August 17, 2018

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER18- ___-000

Tariff Amendment to Implement Energy Storage and Distributed Energy Resource Enhancements

Request for Waiver of Notice Period

Dear Secretary Bose:

The California Independent System Operator Corporation ("CAISO") submits this tariff amendment to expand options for energy storage and distributed resource participation in the CAISO markets.[1] These enhancements result from the second phase of the CAISO's energy storage and distributed energy resource stakeholder initiative ("ESDER"). The CAISO proposes three sets of enhancements:

A. Provide three new demand response evaluation methodologies, transition to scheduling coordinator-based calculation, and clarify demand response terms;

B. Clarify station power treatment for energy storage resources; and

C. Incorporate all relevant gas indices into the net benefits test used to determine when a decrease in demand provides a net benefit.

The first set of proposed enhancements increases the number of methodologies for evaluating demand response resource performance from two to five. Demand response participation models have become one of the most

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1 References herein to "energy storage" generally refer to battery, flywheel, compressed air, and other emerging technologies, but not Pumped-Storage Hydro Units, which already participate in CAISO markets and have distinct operating rules and procedures.

The CAISO submits this filing pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the CAISO tariff, and references to specific sections, articles, and appendices are references to sections, articles, and appendices in the current CAISO tariff and revised or proposed in this filing, unless otherwise indicated.

common and preferred ways for distributed resources to participate in the wholesale markets. Currently, the CAISO tariff provides a day-matching customer load baseline methodology—the 10-in-10 methodology—for pure load resources, and a variation on this methodology for resources that are or include behind-the-meter generation—the metering generator output methodology. CAISO stakeholders have expressed that these methodologies may not perfectly capture the performance of different resources. The CAISO worked with stakeholders and consultants to develop three new methodologies: (1) a control group methodology; (2) a weather-matching methodology; and (3) a 5-in-10 methodology. These new methodologies and growing demand response participation require the CAISO to transfer to scheduling coordinators the responsibility to calculate their own baselines and performances, which the CAISO has calculated to date. For monitoring and compliance purposes, the CAISO will continue to collect all relevant data. The CAISO also proposes to clarify several defined terms for demand response resources.

The second set of proposed enhancements clarifies metering, settlement, and netting rules regarding "station power," which is the energy used to operate generators and storage resources onsite. Current CAISO station power rules center on conventional generation, and could create ambiguity for storage resources whose load can be both wholesale (charging energy sold for resale) and retail (station power to be used onsite). Retail authorities frequently allow station power to be netted from wholesale participation, thus allowing station power to be settled at wholesale rates. The CAISO worked closely with the California Public Utilities Commission to ensure that wholesale and retail tariffs do not create conflicting station power netting rules, as happened previously and resulted in lengthy litigation.[2] The CAISO's proposed rules are sufficiently flexible to allow retail authorities to define whether station power is retail and can be netted from wholesale demand or production.

The third set of proposed enhancements incorporates all relevant gas indices into the CAISO's net benefits test. Order No. 745 established the net benefits test "to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the costs of dispatching and paying LMP to those resources."[3] As directed by Order No. 745, the CAISO's net benefits test establishes threshold prices for peak and off-peak periods at the points where the dispatch of demand response results in a net decrease in the cost of energy.[4] In calculating these prices, the CAISO considers "significant changes in fuel prices."[5]

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2 *See Duke Energy Moss Landing v. CAISO*, 132 FERC ¶ 61,183 (2010) *on remand from Southern California Edison Co. v. FERC*, 603 F.3d 996 (D.C. Cir. 2010).

3 *California Independent System Operator Corp.*, 144 FERC ¶ 61,046 at P 2 (2013).

4 *California Independent System Operator Corp.*, 137 FERC ¶ 61,217 at P 28 (2011).

5 Section 30.6.3.1(ii) of the CAISO tariff.

Currently the CAISO tariff calculates these changes using the average of the Pacific Gas and Electric Company citygate price and the Southern California Edison Company citygate price, which were the relevant prices when the CAISO implemented these tariff provisions in 2011.[6] This is no longer the case, principally because of the expansion of the CAISO Energy Imbalance Market in the West. The CAISO therefore proposes to remove the express reference to the two California citygates from the tariff, and instead enumerate the various relevant indices in the business practice manual. This will provide the CAISO with the flexibility to update its list as frequently as new regions participate in the CAISO markets, or fuel indices become more or less relevant.

The CAISO respectfully requests that the Commission approve the proposed revisions with an effective date of November 1, 2018. Additionally, the CAISO respectfully requests that the Commission waive the notice requirement provided in the Commission's regulations.

II. Background

Under A.B. 2514 and A.B. 2868, the California Public Utilities Commission ("CPUC") has directed California investor-owned utilities to procure nearly 2,000 MW of energy storage (excluding pumped hydro storage) by 2020.[7] The total procurement target is broken down into three locational categories requiring at least 700 MW of energy storage interconnected to the transmission system, 925 MW interconnected to the distribution system, and 200 MW from retail customers.

The CAISO continues to experience the effects of this procurement directive. In 2016 the CAISO generator interconnection queue had 36 interconnection requests for energy storage, comprising 3,093 MW.[8] Today the CAISO queue has 116 interconnection requests for energy storage comprising 23,139 MW. Moreover, over 200 MW of greenfield energy storage projects have interconnected to the CAISO transmission system since 2016, and even more storage has interconnected to the distribution grid.

The CAISO has been working to develop rules and participation models tailored to the unique aspects of energy storage, both for resources connected to the transmission system and the distribution system. The CAISO developed the framework for the non-generator resource model in 2010 in response to the directives of Order Nos. 719 and 890 to facilitate the provision of ancillary services

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6 *Id.*

7 *See* California Energy Commission, "Energy Storage – Tracking Progress," *available at* http://www.energy.ca.gov/renewables/tracking_progress/documents/energy_storage.pdf.

8 https://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx. Note that these figures include "hybrid" interconnection requests that can include other technology types, such as solar and storage or wind and storage.

by non-generator resources.[9] In 2011 the CAISO created the non-generator resource model and detailed the procedures for non-generator resource market participation, including the use of regulation energy management functionality.[10]

In 2014 the CAISO conducted three stakeholder initiatives related to energy storage. First, the CAISO conducted an energy storage interconnection initiative to examine potential issues with energy storage resources' interconnecting to the CAISO controlled grid.[11] This initiative ultimately concluded that the CAISO's existing interconnection rules and study processes could accommodate energy storage resources, and the CAISO added guidance for storage resources on several topics in its business practice manuals ("BPMs"). Second, the CAISO conducted a distributed energy resource provider initiative to allow small distributed energy resources—including energy storage resources—to aggregate into consolidated resources and meet the CAISO's minimum capacity requirement of 0.5 MW. These revisions allow smaller resources to participate in the wholesale market.[12] Third, collaborating with the CPUC and the California Energy Commission, the CAISO completed the California Energy Storage Roadmap, which outlines ways to (1) expand revenue opportunities for energy storage resources, (2) lower costs of integrating and connecting to the grid, and (3) streamline and elucidate policies to increase certainty.[13]

In 2015 the CAISO began the first phase of its ESDER initiative, which sought to solve the CAISO-related issues identified in the California Energy Storage Roadmap and solicit additional suggestions from stakeholders on storage-related issues. This first phase focused on the non-generator resource model, demand

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[9] *California Independent System Operator Corp.*, 132 FERC ¶ 61,211 (2010). The "non-generator resource" model is the principal means by which energy storage resources participate in the CAISO markets. This model allows batteries to operate continuously across an operating range that includes both negative and positive generation (*i.e.*, charging and discharging). This model also recognizes that non-generator resources have MWh constraints that limit the amount of energy they can store and produce.

[10] *California Independent System Operator Corp*., 137 FERC ¶ 61,165 (2011). Scheduling coordinators for non-generator resources may request to certify resources that use regulation energy management to provide regulation service consistent with the continuous energy requirements. Regulation energy management is "a market feature for resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation." Resources that choose to use regulation energy management must sign a participating generator agreement or a participating load agreement. The resources that choose to use regulation energy management must also define their ramp rate for operating as generation and load and allow CAISO to control their operating set point. *See* CAISO tariff Appendix A; tariff section 8.4.1.2.

[11] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorageInterconnection aspx.

[12] *California Independent System Operator Corp.*, 155 FERC ¶ 61,229 (2016).

[13] https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology _CaliforniaRoadmap.pdf.

response enhancements, and clarifications on the rules for "multiple-use applications," namely resources capable of both providing service to end-use customers and the wholesale electricity markets.[14] The Commission approved the CAISO's initial ESDER reforms in 2016.[15]

In 2016 the CAISO began phase two of its ESDER initiative. Phase two focused on the reforms described in the instant filing.[16] The CAISO also is conducting Phase three of the ESDER initiative, which will result in further enhancements next year.[17] Phase three has focused on (1) modeling demand response limitations, (2) creating a load shift product that includes dispatchable consumption, and (3) electric vehicle participation in the CAISO markets.[18] The CAISO also has continued to work closely with CPUC staff on developing a usable framework for multiple use applications in California.

In addition, the CAISO has worked closely with the Commission on national energy storage and distributed energy resource reforms. The CAISO has participated on numerous technical conferences and has submitted many comments on Commission storage proceedings, including Order No. 841.

III. Proposed Tariff Revisions

A. New Demand Response Methodologies

1. Current Framework

Load, storage, and generation resources frequently participate in the CAISO markets via demand response models. These resources can be transmission-connected, distribution-connected, or behind a retail meter. These resources participate in the CAISO markets by providing load curtailment through one of the CAISO's two demand response models: proxy demand resources or reliability demand response resources.[19] A proxy demand resource is a typical demand response resource, and a reliability demand response resource is dispatched only when the CAISO's system is near or in a system emergency.[20] Both models may use the

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[14] The examination of multiple-use application rules did not result in tariff revisions.

[15] *California Independent System Operator Corp.*, 156 FERC ¶ 61,110 (2016).

[16] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx.

[17] *Id.*

[18] *See* CAISO Draft Final Proposal on ESDER Phase 3, *available at* http://www.caiso.com/Documents/DraftFinalProposal-EnergyStorage-DistributedEnergyResourcesPhase3.pdf.

[19] For concision, this letter will simply refer to both as demand response resources.

[20] *See California Independent System Operator Corp.*, 144 FERC ¶ 61,047 at PP 8 *et seq.* (2013) (explaining a reliability demand response resource); *see also* Section 4.13.5 of the CAISO

CAISO's two performance methodologies to calculate their demand response energy measurement, which is the ultimate quantity of performance reported for settlement.[21] These two models are the 10-in-10 methodology and the metering generator output methodology.[22] Both methodologies require historic performance data to compare the performance at the time of dispatch to typical use. The difference between the typical use and performance at the time of dispatch is the demand response energy measurement. The 10-in-10 "day-matching" methodology is the traditional methodology established in Order No. 745 used to measure the performance of load-curtailment resources. The metering generator output methodology was developed by NAESB to measure the performance of resources with behind-the-meter generation. Through a required sub-meter, it allows resources to separate and isolate the demand curtailment from load reduction itself and the demand curtailment from the production of the behind-the-meter generation. The demand response resource's performance can then be measured based on either the load only, the generation only, or both.[23]

Both the 10-in-10 methodology and the metering generator output methodology examine historic use[24] on similar days, i.e., comparing a weekday dispatch to weekday historic use. These methodologies examine the previous 45 days until 10 similar days are found where the resource did not respond to a dispatch in the relevant dispatch intervals, i.e., non-event intervals. Use during the non-event trading intervals on these days is averaged, then adjusted based on the most recent use, to develop the baseline.[25] The demand response resource then compares this baseline to its performance in response to a CAISO dispatch to produce its demand response energy measurement for settlement. In other words, the CAISO settles the difference between the demand response resource's demand at dispatch and its typical demand during similar non-event intervals.

Although these two methodologies have had considerable success in the CAISO markets, the CAISO and its stakeholders always seek to improve market models and respond to changing circumstances. Demand response resources now

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tariff (outlining the characteristics of proxy demand resources and reliability demand response resources).

21 Appendix A to the CAISO tariff defines Demand Response Energy Measurement as "The resulting Energy quantity calculated by comparing the applicable performance evaluation methodology of a Proxy Demand Resource or Reliability Demand Response Resource against its actual underlying performance for a Demand Response Event."

22 *See California Independent System Operator Corp.*, Tariff Amendment to Implement Energy Storage Enhancements, Docket No. ER16-1735-000 (May 18, 2016) (explaining these methodologies in detail); *California Independent System Operator Corp.*, 156 FERC ¶ 61,110 (2016); Sections 4.13.4 and 11.6 of the CAISO tariff.

23 *See California Independent System Operator Corp.*, 156 FERC ¶ 61,110 at P 5 (2016).

24 *I.e.,* use not subject to dispatch or outage.

25 Adjustment factors are described in detail below.

include industrial plants with the load of a city, residential air conditioners and appliances, commercial air conditioners, electric vehicle charging stations, mills, refineries, smelters, farms, labs, and schools. Pacific Gas & Electric Company even offers specialized demand response consulting for wineries.[26] To make the data more complex, a large and growing share of these resources have their own onsite generating capacity and/or batteries. Needless to say, the typical use and dispatched response of these resources is not always the same, especially because they are now participating in the wholesale markets. For this reason, in phase two of the CAISO's ESDER initiative the CAISO formed a special "Baseline Accuracy Work Group" of interested stakeholders. Its mandate was to "provide quantitative analysis on the accuracy, bias, and variability of any proposed baselines, and how application of a new baseline will significantly improve accuracy, and reduce bias and variability over the current 10-in-10 baseline method for a particular customer, customer class or end-use technology."[27] The working group included many utility experts, demand response providers, consumer groups, and consultants. Ultimately the working group recommended the three new methodologies proposed here, which the CAISO and its stakeholders approved.[28] These recommendations resulted from 120,000 tested combinations of baselines, adjustments rules, aggregation levels, and dispatch frequency, all based on the hourly data of nearly 104,000 customers of Pacific Gas & Electric Co. ("PG&E"), Southern California Edison Co. ("SCE"), and San Diego Gas & Electric Co. ("SDG&E").[29]

2. Proposed Tariff Revisions: Control Group Methodology

The first new demand response performance methodology the CAISO proposes to implement is the control group methodology.[30] A traditional demand response baseline examines historic, similar use of the participating demand response resources themselves. This historic use baseline is then subtracted from the resources' performance during the trading interval when dispatched. The control group methodology, on the other hand, examines the performance of a set of similar, non-participating resources during the trading interval when the

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[26] *See* https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/incentivesbyindustry/agriculture/06_wineries_fs_v4_final.pdf.

[27] ESDER Phase 2 Issue Paper at p. 11, *available at* http://www.caiso.com/Documents/IssuePaper-EnergyStorageandDistributedEnergyResourcesPhase2.pdf.

[28] Based on stakeholder comments and CAISO review, the CAISO deviated from the Baseline Accuracy Work Group's proposal in only one minor aspect: The Work Group recommended different minimum/maximum adjustment limits for the 5-in-10 methodology proposed below based on whether the dispatch was on a business day or non-business day. Stakeholders and the CAISO agreed that separate adjustment limits for this distinction added significant calculation complexity without sufficient basis.

[29] Data sources are explained in detail in Sections 2.3 and 3 of the Nexant Baseline Accuracy Assessment Report, included here as Attachment F.

[30] Proposed Tariff Section 4.13.4.3.

participating resources are responding to dispatch. This control group's performance during the trading interval establishes the baselines for the demand response resources.

Assume an apartment complex has 300 units, all separately metered, with comparable demand profiles. Assume that 150 of the units are an aggregated proxy demand resource, which responds to a CAISO dispatch on a Tuesday from 4 p.m. to 5 p.m. A traditional demand response baseline like the 10-in-10 baseline would establish a baseline by examining these 150 participating resources' typical use at 4 p.m. on weekdays. The fundamental premise of this methodology is that past weekdays at the same time is comparable, so any performance over that typical use is an incremental performance in response to dispatch, and benefits the grid. The control group methodology compares the performance of the 150 participating units on a Tuesday from 4 p.m. to 5 p.m. to the 150 non-participating units on the same Tuesday during the same hour. It does not use historic data. The fundamental premise of this methodology is that concurrent use of similar resources is comparable, so any difference between the two is an incremental performance in response to dispatch that benefits the grid. This approach offers significant advantages because the baseline is based on the actual trading hour, meaning that the control group's performance resulted from the exact same grid, temperature, and weather conditions as the participating resources' performance. Unlike methodologies that use historic data, the control group methodology captures whether the demand response resources just put up their Christmas lights, are watching the Super Bowl, or whether the temperature has just spiked. Simulation and testing demonstrate that the control group methodology is likely to produce the most statistically accurate and precise baseline.[31]

Of course, it is critical that the control group be similar to the demand response resources so that there is an "apples to apples" comparison. The Baseline Accuracy Work Group and the CAISO developed composition and validation requirements for the control group. The CAISO proposes the following requirements for control groups:

- The control group must consist of at least 150 distinct end users;[32]
- The control group must have nearly identical demand patterns in aggregate to the demand response resources;[33]
- The control group must be geographically similar to the demand response resources such that they experience the same weather

[31] Accuracy also is expressed as a lack of bias, the tendency to over or under predict a result. *See* Nexant, Baseline Accuracy Work Group Proposal, Section 2.1, included here as Exhibit E; Nexant, Baseline Accuracy Assessment Report, Section 5, included here as Attachment F.

[32] Proposed Section 4.13.4.3(a).

[33] *Id.*

patterns and grid conditions;[34]

- Scheduling coordinators must re-validate the accuracy of the control group every other month, or monthly if the number of end users in the control group changed by over ten percent in the prior month.[35]

The CAISO also proposes to require that control group randomization, equivalence, and validation, and all demand response calculations are subject to CAISO audit for three years from dispatch.[36] All results must be reproducible, including underlying interval data, randomization, validation, bias, confidence, precision, and analysis. These requirements are consistent with other resource requirements to ensure that CAISO staff can verify resources' compliance with the tariff.

3. Proposed Tariff Revisions: 5-in-10 Methodology

The CAISO also proposes to offer a new 5-in-10 day-matching baseline methodology. This methodology is an important new option for residential demand response resources dispatched so frequently that they struggle to find ten matching trading intervals on similar days when they were not responding to dispatch.[37] When such resources cannot meet the 10-day target, they have to fall back on days in which they responded to dispatch, skewing the data on their "typical use" absent dispatch.[38] In essence, robust demand response participation makes it more difficult to calculate a baseline under the 10-in-10 methodology requirements, highlighting the need for a methodology that requires fewer days but then takes the most comparable days.

The 5-in-10 methodology is modeled on the 10-in-10 methodology in that it examines the previous 45 days to find a target number of the same trading interval on similar days; however, instead of using all ten of the most recent qualifying

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[34] *Id.*

[35] Proposed Section 4.13.4.3(d). To validate the control group, meter data of the control group and the demand response resources from the previous 75 days must be evaluated, excluding event days where the demand response resources provided demand response services or participated in a utility demand response program. Using the most recent days, at least 20 eligible days of meter data must be used for validation. From these days, an average of the hourly load profile from 12 p.m. to 9 p.m. must be developed for the demand response resources and the control group by day and by hour. The average hourly demand of the demand response resources is then regressed against the average hourly demand of the control group. The control group must statistically demonstrate (i) lack of bias, (ii) sufficient statistical precision, with (iii) sufficient confidence. Control groups that fail these screens may not be used.

[36] Proposed Section 4.13.4.3(f).

[37] Proposed Section 4.13.4. Non-residential demand response resources may use the existing methodologies or the other methodologies proposed herein.

[38] Section 4.13.4.1(a).

business days to create the baseline, the 5-in-10 methodology only uses the five business days with the highest totalized load during the relevant trading interval from the ten most recent similar days.[39] These intervals are then averaged to form the baseline.[40] For non-business days, the scheduling coordinator creates a baseline using the three days with the highest totalized load during the relevant trading interval from the five most recent similar days.[41] Of the intervals on these three days, the scheduling coordinator will calculate a weighted average by giving the most recent day a weight of 50 percent, the next closest 30 percent, and the furthest a weight of 20 percent. Essentially, the 5-in-10 methodology uses the best days to establish a baseline instead of simply using the most recent.

Similar to the 10-in-10 methodology, scheduling coordinators apply a same-day adjustment factor to the averaged intervals used for the baseline. Same-day adjustments calibrate the baseline to the observed non-event hours on the event day to improve precision and accuracy. Including both a post-event adjustment and a pre-event adjustment can scale the baseline up or down to capture additional information regarding the event day conditions, especially temperature. This ensures the historic data of the baseline better matches the actual event day.

The Baseline Accuracy Work Group tested several adjustment factors for the 5-in-10 methodology to ensure statistical accuracy and precision.[42] Based on its analysis, the CAISO proposes to require scheduling coordinators to adjust baselines by a percentage equal to the ratio of the average demand during the adjustment periods on the event day and on the days used for the baseline, up to a factor of 1.4.[43] The adjustment periods consist of the period from four hours to two hours prior to the event hour, and the period from two hours to four hours after the event hour.[44] This two-hour buffer from the event hour reduces the risk of contamination by allowing pre-cooling and snapback to occur in the hours directly before and after the event, without using those hours to adjust the baseline.[45] Detailed examples and analysis are provided in the Baseline Accuracy Work Group

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[39] Proposed Section 4.13.4.4(a).

[40] Proposed Section 4.14.4.4(b).

[41] Proposed Section 4.13.4.4(a).

[42] *See* Nexant, Baseline Accuracy Work Group Proposal, Sections 2.2.2 and 3, included as Attachment E; Nexant, Baseline Accuracy Assessment Report, Section 2.5, included here as Attachment F.

[43] Proposed Section 4.13.4.4(c).

[44] *Id.*

[45] Cycling air conditioners, for example, do not immediately turn back on the moment a dispatch interval ends.

papers, included here as Attachment E and Attachment F.[46]

4. Proposed Tariff Revisions: Weather Matching Methodology

The CAISO also proposes to offer a "weather matching" methodology.[47] The weather matching methodology is similar to the 10-in-10 methodology in that it establishes a baseline of historic use from the participating demand response resources; however, instead of simply using the most recent qualifying days to form the baseline, the weather matching methodology uses the days with the most similar weather patterns. This methodology will be especially accurate for air-conditioner cycling programs, which are highly temperature dependent and one of the most popular demand response programs.

The Baseline Accuracy Work Group tested seven weather-matching methodologies.[48] The CAISO proposes to implement the methodology that consistently provided the most accurate and precise results. This methodology requires the scheduling coordinator to examine the 90 days preceding the trading day when the demand response resource responded to dispatch.[49] The scheduling coordinator then averages the demand on the relevant hour on the four days[50] with the closest daily maximum temperature to the trading day.[51] The Baseline Accuracy Work Group analysis demonstrates these four days provide a statistically accurate baseline. The weather-matching methodology also uses an adjustment factor to ensure that historic data accurately matches trading day conditions. Based on the Baseline Accuracy Work Group's recommendation, this adjustment factor is the same as the adjustment factor for the 5-in-10 methodology discussed above.[52]

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[46] *See* Nexant, Baseline Accuracy Work Group Proposal, Section 2.2.2, included as Attachment E; Nexant, Baseline Accuracy Assessment Report, Section 2.5, included here as Attachment F.

[47] Proposed Section 4.13.4.5.

[48] Sections 2.2 and 3.2 of Nexant, "Baseline Accuracy Work Group Proposal," attached as Exhibit E.

[49] Proposed Section 4.13.4.5(a).

[50] Examining business days where the trading day is a business day, non-business days where the trading day is a non-business day.

[51] Proposed Section 4.13.4.5(a)-(b). As with other methodologies, these would be "non-event" days when the resources did not respond to dispatch or have an outage.

[52] Proposed Section 4.13.4.5(c).

5. Proposed Tariff Revisions: Transition to Scheduling Coordinator Calculation

Currently, scheduling coordinators submit to the CAISO the raw data for the CAISO to compute demand response resources' baselines and demand response energy. These computations have become increasingly burdensome to the CAISO, which cannot sustain this level of growth. Moreover, if the CAISO continued to compute the baselines and demand response energy for all resources and wanted to implement the methodologies proposed above (or new ones in the future), it would take significant time for the CAISO to upgrade its software and hardware sufficiently, delaying the implementation of new performance evaluation methodologies. The CAISO also is poorly positioned to gather than non-participating resource data required for the control group methodology.

Regardless of the new methodologies, the CAISO proposes to revise its tariff to require scheduling coordinators to be responsible for calculating demand response resources' baselines and the resulting demand response energy for settlement. The CAISO proposes to effect this revision principally by revising demand response several provisions in the CAISO tariff such as "The CAISO will calculate…" to "The Scheduling Coordinator will be responsible for calculating…."[53] The CAISO also proposes to add language regarding the level of interval meter data scheduling coordinators will have to submit.[54]

Critically, the CAISO will continue to collect the customer baseline figures and all the meter data used to select qualifying days and used to create the baselines calculated by scheduling coordinators.[55] The CAISO and its Department of Market Monitoring believe that such data are necessary to monitor and review

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[53] Proposed revisions to Sections 4 and 11 of the CAISO tariff. Revisions generally take the form of removing the CAISO as the actor in several sentences and revising the verbs the passive voice. For example, the CAISO proposes to revise "If the CAISO is unable to collect Meter Data for the minimum number of calendar days described above, the CAISO will instead collect…" to "If these targets cannot be met, Meter Data will be collected…." In such cases, the Scheduling Coordinator is already described as the responsible party. These revisions allow the CAISO to effect this tariff revision without rewriting every provision anew. Moreover, these tariff provisions require the scheduling coordinator to be the party ultimately responsible for compliance while allowing it to use other parties for the actual meter data and calculation, which is the common industry practice.

