ex-post. The load impact values will be determined by running a regression of performance relative to temperature, subject to these predetermined changepoints.

Determining the Ex-Ante Capacity Value

The ex-ante capacity value can be determined unambiguously from the ex-ante capability profile. For each capability profile, the capacity value is the load impact (MW) value that corresponds with the planning temperature for that month. Figure 12 illustrates this graphically: the planning temperature (85ºF) can be traced from the x-axis to the capability profile, and then followed to the intersection with the y-axis to reveal a capacity value of 2.5 MW.

Figure 12. Graphical Illustration of Ex-Ante Capacity Determination



Review and Approval

CPUC staff retain the role of approving final DR QC values. Other DR QC working group stakeholders have submitted proposals including requirements for reporting requirements, including data and evidence for the capability to meet future capacity obligations.[3] This proposal does not weigh in on the specific reporting requirements, but notes the existing

---

3 See proposals from OhmConnect and California Energy Efficiency and Demand Management Council for possible reporting requirements.

process includes many reporting requirements not currently required for determining QC in the following year, and we support streamlining these requirements as appropriate.

This proposal includes constraints on how CPUC staff can adjust QC values, however. To adjust the final QC, the underlying capability profile must be changed. This can be done by adjusting the MW values of the change points that result in the desired final QC value while preserving the relationship between the capability profile and the final capacity value.

Streamlined Approval

We also propose a streamlined approval process for DR providers and resources that have a proven track record and are growing at a reasonable pace year-over-year. Specifically, we propose for CPUC staff automatically approve requested QC of any resource aggregation for any hour and month that meets the following two criteria:

1. Ex-post capacity value is at least 90 percent of the committed capacity.
2. Requested ex-ante capacity is no more than 25 percent above the ex-post delivered capacity in the previous year

Such a rule will reduce administrative burden on both DR providers and CPUC staff, while still retaining oversight abilities in cases where a DR provider underperformed in the previous year or a significant increase in QC is requested.

CHAPTER 4:
Incentive Mechanism

The final component of the proposed process (step 5) is an incentive mechanism that is assessed based on the ex-post delivered capacity relative to committed capacity (which is limited to QC). An incentive mechanism known as the Capacity Shortfall Penalty (CSP) is proposed as an alternative to the current incentive mechanism in the California ISO markets, the Resource Adequacy Availability Incentive Mechanism (RAAIM). Unlike the CSP, RAAIM is assessed on bids relative to a must-offer obligation (MOO). This chapter first addresses RAAIM and the MOO, then introduces the CSP as an alternative.

RAAIM and the MOO

The RAAIM is assessed based on bids over the course of the AAH, which are indeed the hours in which loss-of-load events are likely to occur. However, the MOO requires resources to bid their net QC in each AAH. This structure generally appears sufficient for traditional dispatchable generation resources that can produce a constant output over many hours; if a natural gas power plant bids 100 MW for five consecutive hours, it is highly likely to deliver that power if called upon to do so.

For this proposal to function as intended, elimination of RAAIM and the fixed MOO is proposed for all DR resources. The California ISO is requested to clarify that DR providers can and should bid their true availability rather than QC value and to ensure that DR providers are not in violation of the ISO tariff for doing so.

DR must be recognized as a variable output resource that must be able to bid according to its actual capability, rather than a fixed MOO. Even if the MOO varies by hour under the slice-of-day framework, it must be able to bid variably across different days with different weather conditions. As such, we propose exemption from the RAAIM. An alternate approach would be to implement a weather-adjusted MOO, which changes with temperature per the ex-ante capability profile developed in step 1. However, the California ISO system is not currently able to implement such a variable MOO.

Simply eliminating RAAIM would retain a static MOO by hour in each month but would eliminate the financial penalties associated with offering a lower value. We recognize that retaining the fixed MOO for DR could put providers out of compliance with the California ISO tariff when offering lower values and suggest a variable MOO be investigated in the future. In the near- to mid-term, eliminating the RAAIM will have the same effect.

Intervals for which a resource has an RA obligation but does not bid are imputed with a BNLI of zero when determining load impacts in step 3 above, providing an incentive to bid.

Capacity Shortfall Penalty

DR resources are fundamentally different and only some types of DR can deliver sustained constant load impacts over many consecutive hours. Even so, variable DR resources can provide significant capacity contributions. The incentive mechanism differs from the RAAIM by applying to the ex-post measured capacity relative to the committed capacity, defined as the lesser of contracted capacity and QC. In doing so, it accounts for actual performance where applicable through the definition of BNLI. This feature is critical to ensure DR providers cannot avoid penalties under a RAAIM-like system by bidding the contracted capacity value and purchasing the difference in the spot market.

The CSP is defined as the product of any shortfall in demonstrated capacity relative to the contracted capacity, the market price for capacity, and a penalty parameter:

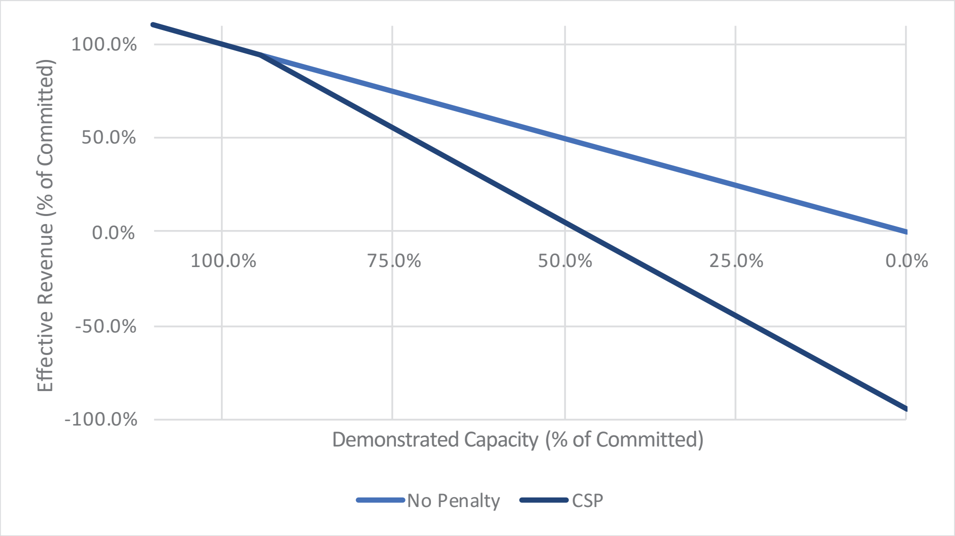
$$CSP = 2\,P\,\max\left(0.945 Cap_{Com} - Cap_{Dem}, 0\right)$$

where the value of 2 is the parameter that defines the relative intensity of the penalty, P is the price of capacity, 0.945 is the percentage of committed capacity (94.5%) below which the penalty is imposed on demonstrated capacity, Cap_{Com} is the committed capacity, and Cap_{Dem} is demonstrated capacity. The cutoff of 94.5 percent is chosen for consistency with the existing RAAIM structure and mitigates performance risk by allowing slight underperformance that may be attributable to some combination of random conditions and statistical measurement error.

Note the maximum function ensures DR providers face a penalty for delivering below the capacity award, but do not receive a bonus for surpassing it. However, we also propose allowing DR providers to contract for a range of capacity within which they will be paid for their delivered capacity. The DR provider will only face the penalty when the portfolio delivers less than 94.5 percent of the bottom of the range. However, we note that this provision need not be explicitly adopted for the RA program — these can be negotiated in RA contracts with LSEs.

Figure 13 illustrates the effective revenue of a resource relative as a function of its demonstrated capacity, including a provision to be compensated for up to 110 percent of committed capacity for illustration. Below 47.25 percent of committed capacity, the DR provider will owe more in penalties than the contract value; by 0 percent it will pay 94.5 percent of its entire contract value back as a penalty.

Figure 13. Effective Capacity Revenue under Capacity Shortfall Penalty



The CSP will apply on a monthly basis to the average capacity value of the resource across the hours (that is, slices) to which it is committed. These include hours with takeback or other negative load impacts. As an example, see Figure 10 and note the difference between the average capacity in the fixed window for the 1-in-2 peak temperature and the variable bidding that better reflects how an economic resource might behave. So long as the average ex-post capacity value (0.47) is no less than the average ex-ante capacity value (0.44), the resource will not face a penalty.

Underperformance risk from unavoidable future uncertainty and randomness can also be actively mitigated through aggregating a DR portfolio as discussed in the following section.

Capacity Aggregation

Underperformance risk can be mitigated by aggregating delivered DR capacity across a provider's resources before applying the CSP described above. To illustrate, we assume DRPs face the CSP and that DR providers can aggregate their resources that are eligible to provide the same capacity product (for example, system capacity). Consider ten hypothetical DR providers, each with one-hundred resources with 1 MW expected capacity and a standard deviation of 0.4 MW. Each resource is contracted to provide 1 MW of capacity. The total expected value of each DR provider's aggregate capacity is 100 MW with standard deviation 4 MW. A simulation of each provider's aggregate capacity contribution resulted in values from about 94–110, as shown in Table 3.

Table 3. Simulated capacity deliveries and shortfall with and without aggregation.

Delivered Capacity (MW)	Shortfall (No Aggregation)	Shortfall (Aggregated)
109.49	12.33	0.00
104.96	14.03	0.00
102.30	15.74	0.00
101.62	15.12	0.00
98.84	18.31	1.16
97.95	15.79	2.05
97.03	19.38	2.97
96.06	18.06	3.94
95.92	19.64	4.08
94.41	19.15	5.59

Without aggregation, faced shortfalls in the range of 10–20 percent, which equates to 20–40 percent of the capacity value of the resources as proposed under the CSP. Notably, all DR providers – including those that overperform in aggregate – face a shortfall because individual resources that underperform are not cancelled out against those that overperform. In contrast, shortfalls are much lower with aggregation, ranging from 0–6 percent.

CALIFORNIA
ENERGY COMMISSION

CALIFORNIA
NATURAL
RESOURCES
AGENCY

California Energy Commission

Staff White Paper

Hourly Regression Capacity Counting Methodology for Supply-Side Demand Response

Implementation Guide

January 2023

California Energy Commission

Erik Lyon

Primary Author

Daniel Hills-Bunnell

Contributing Author

Tom Flynn

Project Manager

TABLE OF CONTENTS

Page

Table of Contents i

List of Figures i

List of Tables ii

Executive Summary 1
  Ex Ante Process 2
  Ex Post Process 4

CHAPTER 2: Ex Ante Capacity Determination 6
  Determining Ex Ante Capability Profiles 6
  Determining the Ex ante Capacity Value 10
  Review and Approval 11

CHAPTER 3: Ex Post Hourly Capacity Counting Methodology 13
  Calculating Load Impacts and Normalizing for Availability 13
  Impact Profile Regression 15

CHAPTER 4: Incentive Mechanism 19

APPENDIX A: Sample Reporting Templates A-1

LIST OF FIGURES

Page

Figure 1: Illustration of an *Ex Ante* Capability Profile 2

Figure 2: Illustration of Ex ante Capacity Determination 3

Figure 3. Representative slice-of-day table........ 3

Figure 4: Impact Profile Regression of Aggregation with Hot Weather Sensitivity 4

Figure 5: Revenue under Capacity Shortfall Penalty with Forced Outage Multiplier 5

Figure 6. *Ex Ante* Hourly Capability Profile with Hot and Cold Weather Sensitivity 7

Figure 7. Takeback Profile Exhibiting Hot Weather Sensitivity 8

Figure 8: Illustration of First-hour Effect on Capability Profile 9

Figure 9. Ex ante Capacity Determination for Two Months Within One Season 11

Figure 10: Example bid-normalized load impact for bid of 100 MW and dispatch of 50 MW 14

Figure 11: Impact Profile Regression of Aggregation with Hot Weather Sensitivity 16

Figure 12: Demonstrated April and July Capacity Values from Impact Profile Regression 17

Figure 13: Takeback pre- and post-dispatch regressions for a given hour and season 17
Figure 14: Revenue under Capacity Shortfall Penalty with Forced Outage Multiplier 19

LIST OF TABLES

Page
Table 1. *Ex Ante* Profile Change Point Constraints... 8
Table 2: Aggregation Capability Profiles in Tabular Form 10
Table 3: Additional model terms available by default..15
Table 4: Resource ID Aggregation Table 1
Table 5: Resource ID Aggregation Table 1
Table 6: Season Definition for Aggregation A 2
Table 7: Ex Ante Capability Profile Submission Table for Aggregation A................................ 3
Table 8: Ex Ante Capacity Submission Table for Aggregation A 4
Table 9: Ex Ante Capacity Submission Table for Portfolio A.. 4

EXECUTIVE SUMMARY

This implementation guide was prepared by CEC staff as a supplement to the Qualifying Capacity of Supply Side Demand Response Working Group Final Report adopted at the January 25, 2023 California Energy Commission business meeting. This implementation guide was not presented to the CEC for adoption. The intent of this document is to illustrate and clarify how the recommendations made in the Commission Report can be implemented. Accordingly, this document contains little discussion of the rationale behind these recommendations, other proposals submitted through the working group process, or stakeholder positions on these proposals. It is informed by the original proposal submitted by the CEC but includes changes that were recommended in the Final Report.

Different levels of granularity and aggregation are used at different stages of the methodology. Throughout, the following terminology is used to distinguish these different levels of granularity:

- **Customer:** DR resources are made up of individual customer accounts and meters. *Customer* refers to this fundamental unit of DR, the participating end-use customer.
- **Resource:** The California ISO manages the grid by dispatching individual resources with unique identifiers. For naming consistency with the ISO, *resource* refers to this usage. DR *resources* within the California ISO are made up of *customers* and are registered as Proxy Demand Resources (PDRs) or Reliability Demand Response Resources (RDRRs).
- **Aggregation:** Under this proposal, one or more ISO resources with similar characteristics and within a sub-LAP may be combined at the discretion of the DR provider to form an *aggregation* of resources. An aggregation is the unit of analysis under this methodology, except for penalty application. Although resources are themselves aggregations of customers, the term *aggregation* applies to groups of resources to distinguish from *resource*.
- **Portfolio:** A *portfolio* is one or more aggregations with similar characteristics or underlying load types *across* sub-LAPs. Portfolios are also determined at the discretion of the DR provider. For example, a DR provider might define separate portfolios for residential customers, commercial cold storage customers, and commercial AC customers. However, separate portfolios must be defined for each system and local capacity product. For example, a system RA product and local RA products for two local areas must be included in three separate portfolios. Portfolio is the level at which CPUC staff assess reasonableness of requested QC values.
- **Committed and Demonstrated Capacity:** *Committed capacity* is the *ex ante* sum of capacity across portfolios that has been contracted and shown for RA compliance. Committed capacity is limited to the sum of approved QC values across all portfolios for a given RA capacity product. *Demonstrated capacity* is the sum of measured *ex post* capacity, again for a given RA capacity product. The penalty mechanism outlined in this report is applied on the shortfall of demonstrated capacity relative to committed capacity.

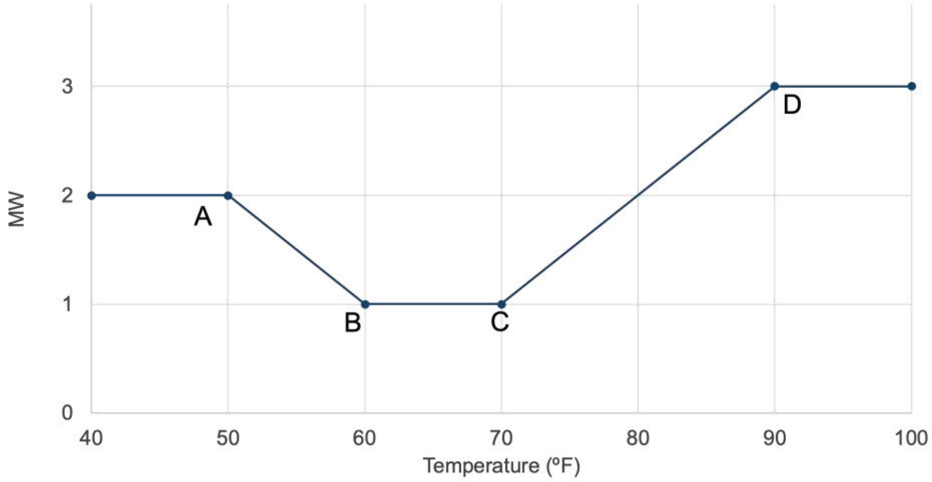
The hourly regression capacity counting methodology proposal is centered on a closed cycle of *ex ante* capacity projection and *ex post* capacity measurement. The *ex post* measurement is standardized such that DR providers, load-serving entities, and California policy makers can agree in advance to the measurement procedure and its outcome. Each step in the process is described in additional detail below.

Ex Ante Process

1. **The DR provider creates capability profiles for each aggregation for each hour.** Capability profiles project of how a DR aggregation can be expected to perform under varying conditions, including month, hour of day, and temperature. A profile is required for each combination of month and hour slice for which DR provider seeks a capacity value. DR providers must determine the hours an aggregation is expected to operate on the "worst day," the months across which an aggregation behaves consistently with respect to temperature (referred to as *seasons*), change points that define the weather sensitivity of the aggregation for each season, and corresponding capacity values for all combinations of these conditions.