[54] *See, e.g.,* Proposed Section 11.6.3. Because validation and correction windows will not lapse until after these tariff revisions become effective, the CAISO also proposes to add a provision stating the CAISO will retain authority to calculate and correct calculations for the meter data submitted to the CAISO before the CAISO transitions to scheduling-coordinator-based calculations. Proposed Section 4.13.4.

[55] Proposed Section 11.6.1 of the CAISO tariff: "For monitoring, compliance, and audit purposes, Scheduling Coordinators must submit in the Settlement Quality Meter Data Systems the Customer Load Baseline, as applicable, and the actual underlying consumption or Energy during all hourly intervals for the calendar days for which the Meter Data was collected to develop the Customer Load Baseline pursuant to Section 4.13.4."

demand response performance.[56] The difference will be that the scheduling coordinator rather than the CAISO is computing this data for submission and settlement purposes. This practice will be consistent with all scheduling coordinator metered entities today, which are not directly metered by the CAISO, and for which the scheduling coordinator provides the validation, estimation, and editing.[57] The CAISO also will maintain its ability to audit all meter data for demand response resources.[58]

6. Proposed Tariff Revisions: Defined Terms

The CAISO proposes to revise the use of the term "Business Days" for demand response resources.[59] Demand response resources must match Business Day trading days to historic Business Days, and non-Business Day trading days to historic non-Business Days. This ensures that the historic days are subject to similar conditions and load patterns as the trading day, making their meter data comparable. For example, most residences have similar demand patterns on weekdays when their residents are at work or school most of the day: there is some demand in the morning, low demand during the day, and then high demand in the late afternoon and evening when everyone returns home and turns on devices. On weekends and holidays, demand patterns oscillate far less, but overall demand might be higher (e.g., the air conditioner may run all day instead of just the afternoon and evening).

By capitalizing Business Day in the demand response sections of the tariff, the CAISO must apply the definition in Appendix A to the CAISO tariff. Appendix A to the CAISO tariff defines a Business Day as "Monday through Friday, excluding federal holidays and the day after Thanksgiving Day." Using federal holidays is problematic for demand response resources. Federal holidays include Columbus Day, Veterans Day, and Washington's Birthday (or President's Day). Many or most people still work or go to school on these days, so their demand patterns match

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[56] Because the CAISO will continue to require this additional data, the CAISO proposes to clarify in the tariff that only the demand response energy measurement will be considered Settlement Quality Meter Data, consistent with how other Scheduling Coordinator Metered Entities are treated under the CAISO tariff. *Id*.

[57] *See* Section 10.1 of the CAISO tariff.

[58] Section 10.3.6.6 of the CAISO tariff.

[59] The CAISO will make this revision throughout Sections 4 and 11 of the CAISO tariff regarding demand response resources by simply de-capitalizing the terms, which would no longer subject them to the Appendix A definition. The CAISO also proposes to reiterate that demand response resources providing ancillary services must submit meter data for the intervals immediately preceding, during, and following the trading interval(s) in which they were awarded Ancillary Services. This allows the CAISO to ensure that it has sufficient data to ensure that demand response resources had sufficient capacity and responded to an ancillary service dispatch. See Proposed Section 4.13.4.

Business Days more than non-Business Days. NERC and NAESB use their own holiday list instead of the federal holiday list for this reason.[60]

The CAISO proposes to de-capitalize references to Business Days in the CAISO tariff sections on demand response calculations. This will allow the CAISO to forego using its current tariff definition, and instead define "business day" in the CAISO's public demand response user guide such that the definition relates to demand patterns. The CAISO notes it cannot revise its tariff definition of Business Day only to accommodate the calculation of demand response services: Business Day appears in the CAISO tariff over 500 times, and those references generally have nothing to do with demand patterns.

The CAISO also proposes to remove an extraneous and confusing clause from the tariff's definition of Customer Load Baseline and Generator Output Baseline. The tariff currently defines a Customer Load Baseline as "A value or values based on historical or statistically relevant Load meter data to derive a measured delivery of Demand Response Services."[61] Generator Output Baseline is similarly defined as "A value or values based on historically relevant Energy output meter data from behind-the-meter generation to derive a measured delivery of Demand Response Services."[62] Market participants have expressed confusion regarding the clause "to derive a measured delivery of Demand Response Services." This confusion is well founded because the baseline meter data is used to calculate the demand response energy measurement, not "derive" the Demand Response Service, which is the Demand bid into the CAISO markets.[63] In any case, this clause is superfluous because it (poorly) describes the terms' uses instead of their definitions. The CAISO proposes to remove these clauses and limit these definitions to the defining clauses only. Doing so will provide clarity and avoid confusion.

7. Proposed Tariff Revisions: Summary

The demand response enhancements proposed above will greatly improve the ability of load, generation, and storage resources to participate in the CAISO markets. These enhancements represent considerable effort and analysis by CAISO staff, stakeholders, and consultants. The 5-in-10 methodology, weather matching methodology, and control group methodology were three options among many, and

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60 https://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/Additional_Off-peak_Days.pdf.

61 Appendix A to the CAISO tariff (emphasis added).

62 *Id*. (emphasis added).

63 Appendix A to the CAISO tariff defines Demand Response Services as "Demand from a Proxy Demand Resource or Reliability Demand Response Resource that can be bid into the Day-Ahead Market and Real-Time Market and dispatched at the direction of the CAISO."

they best capture the Commission's intent in Order No. 745. The optionality they will provide will greatly improve the statistical accuracy and precision for demand response resources. The CAISO intends to provide additional demand response methodologies in the future, but believes these three represent the next best step for the CAISO and demand response nationally. Further, the transition to scheduling-coordinator-based computations will allow demand response participation to continue to grow unabated, and it will align the submission of meter data from demand response resources with the submission of meter data from other resources. For these reasons, the CAISO requests that the Commission approve these enhancements as just and reasonable.

B. Station Power

1. Current Framework

The CAISO tariff currently defines station power as

> energy for operating electric equipment, or portions thereof, located on the Generating Unit site owned by the same entity that owns the Generating Unit, which electrical equipment is used exclusively for the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit; and for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the Generating Unit; located on the Generating Unit site; and used exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit.[64]

The tariff definition then states that "station Power does not include any Energy used to power synchronous condensers; used for pumping at a pumped storage facility; or provided during a Black Start procedure. Station Power does not include Energy to serve loads outside the CAISO Balancing Authority Area."[65]

This definition is problematic for several reasons. First, it only addresses "generating units," and ignores modern resources like energy storage. Second, it goes well beyond a simple definition and lists several specific inclusions and exclusions, thus narrowing a standard into a rule unnecessarily. Memorializing these examples in the tariff makes an inflexible framework for new and emerging technologies that do not fit old examples. Third, and perhaps most problematic, in California station power generally is energy "consumption," rather than energy sold

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[64] Appendix A to the CAISO tariff.

[65] *Id*. (emphasis added).

for resale under the Federal Power Act.[66] The CAISO's current tariff thus seeks to define a term where local regulatory authorities have jurisdiction; not the CAISO or the Commission.[67]

Of course, a definition only matters as much as it is used in the tariff. The principal purpose of the CAISO's station power definition is to describe what type of retail energy can be netted from generators' wholesale energy output onto the grid. Netting station power from wholesale output results in the generator losing MWh output at the wholesale LMP while avoiding retail settlement for the station power. However, when the CAISO implemented this definition, it limited the use of the station power definition to the station power protocol under Appendix I to the CAISO tariff. The Commission had required the station power protocol to allow generator owners to create a portfolio of generators in the CAISO, and then net their station power use from their monthly output if the latter was larger than the former (a certainty for any online generator). This conflicted with California's netting rules for station power, which were based on hourly intervals at the time.[68] The conflict resulted in litigation wherein the Commission ultimately held:

> In light of the D.C. Circuit's remand order, the Commission here concludes that states need not use the same methodology the Commission uses to determine the amount of station power that is transmitted in interstate commerce to determine the amount of station power that is sold at retail . . . . State-jurisdictional retail sales of station power are properly the subject of state tariffs.[69]

Because of this decision, most generators in California were barred by their local regulatory authorities from continuing to use the station power protocol.

Separate and independent of the station power protocol, the CAISO also has tariff provisions governing when any station power or auxiliary load may be netted from wholesale output.[70] Section 10.1.3.1 currently states:

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[66] The CAISO notes that energy is never actually "consumed," and is instead grounded, converted to heat, etc.

[67] *See Duke Energy Moss Landing v. CAISO*, 132 FERC ¶ 61,183 (2010) *on remand from Southern California Edison Co. v. FERC*, 603 F.3d 996 (D.C. Cir. 2010).

[68] *See Southern California Edison Co.*, 603 F.3d at 998.

[69] *Duke Energy Moss Landing*, 132 FERC ¶ 61,183 at P 2.

[70] Generally the term "auxiliary load" refers to any load—including station power—at a generator site; however, some use the term to refer to all load at a generator site except for the station power. The CAISO tariff currently refers to the former, but the CAISO is resolving any ambiguity between auxiliary load and station power in the instant filing.

> CAISO Metered Entities and Scheduling Coordinators may,[71] when providing Meter Data to the CAISO, net kWh or MWh values for Generating Unit output and auxiliary Load equipment electrically connected to that Generating Unit at the same point provided that the Generating Unit is on-line and is producing sufficient output to serve all of that auxiliary Load equipment.

Again, this netting provision addresses "Generating Units" and their output only. It fails to capture energy storage resources that can provide market services through both charging and discharging, which may qualify for netting by their local regulatory authority.[72] The same is true for Section 10.1.3.2, which summarizes prohibited netting arrangements.

2. Proposed Revisions

The CAISO worked carefully with stakeholders and its local regulatory authorities to accomplish two goals with the CAISO's tariff revisions: (1) ensure that the CAISO tariff does not conflict with local regulatory authorities' definition of retail loads like station power; and (2) ensure that the CAISO tariff provisions are broad enough to encompass new and future technologies. The CAISO's proposed revisions effect these goals by removing the narrow, anachronistic language described above, and by adding broad, clarifying language.

First, the CAISO proposes to revise its definition of station power to "retail Energy, as defined by the Local Regulatory Authority, for operating electric equipment, for the sole purpose of participating in the CAISO Markets."[73] This definition allows each jurisdictional authority to define what constitutes retail energy and station power. It also limits the definition to only that energy used for operating electric equipment, preventing other loads from inclusion. Finally, this definition is not limited to the production of Energy, and instead includes all forms of participation in the CAISO Markets. As the Commission noted in Order No. 841, energy storage resources can provide market services through both discharging (output) and charging (demand).[74] There could be instances where energy storage resources have station power eligible for netting without "the production of Energy."

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[71] The CAISO receives settlement quality meter data from CAISO Metered Entities, which are metered directly by the CAISO, and Scheduling Coordinator Metered Entities, which are metered by their Scheduling Coordinator and subject to review and audits by the CAISO. *See, e.g., California System Independent System Operator Corp.*, Letter Order Approving Tariff Revisions, Docket No. ER17-949-000 (March 31, 2017).

[72] Section 10.1.3.1 also provides an example of prohibited netting, which the CAISO will move into the more appropriate "Prohibited Netting" section that follows.

[73] *See* Proposed Appendix A.

[74] *See Electric Storage Participating in Markets Operated by RTOs and ISOs*, Order No. 841, 162 FERC ¶ 61,127 at P 298 (2018).

Second, the CAISO proposes to remove the examples of what are, and are not, station power. Such examples are inappropriate for a tariff definition in the first place, and their inclusion in the tariff prevents the flexibility to adopt to local regulatory authorities' definitions of retail energy including station power, and future technologies.

Third, the CAISO proposes to add a general provision stating that CAISO resources may net station power only to the extent allowed by their local regulatory authorities. This provision helps ensure that CAISO resources have worked with their distribution utility to ensure compliance with retail tariffs in addition to the CAISO tariff.

Fourth, the CAISO has removed references to generators and replaced these references to "CAISO resources" or the metered entities that provide the settlement quality meter data, regardless of their technology type. This revision makes these tariff provisions technology neutral to avoid the exclusion of other resources.

Fifth, the CAISO has replaced references to "auxiliary Load equipment" in the Permitted Netting section with Station Power. The tariff will only refer to one term instead of two, avoiding confusion and increasing clarity.

Sixth, some local regulatory authorities—such as the CPUC—allow storage resources to receive wholesale treatment for station power where the resources provide services to wholesale markets in excess of their station power. As such, the CAISO has included a new provision in the Permitted Netting section stating that CAISO resources may include station power within the resource's wholesale Demand. The tariff currently only allows station power to be netted against output, preventing equal treatment for the unique market services that storage resources can provide via charging.

Finally, for clarity the CAISO has moved the provision describing prohibited netting arrangements from the Permitted Netting section into the Prohibited Netting section.

The CAISO respectfully requests that the Commission approve these revisions as just and reasonable. They will greatly aid new, emerging, and current market participants by clarifying tariff provisions that are unnecessarily complex and outdated. The CAISO's proposed tariff revisions will also avoid jurisdictional conflicts over retail and wholesale billing while helping resources and ratepayers avoid double billing for the same energy.

C. Net Benefits Test Gas Indices

1. Current Framework

The net benefits test in Section 30.6.3 of the CAISO tariff was established by Order No. 745 "to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the costs of dispatching and paying LMP to those resources."[75] As directed by Order No. 745, the CAISO's net benefits test establishes threshold prices for peak and off-peak periods at the points where the dispatch of demand response results in a net decrease in the cost of energy.[76] The CAISO establishes these prices by generating an on-peak and off-peak supply curve each month that depicts system-wide aggregated power supplies and different offer prices in the CAISO markets.[77] The CAISO collects its supply curve data for the month using data from the previous year for that month. Pursuant to Order No. 745, the CAISO then adjusts supply curve data to reflect differences in resource availability and fuel prices between the target month and the reference month to ensure comparability. In calculating these prices, the CAISO considers "significant changes in fuel prices."[78] Currently the CAISO tariff calculates these changes for all resources in the CAISO and Energy Imbalance Market using the average of the Pacific Gas and Electric Company citygate price and the Southern California Edison Company citygate price, which were the relevant prices when these tariff provisions were established in 2011.[79] If those prices are unavailable, the CAISO uses the Henry Hub price.

During phase two of the ESDER initiative, the CAISO's Department of Market Monitoring pointed out that using only two citygate prices for all demand response resources is no longer sufficient. With the expansion of the Energy Imbalance Market in the West, these two citygate prices are a crude and narrow reflection of the relevant fuel indices—and thus threshold price—for demand response resources participating in the CAISO markets.

2. Proposed Revisions

The CAISO proposes to remove the tariff reference to the "Pacific Gas & Electric Company citygate price and the Southern California Edison Company citygate prices, of if those prices are unavailable, . . . the Henry Hub price."[80]

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75 *California Independent System Operator Corp.*, 144 FERC ¶ 61,046 at P 2 (2013).

76 *California Independent System Operator Corp.*, 137 FERC ¶ 61,217 at P 28 (2011).

77 Section 30.6.3.1 of the CAISO tariff.

78 Section 30.6.3.1(ii) of the CAISO tariff.

79 *Id.*

80 Proposed Section 30.6.3.1(ii) of the CAISO tariff.

Instead, the CAISO tariff will state that "significant changes in fuel prices will be determined using the simple average of the relevant fuel indices as specified in the Business Practice Manual." This change will better comply with Order No. 745 by accurately reflecting relevant fuel prices in establishing the net benefits test. Moreover, this change will provide the CAISO with the flexibility to adjust the relevant indices (1) as new demand response resources from new regions join the CAISO markets, and (2) as gas indices become more or less relevant (for example, if a gas index ceases to exist).[81] To ensure that the Business Practice Manual will be ready if the Commission accepts the instant revisions, the CAISO has already posted its potential Business Practice Manual changes for stakeholder review. They establish the use of 13 gas indices across the West, which will accurately reflect fuel prices in the CAISO markets.[82]

The CAISO recognizes that moving provisions from the tariff to a business practice manual or public website creates potential concern for the Commission. The CAISO believes that the list of gas indices used to determine significant changes in fuel prices is inappropriate for the tariff under the Commission's "rule of reason." The indices themselves are simply an implementation tool for the net benefits test itself. Moreover, the indices are not ends unto themselves, but merely references to the actual gas prices they produce every day. Listing the indices in the Business Practice Manual will provide the CAISO and its stakeholders with the flexibility needed to ensure that the CAISO uses the most accurate gas indices. At the same time, the CAISO's business practice manual revision process ensures that any potential revision will be posted publicly for stakeholder comment before implementation. This process will be more sensible than needing to modify the tariff every time a fuel index is retired, created, or becomes more or less relevant, and every time a new entity joins the CAISO or its Energy Imbalance Market.

The CAISO also proposes to add a clarifying sentence to introduce the net benefits test in the tariff. Currently Section 30.6.3 states that "the CAISO will apply a net benefits test to determine whether Bids for Proxy Demand Resources qualify as a Schedule as set forth in Section 31." Section 31 is 23 pages long and covers a broad array of provisions on the CAISO's day-ahead market, so this reference is far from informative. The CAISO proposes to replace this sentence with clarifying and accurate language on the purpose of the net benefits test: "In accordance with Section 11.5.2.4, the CAISO will apply a net benefits test to determine a threshold Market Clearing Price for Proxy Demand Resources or Reliability Demand Response Resources settlement adjustments." This statement conveys actual information, and directs the reader to the correct tariff provision that explains how

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[81] All business practice manual revisions are posted for stakeholder review and comment. The CAISO holds monthly public teleconferences to review all posted revisions with stakeholders.

[82] The posted revisions are available at https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=1070&IsDlg=0. *See* http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx.

market clearing prices are used to settle demand response energy.[83]

The CAISO requests that the Commission approve these revisions as just and reasonable. They result directly from a recommendation from the CAISO's Department of Market Monitoring, and are supported by CAISO stakeholders. Because these revisions address an issue generated by the growth of the CAISO's Energy Imbalance Market, both the CAISO Board of Governors and the Energy Imbalance Market Governing Body approved them.[84]

IV. Stakeholder Process

The stakeholder process that resulted in this filing included:

- Six issue papers produced by the CAISO;
- A stakeholder working group devoted to working on the demand response baselines;
- Nine stakeholder meetings and conference calls to discuss the CAISO papers and the draft tariff provisions, including two workshops jointly held by the CAISO and CPUC; and
- Seven opportunities to submit written comments on the CAISO issue papers and the draft tariff provisions.[85]

The policies resulting in these proposed tariff revisions received broad stakeholder support. They were presented to the EIM Governing Body and the CAISO Board of Governors on July 26, 2017, where the Board voted unanimously to authorize this filing.[86]

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[83] Section 11.5.2.4 states: "For the purpose of settling Uninstructed Imbalance Energy of a Scheduling Coordinator representing a Load Serving Entity, the amount of Demand Response Energy Measurement delivered by a Proxy Demand Resource or Reliability Demand Response Resource that is also served by that Load Serving Entity and that is paid a Market Clearing Price below the threshold Market Clearing Price set forth in Section 30.6.3.1 will be added to the metered load quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource or Reliability Demand Response Resource is associated."

[84] The Energy Imbalance Market Governing Body received a briefing on the proposal and provided an advisory vote to the CAISO Board of Governors. *See* http://www.caiso.com/Documents/NoticeofInitialDecisionalClassification-EnergyStorageandDistributedEnergyResourcesPhase2.pdf.

[85] All stakeholder materials are available on the CAISO website: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx.

[86] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=96709FAF-01FD-471B-AA6E-C16ACCC888FB.

V. Effective Date and Request for Waiver of Notice Period

The CAISO respectfully requests that the Commission waive its notice requirements,[87] and approve the proposed revisions within 60 days with an effective date of November 1, 2018. Approval within this timeline will provide the CAISO and its software developers with the requisite certainty to develop, test, and implement the enhanced software—pursuant to a Commission order—before the tariff revisions go into effect on November 1. An order in advance of November 1 also will provide demand response providers with the confidence to register resources under the new methodologies such that they can begin participation on November 1. As such, good cause exists to grant waiver of the Commission's notice requirements and approve the CAISO's requested effective date.

VI. Communications

Pursuant to Rule 203(b)(3) of the Commission's Rules of Practice and Procedure,[88] the CAISO requests that all correspondence, pleadings, and other communications regarding this filing should be directed to following:

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General Counsel
Sidney L. Mannheim
Assistant General Counsel
William H. Weaver
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VII. Service

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

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87 Specifically, pursuant to Section 35.11 of the Commission's regulations (18 C.F.R. § 35.11), the CAISO requests waiver of the notice requirements set forth in Section 35.3 of the Commission's regulations (18 C.F.R. § 35.3).

88 18 C.F.R. § 385.203(b)(3).

VIII. Contents of Filing

Besides this transmittal letter, this filing includes these attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions in this tariff amendment
Attachment C	Draft final proposal
Attachment D	Board memoranda
Attachment E	Nexant: Baseline Accuracy Work Group Proposal
Attachment F	Nexant: California ISO Baseline Accuracy Assessment
Attachment G	List of key dates in the stakeholder process

IX. Conclusion

For the reasons set forth above, the CAISO respectfully requests that the Commission accept these proposed tariff revisions with an effective date of November 1, 2018.

Respectfully submitted,

/s/ William H. Weaver

Roger E. Collanton
General Counsel
Sidney L. Mannheim
Assistant General Counsel
William H. Weaver
Senior Counsel

Counsel for the California Independent
System Operator Corporation

Attachment A – Clean Tariff

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

4.13.1 Relationship Between CAISO and DRPs

The CAISO shall only accept Bids for Energy from Reliability Demand Response Resources, and shall only accept Bids for Energy or Ancillary Services from Proxy Demand Resources, Submissions to Self-Provide Ancillary Services from Proxy Demand Resources, or submissions of Energy Self-Schedules from Proxy Demand Resources that have provided Submissions to Self-Provide Ancillary Services, if such Reliability Demand Response Resources or Proxy Demand Resources are represented by a Demand Response Provider that has entered into a Demand Response Provider Agreement with the CAISO, has accurately provided the information required in the Demand Response System, has satisfied all Reliability Demand Response Resource or Proxy Demand Resource registration requirements, and has met standards adopted by the CAISO and published on the CAISO Website. Reliability Demand Response Resources and Proxy Demand Resources may not participate in a Distributed Energy Resource Aggregation. The CAISO shall not accept submitted Bids for Energy or Ancillary Services from a Demand Response Provider other than through a Scheduling Coordinator, which Scheduling Coordinator may be the Demand Response Provider itself or another entity. Proxy Demand Response Resources providing Ancillary Services must submit Meter Data for the interval preceding, during, and following the Trading Interval(s) in which they were awarded Ancillary Services for the purposes of determining settlement pursuant to Section 8.10.8.

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4.13.4 Performance Evaluation Methodologies for PDRs and RDRRs

The following methodologies may be utilized to calculate Customer Load Baselines and Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources. Proxy Demand Resources and Reliability Demand Response Resources consisting of residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, five-in-ten methodology, or weather matching methodology. Proxy Demand Resources and Reliability Demand Response Resources consisting of non-residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, or weather matching methodology. Proxy Demand Resources providing Ancillary Services must submit Meter Data for the intervals immediately preceding, during, and following the Trading Interval(s) in which the Proxy Demand Response Resources were awarded Ancillary Services. As specified in the Business Practice Manual, the CAISO will retain authority to calculate or correct Customer Load Baselines and Demand Response Energy Measurements for those resources that used the CAISO's Demand Response System, until all relevant metering, settlement, and correction windows have lapsed since the CAISO retired its ability to calculate on behalf of Scheduling Coordinators in the Demand Response System.

4.13.4.1 Ten-in-Ten Baseline Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the ten-in-ten methodology as follows:

(a) Meter Data will be collected for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred. Where the Proxy Demand Resource or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The collection of Meter Data for this purpose stops upon reaching the target number of calendar days, which is ten (10) calendar days if the Trading Day is a business day or four (4) calendar days if the Trading Day is a non-business day. If these targets cannot be met, a minimum of five (5) calendar days if the Trading Day is a business day or a minimum of four (4) calendar days if the Trading Day is a non-business day must be collected. If these targets cannot be met, Meter Data will be collected for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.1(b) by a percentage equal to the ratio of (i) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the second, third, and fourth hours preceding the hour of the Trading Day on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to (ii) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the same second, third, and fourth hours of the calendar days for which Meter Data has been collected pursuant to Section 4.13.4.1(a). To provide a maximum adjustment factor of twenty (20) percent, the adjusted percentage can have a maximum value of one hundred-twenty (120) percent and a minimum value of eighty (80) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separately from Load to enable the accurate calculation of total gross consumption.

4.13.4.2 Metering Generator Output Methodology

For behind-the-meter generation registered in Proxy Demand Resources or Reliability Demand Response Resources and settling Energy Transactions pursuant to Section 11.6.2, the Generator Output Baseline will be calculated as follows:

(a) Meter Data will be collected for the behind-the-meter generation for the same hour as the Trading Hour on calendar days preceding the Trading Day on which the Demand Response Event occurred for which the Generator Output Baseline is calculated. Meter Data will consist of Energy output of the behind-the-meter generation up to, but not including, output that represent an export of energy from that location. To determine the hours for which the Meter Data will be collected, the calculation will work sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding hours in which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) pursuant to a Bid at or above the net benefits test set forth in Section 30.6.3, or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services pursuant to a Bid at or above the net benefits test set forth in Section 30.6.3, except as discussed below. The calculation will have complete Meter Data for this purpose if and when it is able to collect Meter Data for its target number of hours the same as the Trading Hour, which target number is ten (10) hours if the Trading Day is a business day or four (4) hours if the Trading Day is a non-business day. If it is not possible to collect Meter Data for the target number of hours, the Meter Data will include a minimum of five (5) hours if the Trading Day is a business day or a minimum of four (4) hours if the Trading Day is a non-business day. If it is not possible to collect Meter Data for the minimum number of hours described above, the Generator Output Baseline will be set at zero.

(b) The baseline amount of Energy provided by the behind-the-meter generation will be calculated on the simple hourly average of the collected Meter Data.