   Within a season and hour, DR providers may submit any of four change points to define the temperature sensitivity of an aggregation as well as a first-hour effect, but all are optional. Figure 1 shows an example of a capability profile for a single hour, which can be applied to all months within a defined season.

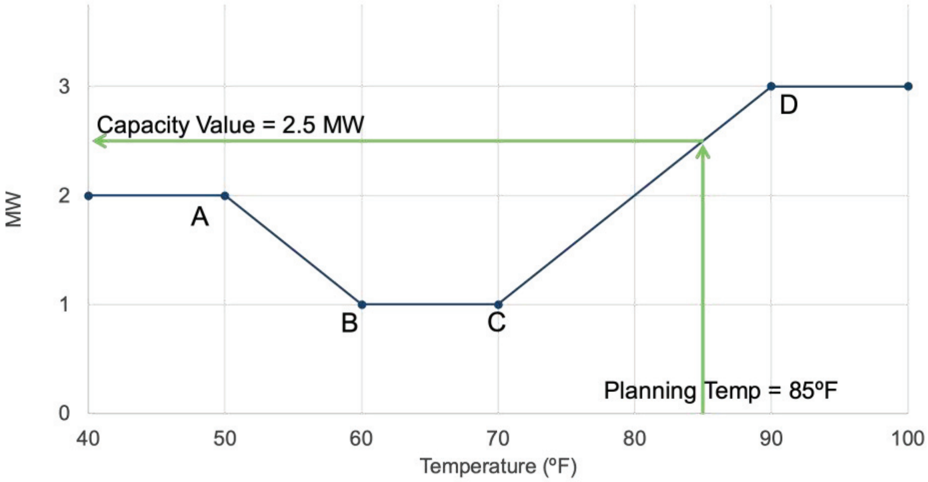
Figure 1: Illustration of an *Ex Ante* Capability Profile



Source: CEC staff

2. **Worst day planning temperatures determine hourly *ex ante* capacity values for each capability profile.** The *ex ante* capacity is defined as the value of the capability profile at the planning temperature. Figure 2 shows a graphical representation of *ex ante* capacity determination for the example aggregation in a hypothetical hour and month. For capability profiles applied to seasons including multiple months, the monthly capacity values are derived from the individual planning temperatures associated with each month.

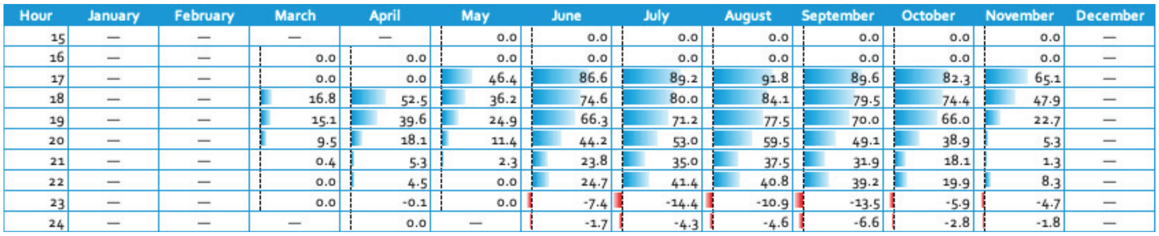
Figure 2: Illustration of Ex ante Capacity Determination



Source: CEC staff

3. **DR providers submit capability profiles and resultant capacity values for review by CPUC Energy Division staff in slice-of-day table.** DR providers convert capability profiles to a tabular format and submit these to CPUC staff along with tables detailing the aggregation structure and seasonal definition of the portfolio. A DR provider will submit a portfolio-level capacity value request for each month and hour they are seeking QC, plus any takeback expected on the worst day in the two hours preceding and two hours following the claimed dispatch period. If takeback profiles and capacity values are not provided, values of 0 MW and no weather sensitivity will be assumed. These values will be submitted in a slice-of-day table in the format illustrated in Figure 4.

Figure 3. Representative slice-of-day table.



Hour	January	February	March	April	May	June	July	August	September	October	November	December
15	—	—	—	—	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
16	—	—	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	—
17	—	—	0.0	0.0	46.4	86.6	89.2	91.8	89.6	82.3	65.1	—
18	—	—	16.8	52.5	36.2	74.6	80.0	84.1	79.5	74.4	47.9	—
19	—	—	15.1	39.6	24.9	66.3	71.2	77.5	70.0	66.0	22.7	—
20	—	—	9.5	18.1	11.4	44.2	53.0	59.5	49.1	38.9	5.3	—
21	—	—	0.4	5.3	2.3	23.8	35.0	37.5	31.9	18.1	1.3	—
22	—	—	0.0	4.5	0.0	24.7	41.4	40.8	39.2	19.9	8.3	—
23	—	—	0.0	-0.1	0.0	-7.4	-14.4	-10.9	-13.5	-5.9	-4.7	—
24	—	—	—	0.0	—	-1.7	-4.3	-4.6	-6.6	-2.8	-1.8	—

Source: Adapted from Demand Side Analytics.

4. **CPUC Energy Division staff review and approve capacity values.** Any portfolio-level capacity value for any combination of month and hour shall be deemed reasonable if it meets the following criteria:
    a. *Ex post* capacity value is at least 90 percent of the committed capacity in the prior year.
    b. Requested *ex ante* capacity is no more than 25 percent greater than the *ex post* delivered capacity in the prior year.

At the discretion of CPUC staff, individual capacity values that do not meet both criteria may be subject to more detailed review of materials including its associated capability profile and any supporting data or documentation.

Ex Post Process

5. **Individual *ex post* load impacts are calculated and adjusted relative to bids.** When possible, DR providers are directed to use the same customer energy baseline method used to calculate settlements in the California ISO energy market for consistency between the operational and planning space. However, an alternative method may be used when two conditions are met:

   a. The alternative method can be shown to be more accurate than the settlement method.

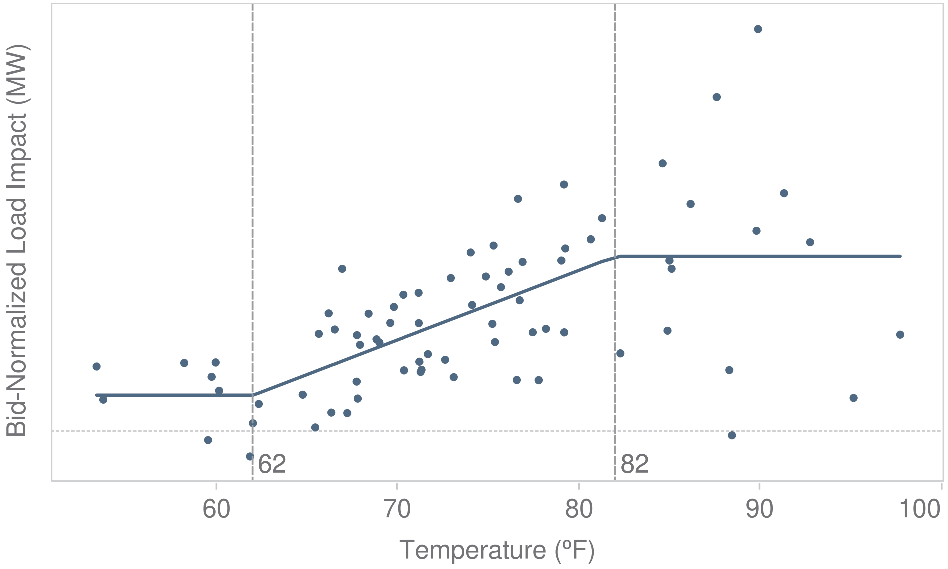
   b. The alternative method is infeasible to implement within the settlement period.

   These load impacts are adjusted relative to the amount bid according to the following definition of bid-normalized load impacts (BNLI):

$$\mathrm{BNLI} = \mathrm{Max}\left(Bid \left(\frac{\mathrm{Min}(Delivered,\ Dispatch)}{Dispatch} \right),\ Delivered \right)$$

6. ***Ex post* load impact profiles are determined by linear regression.** Using any temperature change points, first-hour effects, or both submitted in the *ex ante* capability profiles, a linear regression of capacity is applied to bid-normalized load impacts as a function of temperatures under which aggregations exhibit weather sensitivity. Figure 4 shows the *ex post* regression for a sample resource with changepoints at 62ºF and 82ºF.

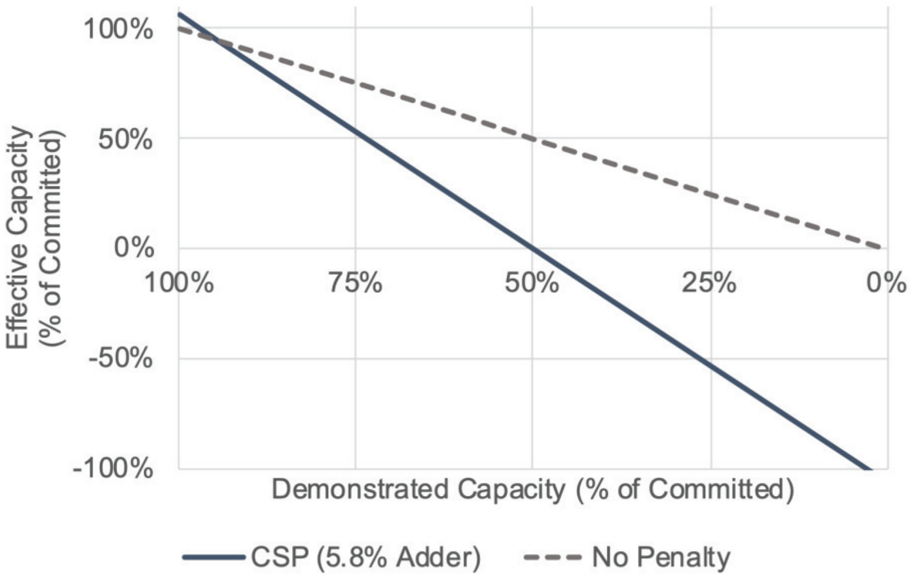
Figure 4: Impact Profile Regression of Aggregation with Hot Weather Sensitivity



Source: CEC staff analysis

7. ***Ex post* capacity is determined from *ex post* impact profiles.** The *ex post* demonstrated capacity is defined as the value of the regression profile at the planning temperature. For capability profiles applied to multiple months, the monthly capacity values are derived from the individual planning temperatures associated with each month.
8. **Penalties are applied to any shortfall in delivered capacity.** Penalties are assessed on the portion of capacity to which the aggregation was committed but failed to demonstrate. Relative to the *committed* capacity (defined as the lesser of contracted capacity and QC), the penalty is equal to two times the shortfall. That is, the aggregation shall be compensated for its *delivered* capacity minus again the shortfall. This penalty can be expressed in terms of capacity (MW), which is then multiplied by 1.058 to account for the target rate of forced outages. Figure 5 shows the revenue a DR provider will receive as a proportion of its contract value as a function of the demonstrated capacity it delivers ex post. DR providers may include contract provisions for compensation above the minimum contracted capacity, but this possibility is not addressed here.

Figure 5: Revenue under Capacity Shortfall Penalty with Forced Outage Multiplier



Source: CEC staff

CHAPTER 2:
Ex Ante Capacity Determination

The *ex ante* capacity determination is made based on the DR provider's assessment of its capability under planning temperatures. The *ex ante* QC determination relies on advance understanding of the *ex post* methods described in the following chapter to be developed appropriately. The capability profiles, as well as the resulting capacity values, should reflect the capability the DRP expects to deliver for each aggregation. The process consists of two main steps:

1. **Determine *ex ante* capability profiles for each aggregation.** Define groupings of one or more months into *seasons*. Select the hours and months for which a DR provider is seeking QC values. For weather-sensitive aggregations, define temperature change points for each relevant hour and season. Define other aggregation characteristics such as first-hour effect. The *ex post* regression model will use the specification defined in this step.

   For each combination of season, hour, first-hour effect, and change point, the DR provider submits an estimate of aggregation capabilities. Capabilities will be imputed between change points to form a capability profile.

2. **Determine the *ex ante* hourly capacity value by the intersection of the capability profile with the monthly planning temperature.** Apply the planning temperature to the capability profile function to generate an estimate of the aggregation's capacity value under planning conditions on the "worst day" as defined by the RA program.

Determining Ex Ante Capability Profiles

The capability profiles will serve as the basis for determining a DR provider's ex ante qualifying capacity each hour/month for which it seeks a capacity value. DR providers must determine the months across which the aggregation behaves consistently with respect to temperature, the hours an aggregation is expected to operate on the "worst day," change points that define the weather sensitivity of the aggregation (if any), and corresponding capacity values for all combinations of these conditions. The specification for the aggregation is defined in the *ex ante* portion of the process and is later applied as a regression model when determining *ex post* capabilities and demonstrated capacity.

Seasons

Capability profiles will be applied to groupings of months referred to as *seasons*. Seasons are groupings of one or more months defined for a given aggregation by the DR provider wherein the aggregation is expected to behave similarly with respect to temperature. Seasons may range from single months to the entire year. Seasons will likely often consist of consecutive months but may also include nonconsecutive months. For example, a DR provider may define a "summer" season, a "winter" season, and a "shoulder" season consisting of both spring and fall months. A DR provider may also define two seasons for the colder months at the beginning and end of the year, particularly if significant aggregation growth is projected from the beginning to end of the year.

Availability and Takeback Hours

DR providers define the hours an aggregation is to be available on the “worst day” of each month as defined by the RA program. The DR provider is responsible for defining the availability hours in each month it will be able to show for RA. The load-serving entity’s capacity needs and underlying DR capabilities will influence which hours the DR provider will seek QC values. CEC staff does not recommend specifying a minimum number of hours or prescriptive window of hours (i.e., availability assessment hours) to be shown for RA.

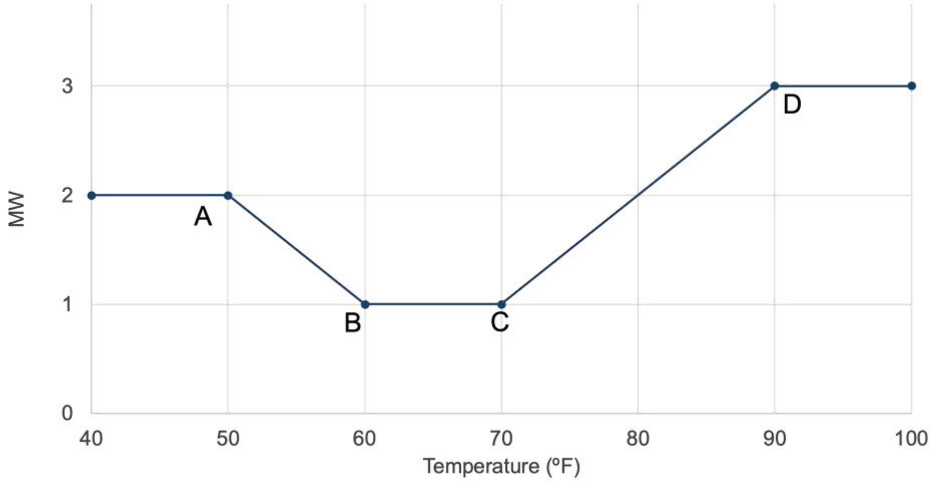
Within each month, the two hours before and after the availability hours will also be included to account for takeback. Submitting takeback profiles are optional. However, profiles of zero takeback across all temperatures will be imputed in the two hours before and after QC awards if not provided to ensure takeback is accounted for.

Weather Sensitivity

If applicable, the DR provider’s capability profile may show expected changes in capability in response to different temperatures. DR providers may include change points in the regression as necessary to account for DR aggregations with capabilities that change under warmer or colder conditions or both, as well as diminishing capabilities under more extreme conditions. The change points must be selected by the DR provider ahead of the relevant RA compliance period. Figure 6 shows a hypothetical capability profile for an aggregation that shows both hot and cold weather sensitivity.

Figure 6 shows a schematic of the possible inputs, marked as points A–D. Points B and C represent the points below and above which the aggregation shows temperature sensitivity. Points A and D represent saturation change points below and above which the aggregation no longer shows temperature sensitivity.

Figure 6. *Ex Ante* Hourly Capability Profile with Hot and Cold Weather Sensitivity



Source: CEC staff

However, a few constraints must be imposed on these change points. These effectively require the profile to behave like the schematic shown above. Change points A–D must be in ascending order of temperature and the MW values of change points A and D must be higher than points B and C. These constraints are summarized in Table 1.