(c) In calculating the Generator Output Baseline pursuant to Section 4.13.4.2(a), the Meter Data must be set to zero in any Settlement Interval in which the behind-the-meter generation is charging.

(d) In any Settlement Interval where the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand), the Meter Data will consist of the Energy output of the behind-the-meter generation up to, but not including, the output greater than its facility Demand that would represent an export of Energy from that location.

4.13.4.3 Control Group Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the control group methodology as follows:

(a) Prior to any Demand Response Event, a randomized control group of End Users that are registered in the Demand Response System but not responding to CAISO dispatch as Proxy Demand Resources or Reliability Demand Response Resources must be submitted to the CAISO. But for any Demand Response Event, the control group must have nearly identical Demand patterns in aggregate as the Proxy Demand Resources or Reliability Demand Response Resources. The control group must be geographically similar to the Proxy Demand Resources or Reliability Demand Response Resources such that they experience the same weather patterns and grid conditions. The control group must consist of 150 distinct End Users or more. Prior to use of the control group baseline methodology, Scheduling Coordinators will be responsible for validating the control group pursuant to Section 4.13.4.3(c).

(b) The control group's aggregate Demand during the same Trade Date and Trading Hour(s) as the Demand Response Event, divided by the relevant number of End Users, will constitute the Customer Load Baseline.

(c) Scheduling Coordinators are responsible for validating that the control group accurately represents its Proxy Demand Resources or Reliability Demand Response Resources. As described in the Business Practice Manual, to validate the control group, Meter Data of the control group and the Proxy Demand Resources or Reliability Demand Response Resources from the previous seventy-five (75) days must be evaluated, excluding days where the Proxy Demand Resources or Reliability Demand Response Resources provided Demand Response Services or participated in a utility demand response program. Using the most recent days, at least twenty (20) eligible days of Meter Data must be used for validation. From these days, an average of the hourly load profile from 12 p.m. to 9 p.m. must be developed for the Proxy Demand Resources or Reliability Demand Response Resources and the control group by day and by hour. The average hourly Demand of the Proxy Demand Resources or Reliability Demand Response Resources is then regressed against the average hourly Demand of the control group. As described in the Business Practice Manual, the control group must statistically demonstrate (i) lack of bias and (ii) sufficient statistical precision with (iii) sufficient confidence. Control groups that fail these screens may not be used.

(d) For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have not changed by more than ten (10) percent in the prior month, the control group must be re-validated every other month. For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have changed by more than ten (10) percent in the prior month, control groups must continue to be re-validated monthly.

(e) Control group randomization, equivalence, and validation, and all Demand Response Event calculations are subject to CAISO audit for three (3) years from the date Demand

Response Event. All results must be reproducible, including underlying interval data, randomization, validation, bias, confidence, precision, and analysis.

4.13.4.4 Five-in-Ten Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the five-in-ten methodology as follows:

(a) Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource will be collected for calendar days preceding the Trading Day on which the Demand Response Event occurred for the Customer Load Baseline. Where the Proxy Demand Response or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The collection of Meter Data for this purpose stops upon reaching the target number of calendar days, which is ten (10) calendar days if the Trading Day is a business day or five (5) calendar days if the Trading Day is a non-business day. From the target days, the five (5) business days and three (3) non-business days with the highest totalized load during the hours when the Demand Response Services were provided will be used. If these targets cannot be met, the Meter Data will instead be used for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or

RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) For business days, the Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource. For non-business days, the Scheduling Coordinator will be responsible for calculating a weighted average of the collected Meter Data to determine a baseline as follows: the day closest to the Demand Response Event receives a weight of fifty (50) percent, the next closest receives a weight of thirty (30) percent, and the furthest receives a weight of twenty (20) percent.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.4(b) by a percentage of the ratio of:

(i) the average Demand of Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.4(a).

To provide maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be separated from Load to enable the accurate calculation of total gross consumption.

4.13.4.5 Weather Matching Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the weather matching methodology as follows:

(a) The Scheduling Coordinator will be responsible for collecting Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred. Where the Proxy Demand Response or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of ninety (90) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services. As detailed in the Business Practice Manual, from the ninety (90) calendar days prior to the Trading Day, the four (4) days with the closest daily maximum temperature to the Trading Day will be used to calculate the baseline.

(b) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.5(b) by a percentage equal to the ratio of:

(i) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.5(a).

To provide a maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separate from Load to enable the accurate calculation of total gross consumption.

* * * * *

10.1.3 Netting

CAISO Metered Entities and Scheduling Coordinator Metered Entities may net Station Power only to the extent allowed by the Local Regulatory Authority and as provided below.

10.1.3.1 Permitted Netting

CAISO Metered Entities and Scheduling Coordinators may, when providing Meter Data to the CAISO, net kWh or MWh values for output and Station Power electrically connected at the same point, provided that the resource is on-line and producing sufficient output to serve all of its Station Power. Where permitted by the Local Regulatory Authority, CAISO Metered Entities and Scheduling Coordinators may, when providing Metered Data to the CAISO, include Station Power within the resource's wholesale Demand or output below zero (for dispatches to charge a storage resource, for example).

10.1.3.2 Prohibited Netting

CAISO Metered Entities or Scheduling Coordinators may not net values for output and Load that is not Station Power. CAISO Metered Entities or Scheduling Coordinators that serve third party Load connected to a resource's auxiliary system must add that third party Load to the resource or Generating Unit's output. Where a resource's Load or Station Power is served via a distribution line that is separate from the switchyard where the resource is connected, that resource and its Load and/or Station Power will not be considered to be electrically connected at the same point. The CAISO Metered Entity may add that third party Load to the resource's output either by means of a hard wire local meter connection between the metering systems of the third party Load and the resource or by requesting the CAISO to use RMDAPS to perform the addition. Scheduling Coordinators representing Scheduling Coordinator Metered Entities that serve third party Load connected to the auxiliary system of a resource must ensure that those Scheduling Coordinator Metered Entities add the Energy consumed by such third parties to output so as to ensure proper settlement of the gross output. The CAISO Metered Entity or the Scheduling Coordinator must ensure that the third party Load has Metering Facilities that meet the standards referred to in this Section 10 and the Business Practice Manuals.

* * * * *

11.6.1 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline Methodology

Settlements for Energy provided by Demand Response Providers from Proxy Demand Resources or Reliability Demand Response Resources shall be based on the Demand Response Energy Measurement for the Proxy Demand Resources or Reliability Demand Response Resources. The Demand Response Energy Measurement for a Proxy Demand Resource or Reliability Demand Response Resource shall be the quantity of Energy equal to the difference between the (i) Customer Load Baseline for the Proxy Demand Resource or Reliability Demand Response Resource and (ii) either the actual underlying consumption or the quantity of Energy calculated pursuant to Section 10.1.7 for the Proxy Demand Resource or Reliability Demand Response Resource for a Demand Response Event. Scheduling Coordinators will be responsible for calculating and submitting Demand Response Energy Measurements in 5-minute intervals. For monitoring, compliance, and audit purposes, Scheduling Coordinators must submit in the Settlement Quality Meter Data Systems the Customer Load Baseline, as applicable, and the actual underlying consumption or Energy during all hourly intervals for the calendar days for which the Meter Data was collected to develop the Customer Load Baseline pursuant to Section 4.13.4. Only Demand Response Energy Measurements will be considered Settlement Quality Meter Data. For such Proxy Demand Resources or Reliability Demand Response Resources, the Scheduling Coordinator will calculate the relevant Customer Load Baseline as set forth in Section 4.13.4. If the Proxy Demand Resource or Reliability Demand Response uses behind-the-meter generation to offset Demand, and has elected to always provide Meter Data consisting of its total gross consumption, the Demand Response Energy Measurement shall be the quantity of Energy equal to the difference between (i) the Customer Load Baseline, which derives from the gross consumption independent of offsetting Energy from behind-the-meter generation for the Proxy Demand Resource or Reliability Demand Response Resource, and (ii) the gross underlying consumption, independent of offsetting Energy from the behind-the-meter generation. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero. Scheduling Coordinators may not submit Demand Response Energy Measurements in Settlement Intervals where the total Expected Energy did not exceed zero.

11.6.2 Settlement of Energy Transactions Using Metering Generator Output Methodology

Settlements for Energy provided by Demand Response Providers from registered behind-the-meter generation in Proxy Demand Resources or Reliability Demand Response Resources shall be based on their Demand Response Energy Measurement. The Demand Response Energy Measurement for Proxy Demand Resources or Reliability Demand Response Resources consisting of registered behind-the-meter generation shall be the quantity of Energy equal to the difference between (i) the Energy output of the Proxy Demand Resources or Reliability Demand Response Resources, and (ii) the Generator Output Baseline for the behind-the-meter generation registered in the Proxy Demand Resource or Reliability Demand Response Resource, which derives from the Energy output of the behind-the-meter generation only, independent of offsetting facility Demand. In calculating the Energy output of such generation, the Meter Data must represent the Energy output of the behind-the-meter generation up to the total facility Demand, but excluding output that would represent an export of Energy from that location in any Settlement Interval in which the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand). For such behind-the-meter generation, the Generator Output Baseline will be calculated as set forth in Section 4.13.4.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. In cases where the Demand Response Energy Measurements are less than zero within a 5-minute interval, that measurement will be submitted as zero. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

11.6.3 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline and Metering Generator Output Methodologies

Settlements for Energy provided by Demand Response Providers using Proxy Demand Resources or Reliability Demand Response Resources that include (i) separately metered, registered behind-the-meter generation Energy output Meter Data, exclusive of facility consumption data pursuant to Sections 4.13.4.2 and 11.6.2, and Proxy Demand Resources or Reliability Demand Response Resources that (ii) reduce consumption independent and separately metered from offsetting behind-the-meter generation pursuant to Sections 4.13.4 and 11.6.1, shall be the sum of the Demand Response Energy Measurements for the

Proxy Demand Resources or Reliability Demand Response Resources as if they were settled separately and independently pursuant to Sections 11.6.1 and 11.6.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

* * * * *

30.6.3 Net Benefits Test for PDRs or RDRRs

In accordance with Section 11.5.2.4, the CAISO will apply a net benefits test to determine a threshold Market Clearing Price for Proxy Demand Resources or Reliability Demand Response Resources settlement adjustments.

30.6.3.1 Supply Curve Used in Applying the Net Benefits Test

The CAISO will generate one (1) on-peak supply curve and one (1) off-peak supply curve for each month that depicts the system-wide aggregated power supplies at different offer prices in the CAISO Markets within that month. The CAISO will generate these two supply curves for each month, using the following sequential methodology:

(i) The CAISO will collect supply curve data for the month that is twelve (12) months prior to the month for which the CAISO is generating the supply curves (the reference month), using all mitigated Bids in the Real-Time Market from any Generating Unit that is either committed or uncommitted and excluding Import Bids and Export Bids.

(ii) The CAISO will adjust the supply curve data to reflect differences in resource availability and fuel prices between the target month and the reference month. Significant changes in resource availability will be determined using the averages of the hourly supply curves over the entire reference month, with the supply quantities being averaged for every price level. Significant changes in fuel prices will be determined using the simple average of the relevant fuel indices as specified in the Business Practice Manual. For every supply quantity, the corresponding price will be scaled using a scaling factor defined as the forward gas price for the Trading Month divided by the historical average gas price for the reference month. These adjustments will result in two representative supply curves for the target month, one (1) on-peak and one (1) off-peak.

(iii) The CAISO will smooth the representative supply curves to twice differentiable using an exponential form function and applying a price window that is likely to contain the threshold Market Clearing Price. The price window may need to be adjusted in the process until the smoothed supply curves fit the representative supply curves closely.

Using the smoothed supply curves, the CAISO will determine a candidate threshold Market Clearing Price for the on-peak and a threshold Market Clearing Price for the off-peak corresponding to the point on each supply curve beyond which (i) the product of the amount of supplied Power (prior to the dispatch of Proxy Demand Resources) and the reduction in Market Clearing Price that results from the dispatch of Proxy Demand Resources exceeds (ii) the product of the Market Clearing Price (prior to the dispatch of Proxy Demand Resources) and the reduction in the amount of supplied Power that results from the dispatch of Proxy Demand Resources. If the candidate threshold Market Clearing Price is outside the corresponding price window being used, the price window needs to be adjusted and this process will be repeated until the price window contains the candidate threshold Market Clearing Price and thus makes it the final threshold Market Clearing Price. If multiple candidate threshold Market Clearing Prices exist, the candidate threshold Market Clearing Price that is concave on the supply curve (a supply function of price) will be the final threshold Market Clearing Price.

* * * * *

Appendix A

Master Definition Supplement

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- Customer Load Baseline

A value or values based on historical or statistically relevant Load meter data.

* * * * *

- Generator Output Baseline

A value or values based on historically relevant Energy output meter data from behind-the-meter generation.

* * * * *

- Station Power

Retail Energy, as defined by the Local Regulatory Authority, for operating electric equipment, for the sole purpose of participating in the CAISO Markets.

* * * * *

Attachment B – Marked Tariff

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

4.13.1 Relationship Between CAISO and DRPs

The CAISO shall only accept Bids for Energy from Reliability Demand Response Resources, and shall only accept Bids for Energy or Ancillary Services from Proxy Demand Resources, Submissions to Self-Provide Ancillary Services from Proxy Demand Resources, or submissions of Energy Self-Schedules from Proxy Demand Resources that have provided Submissions to Self-Provide Ancillary Services, if such Reliability Demand Response Resources or Proxy Demand Resources are represented by a Demand Response Provider that has entered into a Demand Response Provider Agreement with the CAISO, has accurately provided the information required in the Demand Response System, has satisfied all Reliability Demand Response Resource or Proxy Demand Resource registration requirements, and has met standards adopted by the CAISO and published on the CAISO Website. Reliability Demand Response Resources and Proxy Demand Resources may not participate in a Distributed Energy Resource Aggregation. The CAISO shall not accept submitted Bids for Energy or Ancillary Services from a Demand Response Provider other than through a Scheduling Coordinator, which Scheduling Coordinator may be the Demand Response Provider itself or another entity. Proxy Demand Response Resources providing Ancillary Services must submit Meter Data for the intervals preceding, during, and following the Trading Interval(s) in which they were awarded Ancillary Services for the purposes of determining settlement pursuant to Section 8.10.8.

* * * * *

4.13.4 Performance Evaluation Methodologies for PDRs and RDRRs

The following methodologies may be utilized to calculate Customer Load Baselines and Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources. Proxy Demand Resources and Reliability Demand Response Resources consisting of residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, five-in-ten methodology, or weather matching methodology. Proxy Demand Resources and Reliability Demand Response Resources consisting of non-residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, or weather matching methodology. Proxy Demand Resources providing Ancillary Services must submit Meter Data for the intervals immediately preceding, during, and following the Trading Interval(s) in which the Proxy Demand Response Resources were awarded Ancillary Services. As specified in the Business Practice Manual, the CAISO will retain authority to calculate or correct Customer Load Baselines and Demand Response Energy Measurements for those resources that used the CAISO's Demand Response System, until all relevant metering, settlement, and correction windows have lapsed since the CAISO retired its ability to calculate on behalf of Scheduling Coordinators in the Demand Response System.

4.13.4.1 ~~Customer Load~~ Ten-in-Ten Baseline Methodology

~~For each~~ Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the ten-in-ten methodology~~, the CAISO will calculate the Customer Load Baseline~~ as follows:

(a) ~~The CAISO will collect~~ Meter Data will be collected for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred ~~for which the CAISO is calculating the Customer Load Baseline~~. Where the Proxy Demand Resource or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. ~~To determine t~~The calendar days for which the Meter Data will be collected will be determined by ~~, the CAISO will~~ working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only ~~B~~business ~~D~~days if the Trading Day is a ~~B~~business ~~D~~day, including only non-~~B~~business ~~D~~days if the Trading Day is a non-~~B~~business ~~D~~day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The ~~CAISO will stop~~ collectiong ~~g~~ of Meter Data for this purpose stops ~~if and when it is able to collect Meter Data for its~~ upon reaching the target number of calendar days, which ~~target number~~ is ten (10) calendar days if the Trading Day is a ~~B~~business ~~D~~day or four (4) calendar days if the Trading Day is a non-~~B~~business ~~D~~day. If these targets cannot be met, ~~the CAISO is unable to collect Meter Data for its target number of calendar days, it will attempt to collect Meter Data for~~ a minimum of five (5) calendar days if the Trading Day is a ~~B~~business ~~D~~day or a minimum of four (4) calendar days if the Trading Day is a non-~~B~~business ~~D~~day must be collected. If ~~the CAISO is unable to collect Meter Data for the minimum number of calendar days described above~~ these targets cannot be met, ~~the CAISO will instead collect~~ Meter Data will be collected for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) The ~~CAISO~~ Scheduling Coordinator will be responsible for calculatinge ~~e~~ the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the ~~CAISO~~ Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.1(b) by a percentage equal to the ratio of (i) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the second, third, and fourth hours preceding the hour of the Trading Day on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to (ii) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the same second, third, and fourth hours of the calendar days for which ~~the CAISO has collected~~ Meter Data has been collected pursuant to Section 4.13.4.1(a). To provide a maximum adjustment factor of twenty (20) percent, ~~T~~the adjusted percentage can have a maximum value of one hundred-twenty (120) percent and a minimum value of eighty (80) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separately from Load to enable the accurate calculation of total gross consumption.

4.13.4.2 Metering Generator Output Methodology

For behind-the-meter generation registered in Proxy Demand Resources or Reliability Demand Response Resources and settling Energy Transactions pursuant to Section 11.6.2, the Generator Output Baseline will be calculated as follows:

(a) Meter Data will be collected for the behind-the-meter generation for the same hour as the Trading Hour on calendar days preceding the Trading Day on which the Demand Response Event occurred for which the Generator Output Baseline is calculated. Meter Data will consist of Energy output of the behind-the-meter generation up to, but not including, output that represent an export of energy from that location. To determine the hours for which the Meter Data will be collected, the calculation will work sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only ~~B~~business ~~D~~days if the Trading Day is a ~~B~~business ~~D~~day, including only non-~~B~~business ~~D~~days if the Trading Day is a non-~~B~~business ~~D~~day, and excluding hours in which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) pursuant to a Bid at or above the net benefits test set forth in Section 30.6.3, or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services pursuant to a Bid at or above the net benefits test set forth in Section

30.6.3, except as discussed below. The calculation will have complete Meter Data for this purpose if and when it is able to collect Meter Data for its target number of hours the same as the Trading Hour, which target number is ten (10) hours if the Trading Day is a ~~B~~business ~~D~~day or four (4) hours if the Trading Day is a non-~~B~~business ~~D~~day. If it is not possible to collect Meter Data for the target number of hours, the Meter Data will include a minimum of five (5) hours if the Trading Day is a ~~B~~business ~~D~~day or a minimum of four (4) hours if the Trading Day is a non-~~B~~business ~~D~~day. If it is not possible to collect Meter Data for the minimum number of hours described above, the Generator Output Baseline will be set at zero.

(b) The baseline amount of Energy provided by the behind-the-meter generation will be calculated on the simple hourly average of the collected Meter Data.

(c) In calculating the Generator Output Baseline pursuant to Section 4.13.4.2(a), the Meter Data must be set to zero in any Settlement Interval in which the behind-the-meter generation is charging.

(d) In any Settlement Interval where the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand), the Meter Data will consist of the Energy output of the behind-the-meter generation up to, but not including, the output greater than its facility Demand that would represent an export of Energy from that location.

4.13.4.3 Control Group Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the control group methodology as follows:

(a) Prior to any Demand Response Event, a randomized control group of End Users that are registered in the Demand Response System but not responding to CAISO dispatch as Proxy Demand Resources or Reliability Demand Response Resources must be submitted to the CAISO. But for any Demand Response Event, the control group must have nearly identical Demand patterns in aggregate as the Proxy Demand Resources or

Reliability Demand Response Resources. The control group must be geographically similar to the Proxy Demand Resources or Reliability Demand Response Resources such that they experience the same weather patterns and grid conditions. The control group must consist of 150 distinct End Users or more. Prior to use of the control group baseline methodology, Scheduling Coordinators will be responsible for validating the control group pursuant to Section 4.13.4.3(c).

(b) The control group's aggregate Demand during the same Trade Date and Trading Hour(s) as the Demand Response Event, divided by the relevant number of End Users, will constitute the Customer Load Baseline.

(c) Scheduling Coordinators are responsible for validating that the control group accurately represents its Proxy Demand Resources or Reliability Demand Response Resources. As described in the Business Practice Manual, to validate the control group, Meter Data of the control group and the Proxy Demand Resources or Reliability Demand Response Resources from the previous seventy-five (75) days must be evaluated, excluding days where the Proxy Demand Resources or Reliability Demand Response Resources provided Demand Response Services or participated in a utility demand response program. Using the most recent days, at least twenty (20) eligible days of Meter Data must be used for validation. From these days, an average of the hourly load profile from 12 p.m. to 9 p.m. must be developed for the Proxy Demand Resources or Reliability Demand Response Resources and the control group by day and by hour. The average hourly Demand of the Proxy Demand Resources or Reliability Demand Response Resources is then regressed against the average hourly Demand of the control group. As described in the Business Practice Manual, the control group must statistically demonstrate (i) lack of bias and (ii) sufficient statistical precision with (iii) sufficient confidence. Control groups that fail these screens may not be used.

(d) For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have not changed by more than ten (10) percent in the prior month, the control group must be re-validated every other month. For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have changed by more than ten (10) percent in the prior month, control groups must continue to be re-validated monthly.

(e) Control group randomization, equivalence, and validation, and all Demand Response Event calculations are subject to CAISO audit for three (3) years from the date Demand Response Event. All results must be reproducible, including underlying interval data, randomization, validation, bias, confidence, precision, and analysis.

4.13.4.4 Five-in-Ten Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the five-in-ten methodology as follows:

(a) Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource will be collected for calendar days preceding the Trading Day on which the Demand Response Event occurred for the Customer Load Baseline. Where the Proxy Demand Response or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The collection of Meter Data for this purpose stops upon reaching the target number of calendar days, which is ten (10) calendar days if the Trading Day is a business day or five (5) calendar days if the Trading Day is a non-business day. From the target days, the five (5) business days and three (3) non-business days with the highest totalized load during the hours when the Demand Response Services were provided will be used. If these targets cannot be met, the Meter Data will instead be used for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) For business days, the Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource. For non-business days, the Scheduling Coordinator will be responsible for calculating a weighted average of the collected Meter Data to determine a baseline as follows: the day closest to the Demand Response Event receives a weight of fifty (50) percent, the next closest receives a weight of thirty (30) percent, and the furthest receives a weight of twenty (20) percent.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.4(b) by a percentage of the ratio of:

(i) the average Demand of Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand

Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.4(a).

To provide maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be separated from Load to enable the accurate calculation of total gross consumption.

4.13.4.5 Weather Matching Methodology

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the weather matching methodology as follows:

(a) The Scheduling Coordinator will be responsible for collecting Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred. Where the Proxy Demand Response or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of ninety (90) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response

Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services. As detailed in the Business Practice Manual, from the ninety (90) calendar days prior to the Trading Day, the four (4) days with the closest daily maximum temperature to the Trading Day will be used to calculate the baseline.

(b) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.5(b) by a percentage equal to the ratio of:

(i) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.5(a).

To provide a maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separate from Load to enable the accurate calculation of total gross consumption.

* * * * *

10.1.3 Netting

CAISO Metered Entities and Scheduling Coordinator Metered Entities may net Station Power only to the extent allowed by the Local Regulatory Authority and as provided below.

10.1.3.1 Permitted Netting

CAISO Metered Entities and Scheduling Coordinators may, when providing Meter Data to the CAISO, net kWh or MWh values for ~~Generating Unit~~ output and ~~auxiliary Load equipment~~ Station Power electrically connected ~~to that Generating Unit~~ at the same point, provided that the ~~Generating Unit~~ resource is on-line and ~~is~~ producing sufficient output to serve all of ~~that auxiliary Load equipment~~ its Station Power. Where permitted by the Local Regulatory Authority, CAISO Metered Entities and Scheduling Coordinators may, when providing Metered Data to the CAISO, include Station Power within the resource's wholesale Demand or output below zero (for dispatches to charge a storage resource, for example). ~~For example, where a Generating Unit's auxiliary Load equipment is served via a distribution line that is separate from the switchyard to which the Generating Unit is connected, that Generating Unit and auxiliary Load equipment will not be considered to be electrically connected at the same point.~~

10.1.3.2 Prohibited Netting

CAISO Metered Entities or Scheduling Coordinators may not net values for ~~Generating Unit~~ output and Load that is not Station Power. CAISO Metered Entities or Scheduling Coordinators that serve third party Load connected to a ~~Generating Unit's~~ resource's auxiliary system must add that third party Load to the resource or Generating Unit's output. Where a resource's Load or Station Power is served via a distribution line that is separate from the switchyard where the resource is connected, that resource and its Load and/or Station Power will not be considered to be electrically connected at the same point. The CAISO Metered Entity may add that third party Load to the ~~Generating Unit's~~ resource's output either by means of a hard wire local meter connection between the metering systems of the third party Load and the ~~Generating Unit~~ resource or by requesting the CAISO to use RMDAPS to perform the addition. Scheduling Coordinators representing Scheduling Coordinator Metered Entities that serve third party Load connected to the auxiliary system of a ~~Generating Unit~~ resource must ensure that those Scheduling Coordinator Metered Entities add the Energy consumed by such third parties to ~~that Generating Unit's~~ output so as to ensure proper settlement of the~~at Generating Unit's~~ gross output. The CAISO Metered Entity or the Scheduling Coordinator must ensure that the third party Load has Metering Facilities that meet the standards referred to in this Section 10 and the Business Practice Manuals.

* * * * *

11.6.1 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline Methodology

Settlements for Energy provided by Demand Response Providers from Proxy Demand Resources or Reliability Demand Response Resources shall be based on the Demand Response Energy Measurement for the Proxy Demand Resources or Reliability Demand Response Resources. The Demand Response Energy Measurement for a Proxy Demand Resource or Reliability Demand Response Resource shall be the quantity of Energy equal to the difference between the (i) Customer Load Baseline for the Proxy Demand Resource or Reliability Demand Response Resource and (ii) either the actual underlying ~~Load~~ consumption or the quantity of Energy calculated pursuant to Section 10.1.7 for the Proxy Demand Resource or Reliability Demand Response Resource for a Demand Response Event. Scheduling Coordinators will be responsible for calculating and submitting Demand Response Energy Measurements in 5-minute intervals. For monitoring, compliance, and audit purposes, Scheduling Coordinators must submit in the Settlement Quality Meter Data Systems the Customer Load Baseline, as applicable, and the actual underlying consumption or Energy during all hourly intervals for the calendar days for which the Meter Data was collected to develop the Customer Load Baseline pursuant to Section 4.13.4. Only Demand Response Energy Measurements will be considered Settlement Quality Meter Data. For such Proxy Demand Resources or Reliability Demand Response Resources, the ~~CAISO~~ Scheduling Coordinator will calculate the relevant Customer Load Baseline as set forth in Section 4.13.4.~~1.~~ If the

Proxy Demand Resource or Reliability Demand Response uses behind-the-meter generation to offset Demand, and has elected to always provide Meter Data consisting of its total gross consumption~~ pursuant to Section 4.13.4.1(a)~~, the Demand Response Energy Measurement shall be the quantity of Energy equal to the difference between (i) the Customer Load Baseline, which derives from the gross consumption independent of offsetting Energy from behind-the-meter generation for the Proxy Demand Resource or Reliability Demand Response Resource, and (ii) the gross underlying consumption, independent of offsetting Energy from the behind-the-meter generation. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero. Scheduling Coordinators may not submit Demand Response Energy Measurements in Settlement Intervals where the total Expected Energy did not exceed zero.

11.6.2 Settlement of Energy Transactions Using Metering Generator Output Methodology

Settlements for Energy provided by Demand Response Providers from registered behind-the-meter generation in Proxy Demand Resources or Reliability Demand Response Resources shall be based on their Demand Response Energy Measurement. The Demand Response Energy Measurement for Proxy Demand Resources or Reliability Demand Response Resources consisting of registered behind-the-meter generation shall be the quantity of Energy equal to the difference between (i) the Energy output of the Proxy Demand Resources or Reliability Demand Response Resources, and (ii) the Generator Output Baseline for the behind-the-meter generation registered in the Proxy Demand Resource or Reliability Demand Response Resource, which derives from the Energy output of the behind-the-meter generation only, independent of offsetting facility Demand. In calculating the Energy output of such generation, the Meter Data must represent the Energy output of the behind-the-meter generation up to the total facility Demand, but excluding output that would represent an export of Energy from that location in any Settlement Interval in which the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand). For such behind-the-meter generation, the Generator Output Baseline will be calculated as set forth in Section 4.13.4.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. In cases where the Demand Response Energy Measurements are less than zero within a 5-minute interval, that measurement will be submitted as zero. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

11.6.3 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline and Metering Generator Output Methodologies

Settlements for Energy provided by Demand Response Providers using Proxy Demand Resources or Reliability Demand Response Resources that include (i) separately metered, registered behind-the-meter generation Energy output Meter Data, exclusive of facility consumption data pursuant to Sections 4.13.4.2 and 11.6.2, and Proxy Demand Resources or Reliability Demand Response Resources that (ii) reduce consumption independent and separately metered from offsetting behind-the-meter generation pursuant to Sections 4.13.4~~.1~~ and 11.6.1, shall be the sum of the Demand Response Energy Measurements for the Proxy Demand Resources or Reliability Demand Response Resources as if they were settled separately and independently pursuant to Sections 11.6.1 and 11.6.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

* * * * *

30.6.3 Net Benefits Test for ~~Scheduling of~~ PDRs or RDRRs

In accordance with Section 11.5.2.4, ~~T~~the CAISO will apply a net benefits test to determine ~~whether Bids~~ a threshold Market Clearing Price for Proxy Demand Resources or Reliability Demand Response Resources settlement adjustments~~qualify as a Schedule as set forth in Section 31~~.

30.6.3.1 Supply Curve Used in Applying the Net Benefits Test

The CAISO will generate one (1) on-peak supply curve and one (1) off-peak supply curve for each month that depicts the system-wide aggregated power supplies at different offer prices in the CAISO Markets within that month. The CAISO will generate these two supply curves for each month, using the following sequential methodology~~.~~:

(i) The CAISO will collect supply curve data for the month that is twelve (12) months prior to the month for which the CAISO is generating the supply curves (the reference month), using all mitigated Bids in the Real-Time Market from any Generating Unit that is either committed or uncommitted and excluding Import Bids and Export Bids.

(ii) The CAISO will adjust the supply curve data to reflect differences in resource availability and fuel prices between the target month and the reference month. Significant changes in resource availability will be determined using the averages of the hourly supply curves over the entire reference month, with the supply quantities being averaged for every price level. Significant changes in fuel prices will be determined using the simple average of the ~~Pacific Gas and Electric Company citygate price and the Southern California Edison Company citygate price, or, if those prices are unavailable, using the Henry Hub price~~ relevant fuel indices as specified in the Business Practice Manual. For every supply quantity, the corresponding price will be scaled using a scaling factor defined as the forward gas price for the Trading Month divided by the historical average gas price for the reference month. These adjustments will result in two representative supply curves for the target month, one (1) on-peak and one (1) off-peak.

(iii) The CAISO will smooth the representative supply curves to twice differentiable using an exponential form function and applying a price window that is likely to contain the threshold Market Clearing Price. The price window may need to be adjusted in the process until the smoothed supply curves fit the representative supply curves closely.

Using the smoothed supply curves, the CAISO will determine a candidate threshold Market Clearing Price for the on-peak and a threshold Market Clearing Price for the off-peak corresponding to the point on each supply curve beyond which (i) the product of the amount of supplied Power (prior to the dispatch of Proxy Demand Resources) and the reduction in Market Clearing Price that results from the dispatch of Proxy Demand Resources exceeds (ii) the product of the Market Clearing Price (prior to the dispatch of Proxy Demand Resources) and the reduction in the amount of supplied Power that results from the dispatch of Proxy Demand Resources. If the candidate threshold Market Clearing Price is outside the corresponding price window being used, the price window needs to be adjusted and this process will be repeated until the price window contains the candidate threshold Market Clearing Price and thus makes it the final threshold Market Clearing Price. If multiple candidate threshold Market Clearing Prices exist, the candidate threshold Market Clearing Price that is concave on the supply curve (a supply function of price) will be the final threshold Market Clearing Price.

* * * * *

Appendix A

Master Definition Supplement

* * * * *

- Customer Load Baseline

A value or values based on historical or statistically relevant Load meter data~~ to derive a measured delivery of Demand Response Services~~.

* * * * *

- Generator Output Baseline

A value or values based on historically relevant Energy output meter data from behind-the-meter generation~~ to derive a measured delivery of Demand Response Services~~.

* * * * *

- Station Power

Retail Energy, as defined by the Local Regulatory Authority, for operating electric equipment, for the sole purpose of participating in the CAISO Markets. ~~or portions thereof, located on the Generating Unit site owned by the same entity that owns the Generating Unit, which electrical equipment is used exclusively for the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit; and for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the Generating Unit; located on the Generating Unit site; and used exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit. Station Power includes the Energy associated with motoring a hydroelectric Generating Unit to keep the unit~~

~~synchronized at zero real power output to provide Regulation or Spinning Reserve. Station Power does not include any Energy used to power synchronous condensers; used for pumping at a pumped storage facility; or provided during a Black Start procedure. Station Power does not include Energy to serve loads outside the CAISO Balancing Authority Area.~~

* * * * *

Attachment C – Draft Final Proposal

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

Energy Storage and Distributed Energy Resources Phase 2

Draft Final Proposal

June 8, 2017

Market & Infrastructure Policy

Table of Contents

1 Executive Summary

The central focus of the California Independent System Operator's ("CAISO") energy storage and distributed energy resources ("ESDER") initiative is to lower barriers and enhance the ability of transmission grid-connected energy storage and distribution-connected resources, i.e., distributed energy resources ("DER"), [1] to participate in the CAISO market. The number and diversity of these resources are growing and represent an increasingly important part of the resource mix. Integrating these resources will help lower carbon emissions and add operational flexibility.

The ESDER initiative is an omnibus initiative covering several related but distinct topics. For the second phase of ESDER, i.e., "ESDER 2" these topics include demand response ("DR"), non-generator resources ("NGR"), multiple-use applications ("MUA"), and station power for storage resources. ESDER 2 is taking multiple approaches to pursue and address each topic. For example, in the case of the DR topic, a stakeholder-led working group – the Baseline Analysis Working Group ("BAWG") is discussing and recommending stakeholder-desired enhancements to the proxy demand resource ("PDR") performance evaluation methods. The proposal produced by this working group is not the ISO's proposal, but is the work product of the working group. A working group for the NGR topic is exploring use-limitations for storage resources. A different approach is being used for the remaining two topics of ESDER 2 – MUA and station power for storage resources – wherein the ISO is continuing its efforts to address these two topics in collaboration with the California Public Utility Commission ("CPUC") through its energy storage proceeding.[2]

In this third revised straw proposal, the ISO presents the status of its work in addressing the four topics of ESDER 2. The ISO is preparing to submit three topics – DR enhancements in the form of alternative baselines, distinguishing between charging energy and station power, and a net benefits test for DR resources that participate in the Energy Imbalance market ("EIM") - for approval by the CAISO Board on July 26-27, 2017. The ISO will continue collaborating with stakeholders on the remaining ESDER 2 topics in a phased policy approach that is appropriate in a rapidly evolving market environment that currently does not have a clear end state. In this situation, an incremental approach best serves the CAISO as it observes and learns from the changes occurring and their influence on the diversity and decentralization of resources serving

[1] DERs are those resources on the distribution system on either the utility side or the customer side of the end-use customer meter, including rooftop solar, energy storage, plug-in electric vehicles, and demand response.
[2] CPUC Rulemaking 15-03-011.

grid operations. The ISO will carry forward into a new ESDER Phase 3 ("ESDER 3") stakeholder initiative any topics that are not approved by the ISO Board in 2017. ESDER 3 will start in September 2017 with the posting of an issue paper.

2 Stakeholder Process

The CAISO is at the "Draft Final Proposal" stage in the ESDER 2 stakeholder process. Figure 1 below shows the status of the draft final proposal within the overall ESDER 2 stakeholder process.

Figure 1
Stakeholder Process for ESDER 2 Stakeholder Initiative

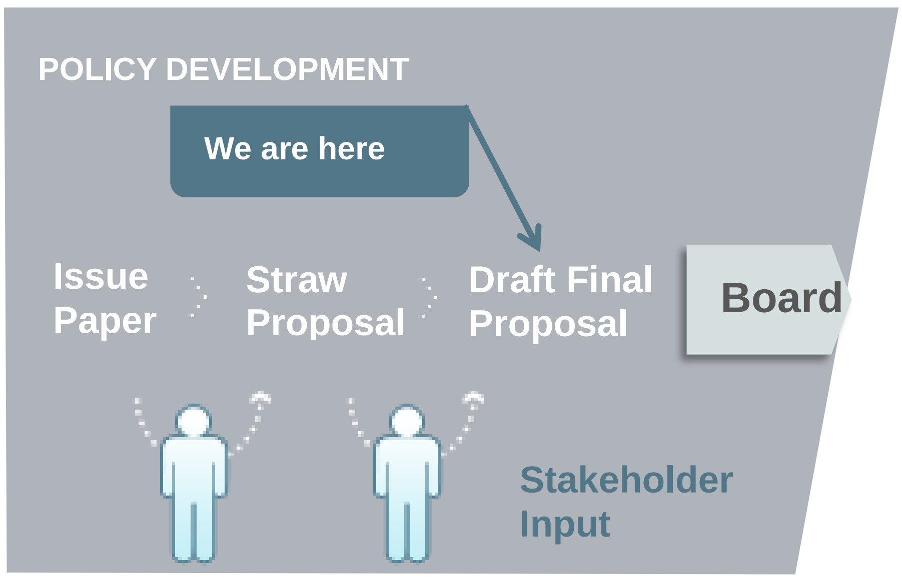

Table 1 below summarizes the major milestones for the ESDER 2 and ESDER 3 stakeholder initiatives. Table 1 does not include implementation steps, including milestones for developing and filing the tariff amendments, changes to CAISO business practice manuals, and changes to implement new market system software and hardware.

The policy issues in ESDER 2 will affect the CAISO's EIM where a participating EIM entity may employ the CAISO's demand response resource and distributed energy resource functionality in its EIM entity area. Therefore, the EIM Governing Body will have an advisory role in approving the policies resulting from this initiative, and the ISO will present its ESDER 2 proposal at the July 13, 2017 EIM Governing Body meeting.

The ISO will present its ESDER 2 proposal to the CAISO Board of Governors for approval on July 26-27, 2017. Stakeholders will have a final opportunity to provide written comments on the draft final proposal by June 23, 2017 and prior to the Board of Governors meeting.

Table 1
ESDER 2 and ESDER 3 Stakeholder Process Schedule
(Shaded Milestones are completed)

Milestone	Date	Activity
ESDER 2 Issue Paper	March 22, 2016	Post ESDER 2 issue paper
	April 4	Hold stakeholder web conference
	April 18	Stakeholder written comments due
Straw Proposal	May 24	Post ESDER 2 straw proposal
	May 31	Hold stakeholder web conference
	June 9	Stakeholder written comments due
Revised Straw Proposal	July 21	Post ESDER 2 revised straw proposal
	July 28	Hold stakeholder web conference
	August 11	Stakeholder written comments due
Second Revised Straw Proposal	September 19	Post ESDER second revised straw proposal
	September 27	Hold stakeholder web conference
	October 11, 2016	Stakeholder written comments due
Third Revised Straw Proposal	April 17, 2017	Post ESDER 2 third revised straw proposal
	May 4	Hold stakeholder meeting
	May 18	Stakeholder written comments due
Draft Final Proposal	June 8	Post ESDER 2 draft final proposal
	June 15	Hold stakeholder meeting
	June 23	Stakeholder written comments due
Presentation to EIM Governing Body	July 13	Present ESDER 2 proposal at Energy Imbalance Market Governing Body meeting
Presentation to Board for Approval	July 26-27	Present ESDER proposal for approval at ISO Board meeting
ESDER 3 Issue Paper	September 29	Post ESDER 3 issue paper

The CAISO received comments from stakeholders on all of the topics discussed in the April 17, 2017 Third Revised Straw Proposal.[3] The CAISO incorporates written stakeholder comments and CAISO responses in the sections below by ESDER 2 topic.

3 Introduction

The central focus of the ESDER initiative is to lower barriers and enhance the ability of transmission grid-connected energy storage and DER to participate in the CAISO market. The number and diversity of these resources is growing and represent an increasingly important part of the resource mix. Integrating these resources will help lower carbon emissions and add operational flexibility.

In 2015, the CAISO conducted the first phase of ESDER ("ESDER 1")[4], which made progress in enhancing the ability of storage and DER to participate in CAISO markets. The CAISO worked with stakeholders to develop policy proposals. The CAISO Board approved proposals that needed tariff changes – enhancements to the NGR model and enhancements to DR performance measures – at its February 3-4, 2016 meeting. The CAISO filed tariff changes with FERC on May 18, 2016.[5] On August 16, 2016, FERC accepted the tariff revisions effective October 1, 2016.[6]

In 2016, the CAISO began ESDER 2 to explore additional topics of interest to stakeholders.

- In its March 22, 2016 ESDER 2 issue paper, the CAISO proposed the following topics: further NGR model enhancements, further DR enhancements, further

[3] (1) Alta Gas – Pomona Energy Storage (Pomona); (2)California Energy Storage Alliance ("CESA"); (3) California Efficiency and Demand management Council; (4) California Hydrogen Business Council (CHBC); (5) California Energy Storage Alliance ("CESA"); (6) California Large Energy Consumers Association ("CLECA"); (7) Electric Motor Werks, Inc. (eMotorWerks); (8) Independent Energy Producers Association (IEP); (9) Pacific Gas & Electric Company ("PG&E"); (10) Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (the "Six Cities");(11) Stem Inc.;(12) Tesla; (13) Trans Bay Cable, and (14) Department of Market Monitoring (DMM) submitted written stakeholder comments on the April 17, 2017 third revised straw proposal.

[4] More information about ESDER 1 may be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesphase1.aspx.

[5] The ESDER 1 tariff filing may be found at: http://www.caiso.com/Documents/May18_2016_TariffAmendment_ImplementEnergyStorageEnhancements_ER16-1735.pdf

[6] http://www.caiso.com/Documents/Aug16_2016_LetterOrderAcceptingTariffAmendment_EnergyStorage_DistributionEnergyResourceInitiative_ER16-1735.pdf

work on MUA, clarify station power for energy storage, and review the allocation of transmission access charge to load served by DER.

- In its May 24, 2016 straw proposal, the CAISO refined the scope of topics for ESDER 2 and clarified its proposed direction on these topics based on stakeholder feedback, i.e., feedback received from both written comments and the joint workshop held with the CPUC.
- In its July 21, 2016 revised straw proposal, the CAISO further refined topics in scope and made progress in developing proposals to address those issues.
- In its September 19, 2016 second revised straw proposal, the CAISO presented the status of its work with stakeholders in addressing the four topics of ESDER 2.
- In its April 17, 2017 third revised straw proposal, the CAISO presented the status of its work with stakeholders in addressing the four topics from the ESDER 2 second revised straw proposal, introduction of a new topic, and developed proposals on three topics that the CAISO proposes to take to the CAISO Board for approval on July 26-27, 2017.
- In this June 8, 2017 draft final proposal, the CAISO provides additional detail on its final proposals for the three topics that will go before the CAISO Board for approval in July and summarizes the status of the remaining ESDER 2 topics, including a discussion of future topics considered in the ESDER 3 initiative.

4 Changes from Third Revised Straw Proposal

This section discusses the changes in the draft final proposal the CAISO made since the third revised straw proposal. The major changes are:

1. Finalized proposals that are ready for approval by the CAISO Board at the July 26-27, ISO Board meeting, and the topics that the CAISO believes require additional discussion in ESDER 3.
2. Provided a finalized proposal from the BAWG working group on DR enhancements in the form of alternative baselines, which the CAISO plans to present for approval at the July 26-27, 2017 Board meeting.
3. Provided an updated proposal from the ISO on distinguishing between charging energy and station power, which the CAISO plans to present for approval at the July 26-27, 2017 Board meeting.

4. Provided further detail on the proposal introduced by the CAISO in the third revised straw proposal changing how the threshold price for demand response, determined by the net benefits test, is developed to account for EIM participant bidding, which the CAISO plans to present for approval at the July 26-27, 2017 Board meeting.
5. Provided updated discussion on the following three ESDER 2 topics that the CAISO does not plan to take to the July 26-27, 2017 Board meeting: DR enhancement in the form of increased load consumption, NGR enhancements, and MUA.

Figure 2 on the following page shows the breakout of the scope between ESDER 2 and ESDER 3, as well as the general timeline of the ESDER stakeholder process.

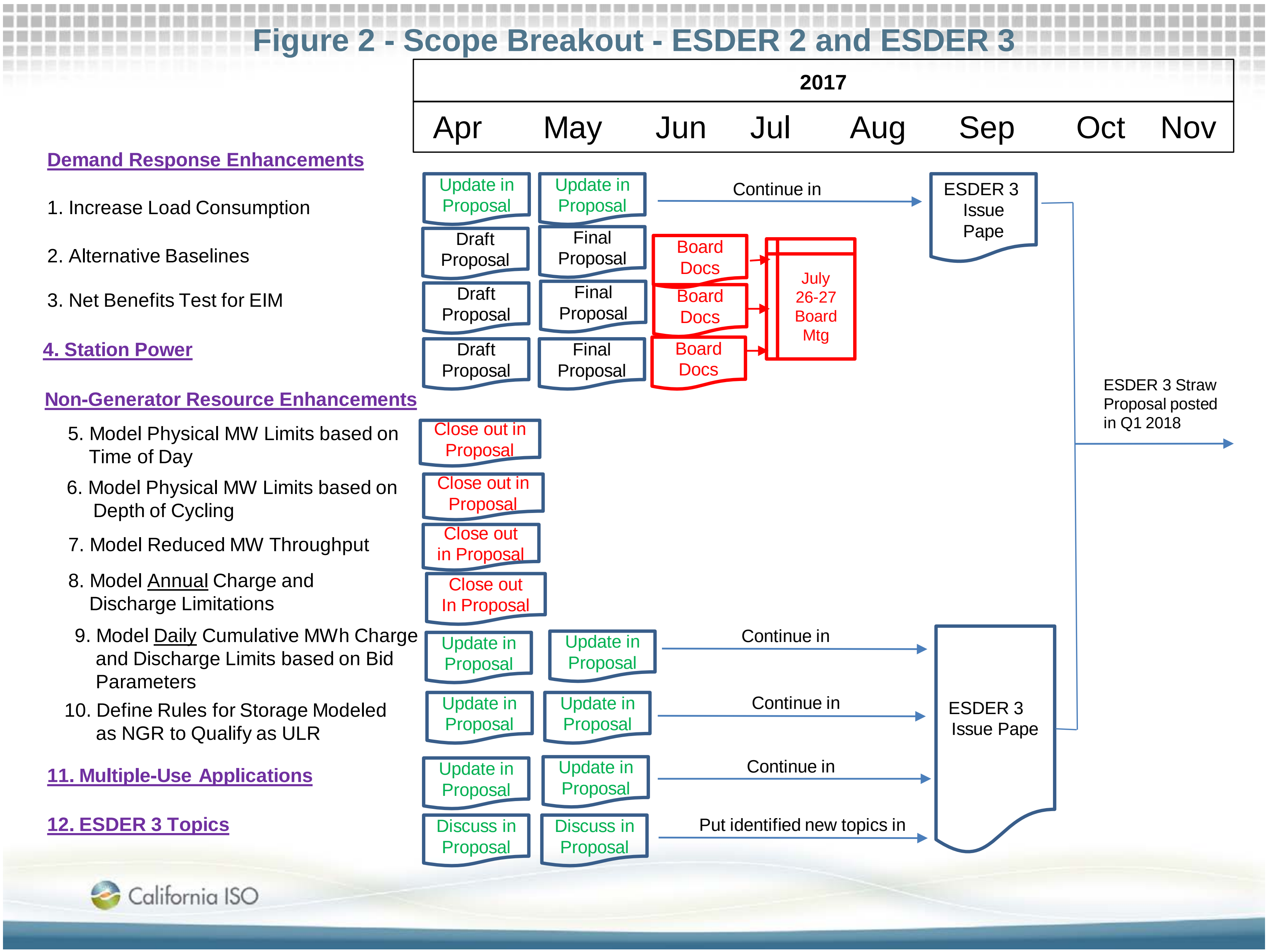

Figure 2 - Scope Breakout - ESDER 2 and ESDER 3

5 Proposals for July 26-27, 2017 Board Meeting

The CAISO will seek approval of the following three topics at the CAISO Board meeting on July 26-27, 2017: (1) alternative baselines to enhance DR, (2) distinguishing between charging energy and station power; and 3) changes to the net benefits test for Demand Response. This section of the paper discusses these three topics.

5.1 Alternative Baselines to Enhance DR

In this section, the ISO summarizes the written comments received from stakeholders on its third revised straw proposal, the CAISO's response to those written comments, and the CAISO's final straw proposal.

5.1.1 Stakeholder Comments to Third Revised Straw Proposal

A majority of stakeholders were supportive of the work and proposal developed by the BAWG. Stakeholders who supported the proposal stated that the use of additional baselines for residential and non-residential customers would improve the accuracy and reduce bias in the performance calculation in comparison to the 10 in 10 customer load baseline methodology[7] (CLB) option currently available. CLECA commented that the CAISO's proposal to establish an approval process and auditing of a Demand Response Providers ("DRPs") use of an alternative baseline "will be important to provide assurance that these are being performed correctly". Market participants also commented on process impacts to incorporate and calculate their own resource's performance using the new baselines and the existing 10 in 10 CLB calculation, which under this proposal would shift from the CAISO performing the calculation using its demand response system (DRS) [8] to the demand response provider through its scheduling coordinator. Stakeholders request that impacts of shifting the calculation responsibility to the demand response provider and its scheduling coordinator be consider in the timing of the proposal implementation. Stakeholders also commented on the auditing procedures of the SQMD and the importance of incorporating validation provisions within it.

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[7] See DRS User Guide for DR Energy Measurement Adjustment for Real Time beginning on page 160 http://www.caiso.com/Documents/DemandResponseUserGuide.pdf

[8] The CAISO plans to retire its legacy Demand Response System once the demand response providers and their scheduling coordinator take responsibility for calculating their resources' performance using the approved baselines.

5.1.1 ISO Response to Stakeholder Comments

The CAISO appreciates the overwhelming support of the alternative baseline proposal. In agreement with other stakeholders, the CAISO would like to recognize the tremendous work by the BAWG. The CAISO believes that it has addressed many of the comments through the frequent working group conference calls and multiple releases of the BAWG proposal. In response to comments received requesting additional implementation detail and timeline consideration, the CAISO will ensure consideration of identified impacts when developing the implementation plan. The CAISO believes, supported by stakeholder comments, having both current and newly proposed CLB calculations performed by the DRP, or DRPs SC, provides all parties greater flexibility in the consideration of new baselines and ease of their deployment. In response to stakeholder comments for clarification of auditing of CLB results submitted by the DRP or DRPS SC as settlement quality meter data (SQMD), the CAISO has provided additional insight to the structure of the auditing process. The CAISO is committed to continue working with stakeholders on the provision of additional detail during the implementation phase including further engagement, and opportunity for review and comment, throughout its tariff development and business practice manual (BPM) stakeholder processes.

5.1.2 Draft Final Proposal

This section summarizes the alternative baselines proposed by the BAWG. The BAWG focused on three major areas of research and analysis.