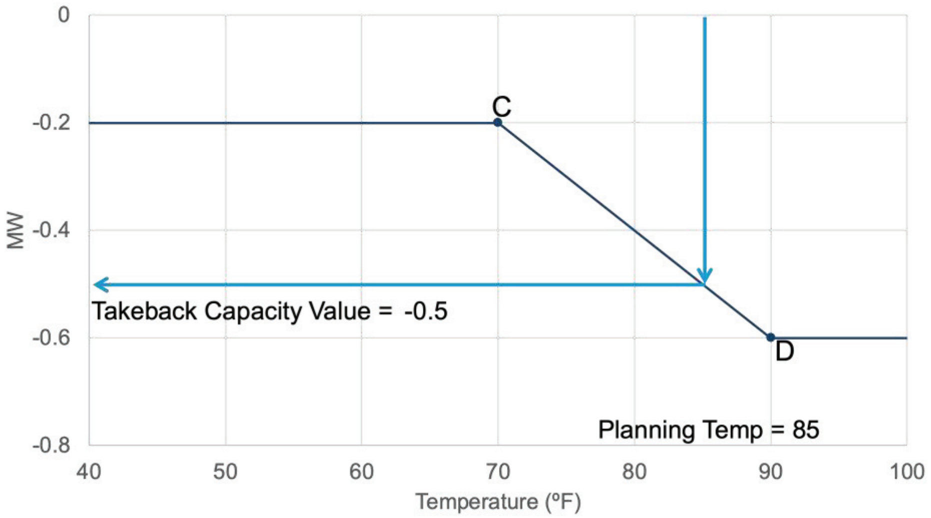
Table 1. *Ex Ante* Profile Change Point Constraints

Point	**Required?**	**Temperature Constraint**	**Load Impact Constraint**
A	No	A<B	|A|>|B|
B	Only if A submitted	A<B≤C	B=C
C	Only if D submitted	B≤C<D	C=B
D	No	D>C	|D|>|C|

Source: CEC staff

Constraining the *absolute value* of load impact values allows the rules to be applied to takeback hours as well. To illustrate, Figure 7 shows a takeback profile for an aggregation with hot weather sensitivity. The takeback profile meets the temperature constraint because the temperature of point D is greater than that of point C. The profile meets the load impact constraint because the *absolute value* of the capability value is greater than that of point C, even though the capability value (MW) of D is less than that of C.

Figure 7. Takeback Profile Exhibiting Hot Weather Sensitivity



Source: CEC Staff

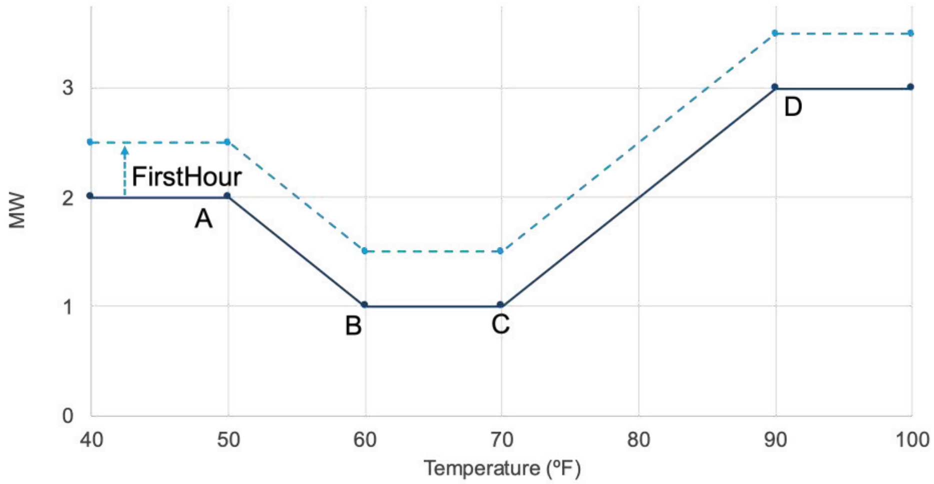
Critically, the temperature values of the change points must be committed to ex ante and applied when evaluating ex post. The load impact values will be determined by running a regression of performance relative to temperature, subject to these predetermined changepoints.

First-hour Effect

DR aggregations often have a larger impact in the first hour of a dispatch than the following hours, regardless of the time of day the dispatch begins. For example, with air-conditioning backed DR, load impacts may be highest in the first hour as thermostats are set higher; indoor temperatures will drift upward without triggering the system to turn on. After this initial phase, the air conditioner will keep the temperature at the higher set point, reducing demand relative to the counterfactual of no dispatch, but increasing demand relative to the initial period.

To account for this common characteristic, an optional first-hour effect term is available for inclusion in the DR capability profile specification. The first-hour effect term is represented by a vertical increase of the capability profile when the hour is the first of the dispatch.

Figure 8: Illustration of First-hour Effect on Capability Profile



Source: CEC staff

The first-hour effect variable can also be applied to the takeback hours directly preceding and following the dispatch. For the pre-dispatch model, the first-hour effect would apply to the hour closest to the dispatch (the “first” hour starting from the beginning of the dispatch window) rather than the first hour chronologically.

Representing Capability Profiles in Tabular Format

Capability profiles for each relevant combination of hour and season must be submitted in tabular format. Aggregations without weather sensitivity or first-hour characteristics simply leave the corresponding values in the tabular format blank. Table 2 represents the weather-sensitive aggregation with first-hour effect illustrated in Figure 8 (WS, the most complicated possible), a hot-weather-sensitive aggregation (HWS) without first-hour effect, and a non-weather-sensitive aggregation (NWS) without first-hour effect for a given combination of season and hour. In the simplest case of NWS, only the single value of MW_{BC} is required.

Table 2: Aggregation Capability Profiles in Tabular Form

Aggregation	Season	Hour Ending	Temp A (ºF)	MW A	Temp B (ºF)	MW B C	Temp C (ºF)	Temp D (ºF)	MW D	FirstHour (MW)
WS	A	20	50	2	60	1	70	90	3	0.5
HWS	A	20	—	—	—	1	70	90	3	—
NWS	A	20	—	—	—	1	—	—	—	—

Source: CEC staff

The capability profile can be represented mathematically as the following function:

$$\begin{aligned} Capability(Temp_{Plan}, FirstHour) &= MW_{BC} \\ &+ \frac{MW_A - MW_{BC}}{Temp_A - Temp_B}(Temp_B - \min(\max(Temp_{Plan}, Temp_A), Temp_B)) \\ &+ \frac{MW_D - MW_{BC}}{Temp_D - Temp_C}(\min(\max(Temp_{Plan}, Temp_C), Temp_D) - Temp_C) \\ &+ MW_{FirstHour} FirstHour \end{aligned}$$

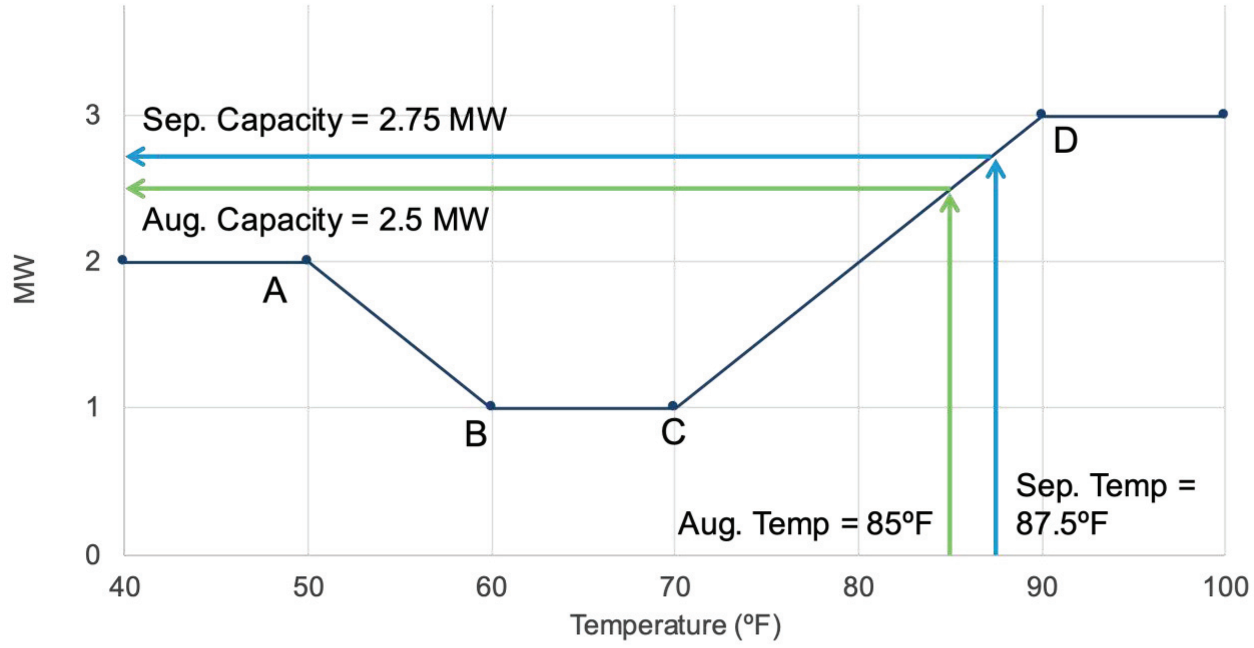
The submitted values from the tabular capability profile submitted by the DR provider can be entered into the formula to derive a capability profile as a function of temperature (and, if appropriate, the first-hour effect). Any terms not included in the tabular submission are dropped from the mathematical function. This function will be used to determine the *ex ante* capacity value, as described in the following section.

Determining the Ex ante Capacity Value

The DR provider and implementing agency can unambiguously determine hourly *ex ante* capacity values from the *ex ante* capability profile. For each capability profile, the capacity value is simply the load impact value (MW) that corresponds with the planning temperature for that month.