- The use of alternative traditional baseline methods to estimate the load impact of current DR resources.
- The option of using control groups rather than traditional baselines to estimate the load impacts of DR resources.
- The impact of frequently dispatched resources in the evaluation of baselines.

The complete BAWG proposal, including detail on multiple baselines accuracy assessments performed in development of this proposal, has been posted to the ESDER Phase 2 Initiative website at:

http://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf

The BAWG proposal includes updates from its last publication as follows:

- Spreadsheet examples embedded in the proposal are separately posted on the ESDER 2 website
- Inclusion of requirement to zero out calculated demand reductions if they are negative (i.e., load increases) footnoted in the spreadsheet examples.

- Addition of footnote to Section 3 recommendation table clarifying how to use proposed baselines when resource is composed of both residential and non-residential customers.
- Addition of footnote to the Section 3 recommendation table defining residential and non-residential customers.

The CAISO currently provides multiple performance evaluation methodology options for PDR and RDRR [9] however, the only day matching performance evaluation method offered uses a 10 in 10 customer load baseline with a 20% same day adjustment. While research has shown this day matching baseline to be accurate for many medium and large commercial and industrial customers, research has also shown that this baseline is not accurate for all customer types. The objective of the BAWG was to identify additional performance evaluation methodology options, which, when offered in addition to the 10 in 10 customer load baseline, will enable a wider variety of CAISO DR resources to be accurately estimated and settled.

The BAWG analyzed and proposed the three types of customer load baseline methodologies summarized below.

- **Control Groups**
  A control group performance evaluation method determines a resource's performance by evaluating the energy consumption of a set of similar, but non-participating customers with the energy consumption of the participating customers. A control group should be made of customers who have nearly identical load patterns and experience the same weather patterns and conditions as the customers dispatched. The control group establishes the baseline of what load patterns would have been absent the curtailment event. There are three ways to establish valid control groups: random assignment of customers, random assignment of clusters, and matching.

- **Day Matching**
  Day-matching baselines estimate what electricity use would have been in the absence of a DR dispatch, relying exclusively on the electricity use data from the dispatched customers. The load patterns during a subset of non-event days are used to estimate the baseline for the event day. A total of 13 day matching baselines were evaluated to determine the most accurate and precise of the 13.

- **Weather Matching**

[9] See DRS User Guide for available Performance Evaluation Methodologies beginning on page 149 http://www.caiso.com/Documents/DemandResponseUserGuide.pdf.

Like-day-matching baselines, weather-matching baselines estimate what electricity use would have been in the absence of dispatch by relying exclusively on electricity use data from the dispatched customers. The load patterns with the most similar weather conditions during a subset of non-event days are used to estimate the baseline for the event day. Weather matching baselines do not include information from an external control group. A total of seven weather-matching baselines were evaluated to determine the most accurate and precise of the seven.

The CAISO accepts the following recommended additional performance evaluation methodologies as proposed by the BAWG, summarized in Table 2 below.

Table 2: BAWG's Recommended Baselines for ISO Performance Evaluation Methodologies[10]

Customer Segment[11]	Weekday	Baselines Recommended	Adjustment Caps
Residential	Weekday	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 5/10 day matching	+/- 40%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 3/5 weighted day matching	+/- 40%
Non-residential	Weekday	Control Group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		10/10 day matching	+/- 20%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		4 eligible days immediately prior (4/4)	+/-20%

The proposal considered the best performing baselines for residential and non-residential loads. The analysis showed that randomized control groups with sample sizes between 200 and 400 participants were more than twice as precise as day or weather matching baselines. The addition of day or weather matching baselines provides alternative options for DRPs that do not have the proposed minimum size of

[10] In the case of PDR resources that combine residential and non-residential customers, the aggregate baselines for the two customer groups should be calculated separately using the appropriate baseline for residential and non-residential customers, then added together to represent the full resource. This subdivision is not necessary if the baseline method for both residential and non-residential customers is the same, as is the case for the current recommended weather matching baselines.

[11] A customer's rate class, established by their local distribution company LDC, determines the customer's residential or non-residential designation. That is, if a customer is served under a non-residential LDC rate, that customer classification is non-residential customer.

150 participants. Section 3.1-3.3 in the BAWG proposal details the process and rules for each baseline and are included as Appendices A-C in this proposal.

The BAWG recognizes that the proposed performance calculation results provided to the CAISO as SQMD must be in intervals of five minutes when a PDR or RDRR offers real-time or ancillary services (non-spin and spinning reserve) and has concurred with CAISO's proposal on how a 5-minute performance measurement could be derived. Therefore, it is recommending that the current method used by the CAISO, in conjunction with the 10 in 10 customer load baseline methodology, be applied when using any of the BAWG proposed methodologies. In summary, to achieve a 5-minute DR Energy Measurement[12], an hourly baseline is pro-rated to create a 5-minute baseline from which the 5-minute interval actual load, measured during the event, is subtracted. The CAISO would maintain its current requirement that baselines, and measured load during the event, be derived using, at maximum, a 15-minute interval load measurement when the PDR or RDRR is participating in real-time or for PDR ancillary service markets participation. For greater flexibility and timely baseline implementation, the CAISO is proposing to have all baseline calculations, including the current 10 in 10 customer load baseline, performed by the DRP or its SC and submitted to the CAISO by the SC as SQMD. Shifting this responsibility to the SC accelerates the needed retirement of the CAISO's legacy Demand Response System and gives the SC access to the CAISO's Market Results Interface- Settlements ("MRI-S") system to submit, view, export and upload SQMD in batch files. The CAISO believes this change will provide a more consistent and flexible approach to performance calculation management and SQMD processing.

The CAISO will continue to rely on a pre-established approval process for use of a performance methodology that requires the DRP to submit a request with detail on how they will perform calculations in compliance with tariff requirements for the methodology requested. Additionally, the CAISO will continue to leverage auditing provisions including the bi-annual SC self-audit and, on an as-needed basis, selective auditing to ensure accurate development and submission of SQMD to the CAISO.

With the addition of new baselines, the CAISO will establish a three-step registration and auditing process described at a high level below. The CAISO will continue to obtain and review stakeholder feedback on the specifics of the review and audit processes during the development of the Business Practice Manual (BPM) and the DR User Guide language.

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[12] The resulting Energy quantity calculated by comparing the applicable performance evaluation methodology of a PDR or RDRR against its actual underlying performance for a Demand Response Event.

The CAISO will establish an internal three-step process to register an SC's requested baseline and monitoring with selective auditing program to ensure accurate development and submission of SQMD.

1. **Baseline Registration**
   The CAISO will collect all registered baseline calculations, required information and justification for the baseline designation for each DR resource. Performance of the monitoring and auditing processes below will utilize this registration database.

2. **Monitor**
   The CAISO will review and monitor SQMD with references to bids and event days of all DR participants.

3. **Audit**
   Using available auditing provisions, the CAISO will audit DR resources to ensure the accurate development and submission of SQMD.

5.2 Distinguishing between Charging Energy and Station Power

5.2.1 Background

Throughout this initiative, the CAISO has worked toward resolving potential issues in distinguishing between wholesale "charging energy" and retail station power. The CAISO examined this topic area through its collaboration with the CPUC in Track 2 of the CPUC's energy storage proceeding (CPUC Rulemaking 15-03-011) and through ESDER 2. This dual-track effort recognizes that the CAISO's efforts in re-defining station power from a wholesale perspective could be counter-productive if the CPUC makes different station power determinations from a retail perspective.[13] Without careful consideration between the CPUC and the CAISO, incompatible retail and wholesale station power rules could result in the same energy incurring both wholesale and retail charges, resuscitating the years of litigation that preceded the current station power framework.[14] The CAISO believes it is important that its station power regulations be consistent with the CPUC's, and vice versa.

The CAISO tariff currently defines station power as "energy for operating electric equipment, or portions thereof, located on the Generating Unit site owned by the same

[13] See, e.g., *Southern California Edison Co. v. FERC*, 603 F.3d 996, 1002 (D.C. Cir. 2010)
[14] See, e.g., *id.*; *Calpine Corp. v. FERC*, 702 F.3d 41 (2012); *Duke Energy Moss Landing LLC v. CAISO*, 134 FERC ¶ 61,151 (2011).

entity that owns the Generating Unit, which electrical equipment is used exclusively for the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit; and for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are owned by the same entity that owns the Generating Unit; located on the Generating Unit site; and used exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy by the Generating Unit."[15] The CAISO tariff specifically excludes from its station power definition "any Energy used to power synchronous condensers; used for pumping at a pumped storage facility; or provided during a Black Start procedure. Station Power [further] does not include Energy to serve loads outside the CAISO Balancing Authority Area."

The CAISO tariff explicitly states that station power includes, for example, the energy associated with motoring a hydroelectric generating unit to keep the unit synchronized at zero real power output to provide regulation or spinning reserve.[16]

As part of the CAISO's new resource implementation process, the CAISO verifies that new resources have a load serving entity in place to meet station power needs prior to commercial operation.

5.2.1 Stakeholder Comments to Third Revised Straw Proposal

Stakeholders support the CAISO's efforts to clearly distinguish between wholesale and retail energy consumption activities by energy storage devices and conventional generation. Stakeholders focused their comments on two aspects of this distinction: the tariff definition of station power and metering rules for resources.

Regarding the definition of station power, stakeholders either supported expanding the definition to list retail examples and wholesale examples consistent with the CPUC's decision, or supported simplifying the definition. For example, the Six Cities commented that they "are not opposed to the CAISO's proposal to 'reduce the amount of verbiage' in the current definition of station power, the Six Cities are concerned that the proposed definition could result in a lack of clarity." PG&E, however, notes that "the additional modification to exclude specific uses from station power could be inconsistent with the definition and implementation of station power in conventional generation." Other parties offered specific use cases they would like added for clarity.

[15] Appendix A to the ISO tariff.

[16] Station power does not include any energy used to power synchronous condensers; used for pumping at a pumped storage facility; provided during a black start procedure; or to serve loads outside the ISO BAA.

Regarding metering rules, stakeholders supported deference to the local energy provider and the resource, or favored mandating separate metering for wholesale and retail activities (i.e., in lieu of the option for a single meter with a fee or calculation for station power based on agreement, testing, etc.). Other stakeholders suggested that the two may not be mutually exclusive, and that the CAISO should defer to retail authorities while mandating separate metering.

5.2.2 Draft Final Proposal

Stakeholder comments reflect one general theme: station power is a retail issue. As such, the CAISO's efforts to mirror retail rules in its wholesale tariff may be unwise. After all, the CAISO's tariff can be consistent with retail tariffs by reference or adoption instead of copying exact language.

The CPUC's recent decision on station power rules for energy storage resources demonstrates that listing specific use cases of either retail or wholesale functions in the CAISO tariff would prove futile given the extraordinary number of use cases that could exist as systems and technologies evolve. Additionally, the CPUC is not the only local regulatory authority in the CAISO, so its findings are not binding on all CAISO resources. Second, other local regulatory authorities may define station power use cases differently than the CPUC. Third, the need to list use cases as retail or wholesale will not be complete any time soon, as myriad new technologies present themselves each year. As such, the CAISO believes that it is prudent to simplify the definition of station power to energy for operating the electrical equipment of an energy resource subject to a retail tariff, as defined by the Local Regulatory Authority. This definition would allow the CAISO's practices to remain consistent with all local regulatory authority definitions, even as they may change in the future. Put another way, this definition would avoid any conflict with changing or varying station power definitions, which also would obviate the need to change the CAISO's definition in the future if the CPUC or another local regulatory authority revised its rules because of innovation, need, or policy. The CAISO intends to work with stakeholders in the tariff development process to ensure that this approach is sufficiently flexible and clear.

The CAISO understands that examples and use cases of wholesale and retail uses can provide meaningful guidance to potential and current market participants; however, the CAISO does not believe that the tariff is the best place to do so. The CAISO thus proposes to work with stakeholders to implement Business Practice Manual revisions that provide useful examples.

The CAISO also believes that deference to local regulatory authorities on metering station power is both prudent and required. The CAISO agrees with CESA and others that "the CAISO should not at this time pursue or establish metering criteria, but should direct principled metering such that wholesale and costs can be reasonably differentiated and calculated as separate from retail costs." PG&E, notes, for example, that it "has concerns when not having separate metering," though others may not. In any case, it is reasonable to rely on the assumption that the local energy providers themselves under the authority of their local regulatory authority will ensure that resources' station power is accurately metered and settled, and as such, the CAISO itself does not need its own detailed rules on doing so. Moreover, it is both the local energy provider's interest and responsibility to ensure that that its customers are not avoiding retail charges. The CAISO thus proposes simply to state in its metering tariff provisions that, as part of the interconnection process, generating units interconnecting to the CAISO will work with their local energy provider to ensure that their metering configurations accurately account for station power, where and as required by local regulatory authorities. The CAISO believes that this approach will avoid interfering with any resource and its local energy provider coming to a mutually agreeable metering configuration consistent with local regulatory authority standards.

5.3 Net Benefits Test

5.3.1 Stakeholder Comments to Third Revised Straw Proposal

Stakeholders were either supportive/did not oppose or had no position on the proposal to include additional gas price indices in the net benefits test NBT calculation. PG&E recommended a set of gas price indices for EIM participants.

5.3.2 ISO Response to Stakeholder Comments

The CAISO is currently in the process of updating its Business Practice Manual for the inclusion of the various EIM gas price indices.

5.3.3 Draft Final Proposal

The DR-net benefits test establishes a price threshold above which DR resource bids are deemed cost effective. CAISO staff, along with the Department of Market Monitoring ("DMM"), identified a gap in the DR net benefits test formula as it applies to EIM entities.

Currently, an adjustment is made to the supply curve used in calculating the DR net benefits test to reflect differences in resource availability and fuel prices between the target and reference month. The CAISO tariff explicitly states that significant changes in fuel prices will be determined by using a simple average of the Pacific Gas and Electric

Company Citygate price and the Southern California Edison Company Citygate price.[17] If neither of the prices are available, then the formula will default to the Henry Hub price.[18]

The CAISO is proposing to expand the list of gas price indices available for use in the calculation of the DR net benefits test to represent prices relevant to EIM entities outside of California. The fuel indices will be included in the business practice manual for market instruments rather than hardcoded in the CAISO tariff.[19] The proposal aligns the need for the DR net benefits test to recognize a variety of regional gas price indices, which will accommodate EIM entities outside of California that want to participate as DR in the CAISO market.

6 ESDER 2 Topics that require Further Development

This section discusses the following three topics that began development as part of the ESDER 2 effort, but were determined not to be ready for CAISO Board approval in July 2017: increase load consumption as DR enhancements, NGR enhancements, and MUA. The CAISO will further develop the topics discussed in this section over the rest of 2017, obtaining additional feedback from stakeholder during ESDER 2 with continued development occurring in the ESDER 3 stakeholder processes.

6.1 Increase Load Consumption as Demand Response Enhancement

In this section, the CAISO summarizes the discussion on this topic that occurred in the third revised straw proposal, the latest written comments received from stakeholders, the CAISO's response to those written comments, and the status of this effort. For completeness of the record, the CAISO begins this section by including prior stakeholder comments and CAISO responses to the ESDER 2 <u>second</u> revised straw proposal. A summary of the Stakeholder comments received on the third revised straw proposal, and the CAISO's responses to those comments begins at section 6.1.2.

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[17] Refer to ISO tariff section 30.6.3.1

[18] A natural gas pipeline that serves as the official delivery location for futures contracts on the NYMEX.

[19] Link to the BPM for Market Instruments: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

6.1.1 Prior Stakeholder Comments Received on the Second Revised Straw Proposal and the ISO's Responses

AMS, SolarCity and Stem - AMS, SolarCity and Stem all participate in the Baseline Analysis and Load Consumption working groups (LCWG) and are highly supportive of these important initiatives under the ESDER Phase II. We encourage the CAISO to adopt the working group's recommendations reflected in the Staff Proposal. In particular, AMS, Solarcity and Stem are encouraging swift extension of frequency regulation to PDR as proposed by the LCWG. AMS, SolarCity and Stem strongly believe that regulation markets should be accessible to BTM energy storage systems.

PG&E - PG&E remains supportive of expanding PDR functionality to include load consumption and regulation services. What remains open is how this conceptual proposal will be operationalized. Turning a concept into reality will require a forum, which does not seemingly exist. Therefore, PG&E recommends that the CAISO consider this topic for inclusion in a Phase 3 of ESDER or possibly another forum that is available for undertaking what could be a significant effort.

SCE - SCE supports the LCWG proposal to maintain the separation of wholesale and retail energy settlement for increased load consumption. In past comments, SCE has supported this aspect of the proposal because, among other purposes, it helps eliminate jurisdictional issues while also maintaining the same relationship between wholesale market payments and retail billing that exists for current load reduction demand response. The stakeholder comments template asks: "The LCWG proposes to maintain the separation of wholesale and retail energy settlement for increased load consumption. This supposes that the value of increased wholesale consumption, perhaps at a negative price, has value to the DRP or customer since the increased consumption would also be charged under retail rates. Under this construct, is this a feasible concept?" SCE believes this is appropriate and, given is how demand response works today, does not understand why it could not be feasible. Retail rates account for more than just wholesale market costs (including distribution costs). Increased load consumption, even when directed by the CAISO through a new DR product, still requires use of the distribution system, transmission system, and other factors and those costs need to be accounted for. This construct also appropriately assumes that there is potential value to increased load from customers. Customers have the choice at which price point to bid increased load consumption. Even if the price a customer is bidding does not completely offset their retail bill, the load consumption product is effectively acting as a discount to their retail bill. There are still multiple details that need to be developed for the load consumption product. In the last set of comments, SCE identified issues surrounding baseline applications and uninstructed imbalance energy. In addition to these issues, SCE believes the stakeholder process needs to eliminate revenue insufficiency issues created by the load consumption product. Similar to the revenue insufficiency created by traditional DR, load consumption DR will create a need for uplift since both the DR resource and Load Serving Entity (LSE) load are being compensated for the increased load during periods of negative prices. A DR resource will in effect be paid for consuming energy at a negative LMP while the LSE will see an increase in load in the real time market, likely at a discounted DLAP price, and be compensated as well. That means for every 1 MW of load consumption DR dispatched by the CAISO, the CAISO could need to pay for 2 MW of increased consumption. This discrepancy will result in the need for uplift, a market inefficiency, and should be avoided. The CAISO should commit, as part of this process, to work with stakeholders to resolve this issue before finalizing a proposal.

<u>SDG&E</u> - SDG&E is waiting to review the results of the Demand Response Enhancements working group.

The ISO specifically responded to SCE's and PG&E's comments on the ESDER 2 second revised straw proposal.

In the ESDER 2 second revised straw proposal, SCE expressed concern about additional distribution and transmission system costs from increased throughput due to directed load consumption. SCE raises concern that market inefficiencies result when the CAISO pays both the demand response provider and the load-serving entity for consuming negatively priced energy, once as an instructed energy settlement to the DRP for the load consumption, and twice as an uninstructed energy settlement for the excess load consumed above the load-serving entity's scheduled demand (assuming negative priced energy). The ISO responded that SCE's market inefficiency concern has the same analog on the load curtailment side. Addressing this market inefficiency in the original PDR design generated intense debate, which led to the CAISO implementing the default load adjustment settlement mechanism, and, in part, FERC instituting a net benefits test price threshold. Directed load consumption begs these same questions about creating market inefficiencies and double payments and how these issues should be resolved. Resolving these issues is essential to bringing a wholesale bi-directional PDR product to market.

In the ESDER 2 second revised straw proposal, PG&E questions how the conceptual idea of directed load consumption turns into operational reality. PG&E's excess supply pilot is exploring how customers can shift loads to take advantage of renewable energy available in situations of excess supply given new usage patterns from adoption of new technologies, such as EV, battery storage, PV, and appliances. On March 24, 2017, PG&E presented lessons learned from their excess supply pilot, which were informative to this effort. Two particular challenges PG&E highlighted in their presentation were 1) the impacts of participation on the customer's retail bill (i.e. how demand charges are affected), and 2) how to ensure directed load consumption actions do not create operational and congestion problems on the distribution system. In its ESDER 2 comments, PG&E questioned where the forum is to vet these issues to make load consumption an operational reality. The CAISO responded stating that it believed the forums already exist, including at the CPUC, where fundamental rate design concerns and distribution system impacts must be resolved; the existing load consumption working group where issues can be identified and vetted collaboratively; and importantly, PG&E's own excess supply pilot where information and ideas can be tested and shared about how directed load consumption works, what customer, policy, and technical barriers exist, and how to measure and validate load response.

6.1.2 Stakeholder Comments to Third Revised Straw Proposal

CESA, Stem, eMotorWerks, Tesla – The storage community strongly supports development of a bi-directional PDR product, conveying that time is urgent given oversupply and increasing amounts of renewable resource curtailments. These stakeholders also agree that retail rate and retail-wholesale jurisdictional issues should not impede the CAISO's efforts to develop a bi-directional PDR product. Tesla conveys that "[w]hile we recognize CAISO's concerns around retail rate impacts and demand charges, we believe that the burden is on customers to ensure wholesale market activity does not create net charges for the customer when considering wholesale and retail settlements combined."[20] CESA states that "[r]etail rate concerns cannot be controlled by the CAISO and, while important to address in the right forum, do not amount to a basis for no CAISO action."[21] CESA also conveys that ISO leadership is essential to help motivate resolution of retail policies and rate reforms that support a wholesale load consumption capability. Stem and eMotorWerks acknowledge that load consumption capability exists in the CAISO market via the non-generator resource model, but explain the non-generator resource model imposes barriers to behind the meter storage, stating "...although BTM storage could theoretically participate in load consumption using the NGR model, the practical barriers result in a CAISO tariff that unreasonably restricts competition."[22] Finally, these stakeholders urge the ISO to move the load consumption working group forward, stating the ISO should "...immediately re-

[20] Tesla at p. 4.
[21] CESA at p. 6.
[22] Stem and eMotorWerks at p. 4.

constitute the LCWG to work on a minimum viable load consumption product well ahead of the proposed Phase 3 Issue Paper timeline."[23]

CLECA, PG&E, CHBC, IEP- These parties generally acknowledged that important questions and policies need to be addressed and answered by stakeholders at the CPUC, and more time is needed prior to the ISO developing a bi-directional PDR product. Specifically, PG&E questions how such a [bi-directional PDR] product interacts with Time of Use rates and demand charges.[24] CHBC agrees "...that demand charges can be a fundamental barrier and must be addressed before implementing a Bi-Directional Proxy Demand Response (PDR) product."[25] IEP states that first priority issues must be addressed such as "...issues associated with resource configuration and the accurate metering to distinguish between wholesale and retail consumption."[26]

Trans Bay Cable- recognizes the difficulty in the CAISO acting alone to develop a PDR-wholesale load consumption product, and express that "...multiple models could be used for wholesale consumption, such as the NGR model where the Pmax is set to zero and the entity is entirely metered as an ISO resource."[27]

6.1.3 ISO Response to Stakeholder Comments

The CAISO appreciates the diverse set of stakeholders that commented on enabling a bi-directional PDR capability. Overall, the submitted comments on load consumption land in two camps, with the storage community expressing strong and urgent support for the CAISO to develop a bi-directional PDR product, and a somewhat countervailing view from a broad cross-section of stakeholders expressing the need for the CAISO to take more time to resolve issues, consider options, and coordinate with the CPUC.

6.1.4 Draft Final Proposal

The CAISO and a diverse set of stakeholders recognize there remain outstanding technical and policy issues that impact developing a bi-directional PDR product. The LCWG's discussions largely focused on the technical aspects and design of a wholesale bi-directional product, never formally delving into identifying and resolving some of the deeper policy discussions around retail rate interactions, customer costs and benefits,

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[23] Id. at p.3

[24] PG&E at p. 5.

[25] CHBC at p. 3.

[26] IEP at p.4.

[27] Trans Bay Cable at p. 3.

customer interest, demand charges, and technical implementation issues. PG&E's excess supply pilot has delved into these issues and has reported that participants are concerned about rate impacts and ratcheting demand charges. The California Hydrogen Business Council stated in its ESDER 2 comments that it "...agrees with CAISO's concern that demand charges can be a fundamental barrier and must be addressed before implementing a Bi-Directional Proxy Demand Response (PDR) product," and "[r]etail rates coupled with above charges can impede cost competitiveness and hinder adoption of emerging energy storage technologies in California."[28]

The CAISO continues to believe that retail rate impacts and demand charges are fundamental barriers to address, and on a path to resolution, before the CAISO can investment significant time and resources creating a wholesale bi-directional PDR product. Contrary to comments from the storage community, the CAISO does not view these barriers as jurisdictional in nature, but as real impediments to customer interest and robust customer participation in a bi-directional PDR product.[29]

The CAISO appreciates the sentiment that having the CAISO take a leadership role in this area is valued; however, the CAISO's concern is that without resolution of retail issues, the CAISO will expend significant staff time, information technology resources, and money developing a product that will languish until retail rules and or rate reforms are on a path to resolution. Like all demand response products, a bi-directional PDR product has retail impacts and interactions that must be clearly understood and resolved as a first priority.

Contrary to certain stakeholder opinions, the CAISO has been very progressive in the demand response and distributed energy resource space relative to other ISOs and RTOs, and does not believe it is unreasonably restricting competition.[30] In fact, the CAISO has provided multiple pathways for DER wholesale market participation, including under the Distributed Energy Resource Provider (DERP) model, as a Non-

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[28] CHBC at pp. 3-4.

[29] The ISO provided its opinion to the load consumption working group in an email back in December 2016 stating the CAISO believes the risk is low that FERC would reject oversight over wholesale-market directed load consumption (especially in light of FERC Order 745), yet the CAISO acknowledges that this is a matter that will ultimately be decided by FERC and perhaps by the courts.

[30] Stem and eMotorWerks state "[t]hus, although BTM storage could theoretically participate in load consumption using the NGR model, the practical barriers result in a CAISO tariff that unreasonably restricts competition. The FERC NOPR on Energy Storage and Distributed Energy Resource Aggregation issued in 2016 as well as the February ruling on MISO vs Indiana Power & Light both affirm that wholesale market operators should allow and encourage energy storage to provide all the services [sic] that the technology is technically capable of providing. At p. 4.

generator Resource (NGR), and as demand response resource under the Proxy Demand Resource (PDR) model. Both the NGR and DERP models allow a distribution connected storage device to "consume" energy as a wholesale resource. Stem and eMotorWerks detail why these models have limitations in their comments; however, the DERP and NGR models may be a better fit for a storage device given these new models were designed for storage versus the existing PDR model, which was designed for traditional load curtailment response.[31] For instance, under the NGR model, a storage device is a wholesale resource and subject to distribution interconnection rules, and the ISO understands that wholesale distribution access tariffs may impose a barrier to market participation. However, such issues like interconnection are ripe for re-evaluation and a discussion on this topic is warranted given the expansion of DERs on the distribution grid. Encouragingly, the CPUC appears motivated to address load consumption and bi-directional products, and is soliciting formal feedback from parties about their interest in these areas, and, the appropriate forum to address these issues.[32] The CAISO looks forward to reviewing the comments the Commission receives on this subject, and believes these comments will help inform the direction of this particular effort.

As the vetting of load consumption and bi-directional products move forward, and as parties submit comments on this subject at the CPUC, parties should detail issues that need further investigation in their comments. For example, the interconnection issues raised by Stem and eMotorWerks in their comments. The comments PG&E raised about what is the interaction of directed wholesale load consumption and time-variant (time-of-use), and other dynamic retail rate forms. How to avoid creating market inefficiencies given the interaction between rates and directed wholesale load consumption? Additionally, how to address technical issues such as in the future if a customer receives a dispatch instruction from the CAISO to consume more energy, could a load-serving entity turn its retail demand charge settlement off and on in sync with that instruction? Is this feasible, and if so, what information technology would this functionality require and what changes would be needed to legacy billing systems? What is the impact of load consumption on rates, rate designs, and revenue requirements? Is a retail load consumption "program incentive" appropriate, and if so, how is it set and valued since the underlying retail customers participating in a load

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[31] See Stem and eMotorWerks comments on ESDER Phase 3 items, at p. 5.

[32] R.13-09-011, Administrative Law Judge's Ruling Requesting Responses to Questions Regarding the Pathway to New Models of Demand Response, Implementation of the Competitive Neutrality Cost Causation Principle, and Remaining Barriers to the Integration of Demand Response Into the CAISO Market, May 22, 2017, Attachment A, p. 2, Item #3.

consuming supply resource are not paid the negative wholesale energy price, but are charged a retail rate.[33] Additionally, how is the value of load consumption determined since load consumption is not a "capacity" or resource adequacy resource in the traditional sense and load consumption is not valued on a traditional avoided generation and transmission and distribution cost basis? How does directed load consumption impact distribution system assets and ensuring dispatches are feasible end-to-end?

The CAISO endorsed two stakeholder led working groups, the Load Consumption Working Group and the Baseline Analysis Working group. The intent of these two working groups was for interested stakeholders to identify and resolve issues around the respective topic areas and bring a fleshed out and working group approved proposals to the ISO for broader stakeholder review and CAISO Board approval. As the ESDER 2 stakeholder initiative concludes, the CAISO is hopeful that stakeholders can reinvigorate the LCWG and develop well-informed solutions that can be introduced into the ESDER 3 initiative in 2018. Moving forward, the LCWG should consider if and how it interacts with any future CPUC load consumption-working group (if such a group assembles under the auspices of the CPUC), and if a single working group is a the most prudent path forward, with the LCWG emerging in the future to work specifically on directed wholesale load consumption issues. The CAISO looks forward to collaborating with the CPUC and the LCWG to help vet and resolve the issues around load consumption and the possibility of developing a bi-directional PDR product.

6.2 NGR Enhancements

In this section, the CAISO summarizes the discussion on this topic that occurred in the third revised straw proposal, the written comments received from stakeholders on that discussion, the CAISO's response to those written comments, and the CAISO's draft final proposal.

6.2.1 Stakeholder Comments to Second Revised Straw Proposal

AMS, Solar City, and Stem commented that metering and settlement of resources that do not participate in the wholesale market 24 hours a day, seven days a week, and rules that support metering and settlement of storage resources located behind a retail meter are priority areas of interest. Metering and settlement frameworks that support these

[33] This is the converse of traditional "load curtailment" demand response where the customer benefits by receiving a demand response incentive payment and avoids retail rate charges for energy not consumed.

use cases will be required for Multi Use Application opportunities to provide benefits to multiple customers. They stated that NGR-modeled storage resources should be able to qualify as an ISO designated use-limited resources and that understanding storage performance limitations and non-linear degradation based on state of charge and depth of cycling is important. The ability to reflect opportunity costs and commitment costs in energy bids to manage limitations need to be explored and should reflect economic considerations of multi-use commitments. These commitments may include shifting retail charging from off-peak to on-peak or missing the opportunity to curb peak demand as a result of wholesale market dispatch, increased battery cycling, and multiple transitions to charge and discharge states per day.

CESA commented that NGR's should be eligible for ISO Use Limitation status and that NGRs should be able to represent commitment costs and throughput or other limitations. CESA stated that the development of a 'MWh-throughput limitation' tool or constraint to help manage NGR resources in line with use-limitations, contractual restrictions, or physical parameters of the resource would be helpful. CESA stated that the Commitment Costs for NGRs remain poorly understood and the CAISO should address this dearth of information through accommodating rules that clarify how resources may economically or administratively reflect their preferences for dispatch. CESA stated that the CAISO should not regulate or limit use-limited resources or access to this status based on planning capacity views, which they understand are currently out of scope for ESDER.

PG&E, SCE, and SDG&E commented that a MWh constraint would help them manage battery cycling that is in accordance to battery contracts and performance guarantees and would allow the ISO to best optimize the resources based on overall system needs as opposed to having the SC do this in their bidding strategy. PG&E added that this daily limit should be managed in a way that does not expose resources providing RA to RAAIM penalties once the daily throughput limit is exhausted through regulation or energy dispatch. Participants should have flexibility not to bid the resource in real time if the resource has reached its throughput limit in order to ensure the limit is respected.

SCE commented that that they would like to pursue the ability to represent use limitations for energy storage resources as Non-Generating Resource model enhancements while also open to defining storage as Use Limited Resources. SCE would also like to investigate opportunities to utilize a Major Maintenance Adder, multiple bid stacks, or multi-stage capability for storage resources.

SDG&E commented that they do not support extensive changes to CAISO market mechanisms to accommodate the specific attributes of specific NGRs. The existing CAISO market mechanisms are adequate to allow NGRs to express their economic preferences in the form of start-up costs and price/quantity offers that internalize the opportunity costs of dispatching the NGR during day-ahead and real-time market intervals. SDG&E stated that NGRs, like generating resources, should be allowed to reflect opportunity costs in their price/quantity offers submitted into the day-ahead and real-time markets, allowing the NGR scheduling coordinator to control, on an economic basis, when the NGR will be dispatched to supply or consume energy, or to provide ancillary service capacity. SDG&E provided examples of opportunity costs of foregone profits where a limited energy NGR is dispatched at intervals where clearing prices are lower than later intervals and commitment costs that include increases or decreases in work force and inventories depending on whether the price/quantity offer submitted by the NGR scheduling coordinator results in an increase or decrease in load.

6.2.2 ISO Response to Third Revised Straw Proposal Stakeholder Comments

The ISO received valuable comments and feedback, which continue to shape the discussion on expressing storage limitations through resource modeling, market optimization, and the ability to identify and represent explicit costs and use limitations. In addition, several new enhancements were proposed by stakeholders for consideration as ESDER 2 transitions to ESDER 3.

In the area of managing physical use limitations, stakeholders continue to express the need to have new tools to manage throughput limitations and State of Charge. The ISO clarified in the third revised draft proposal that current modeling and bidding practices allow the resource to be represented to the ISO market in a way to meet the resource's physical limitations, including the use of the ISO Outage Management System to reflect true physical resource limitations. The ISO also continued to suggest that there could be a need to further utilize resource outages for managing adverse cell degradation and battery health as a physical limitations as well as the potential for the ISO to manage cumulative MWh charge and discharge values to help manage depth and frequency of cycling and facilitate contractual limitations or performance guarantees. Stakeholders comment that these limitations should apply daily or even hourly and implemented in a way to protect the resource from RAAIM penalties when these energy throughput limits are reached.

After reviewing all stakeholder input, the ISO would like to clarify in this revised third draft proposal that using the ISO Outage Management System, or utilizing MWh limitations to facilitate contractual or economic based limitations is not a physical limitation. As emphasized in the comments by the Department of Market Monitoring:

> "The limitations imposed by contractual obligation, while expressed for a defined period of time, appear to have little physical relationship with the period of time beyond ensuring a particular level of battery life and cell health for an agreed upon period of time, or delaying maintenance activities for as specified period of time. These limitations are not exogenous to the resource operator, and indeed may be made more restrictive in exchange for more favorable terms in capacity acquisition. For this reason particularly, it is not appropriate to exempt NGR storage resources from RAAIM penalties when contractual use limits are exhausted. Under this construct, entities contracting with energy storage resource owners may have greater financial incentive to minimize capacity procurement costs at the expense of market availability. This maximizes profits on resource adequacy capacity sold from energy storage resources while simultaneously working to undermine the intent of resource adequacy capacity by limiting its availability."

The ISO will move the discussion to ESDER 3 with the goal to further clarify and understand physical limitations and representation of costs of storage resources. For example, where the costs of operating a storage resource increase due to increased depth and frequency of cycling, the discussion should not be based on contractual warranty but could be better reflected as an explicit cost in the market optimization as a cost per cycle or cost per MWh.

While this may be a longer-term solution to implement, in the near term, the ISO would stress that these costs and limitations can be reflected in energy bids today to limit use in the ISO market at times when participating may increase degradation or void contractual requirements.

Several stakeholders re-emphasized the need for a less than 24x7 settlement to allow for multi-use applications of resources modeled as NGR. As CESA commented, "the concept of 'less than 24 hour a day metering for NGR resources' is a priority and should be in scope…this functionality is key to NGR resources acting in MUAs, including in potential transmission applications which may be related to Aliso Canyon solutions."

As stated in the ESDER 2 Third Revised Straw Proposal, the ISO continues to work with the CPUC to develop policy on this topic. Please refer to the MUA section of this paper for further information.

Stakeholders continue to support allowing NGR resources to be qualified for Use Limited Status. The ISO is open to consideration of use-limed status for NGR resources provided the basis of the use-limitation is consistent with those of other generation resources and complies with the use limited definition in the CCE3 Stakeholder Initiative. Use-limited status could exempt resources with resource adequacy capacity from RAAIM penalties when the use limitations are exhausted. This topic will move to ESDER 3 for further development.

6.2.3 Draft Final Proposal

After reviewing all stakeholder feedback, and in particular the comments from the Department of Market monitoring, the topic of modeling daily cumulative MWh charge and discharge limits based on bid parameters for the purpose of managing economic based limitations will no longer be carried forward to ESDER 3. However, the ISO will continue the topic of reflecting costs and modeling physical limitations for NGRs in ESDER 3.

Several stakeholder provided feedback on additional enhancements they would like to see for NGRs. Suggested enhancement include:

- Tools to restrict over-utilization or frequent cycling due to the fast ramping in excess of warranty rules.
- A 'cycling limit' that may be calculated similar to the calculation of 'mileage' in pay for performance regulation to represent mileage costs.
- The ability for SCs to provide multiple bid stacks for optimization by the ISO based on the resource's state of charge.
- The ability for SCs to provide hourly throughput or mileage limitations
- The ability to provide multi-point or multi-segment Ancillary Service bids, suggesting allowing a NGR to bid higher costs if all of its available capacity is used for AS and greater control of SOC.
- An ability to include a bid cost similar to the use of Variable O&M to allow resources to price maintenance and warranty costs into their bids based on SOC.
- Enhancements to address 'regulation dispatch divergence from RTD price signals'

As stated in the previous section, the ISO is not in support of establishing MWh throughput limitations based on economic factors such as warranty or performance guarantees. The ISO does support understanding how to reflect limitations as explicit costs based on NGR operation, which can be optimized in the ISO market. This includes an ability to reflect maintenance costs and other operational costs as a function of participation. As stated above, this discussion will move forward in ESDER 3.

The topic of providing multiple bid stacks to better optimize a resource based on SOC had been addressed in the ESDER 2 paper. This enhancement was discussed earlier as a potential approach to better optimize batteries that incurred reduced MW throughput at high and low states of charge. It is the ISO's understanding that these specific SOC based MW throughput limitations are, for the most part, removed by the battery manufacturer and battery management and control systems.

The proposed ideas for SCs to provide multi-point or multi-segment AS bids is a topic the ISO supports for further discussion in ESDER 3.

Comments from Alta-Gas – Pomona Energy Storage highlighted an enhancement to address a perceived issue of a 'Regulation Dispatch Divergence from RTD price signals'. They observed several instances where Regulation Down was called during intervals of high LMP. It should be noted that AGC is based on area control error, not on individual resource economics. In Addition, any resource participating under NGR-Regulation Energy Management signals a preference for the ISO to operate their resource at 50% SOC. This incurs increased AGC movement to maximize the ability for the resource to provide regulation capacity in the ISO market.

6.3 Multiple-Use Applications

In this section, the CAISO summarizes discussion on this topic that occurred in the second and third revised straw proposals, the written comments received from stakeholders on that discussion and the CAISO's final draft proposal.

The September 19, 2016 second revised straw proposal stated that the CAISO has not yet identified specific MUA issues or topics that require treatment in ESDER 2 and the CAISO proposes to continue its collaboration with the CPUC in this topic area through Track 2 of the CPUC's energy storage proceeding (CPUC Rulemaking 15-03-011).

Since publication of the April 17, 2017 third revised straw proposal, no issues have been identified that needed to be addressed within ESDER 2, and therefore the CAISO has not amended the scope developed since the last proposal publication.

6.3.1 Stakeholder Comments to Second Revised Straw Proposal

AMS, SolarCity and Stem - As we continue to work with the CAISO, the CPUC and utilities in resolving MUA-related issues, it is important to set the market participation rules and incentives, as well as the performance requirements for specific grid services needed to allow energy storage providers to optimize their technologies and operational characteristics. Stacking the values associated with multiple uses increases the resource value and economic viability of energy storage systems, while improving wholesale market efficiency and reducing costs to the electric grid. With this in mind, AMS, SolarCity and Stem support the CAISO's continued collaboration with the California

Public Utilities Commission in Rulemaking 15-03-011 to develop appropriate standards and guidance for MUAs. MUAs reflect DER owners offering a combination of the thirteen value streams identified by the Rock Mountain Institute to the three identified stakeholders: the ISO, UDC and end-use customers.

CLECA – CLECA supports the current CAISO approach.

PG&E - PG&E supports the approach the CAISO outlines in the straw proposal. There are no new MUA-related issues that need to be addressed at this juncture, although issues will likely arise as the Energy Storage OIR (R.15-03-011), Track 2 unfolds. Furthermore, PG&E commends the CAISO, stakeholders and working groups for recognizing and addressing potential issues that arise with MUA, including the mutual exclusivity of energy and capacity, and the issue of selling the same energy twice. PG&E echoes its previous comments and adds that energy stored for later retail usage should always have a retail rate for charging, compensation should not occur if an action would have otherwise been taken, and that a resource should not be paid twice inadvertently for the same service. The CAISO has been following these principles thus far in the PDR enhancements; a great example of these principles applied to PDR is the clarification that retail rates apply to an end customer for load consumed even when this load is bid into a PDR Load1 Consumption product. PG&E looks forward to working with the CAISO and the CPUC to further develop guiding principles and eventually develop rules for MUA storage.

SCE - SCE agrees that the CPUC's energy storage proceeding is the correct place to address multiple-use applications at this time. SCE is particularly interested in the CPUC and the CAISO developing rules for resources that provide both distribution reliability and resource adequacy.

SDG&E - SDG&E believes the CAISO needs to address the MUA in the context of Energy Storage Phase 2.

6.3.1 Stakeholder Comments to Third Revised Straw Proposal and CAISO Response

Comments received after discussion on the third revised straw proposal continue to support the CAISO's collaborative efforts with the CPUC and continuation of these efforts for establishment of multi-use application (MUA) development in the R.15-03-011 proceedings. Additionally, comments suggest that there be consideration of the inclusion of MUA topics within ESDER 3 scoping to "fully enable DERs to participate in wholesale markets at the CAISO" [34] while other comments request assurance when topics are included that "concerns about double-counting and/or double-compensation" are addressed[35].

The CAISO appreciates the comments received and believes that they continue to support the current approach and joint regulatory activities underway to address multi-use application development.

6.3.2 Draft Final Proposal

At this time, the CAISO proposes to continue its collaborative efforts with the CPUC in the context of the CPUC's energy storage track 2 proceeding, and not to pursue an ISO initiative on MUAs unless and until the collaborative efforts identify an issue that would be most appropriately addressed in a CAISO initiative.

CAISO and CPUC staff finalized the "Joint Workshop Report and Framework – Multiple-Use Applications for Energy Storage", issued on May 17, 2017[36], summarizing the efforts on MUA thus far and providing a framework for addressing the issues identified. Following the release of the report, the CPUC and CAISO jointly hosted a workshop on June 2, 2017 to discuss the report and invited a round of written comments on the report and the workshop. The CAISO expects to continue working with CPUC staff to resolve the remaining issues as far as possible. If these activities identify issues that need addressing in a CAISO initiative, the CAISO will include them in the scope of ESDER 3 when that effort begins in September 2017.

The CAISO requests stakeholders to provide comments to the CAISO/CPUC joint workshop to best inform the scoping efforts for ESDER 3.

7 ESDER Phase 3

The CAISO is planning to continue the ESDER initiative in ESDER 3, which will continue to refine and address enhancements to DR, NGR and MUA. Specifically, the CAISO will continue to address:

[34] See Tesla comments on ESDER Phase 3 items, at p. 5.

[35] See IEP comments on ESDER Phase 3 items, at p. 5.

[36] Joint workshop material available through ESDER2 initiative webpage http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=BC43DF40-778E-4AC7-B266-2A52281B8E68 .

- The development, if feasible, of a load consumption product for DR resources and participation in the regulation market;
- Defined rules for storage modeled as NGR to qualify as a use-limited resource;
- Reflecting costs and modeling of physical limitations of storage as NGR; and
- Any issues identified in the Track 2 of the CPUC's energy storage proceeding (CPUC Rulemaking 15-03-011) on MUA.

The CAISO appreciates all of the topics suggested by stakeholders. The CAISO is planning to release an issue paper in September 2017 that will address all potential scope items mentioned above along with stakeholder suggested topics for the ESDER 3 initiative.

Appendix A Control Group Baseline Process and Rules

The following table summarizes the control group process and rules. The process and baseline rules are identical for residential and non-residential customers and for weekdays and weekends.

Component	Explanation
Baseline process	1. Determine the method for developing the control group 2. Identify the control group customers 3. Narrow data to hours and days required for validation checks (see validation options) 4. Calculate average customer loads for each hour of each day 5. Drop CAISO event days and utility program event days for programs the resource or control customers participate in. 6. Validate on the schedule described in 'Validation Options' below. Conduct validation checks and ensure all of the following requirements are met for: a. Sufficient sample size – 150 customer or more b. Lack of bias - see Section 6 c. Precision – see Section 6 7. Submit information about which sites designated as a control group and which sites will be dispatched to CAISO in advance. 8. Submit the validation checks to CAISO. 9. For event days: a. Calculate the control group average customer load for each hour of event day b. Calculate the dispatch group average customer load for each hour of the event day c. Subtract the control group load (a) from the treatment group load (b) for each hour of the event day. The difference is the change in energy use for the average customer attributable to the event response, known as the load impact. d. Multiply the load impact for each hour by the number of customers controlled or dispatched. 10. Submit summary results to CAISO and store code, analysis datasets, and results datasets. 11. Update control group validation for changes in the resource customer mix of more than +/-10% or to remain compliant with seasonal or rolling window validation requirements.
Event period	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.
Method for control group development	List the method used to develop the control group – random assignment of site, random assigned of clusters, matched control group, or other. For random assignment, please retain the randomization code and set a random number generator seed value.
Replication and Audit	Control group equivalence and event days calculation are subject to audit. The results must be reproducible. The underlying customer level data, randomization files, and validation code, and event day analysis code must be retained for 3 years and be made available the CAISO within 10 business days of a request. In the case where the California ISO deems it necessary, DRPs will be required to securely provide the control and treatment group's interval data to recreate the bias regression coefficient and CVRMSE to ensure they meet the criteria
Validation options	Validation is performed by the DRP and subject to audit by CAISO. The validation method uses 75-day lookback period with a 30-day buffer. Validation is required as described in note e, below. The 75 days selected for

Component	Explanation
	validation should be chosen such that the validation is complete prior to finalizing the control group to act as the designated baseline method for that resource. a. 30 days used to collect and validate the groups b. Prior 45 days used for the validation (t-31 to t-75) c. Candidate validation days used to establish control group similarity are either non-event weekdays (if the resource is dispatched only on weekdays) or all non-event days (if the resource can be dispatched on any day) d. A minimum of 20 candidate days are required to be in the validation period. If there are not 20 non-event validation days, extend the validation period backwards (t-76 and further) until there are 20 candidate days in the validation period. e. Requires validation check updates every other month if the number of accounts in the resource does not change more than ± 10%. If the number of accounts changes by more than ± 10%, the control group must be validated monthly. f. If the validation fails, the control group method is unavailable for that resource unless the control group is updated and revalidated. Control groups may be updated monthly. g. 90% of the population must be in both the validation period and the active period
Aggregation of Control Groups across Sub Load Aggregation Points (subLAPs)	Aggregation of control groups is permissible across different subLAPs; however the same performance on intra-subLAP equivalence checks must be demonstrated. While sourcing a control group from a region with similar weather and customer mix conditions is not explicitly mandated, considerations for these attributes that affect load may help in developing an appropriate control group.
Rotation of control groups	The assignment to treatment and control groups can be updated on a monthly basis; however this assignment must be completed prior to any events. Validation of new control groups must also be completed prior to any events in concurrence with any new control group development. The assignment cannot be changed once set for the month and cannot be changed after the fact

Appendix B Weather Matching Baseline Process and Rules

The following tables summarize the weather matching rules separated between residential/non-residential and weekday/weekend.

B.1 Residential

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an event 2. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 3. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 4. Select the baseline days out of the pool of eligible days 5. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 6. Calculate the same-day adjustment ratio based on the adjustment period hours. 7. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 8. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 9. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	1. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 2. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 3. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. Adjustment ratio=(Total kWh during adjustment hours)/(Unadjusted baseline kWh over adjustment hours)	

Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline

B.2 Non-Residential

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature
Baseline calculation process	10. Identifying eligible baseline days that occurred prior to an event 11. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 12. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 13. Select the baseline days out of the pool of eligible days 14. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 15. Calculate the same-day adjustment ratio based on the adjustment period hours. 16. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 17. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 18. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	4. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 5. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 6. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	

Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. Adjustment ratio=(Total kWh during adjustment hours)/(Unadjusted baseline kWh over adjustment hours)
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline

Appendix C Day Matching Baseline Process and Rules

The following tables summarize the Day matching process and rules separated between residential/non-residential and weekday/weekend.

C.1 Residential

	Weekday Baseline Highest 5 of 10	Weekend Baseline Highest 3 of 5 weighted
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an event 2. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day 3. Calculate total MWh during the event period for each eligible baseline day 4. Rank the baseline days from largest to smallest based on MWh consumed over the event period 5. Select the baseline days out of the pool of eligible days 6. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate. 7. Calculate the same-day adjustment ratio based on the adjustment period hours. 8. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 9. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 10. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.	
Eligible baseline days	10 weekdays immediately prior to event, excluding event days and federal holidays	5 weekend days, including federal holidays, immediately prior to the event
Baseline day selection criteria	Rank days for largest to smallest based on MWh over the event period, pick the top 5 days	Rank days for largest to smallest based on MWh over the event period, pick the top 3 days
Application of weights (if needed)	Not applicable	1. 50% - Highest load day 2. 30% - 2nd Highest load day 3. 20% - 3rd Highest load day
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The weighted hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. **Adjustment ratio=(Total kWh during adjustment hours)/(Unadjusted baseline kWh over adjustment hours)**	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	Cap the ratio between +/- 2x. If the ratio is larger than 2.0, limit it to 2.0. If the ratio is less than 1/2 = 0.50, limit it to 0.50
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

C.2 Non-Residential

	Weekday Baseline Highest 10 of 10	Weekend Baseline Highest 4 of 4
Baseline calculation process	11. Identifying eligible baseline days that occurred prior to an event 12. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day 13. Calculate total MWh during the event period for each eligible baseline day 14. Rank the baseline days from largest to smallest based on MWh consumed over the event period 15. Select the baseline days out of the pool of eligible days 16. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate. 17. Calculate the same-day adjustment ratio based on the adjustment period hours. 18. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 19. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 20. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.	
Eligible baseline days	10 weekdays immediately prior to event, excluding event days and federal holidays	4 weekend days, including federal holidays, immediately prior to the event
Baseline day selection criteria	Keep all 10 eligible days	Keep all 4 eligible days
Application of weights (if needed)	Not applicable	Not applicable
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The weighted hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. Adjustment ratio=(Total kWh during adjustment hours)/(Unadjusted baseline kWh over adjustment hours)	
Adjustment Limit	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

Attachment D – Board Memoranda

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: July 19, 2017

Re: **Decision on the energy storage and distributed energy resources phase 2 (ESDER 2) proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management continues its efforts to lower barriers and enhance the ability of distributed energy resources and transmission grid-connected energy storage to participate in the ISO market through this second phase of the energy storage and distributed energy resources (ESDER) initiative.