Figure 9 illustrates this exercise for a season comprising two months (August and September). The aggregation shares the same capability profile for both months because they are part of the same season. The planning temperatures of 85ºF in July and 87.5ºF in September can be traced from the x-axis to the capability profiles, and then followed to the intersection with the y-axis to reveal capacity value of 2.5 and 2.75 MW, respectively.

Figure 9. Ex ante Capacity Determination for Two Months Within One Season



Source: CEC staff

For the example profile shown in Figure 9 (in tabular form as shown in Table 2), the equation simplifies to:

$$\begin{aligned} &Capability(Temp_{Plan}) \\ &\quad = 1 + \frac{2-1}{50-60}(\min(\max(Temp_{Plan}, 50), 60) - 60) \\ &\quad + \frac{3-1}{90-70}(\min(\max(Temp_{Plan}, 70), 90) - 70) + 0.5FirstHour \\ &\quad = 1 - 0.1(60 - \min(\max(Temp_{Plan}, 50), 60)) \\ &\quad + 0.1(\min(\max(Temp_{Plan}, 70), 90) - 70) + 0.5FirstHour \end{aligned}$$

Under the July planning temperature of 85ºF when the hour is not the first hour of the dispatch ($FirstHour = 0$), the formula outputs a result of 2.5 MW:

$$\begin{aligned} &Capability(Temp_{Plan}) \\ &\quad = 1 - 0.1(60 - \min(\max(85,50), 60)) + 0.1(\min(\max(85,70), 90) - 70) + 0.5(0) \\ &\quad = 1 - 0.1(60 - \min(85,60)) + 0.1(\min(85,90) - 70) + 0 \\ &\quad = 1 - 0.1(60 - 60) + 0.1(85 - 70) \\ &\quad = 1 - 0.1(0) + 0.1(15) = 1 - 0 + 1.5 \\ &\quad = 2.5\text{ MW} \end{aligned}$$

Review and Approval

CPUC staff retain the role of approving final DR QC values. This proposal, however, includes constraints on how CPUC staff can adjust QC values. If the final approved QC is different from the capacity values that have been requested by the DR provider, the underlying capability profile must also be changed. This can be done by adjusting the capability (MW) values of the change points (as opposed to the temperature values) that result in an appropriate final QC value.

A streamlined approval process for demand response portfolios with a proven track record and that are growing at a reasonable pace year-over-year would minimize administrative and reporting burden for both the DR provider and CPUC Energy Division staff. Specifically, CPUC staff would automatically approve requested QC of any portfolio for any hour and month that meets the following two criteria:

1. *Ex post* delivered capacity value is at least 90 percent of the committed capacity in the previous year.
2. Requested *ex ante* capacity is no more than 25 percent above the *ex post* delivered capacity in the previous year.

Portfolios that do not meet both criteria for all hours may be subject to more detailed review at the discretion of CPUC Energy Division staff. This review can be focused on the specific values for seasons or hours that do not meet the criteria.

CHAPTER 3:
Ex Post Hourly Capacity Counting Methodology

This chapter details the proposed *ex post* hourly regression capacity counting methodology. For each hour in each month, the methodology includes the following steps, which are described in greater detail in the following sections:

1. **Calculating Load Impacts and Normalizing for Availability:** Before capacity values can be calculated for reliability planning purposes, hourly DR availability and performance must be assessed. Load impacts are calculated at the customer level and summed at the aggregation level. These load impacts are then normalized
2. **Run a regression of load impacts as a function of temperature:** Create an ordinary least squares linear regression model of adjusted load impacts on temperature for each season using the change point temperature values specified in the *ex ante* capability profiles. The regression line generated by this model is the aggregation's *ex post* hourly impact profile and is analogous to the *ex ante* hourly capability profile.
3. **Determine the *ex post* hourly capacity value by the intersection of the impact profile with the monthly planning temperature.** Apply the planning temperature to the load impact function to generate an estimate of the aggregation's capacity value under planning conditions.

Calculating Load Impacts and Normalizing for Availability

This section introduces constraints on customer energy baseline for calculating individual load impacts, and how individual load impacts with be adjusted for partial dispatches.

Customer Energy Baselines

The following guideline for measuring delivered load impacts from individual dispatches relative to a counterfactual baseline directs DR providers to use California ISO settlement baselines as a default. However, the rule provides an exception for aggregations for which the accepted baselines are problematic, such as weather-sensitive aggregations. The baseline method used to measure load impacts for the purpose of calculated *ex post* capacity shall be the same baseline method used to calculate settlements in the California ISO energy market unless two conditions are met:

1) The alternative method can be shown to be more accurate than the settlement method.
2) The alternative method is infeasible to implement for settlement purposes.

Normalizing Load Impacts for Availability

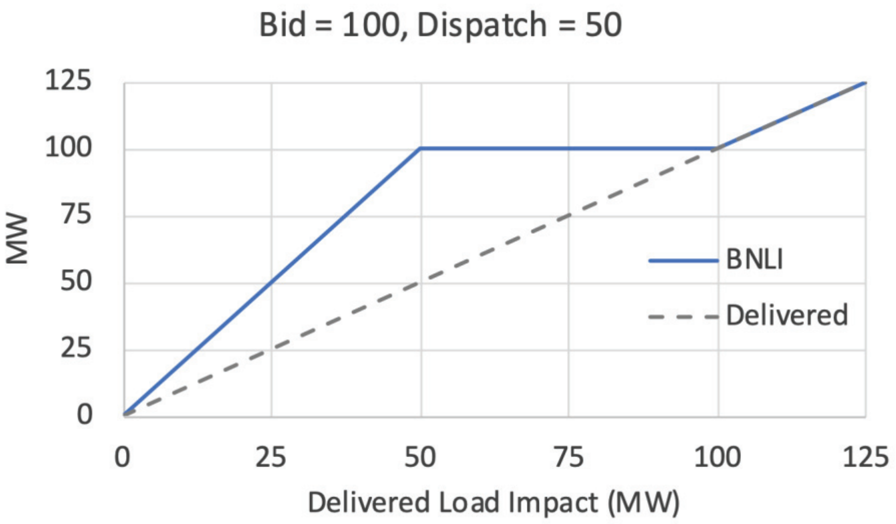
Individual load impacts will be normalized relative to the amount bid and dispatched. The formula uses bid (or self-schedule), dispatch (or test), and load impact data. Each of these values is the sum of the respective resource-level bid, dispatch, and load impact values across an aggregation. Bid-normalized load impact (BNLI) is calculated according to the following formula for any period in which a DR aggregation receives a dispatch, including a partial dispatch:

$$\text{BNLI} = \text{Max}\left(Bid\left(\frac{\text{Min}(Delivered,\ Dispatch)}{Dispatch}\right),\ Delivered\right)$$

In the formula, "bid" refers to both true bids and self-schedules. If the amount bid or self-scheduled changes between the day-ahead, hour-ahead, and real-time markets, the bid amount shall be defined as the least of these amounts. Intervals in which a DR resource has an RA obligation but does not bid will be assigned a value of zero.

Figure 10 illustrates the calculation of bid-normalized load impacts for a bid of 100 MW and a partial dispatch of 50 MW. If the aggregation delivers the dispatched amount, the formula produces a bid-normalized load impact of the full bid amount. If the aggregation delivers less than the dispatched amount, the formula returns the proportion of the dispatch that was delivered times the full bid amount. If the aggregation exceeds its bid, the formula again returns the delivered amount.

Figure 10: Example bid-normalized load impact for bid of 100 MW and dispatch of 50 MW



Source: CEC staff analysis

DR tests can be used in addition to or in the absence of ISO dispatches if necessary. In these cases, the amount bid and dispatched should be assumed to equal the entire aggregation. That is, the concept of a partial dispatch is not applicable to a test event. Mathematically, this implies that the amount that the DR provider believes it can provide (the "bid") and the amount it is attempting to provide (the "dispatch") are the same, so bid-normalized load impacts are equal to delivered load impacts across all values. In the case of a test event, the DR provider does not need to include bid or dispatch values, but the result is conceptually compatible with actual dispatch data.

The hourly *ex post* regression takes these bid-normalized load impact values along with the corresponding temperatures as inputs.

Impact Profile Regression

This section details the process to specify ordinary least squares linear regressions that parallel the *ex ante* capability profiles detailed in Chapter 2. For each season, three separate ordinary least squares regressions are run: pre-dispatch, dispatch, and post-dispatch.