ESDER is an on-going omnibus initiative that covers distinct topics related to demand response, non-generator resources, storage resources, and distributed energy resource (DER) multi-use applications. The current second phase of this initiative (ESDER2) addressed multiple topics. Management proposes the following three items for Board approval:

1) Provide three new types of demand response performance evaluation methods. (decision)
2) Clarification of station power treatment for storage resources. (decision)
3) Incorporating additional gas indices into the net benefits test calculation to reflect all real-time participation regions. (Approved by the EIM Governing Body, and on the Board's July 26, 2017 consent agenda)

The first of ESDER 2's three proposals enhances the proxy demand resource (PDR) and reliability demand response resource (RDRR) market participation models by providing demand response providers with three additional types of performance evaluation methods to best reflect the performance of different types and configurations of demand response. Currently, the tariff only provides a day-matching customer load baseline performance evaluation methodology, which must cover all demand response configurations from industrial to residential. Stakeholders have voiced repeatedly that this one day-matching baseline methodology is not robust enough to accurately assess the performance of all demand types and configurations. To remedy this, Management proposes to offer three new classes of baseline performance evaluation methodologies including a control group methodology, a weather matching methodology, and an additional day-matching methodology baselines applicable to retail customer segments. The EIM governing body, at its July 13 meeting, voted to provide an advisory opinion in support of this proposal.

The second of ESDER 2's three proposals provides regulatory certainty for storage resources regarding station power, which is the retail energy used onsite to produce energy. Stakeholders were concerned that the ISO tariff and retail tariffs could define wholesale charging functions and retail station power functions differently, which would lead to conflicting rules and settlements. Because the question of what constitutes station power is in the retail jurisdiction, Management determined its station power proposal should simplify the ISO's station power tariff definition and defer to the station power rules as applied by the relevant local regulatory authority. The ISO will incorporate wholesale charging examples in the ISO Business Practice Manual and will ensure the storage resource developer attests to complying with the relevant local regulatory authority's station power requirements within the ISO's new resource implementation process. The EIM governing body, at its July 13 meeting, voted to provide an advisory opinion in support of this proposal.

The third of ESDER 2's three proposals addresses the net benefits test. The ISO calculates a net benefits test price threshold to indicate when a decrease in demand from demand response provides a net benefit to all purchasers in terms of a wholesale market price reduction. The net benefits test price threshold is used by the ISO to determine when an adjustment is required to the settlement of the load serving entity who procured the load the demand response resource curtailed.

Every month, the ISO estimates the price at which the net benefit is triggered. Management's proposal in ESDER 2 simply removes existing tariff language that ties certain gas price indices to the derivation of the net benefits test price threshold. Management proposes to incorporate *all* relevant gas price indices used to derive the net benefits test price threshold into the ISO's Business Practice Manual for Market Instruments. The reason for this requested change is as new Energy Imbalance Market participants are added to the real-time market, the net benefits test price threshold calculation should incorporate a greater number of gas price indices to reflect participation that occurs across the expanded real-time market footprint. Adding additional gas price indices through the business practice manual process versus through subsequent and repeated tariff amendments each time a new participant joins the ISO provides the flexibility needed to easily add new gas price indices used to calculate the net benefits test price threshold. This third proposal of ESDER 2 has been approved by the EIM Governing body at its July 13 meeting, as an exercise of its primary authority, and is thus on the ISO Board's July 26 consent agenda.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the* energy storage and distributed energy resources phase 2 *proposal, as described in the memorandum dated July 19, 2017; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

Below is an overview of the three proposals prepared by Management under the second phase of the ESDER initiative:

1) Proposed baseline methodology enhancements for PDRs and RDRRs

Currently, the ISO uses a day-matching customer load baseline performance evaluation method. The method consists of a "10-in-10" customer load baseline where the ISO evaluates each hour during the past 10 similar days to establish an average performance baseline. PDRs and RDRRs are then settled based on responses to dispatch above their baselines. While research has shown this day-matching baseline to be accurate for many medium and large commercial/industrial customers, research has also shown that this baseline may not perfectly capture the performance of smaller resources. A stakeholder-led Baseline Alternative Working Group (BAWG) was established within the ESDER2 initiative to identify additional performance evaluation methodology options.

The BAWG analyzed and proposed the three types of customer load baseline methodologies summarized below.

- Control Groups: Evaluates the energy consumption of a set of similar, but non-participating customers. The control group establishes the baseline of what load patterns would have been, absent the dispatch.

- Day Matching: Estimates what electricity use would have been in the absence of a dispatch, relying exclusively on the electricity-use data from the dispatched customers. The load patterns during a subset of non-event days are used to estimate the baseline for the dispatch day.

- Weather Matching: The load patterns with the most similar weather conditions during a subset of non-event days are used to estimate the baseline for the dispatch day.

For greater flexibility and timely baseline implementation, Management is proposing to have all baseline calculations, including the current 10-in-10 customer load baseline, performed and submitted by the resources' scheduling coordinators (SCs). Shifting this responsibility to the SC accelerates the needed retirement of the legacy system currently calculating baselines, and it gives the SC access to the ISO's Market Results Interface-Settlements ("MRI-S") system to submit, view, export and upload data in batch files. The ISO believes this change will provide a more consistent and flexible approach to performance calculation management and data processing for demand response resource participation. To ensure the accurate development and submission of performance evaluation results, the ISO will leverage auditing provisions including the bi-annual SC self-audit and, on an as-needed basis, selective auditing by ISO staff.

2) Clarification of station power treatment for storage resources

Through the ESDER2 initiative, Management has worked toward resolving potential issues in distinguishing between wholesale charging energy and retail station power. In joint stakeholder workshops, the topic was examined in collaboration with the CPUC as part of the CPUC's energy storage proceeding (CPUC Rulemaking 15-03-011) and within ESDER 2. This joint CPUC-ISO effort recognized that re-defining station power from a wholesale perspective could be counter-productive if the CPUC makes different station power determinations from a retail perspective. The ISO's current station power tariff definition is prescriptive and lengthy and includes details specific to generation units that may not be relevant or exclude elements of station power for storage resources. But station power is inherently a retail issue, and therefore not defined by the ISO tariff or FERC. As such, the ISO's efforts to mirror retail rules in its wholesale tariff is imprudent and impractical. Therefore, Management proposes that the ISO's tariff be made consistent with retail tariffs by expressly deferring to the local regulatory authority on what constitutes station power.

This still leaves the question of how to separately account and settle for wholesale charging energy and retail station power, so Management also proposes to include a rule in the ISO's metering provisions stating that resources will ensure that they work with their retail energy provider (likely during interconnection) to ensure compliance with their local regulatory authority on this issue. Management views this as a prudent compliance measure because the retail energy provider is the entity incentivized and responsible for ensuring that its customers are not avoiding retail charges.

3) Proposal to incorporate additional gas indices into the net benefits test calculation and move gas indices from the tariff to Business Practice Manual

The demand response net benefits test was established by FERC in Order No. 745. It requires ISOs and RTOs to pay demand response resources the full locational marginal price, as if they were generating resources, without any offset or reduction to reflect avoided fuel costs. When the system price of energy exceeds a certain price threshold, FERC ruled the decrease in demand from demand response energy reductions provides a net benefit, i.e. a lower cost to all purchasers in the wholesale market.

The net benefits test price threshold is used by the ISO to determine when an adjustment is required to the settlement of the load serving entity who procured the load the demand response resource curtailed. If a demand response resource's energy reduction occurs when the market clearing price is below the calculated net benefits test price threshold, then that load reduction is deemed not net beneficial to the market. When this occurs, the load-serving entity's uninstructed imbalance energy quantity is adjusted in settlements to avoid a non-beneficial settlement outcome. There is no adjustment to a load-serving entity's settlement when a demand response resource's energy reduction is paid at a price above the net benefits test price threshold since that energy reduction and the resulting settlement outcome is deemed net beneficial to the system.

The net benefits test price threshold is calculated each month by taking the aggregate supply curve from the same month of the previous year, adjusting the curve using updated fuel prices, and then calculating the price threshold where demand response net benefits occur. The existing tariff explicitly states that fuel prices used to update the monthly net benefits test price threshold are determined by using a simple average of the PG&E Citygate price and the Southern California Edison Company Citygate price.

Management and the Department of Market Monitoring ("DMM") identified a gap in the existing formulation of the net benefits test price threshold. The existing net benefits test price threshold is derived using only California-specific gas price indices, yet the real-time market has expanded beyond California. Management is therefore proposing to expand the gas price indices available for use in the calculation of the net benefits test price threshold to represent gas prices relevant to all real-time market bids. Management also is proposing to remove existing tariff language that ties specific gas price indices to the derivation of the net benefits test price threshold and, instead, incorporate all relevant gas price indices used into the ISO's Business Practice Manual for Market Instruments. Moving the gas price indices out of the tariff and into the business practice manual provides the ISO the flexibility needed to easily add new gas price indices to the net benefits test price threshold calculation as new participants join the energy imbalance market or the ISO. The EIM Governing body, exercising its primary authority at its July 13 meeting, approved this proposal for inclusion on the Board's July 26 consent agenda.

POSITIONS OF THE PARTIES

Stakeholder comments were generally supportive of ESDER 2's three proposals. Management addresses stakeholder comments in Attachment A.

CONCLUSION

Management requests the Board approve its proposals for the provision of three new types of demand response performance evaluation methods and to clarify station power treatment for storage resources. Management's first two proposals in ESDER 2 are presented for Board approval, with the EIM Governing Body's support in the form of an advisory opinion. Management's third ESDER 2 proposal, incorporating additional gas indices into the net benefits test calculation to reflect all real-time participation regions, was approved by the EIM Governing Body under its primary authority and is included on the Board's consent agenda.

Attachment E – Nexant: Baseline Accuracy Work Group Proposal

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

DRAFT

Reimagine tomorrow.

California ISO

Baseline Accuracy Work Group Proposal

April 4, 2017

Figures

Tables

1 Introduction

Currently, the proxy demand resource (PDR) and reliability demand response resource (RDRR) use a 10 of 10 baseline with a 20% same day adjustment to estimate the load impact achieved by the resource. While research has shown this baseline to be accurate for many medium and large commercial and industrial customers, research has also shown that this baseline is not accurate for all customer types. The purpose of the Baseline Analysis Working group (BAWG) is to identify additional settlement methods which, when offered in addition to the 10 of 10 baseline, will enable the load impacts from a wider variety of demand response resources to be accurately estimated.

The BAWG identified three major areas of research.

- The use of alternative traditional baseline methods to estimate the load impact of current demand response resources.
- The option of using control groups rather than traditional baselines to estimate the load impacts of demand response resources.
- Ways to accurately measure load impacts of resources that are frequently dispatched.

1.1 Traditional baselines methodologies for current demand response resources

The research objective has been to identify additional traditional baselines which accurately estimate the load impacts of existing demand response resources that are not accurately estimated by the current CAISO-approved 10 of 10 baseline. Research has shown that the 10 of 10 baseline underestimates the load impact from residential customers, so identifying baselines for residential customers was an important task. In order to address this issue, analysis was done using data from the air-conditioning cycling programs of all three utilities. The analysis estimated the effectiveness of the current 10 of 10 baseline and tested the effectiveness of alternative baseline methodologies. In addition, the effectiveness of the 10 of 10 baseline on estimating the load impacts of reliability programs such as the Base Interruptible Program (BIP), Agricultural Pump Interruptible Program and small commercial AC load control has not been rigorously tested and these customers currently do not rely on a 10 of 10 baseline for their retail compensation.

The working group also addressed the issue of how to determine which baseline should be applied to which resources. Offering more than one baseline option raises the issue of whether or not all baseline options should be available to all customer types. For example, if a particular baseline is more accurate for residential customers than it is for commercial customers, the baseline might only be made available to resources consisting of residential customers. The working group also identified other operational barriers that may arise due to offering more than one baseline option. Ultimately, the working group recommended one day matching, one weather matching, and one control group option for both residential and non-residential customers for both weekdays and weekends. This provides flexibility for DRPs to rely on the baseline that is the most accurate for their population while ensuring that the number of baselines available does not proliferate.

1.2 Control Groups

Control groups provide an alternative to traditional baseline methodologies for the estimate of load impacts. Control group methodologies use the energy use of a group of customers who do not participate in the demand response event to compare to that of those who do. There are two main types of control groups: 1) a randomized controlled trial (RCT) and, 2) a matched control group. In the RCT a subset of participants is randomly selected in advance and withheld from curtailment during the event period. A matched control group consists of non-participants with similar characteristics to participants. The working group studied control group settlement methodologies already in use by other independent system operators and determined if they can be implemented by the CAISO. Questions that were addressed in this area include:

1. What requirements would need to be put in place to ensure the energy use of the control group accurately reflects the energy use of the treatment group?
2. What requirements regarding samples sizes or precision should be established?
3. How will the control groups be identified operationally?
4. Is it feasible to allow control groups to vary by events/rotate?
5. How can control group methodologies be established that work for both utilities and third party demand response providers (DRPs)?

1.3 Frequent Dispatch

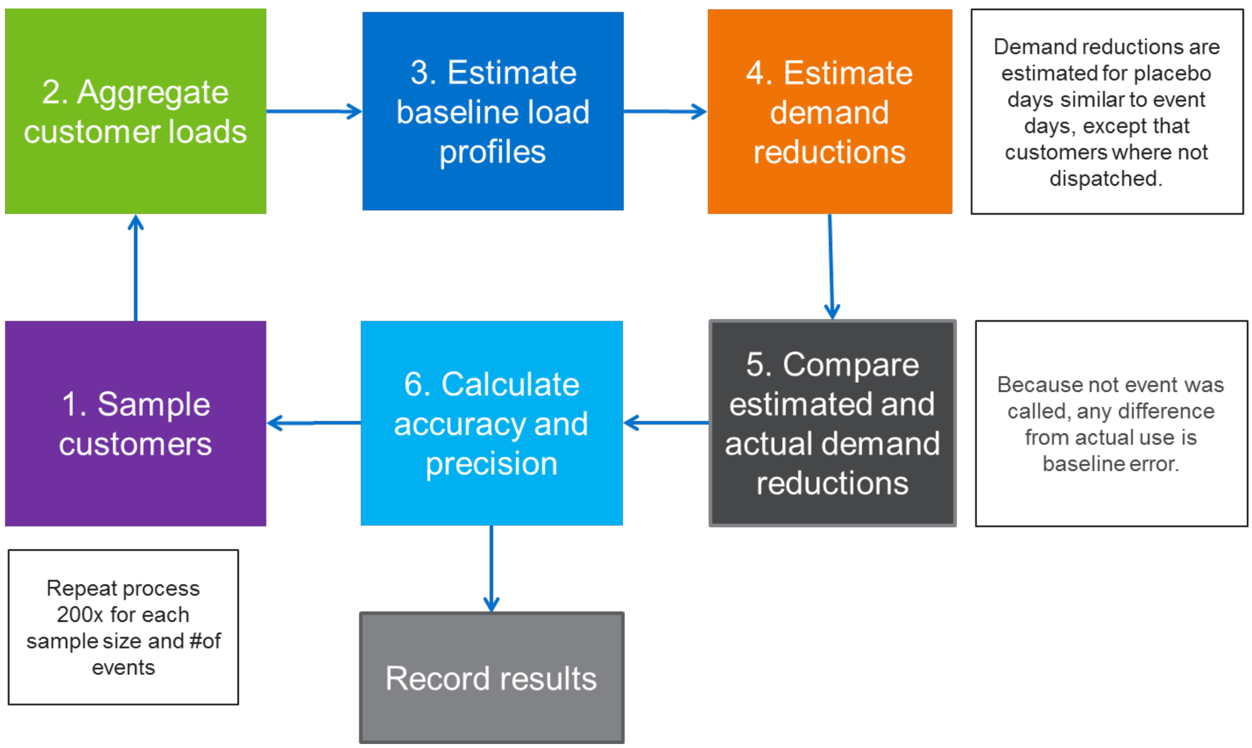
The current 10 of 10 PDR baseline methodology relies upon historical non-event day data in order to estimate a baseline. It may be challenging to find 10 previous non-event days for resources which are frequently dispatched during a period within a reasonable proximity of the event day. In particular, behind the meter storage which is not separately metered and participating in a PDR or RDRR product may participate frequently in the market. The working group explored how the load impact of frequently dispatched resources can be accurately estimated using only data from the premise. Cases in which meter generator output is available and used for settlement will be considered out of the scope of this working group because it has been addressed in the ESDER Phase 1 initiative. Research was conducted to examine how many days are necessary to establish an accurate baseline.

2 Assessing Baseline Accuracy

To assess the accuracy of the estimated values, one needs to know the correct values. When the correct answers are known, it is possible to assess if each alternative settlement option correctly measures the demand reduction and, if not, by how much it deviates from the known values. Figure 2-1 summarizes the approach for assessing accuracy and precision. The basic approach is used to address all three primary areas of research.

The objective is to test different baselines with different samples of participants using actual data from participants in order to identify the most accurate analysis method. Baseline accuracy is assessed on placebo days, which are treated as event days. Because no event was called, any deviation between the baseline and actual loads is due to error.

Figure 2-1: Method for Testing Baseline Accuracy



The process is repeated hundreds of times, using slightly different samples – a procedure known as bootstrapping – to construct the distribution of baseline errors. In addition, the accuracy of the baselines is tested at granular geographic levels, such as subLAPs, to mimic market settlement. A key question is the degree to which more or less aggregation influences the accuracy and precision of the estimates. This is assessed by repeating the below process using different subsets of customers so the relationship between the amount of aggregation and baseline accuracy is quantified. Another important question is how high frequency dispatch, which limits baseline days, affects baseline accuracy. This is assessed by repeating the same process described below for different number of event days per year, thus producing a plot of accuracy and precision as a function of the number of events.

2.1 Metrics of Identifying Suitable Baselines

For both the accuracy of the baseline and the demand reduction, the BAWG identified the best baselines as those that are both accurate and precise. The figure below illustrates the difference between accuracy and precision. An ideal model is both accurate and precise (example #1). Baselines can be accurate but imprecise when errors are large but cancel each other out (#2). They can also exhibit false precision when the results are very similar for individual events but are biased (#3). The worst baselines are both imprecise and inaccurate, i.e. the individual event results vary substantially and they are also biased.

Figure 2-2: Precision versus Accuracy (Lack of Bias)

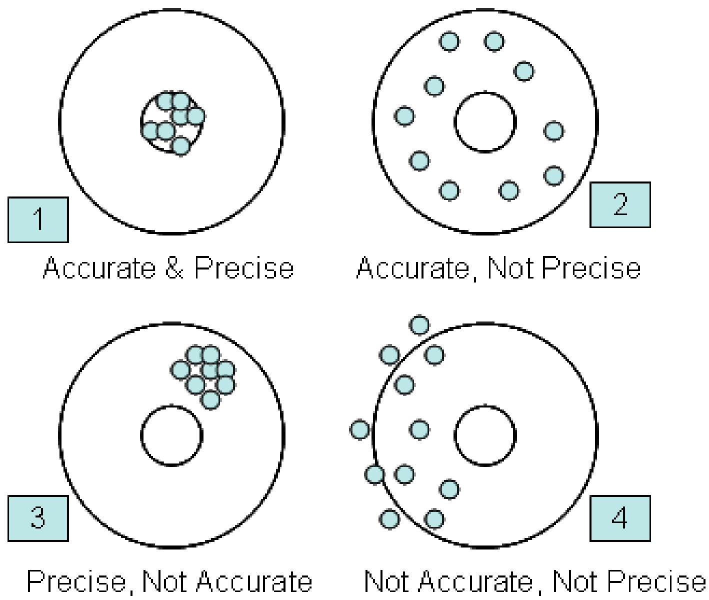


Table 2-1 summarizes metrics for accuracy (bias) and precision (goodness-of-fit) that were produced to assess the different baseline alternatives. Bias metrics measure the tendency of different approaches to over or under predict (accuracy or lack of bias) and are measured over multiple days. The BAWG used the mean percent error since it describes the relative magnitude and direction of the bias. A negative value indicates a tendency to under-predict and a positive value indicates a tendency to over-predict. This tendency is best measured using multiple days. Baselines that exhibit substantial bias were eliminated from consideration.

Precision metrics describe the magnitude of errors for individual events days and are always positive. The closer they are to zero, the more precise the results. The primary metric for precision was CVRMSE, or normalized root mean squared error. Among baselines which exhibit little or no bias, more precise metrics will be favored. Last, but not least, multiple baselines can prove to be both relatively accurate and precise. In which case, the BAWG has submitted its recommendation based on practical considerations such ease of implementation or potential for gaming.

Table 2-1: Accuracy and Precision Metrics Used to Identify Best Performing Baselines

Type of Metric	Metric	Description	Mathematical Expression
Accuracy (Bias)	Mean Percent Error (MPE)	Indicates the percentage by which the measurement, on average, over or underestimates the true demand reduction.	$MPE = \frac{\frac{1}{n}\sum_{i=1}^{n}(\hat{y}_i - y_i)}{\bar{y}}$
Precision (Goodness-of-Fit)	Mean Absolute Percentage Error (MAPE)	Measures the relative magnitude of errors across event days, regardless of positive or negative direction.	$MAPE = \frac{1}{n}\sum_{i=1}^{n}\left\lvert\frac{\hat{y}_i - y_i}{y_i}\right\rvert$
	CV(RMSE)	This metric normalizes the RMSE by dividing it by the average of the actual demand reduction.	$CV(RMSE) = \frac{RMSE}{\bar{y}}$

2.2 Baselines Included for Testing

There are a variety of approaches for measuring the magnitude of demand reduction with different degrees of complexity, data sources, and metering requirements. In addition, each method can be varied based on differences in the number of eligible days used to develop baselines, the type of days used to develop baselines, caps on the magnitude of adjustments, use of different sample sizes, and the granularity of estimates. At a high level, however, the settlement methods under consideration by the BAWG can be classified under three broad categories:

- Control Groups — An ideal control group has nearly identical load patterns in aggregate and experiences the same weather patterns and conditions. The only difference is that on some days, one group has loads curtailed while the control group does not. The control group is used to establish the baseline of what load patterns would have been absent the curtailment event. This approach is the primary method for settlement of residential AC cycling and thermostat programs by Texas' system operator, ERCOT. There are three basis ways to establish control valid control groups: random assignment of customers; random assignment of clusters (for one-way devices that are not directly addressable) and matching.

- Day Matching — Day-matching baselines estimate what electricity use would have been in the absence of curtailment by relying on electricity use in the days leading up to the event. It does not include information from a control group. A subset of non-event days in close proximity to the event day are identified and averaged to produce baselines. A total of 13 day matching baselines are being tested.

- Weather Matching — The process for weather matching baselines is similar to day-matching except that the baseline load profile is selected from non-event days with similar temperature conditions and then calibrated with an in-day adjustment. In general, weather matching tends to include a wider range of eligible baseline days, which are narrowed to the ones with weather conditions closest to those observed during events. A total of 7 weather matching baselines are being tested.

2.2.1 Baselines methods tested

Tables 2-2 and 2-3 provide additional details about the baselines tested. These baselines were identified by reviewing the best performing baselines for past studies, inside and outside of California, for residential, industrial, and commercial loads. For each baseline, a number of baseline rules were tested for using existing customers in the BIP, Agricultural pumping, residential air conditioner, and commercial air conditioner customers. These include rules include various combinations of baseline adjustment hours, adjustments caps and, when possible, assessment of accuracy and precision for actual event days (if large control groups were available) and for non-event days when net CAISO loads were high – proxy event days where the actual loads in the absence of demand response were known.

Table 2-2: Baselines Tested and Compared: Weekday

Control group	Day Matching	Weather Matching
1. Comparison of means	2. Average 3 of last 3 eligible days 3. Use 3 of last 3 eligible days; more recent days receive higher weight 4. Average the top 3 of the last 5 eligible days 5. Use top 3 of the last 5 eligible days; more recent days receive higher weight 6. Average 3 of last 5 eligible days and adjust upward by 5% for all customers 7. Average top 4 of the last 5 eligible days 8. Average top 5 of the last 5 eligible days 9. Average top 3 of the last 10 eligible days 10. Average top 5 of the last 10 eligible days 11. Average 10 of the last 10 eligible days 12. Average top 3 of the last 20 eligible days 13. Average top 5 of the last 20 eligible days 14. Average top 10 of the last 20 eligible days	15. Average 3 days with most similar weather during the last three months 16. Average 4 days with most similar weather during the last three months 17. Average 5 days with similar weather during the last three months 18. Assign days with high temperatures exceeding 80°F to 3 bins based on maximum temperature; baseline equals the average peak-period load on non-event days in a similar bin 19. Assign days with high temperatures exceeding 80°F to 3 bins based on CDD for the day; baseline equals the average peak-period load on non-event days in a similar bin 20. Assign days with high temperatures exceeding 80F to 3 bins based on the total CDH for the day; baseline equals the average peak-period load on non-event days in a similar bin

Table 2-3: Baselines Tested and Compared: Weekend

Control Group	Day Matching	Weather Matching
▪ Comparison of means	▪ 1/1 ▪ 1/2, 2/2 ▪ 1/3, 2/3, 3/3, 3/3 weighted ▪ 1/4, 2/4, 3/4, 4/4, ▪ 1/5, 2/5, 3/5, 3/5 weighted, 4/5, 5/5	▪ Matching baselines based on: – average temperature – sumCDH – maximum temperature ▪ Match on 1-5 days out of 8 prior weekend lookback

2.2.2 Same-Day Adjustments

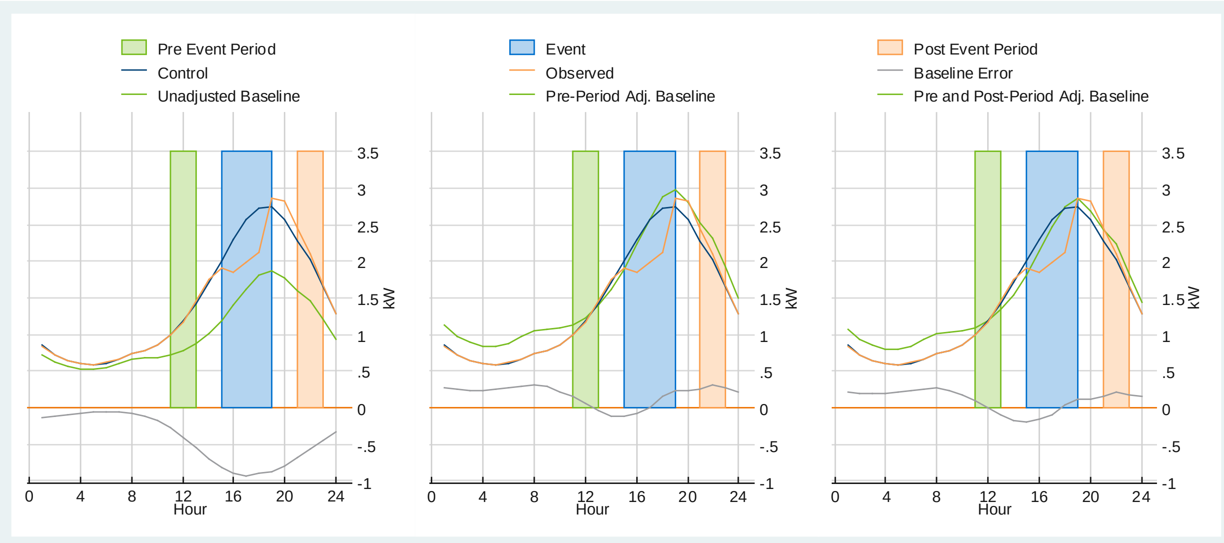
For all baseline methods, the analysis tested unadjusted baselines and the use of same-day adjustments with caps of 20%, 30%, 40%, 50%, 200%, and unlimited caps in addition to no adjustment. Same-day adjustments were tested both using pre-event data only as well as both pre- and post-event adjustments combined. Same-day adjustments calibrate the baseline to the observed non-event hours on the event day to improve precision and accuracy. Including a post-event adjustment in addition to the pre-event adjustment can scale the baseline up or down to capture additional information about the event day conditions. In both cases, the adjustments calibrate the baseline based on hours leading up to the event and after the event, with a buffer between the calibration period and the actual event.