For all aggregations, the capability specification takes the following form:

$$Impact_i = \beta_1 Hour_1 + \cdots + \beta_{\mathrm{n}} Hour_{\mathrm{n}} + \cdots + \varepsilon_i$$

Where $Impact_i$ is the bid-normalized load impact in hour i, β_1 through β_{n} are the model intercept values for the hours shown for RA (including takeback), $Hour_1$ through $Hour_{\mathrm{n}}$ are indicator variables for the n hours, and ε_i is an error term. In contrast to typical regression model design, a model intercept is not estimated. Rather, β_1 through β_{n} represent hour-level model intercepts as if they were separate models. This formulation allows inclusion of inter-hour terms such as the first-hour effect. For simple non-weather-sensitive aggregations, this model specification will result in β values equal to the average (mean) impact of the aggregation in each hour it was dispatched, and no additional terms are required.

To simplify notation for more complex resources, the above equation can be represented to show that load impacts are modeled as a linear function of hour of day (and other terms, if necessary):

$$Impact \sim Hour_{1:n} + \cdots$$

Table 3 summarizes the optional terms available to include in the model for aggregations with additional characteristics, including hot and cold weather sensitivity and a first-hour effect. See Figure 6 for overview of change points A, B, C, and D.

Table 3: Additional model terms available by default

Term Name	Mathematical Representation	Interaction with Hour	Description
Cold Weather Sensitivity (CWS)	$\min(\max(Temp_i, A_h), B_h)$	Yes	Temperature in interval i, bounded by change points A and B in hour h
Hot Weather Sensitivity (HWS)	$\min(\max(Temp_i, C_h), D_h)$	Yes	Temperature in interval i, bounded by change points C and D in hour h
First-hour Effect	$FirstHour_i$	No	Indicator variable that is 1 if the hour is the first hour of a dispatch or the first hour of modeled takeback before/after the dispatch and 0 otherwise.

Source: CEC staff

For example, a regression using all the optional model terms will take the following form:

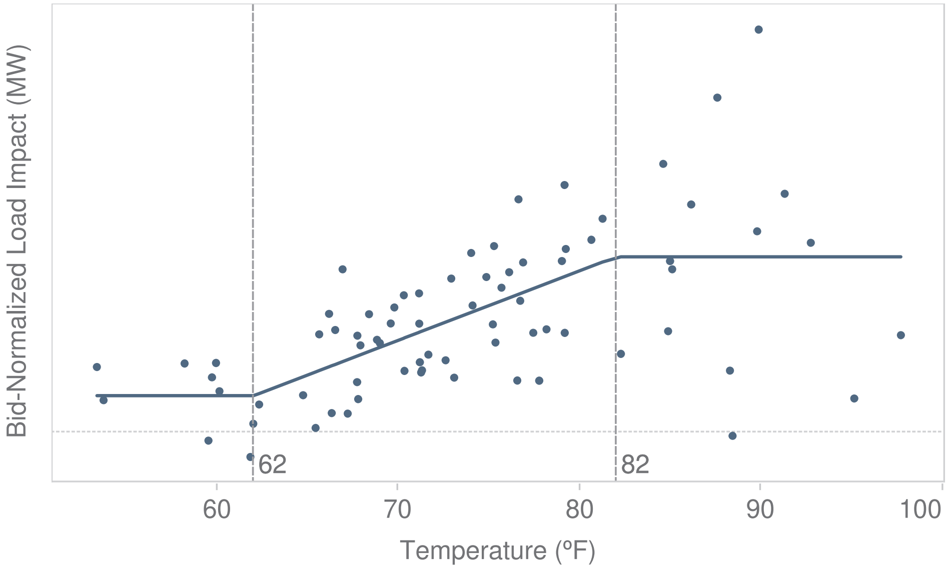
$$Impact \sim Hour_{1:n} + Hour_{1:n}CWS_{1:n} \ + Hour_{1:n}HWS_{1:n} + FirstHour$$
$$Impact \sim Hour_{1:n} + Hour_{1:n}\min(\max(Temp, A_{1:n}), B_{1:n}) \ + Hour_{1:n}\min(\max(Temp, C_{1:n}), D_{1:n}) + FirstHour$$

The temperature variables are interacted with hour and the first-hour effect variable is not. The temperature constants A, B, C, and D are provided by the DR provider for each hour and are not estimated in the *ex post* regression. In long form, for example, the regression for a two-hour aggregation takes the following form:

$$\begin{aligned} Impact_i = \ & \beta_1 Hour_1 + \beta_2 Hour_2 + \beta_3 Hour_1 \min(\max(Temp_i, A_1), B_1) \\ & + \beta_4 Hour_2 \min(\max(Temp_i, A_2), B_2) \ + \beta_5 Hour_1 \min(\max(Temp_i, C_1), D_1) \\ & + \beta_6 Hour_2 \min(\max(Temp_i, C_2), D_2) + \beta_7 FirstHour_i + \ \varepsilon_i \end{aligned}$$

Figure 11 illustrates the results of an *ex post* impact profile regression on a sample aggregation for a given hour and season. The *ex ante* capability profile includes hot weather sensitivity change points C and D at 62ºF and 82ºF, respectively. The regression specification constrains weather sensitivity to this range of temperatures and is flat on either side.

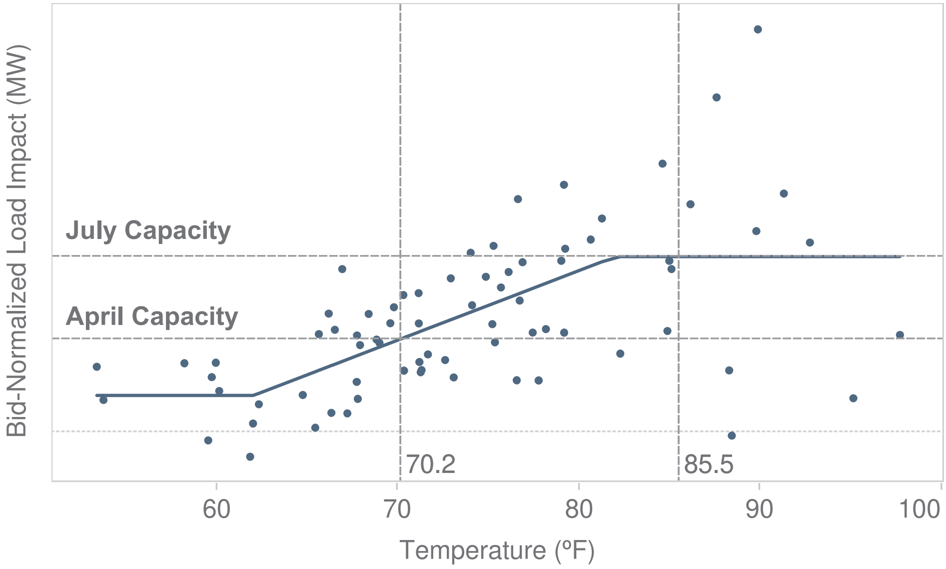
Figure 11: Impact Profile Regression of Aggregation with Hot Weather Sensitivity



Source: CEC staff analysis

Aggregation-level demonstrated *ex post* capacity values are determined from the associated impact profile. Specifically, the value of the impact profile at the planning temperature for each month of the season is the demonstrated capacity value for that month. Figure 12 shows this calculation graphically for April and July, the coolest and hottest months of the season, respectively. All capacity values for planning temperatures above the high change point (D) or below the low change point (C) will be equal.

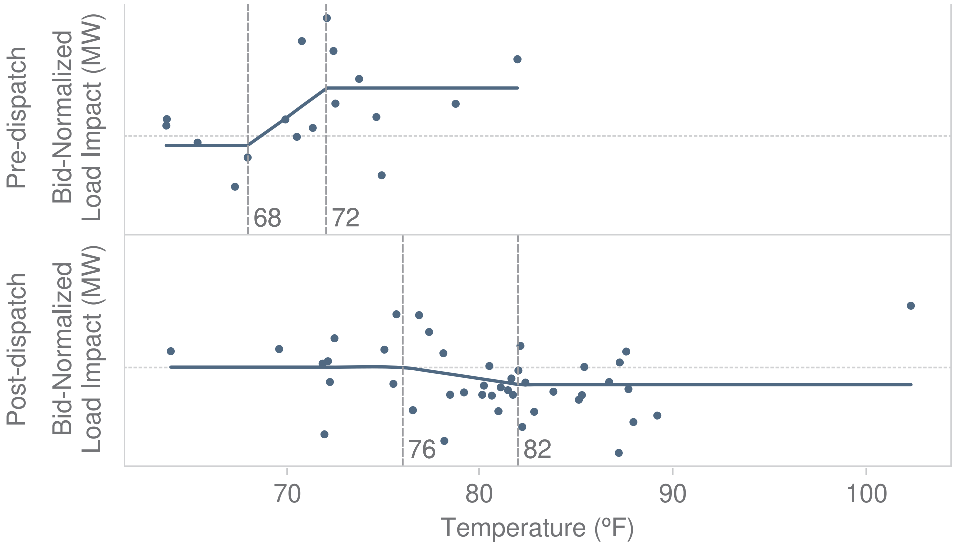
Figure 12: Demonstrated April and July Capacity Values from Impact Profile Regression



Source: CEC staff analysis

Takeback regressions are split into pre-dispatch and post-dispatch models but are otherwise equivalent to the dispatch regression. Figure 13 illustrates the takeback regressions for a given aggregation and season for hour ending (HE) 20. When the dispatch begins in HE 21 and HE 20 precedes the dispatch, the aggregation exhibits spillover (that is, a load reduction) at higher temperatures. When the dispatch ends after HE 19 and HE 20 follows the dispatch, the aggregation exhibits post-dispatch takeback (a load increase) at higher temperatures.

Figure 13: Takeback pre- and post-dispatch regressions for a given hour and season



Source: CEC staff analysis

This example illustrates the importance of separating pre- and post-dispatch takeback models. In addition to differing on the direction of load impacts, they also differ in change points. Separating models allows DR providers to submit different pre- and post-dispatch change points for a given hour. For purposes of creating hourly takeback capacity values, both pre-dispatch and post-dispatch models may not be needed because a single hour cannot simultaneously be used for both in a "worst day" profile. However, takeback models will use data across all pre- or post-takeback hours when determining a first-hour effect and running the regression across all hours requires minimal incremental effort.

Takeback capacity values is be determined in the same manner as the dispatch capacity values. However, takeback capacity values will be constrained to less than or equal to zero. If a DR provider wishes to claim a positive load impact (a load reduction) for that hour, it should be included in the dispatch window in the *ex ante* capability profile and capacity values. The takeback hours must be incremental to the dispatch hours.

Treatment of Small Data Sets

To successfully apply this regression approach, multiple data points are required. This section discusses how the methodology will handle few or zero data points and how this treatment provides an incentive for DR providers to be dispatched in the market. However, this methodology does not specify a minimum dispatch requirement.

In the absence of any event data in a season and hour, DR aggregations will be awarded an *ex post* capacity value of zero. In the case of a single dispatch or test, that single value will be used for capacity across all temperatures.

With a small number of data points, a regression line will still be fit. While such a regression may produce volatile results, that volatility provides an incentive for DR providers to dispatch frequently enough to generate sufficient data to develop a robust *ex post* model to support their committed capacity values. The ability to combine months into "seasons" can allow DR providers to develop that data set over more months if the aggregation behaves consistently relative to temperature across those months. This approach will help aggregations that dispatch less frequently to nonetheless develop evidence of capacity value.

As an extreme example, a non-weather sensitive reliability demand response aggregation that dispatches very infrequently may use the entire year as a season. Even if the aggregation is only called for its minimum required test events and never dispatched under emergency conditions, those test events may form the basis for the demonstrated capacity value for every month of the year.

CHAPTER 4: Incentive Mechanism

An incentive mechanism referred to as the Capacity Shortfall Penalty (CSP) replaces the current incentive mechanism for RA resources in the California ISO markets, the Resource Adequacy Availability Incentive Mechanism (RAAIM). For consistency with the RAAIM, the CSP includes a multiplier of 1.058 to account for a target level of forced outage, taking the place of existing forced outage component of the planning reserve margin adder.

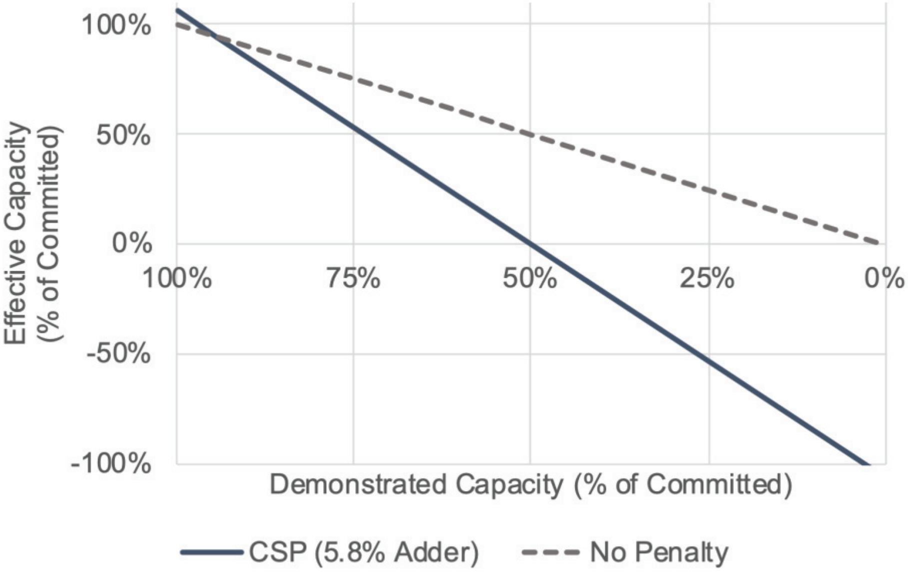
The CSP applies to *ex ante* committed and *ex post* demonstrated capacity averaged across the hours to which it is committed for each month, including the two hours on either side of the worst day dispatch window.

Under the CSP with forced outage multiplier, the CPUC calculates the *ex post* effective capacity, which is the capacity value (MW) a DR provider would have been compensated for if its delivered capacity delivered its committed capacity at the targeted availability rate of 94.5 percent exactly:

$$Cap_{Eff} = 1.058(Cap_{Com} - 2\ \max(Cap_{Com} - Cap_{Dem}, 0))$$

Where 1.058 is the forced outage multiplier, $Cap_{Com}$is the committed capacity, and Cap_{Dem} is demonstrated capacity. Committed capacity is defined as the lesser of QC and contracted capacity in each month. Figure 14 illustrates the effective capacity under the CSP as a function of percentage of committed capacity demonstrated. The dashed "no penalty" line is included as a reference to show where effective capacity is equal to demonstrated capacity, regardless of the *ex ante* capacity commitment.

Figure 14: Revenue under Capacity Shortfall Penalty with Forced Outage Multiplier



Source: CEC staff

Effective capacity starts above 100 percent for instances where DR providers exceed the target level of outage. Effective capacity hits 100 percent at the target level of 94.5 percent of demonstrated capacity. Effective capacity continues to drop steadily below this level, reach zero capacity (and therefore zero capacity revenue) at 50 percent of commitment. Below half of committed capacity, the DR provider will be required to pay a net penalty.

Once effective capacity is calculated, load-serving entities reconcile capacity contract payments with DR providers. Depending on performance and contract structure, load-serving entities may make additional payments to or recoup capacity payments from DR providers. For DR providers with portfolios spanning multiple RA contracts, any shortfall and penalty is distributed on a pro rata basis (per MW) across contracts.

APPENDIX A:
Sample Reporting Templates

Table 4: Resource ID Aggregation Table

Resource ID	SubLAP	Aggregation	Description
CAISO_PDR_1	SLAP_A	A	Res AC (SLAP A)
CAISO_PDR_2	SLAP_A	A	Res AC (SLAP A)
CAISO_PDR_3	SLAP_A	B	Comm AC (SLAP A)
CAISO_PDR_4	SLAP_B	C	Res AC (SLAP B)

Source: CEC staff

Table 5: Resource ID Aggregation Table

Aggregation	Portfolio	Description
A	A	Res AC (System)
C	A	Res AC (System)
B	B	Comm AC (System)

Source: CEC staff

Table 6: Season Definition for Aggregation A

Aggregation	Month	Season
A	1	A
A	2	A
A	3	A
A	4	B
A	5	B
A	6	B
A	7	B
A	8	B
A	9	B
A	10	A
A	11	A
A	12	A

Source: CEC Staff

Table 7: Ex Ante Capability Profile Submission Table for Aggregation A

Aggregation	Season	Period	Hour Ending	Temp A (ºF)	MW A	Temp B (ºF)	MW B_C	Temp C (ºF)	Temp D (ºF)	MW D	FirstHour (MW)
A	B	Pre	16								
A	B	Pre	17								
A	B	Dispatch	18								
A	B	Dispatch	19								
A	B	Dispatch	20								
A	B	Dispatch	21								
A	B	Post	22								
A	B	Post	23								

Source: CEC staff

Table 8: Ex Ante Capacity Submission Table for Aggregation A

Aggregation	Month	Hour Ending	Planning Temperature	Capacity
A	9	16		
A	9	17		
A	9	18		
A	9	19		
A	9	20		
A	9	21		
A	9	22		
A	9	23		

Source: CEC Staff

Table 9: Ex Ante Capacity Submission Table for Portfolio A

Portfolio	Month	Hour Ending	Capacity
A	9	16	
A	9	17	
A	9	18	
A	9	19	
A	9	20	
A	9	21	
A	9	22	
A	9	23	

Source: CEC Staff

(END OF ATTACHMENT)