Baseline estimates of electricity use during an event period can be adjusted up or down based on electricity use patterns during the hours leading up to an event or during both pre- and post-event hours. This procedure is known as *same-day adjustment*. If, during adjustment hours, the baseline is less than the actual load, it is adjusted upwards. Similarly, if the baseline is above the actual load in the adjustment hours, it is adjusted downwards. To adjust the load, the initial baseline value is multiplied by the ratio between the unadjusted baseline and the actual load during adjustment hours. In other words, the baseline is calibrated to match actual usage patterns in the hours leading up to the event as well as the post-event hours. In the case where both a pre- and post-event adjustment used, the calibration window includes hours both before and after the event, though the method for making the adjustment is the same. To avoid contamination of the baseline with perturbed event hours, the BAWG recommends a two-hour buffer be used for both pre- and post-event adjustments. This buffer period reduces the risk of this contamination by allowing pre-cooling and snapback to occur in the hours directly before and after the event without using those hours to adjust the baseline.

Figure 2-3 illustrates the baseline adjustment process. In the example, the event occurs from 3 PM to 6PM. With two hour buffers both before and after the event, the adjustment windows are 11AM-1PM and 8PM-10PM. The green line in each graph is the baseline, unadjusted, adjusted with the pre-event period only or adjusted with both the pre- and post-event period. The orange line is the observed load on the event day, while the black line indicates the counterfactual (modeled here by a control group). The ratio of the observed (orange) loads during the pre-event adjustment window is applied to the baseline in the center graph, while the ratio of the average observed compared to baseline loads for both the pre- and post-event periods is shown in the rightmost graph. The graph on the left shows the unadjusted result.

All the recommended baselines will have an adjustment period that includes two pre-event and two post-event hours (4 hours total), each with a two hour buffer from the event. If an event is called from 2pm to 4pm, the pre-event buffer window will be from 12am to 2pm and the post-event buffer window will be 4pm to 6pm. The pre-event buffer ensures that the adjustment window is free of any load increases that could be associated with pre-cooling, while the post-event buffer allows the increased loads associated with event snapback to diminish without contaminating the adjustment windows.

Figure 2-3: Example of Baseline Same-day Adjustment



If the difference between the unadjusted baseline and the actual load is truly due to baseline estimation error, the adjustment process reduces those errors. Same-day adjustments are often capped to reduce the variance of estimates and to limit the potential for manipulation of loads to influence baselines. To calculate a same-day adjustment once the unadjusted baseline has been calculated, the following steps are performed. A simple example that shows the mechanics of the adjustment, as well as the effect of different adjustment windows with an unlimited cap is shown in Table 2-4.

1. Calculate the average participant load in the adjustment window, factoring in the two-hour buffer. For example, if an event started at 3pm and finished at 6pm, the adjustment window would include the hours of 11am to 1pm and 8pm-10pm. Calculate the average baseline load (or control group load if using a control group) during the same window using the event baseline.

2. The ratio of participant kW during the adjustment window to that of the unadjusted baseline during that same window is the percentage adjustment.

3. Cap the ratio if using a cap. For example, if the adjustment ratio is 112% but the cap on adjustments is 10% (+/-1.1x), then the adjustment ratio will now be 110%. If no cap is being used, the adjustment ratio remains 112%. If the ratio is less than 1/1.10 = 0.91, then the adjustment cap is similarly limited to being 91%.

4. Apply the adjustment ratio to the unadjusted baseline for all hours on the event day.

5. Calculate load impacts as the difference between the adjusted baseline and the observed participant load.

Table 2-4: Adjustment Ratio Calculation

Value	Hours	No Adjustment	Pre-Event Adjustment	Pre- and Post-Event Adjustment
Pre Event Observed kW	11am-1pm	1.32		
Pre Event Unadj. Baseline kW		0.83		
Pre & Post Event Observed kW	8pm-10pm	2.28		
Pre & Post Event Baseline kW		1.54		
Ratio Calculation		None	=1.32/0.83	=(1.32 + 2.28)/(0.83+1.54)
Ratio		1.00	1.58	1.52
Event Period Observed kW	3pm-6pm	1.99		
Unadj. Baseline kW		1.51		
Event Period Baseline = (Unadj. Baseline x Ratio)		1.51	2.39	2.30

3 Baseline Recommendations

Table 3-1 shows the best performing baselines for residential and non-residential loads. Randomized control groups consistently outperformed day and weather matching baselines. With large enough sample sizes, between 200 and 400 participants, they were more than twice as precise as day or weather matching baselines. For this reason, control groups are recommended as a settlement options for both residential and non-residential customers. However, a day matching and a weather matching baseline are also options available to DRPs who may lack a sufficiently large customer base to develop a control group. The baseline option for any portfolio of resources needs to be specified for the month, in advance, and cannot be modified after the fact.

Table 3-1: Recommended Baselines for CAISO Settlement

Customer Segment	Weekday	Baselines Recommended	Adjustment Caps
Residential	Weekday	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 5/10 day matching	+/- 40%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 3/5 weighted day matching	+/- 40%
Non-residential	Weekday	Control Group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		10/10 day matching	+/- 20%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		4 eligible days immediately prior (4/4)	+/-20%

Baseline calculations require multiple steps and definition of rules. For clarity, this section presents the baseline calculation processes and rules for control groups, weather matching baselines, and day matching baselines. Appendix A provides an applied example of control group validation and an example of how the baseline is calculated with a control group. Appendix C includes an applied example of a day matching baseline (the weekend residential baseline). Appendix D provides an applied example of a weather matching baseline.

3.1 Control Group Baselines

Control groups involve using a set of customers who did not experience events to establish a baseline. A control group should be made of customers who have nearly identical load patterns and experience the same weather patterns and conditions as the resource's customers who are dispatched. During event days, the difference is that one group, known as the treatment group, experienced event dispatch while the control group did not.

Table 3-2 summarizes the control group process and rules. The process and baseline rules are identical for residential and non-residential customers and for weekdays and weekends. Section 6 includes additional discussion regarding the implementation of control group baselines. Instructions for demonstrating control group equivalence, with applied examples, are also included in the appendix to this document.

Table 3-2: Control Group Baseline Process and Rules

Component	Explanation
Baseline process	1. Determine the method for developing the control group 2. Identify the control group customers 3. Narrow data to hours and days required for validation checks (see validation options) 4. Calculate average customer loads for each hour of each day 5. Drop CAISO event days and utility program event days for programs the resource or control customers participate in. 6. Validate on the schedule described in 'Validation Options' below. Conduct validation checks and ensure all of the following requirements are met for: a. Sufficient sample size – 150 customer or more b. Lack of bias - see Section 6 c. Precision – see Section 6 7. Submit information about which sites designated as a control group and which sites will be dispatched to CAISO in advance. 8. Submit the validation checks to CAISO. 9. For event days: a. Calculate the control group average customer load for each hour of event day b. Calculate the dispatch group average customer load for each hour of the event day c. Subtract the control group load (a) from the treatment group load (b) for each hour of the event day. The difference is the change in energy use for the average customer attributable to the event response, known as the load impact. d. Multiply the load impact for each hour by the number of customers controlled or dispatched. 10. Submit summary results to CAISO and store code, analysis datasets, and results datasets. 11. Update control group validation for changes in the resource customer mix of more than +/-10% or to remain compliant with seasonal or rolling window validation requirements.
Event period	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.
Method for control group development	List the method used to develop the control group – random assignment of site, random assigned of clusters, matched control group, or other. For random assignment, please retain the randomization code and set a random number generator seed value.
Replication and Audit	Control group equivalence and event days calculation are subject to audit. The results must be reproducible. The underlying customer level data, randomization files, and validation code, and event day analysis code must be retained for 3 years and be made available the CAISO within 10 business days of a request. In the case where the California ISO deems it necessary, DRPs will be required to securely provide the control and treatment group's interval data to recreate the bias regression coefficient and CVRMSE to ensure they meet the criteria
Validation options	Validation is performed by the DRP and subject to audit by CAISO. The validation method uses 75-day lookback period with a 30-day buffer. Validation is required as described in note e, below. The 75 days selected for validation should be chosen such that the validation is complete prior to finalizing the control group to act as the designated baseline method for that resource. a. 30 days used to collect and validate the groups b. Prior 45 days used for the validation (t-31 to t-75)

Component	Explanation
	c. Candidate validation days used to establish control group similarity are either non-event weekdays (if the resource is dispatched only on weekdays) or all non-event days (if the resource can be dispatched on any day) d. A minimum of 20 candidate days are required to be in the validation period. If there are not 20 non-event validation days, extend the validation period backwards (t-76 and further) until there are 20 candidate days in the validation period. e. Requires validation check updates every other month if the number of accounts in the resource does not change more than ± 10%. If the number of accounts changes by more than ± 10%, the control group must be validated monthly. f. If the validation fails, the control group method is unavailable for that resource unless the control group is updated and revalidated. Control groups may be updated monthly. g. 90% of the population must be in both the validation period and the active period
Aggregation of Control Groups across Sub Load Aggregation Points (subLAPs)	Aggregation of control groups is permissible across different subLAPs; however the same performance on intra-subLAP equivalence checks must be demonstrated. While sourcing a control group from a region with similar weather and customer mix conditions is not explicitly mandated, considerations for these attributes that affect load may help in developing an appropriate control group.
Rotation of control groups	The assignment to treatment and control groups can be updated on a monthly basis; however this assignment must be completed prior to any events. Validation of new control groups must also be completed prior to any events in concurrence with any new control group development. The assignment cannot be changed once set for the month and cannot be changed after the fact

3.2 Weather Matching Baselines

Weather-matching baselines estimate what electricity use would have been in the absence of dispatch (the baseline) by relying exclusively on electricity use data for customers who were dispatched. The load patterns during a subset of non-event days with the most similar weather conditions are used to estimate the baseline for the event day. Weather matching baselines do not include information from an external control group.

Table 3-3: Residential Weather Matching Baseline Process and Rules

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an event 2. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 3. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 4. Select the baseline days out of the pool of eligible days 5. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 6. Calculate the same-day adjustment ratio based on the adjustment period hours. 7. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 8. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 9. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	1. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 2. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 3. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

Table 3-4: Non-Residential Weather Matching Baseline Process and Rules

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature
Baseline calculation process	10. Identifying eligible baseline days that occurred prior to an event 11. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 12. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 13. Select the baseline days out of the pool of eligible days 14. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 15. Calculate the same-day adjustment ratio based on the adjustment period hours. 16. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 17. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 18. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	4. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 5. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 6. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \dfrac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

3.3 Day Matching Baselines

Day-matching baselines also estimate what electricity use would have been in the absence of dispatch (the baseline) by relying exclusively on electricity use data for customers who were dispatched. The load patterns during a subset of non-event days are used to estimate the baseline for the event day.

Table 3-5: Residential Day Matching Baseline Process and Rules

<table>
<tr><th></th><th>Weekday Baseline
Highest 5 of 10</th><th>Weekend Baseline
Highest 3 of 5 weighted</th></tr>
<tr><td>Baseline calculation process</td><td colspan="2">1. Identifying eligible baseline days that occurred prior to an event
2. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day
3. Calculate total MWh during the event period for each eligible baseline day
4. Rank the baseline days from largest to smallest based on MWh consumed over the event period
5. Select the baseline days out of the pool of eligible days
6. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate.
7. Calculate the same-day adjustment ratio based on the adjustment period hours.
8. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap.
9. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline.
10. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.</td></tr>
<tr><td>Eligible baseline days</td><td>10 weekdays immediately prior to event, excluding event days and federal holidays</td><td>5 weekend days, including federal holidays, immediately prior to the event</td></tr>
<tr><td>Baseline day selection criteria</td><td>Rank days for largest to smallest based on MWh over the event period, pick the top 5 days</td><td>Rank days for largest to smallest based on MWh over the event period, pick the top 3 days</td></tr>
<tr><td>Application of weights (if needed)</td><td>Not applicable</td><td>1. 50% - Highest load day
2. 30% - 2nd Highest load day
3. 20% - 3rd Highest load day</td></tr>
<tr><td>Event</td><td colspan="2">Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.</td></tr>
<tr><td>Unadjusted baseline</td><td colspan="2">The weighted hourly average of the resource’s electric load during baseline days. The unadjusted baseline includes all 24 hours in day.</td></tr>
<tr><td>Adjustment hours</td><td colspan="2">Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.</td></tr>
<tr><td>Same day adjustment ratio</td><td colspan="2">Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours.
$$\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$$</td></tr>
<tr><td>Adjustment Limit</td><td>Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71</td><td>Cap the ratio between +/- 2x. If the ratio is larger than 2.0, limit it to 2.0. If the ratio is less than 1/2 = 0.50, limit it to 0.50</td></tr>
<tr><td>Adjusted baseline</td><td colspan="2">Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline</td></tr>
</table>

Table 3-6: Non-Residential Day Matching Baseline Process and Rules

	Weekday Baseline Highest 10 of 10	Weekend Baseline Highest 4 of 4
Baseline calculation process	11. Identifying eligible baseline days that occurred prior to an event 12. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day 13. Calculate total MWh during the event period for each eligible baseline day 14. Rank the baseline days from largest to smallest based on MWh consumed over the event period 15. Select the baseline days out of the pool of eligible days 16. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate. 17. Calculate the same-day adjustment ratio based on the adjustment period hours. 18. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 19. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 20. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.	
Eligible baseline days	10 weekdays immediately prior to event, excluding event days and federal holidays	4 weekend days, including federal holidays, immediately prior to the event
Baseline day selection criteria	Keep all 10 eligible days	Keep all 4 eligible days
Application of weights (if needed)	Not applicable	Not applicable
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The weighted hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

3.4 Calculating Baselines with 5 minute data

To be added. One alternative is to calculate a baseline for each individual 5 minute interval and use that to calculate a load reduction for each interval. The other to calculate and hourly baseline and to shape the baseline to 5 minute data as is currently done with the existing PDR baseline. The working group does not have a final recommendation on this topic yet.

4 Implementation of Control Group Settlement Methodology

Randomized control groups consistently outperformed day and weather matching baselines for residential and commercial AC cycling programs during testing. With large enough sample sizes, between 200 and 400 participants, they were more than twice as precise as day or weather matching baselines. For this reason, the BAWG recommends that control groups be one of the settlement options for both residential and non-residential customers.

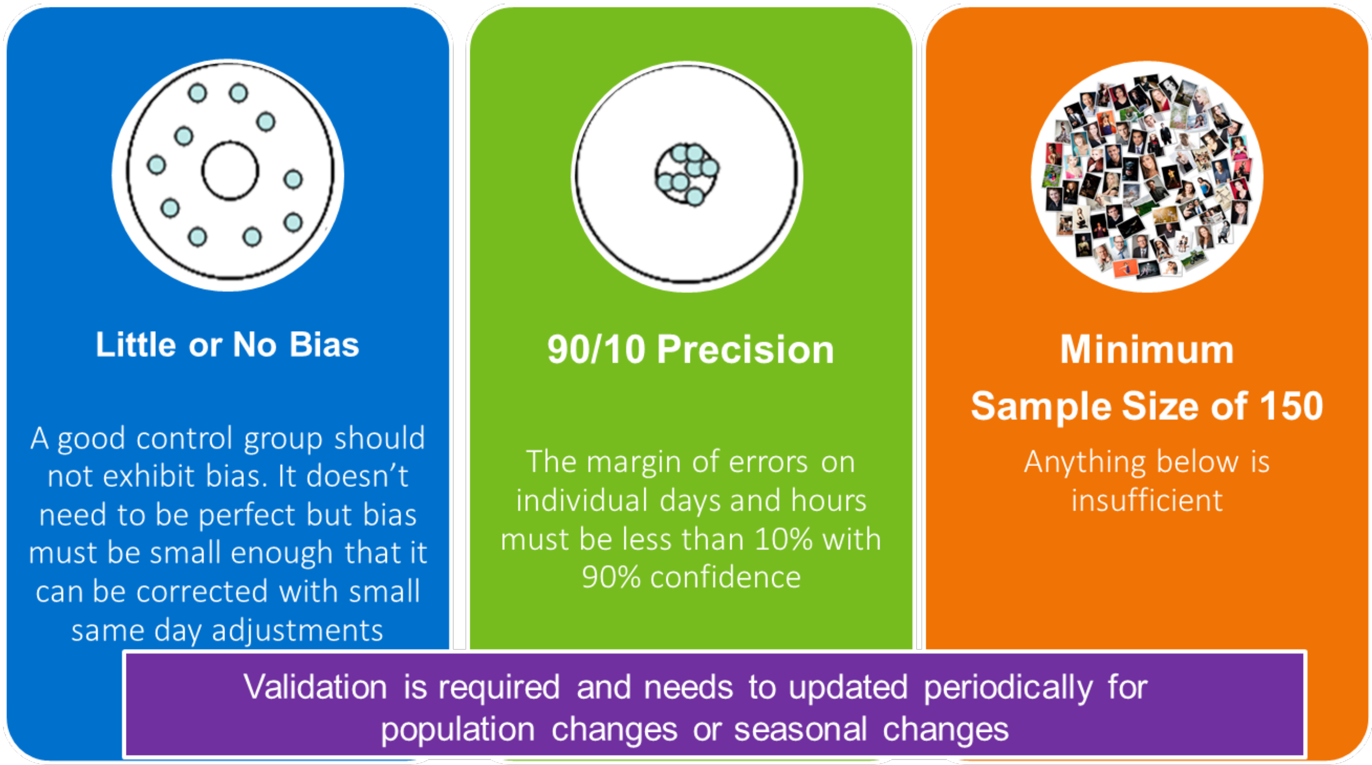
Control groups involve using a set of customers who did not experience events to establish a baseline. A control group should be made of customers who are statistically indistinguishable from the participant group on non-event days to act as a comparison on event days, instead of relying on participants' past performance. There are many ways to develop a control group, including random assignment and statistical or propensity score matching. The rules were intentionally developed so as not preclude use of alternate methods for selecting a control group. There are, however, multiple issues surrounding the development of matched control groups (e.g. data security, equal access to non-participant data, legality, and cost) that were outside of the BAWG scope. Currently, all DRP are able to establish a control group by randomly assigning and withholding a subset of participant resource sites from dispatch. However, not all DRP's have equal access to utility smart meter data for non-participants, which is necessary for development of matched control groups.

The best approach for developing a valid control group is to randomly assign a subset of customers in a resource portfolio to serve as the control group. This requires withholding a subset of participants from event dispatch, thus establishing the baseline. Because of random assignment, there are no systematic differences between the group that is dispatched and the control group, except the event dispatch. With sufficient sample sizes, differences due to random chance are minimized and the control group becomes statistically indistinguishable from the treatment group. This then means that any difference in load profiles on event days can be attributed to the effect of treatment, and that any difference between the two groups on non-event days should be negligible.

However, before a control settlement methodology can be employed it is necessary to demonstrate that the energy use of the control group is an accurate predictor of the energy use of the participants. Three high level requirements for demonstrating the validity of a control group are shown below. Instructions for demonstrating control group equivalence follow, with applied examples in the appendix to this document. Once a suitably accurate and precise baseline has been developed, it can be adjusted using same-day adjustments as described at the end of this section. However, it is the unadjusted baseline that must meet the accuracy, precision and sample size criteria.

Figure 4-1 demonstrates the three key principles for the development and validation of control groups. They must exhibit little or no bias, must be sufficiently precise, and be large enough to represent the treatment population.

Figure 4-1: Control Group Requirements



4.1 Statistical Checks Necessary to Demonstrate Control Group Validity

DRPs will need to demonstrate that the control group reflects the electricity use patterns of customers curtailed (validation). The process for demonstrating equivalence is outlined below. It is the responsibility of the DRP to develop the control group and demonstrate equivalence. The control group(s) developed are subject to audit by the CAISO.

1. The DRP Identifies a control pool of at least 150 customers to be selected via statistical matching or randomly withheld from the participant population. A single control group may be used for multiple subLAP settlement groups; however, equivalence, using the procedure outlined below, must be demonstrated for each of the treatment groups against the control group. For example, if there are five subLAPs, five equivalence checks must be completed to show that the control customers are equivalent to treatment customers in subLAPs A, B, C, D and E. Use of a different control group for each subLAP is also permitted and will be necessary if there are significant differences in weather sensitivity or other characteristics among treatment groups in different subLAPs. In those cases, equivalence must be demonstrated only between the treatment group and the control group for which it is acting as control.

2. For each resource ID, look back 75 days from when the validation occurs, and pull hourly data from the 45 earliest days (t-31 to t-75). The days included in the validation must be in this t-31 to t-75 range, excluding any days that an event has been called for this resource. If the resource is only dispatched on weekdays, the candidate weekend days may be ignored. If the resource can

be dispatched on weekdays and weekends/holidays, all non-event days must be included in the validation period. In addition, exclude event days that the customers in the resource could have participated in. If customers are dually participating in utility load modifying programs, event days of the load modifying resource may also be excluded. If there are not at least 20 available candidate days, continue looking further back (t-76 to t-85 for example) to find additional candidate days until 20 days are available for validation.

3. Average the hourly load profile for all treatment group customers and all control group customers by day and hour.

4. Filter to the appropriate hours and days. Validation is only done on the hours 12-9pm but does include weekdays, weekends, and holidays if the resource can be dispatched on those days.

5. Arrange the data in the appropriate format. For most statistical packages and Excel, regressions are easiest to perform when data is in a long format by date and hour and wide by treatment status. Note that the datasets should be separate for each treatment/control group pairing to be tested.

6. Regress average treatment hourly load against average control hourly load during event hours with no constant. This can be done in a statistical package like R or Stata, or within an Excel file or other spreadsheet application. The functional form of this model should be

$$y_{i,h}^{T} = \beta y_{i,h}^{C} + \varepsilon_{i,h}$$

   Where $y_{i,h}^{T}$ is the average kW across all treatment customers for the non-event day i and hour h, and $y_{i,h}^{C}$ is the average kW across all control customers for that same hour and day. The coefficient,β, represents the bias that exists in the control group; that is, the percent difference between the average treatment kW and the average control kW across all days and event hours. A coefficient of 1.05 means that the treatment group demand is on average 5% higher than that of the control group. Similarly, a coefficient of 0.86 means that the control group load is 86% that of the treatment group. Note that this model explicitly excludes a constant term from the regression.

7. To demonstrate lack of bias, the coefficient β should be between 0.95 and 1.05, minimizing the unadjusted absolute bias from the treatment group.

8. To demonstrate that the control group has sufficient precision, the value of the normalized root mean squared error at the 90% confidence level should be less than 10%. The normalized root mean squared error, or CVRMSE, is calculated according to

$$CV(RMSE) = \frac{\sqrt{\frac{\sum_{i,h}(y_{i,h}^{C} - y_{i,h}^{T})^2}{n}}}{(1/n)\sum_{i,h} y_{i,h}^{T}}$$

In this equation, the squared difference between treatment and control for each event hour and day is summed over all event hours and days, and then divided by the total number of event hours and days (n). The square root of that value is divided by the average treatment load across all event hours and days to normalize the error. Under the assumption that the CVRMSE is normally distributed, the 90% confidence level for this statistic is 1.645 times the CVRMSE. For example, if the CVRMSE is 0.86%, the 90% confidence level for the statistic is 1.414%.

4.2 Using Matched Control Groups to Generate a Baseline

Use of a matched control group would allow DRPs to dispatch their entire participant group during an event, while a separate group of non-participants would act as a control. Alternatively, participants that include customers both inside and outside a subLAP could act as a control group.

The BAWG is open to the possibility of a matched control group baseline option. It is the preferred option for SCE. However, PG&E, SCE, and SDG&E were concerned about customer data security, the allocation of cost to fund this option, and potential legal issues associated with having utilities involved in identifying a matched control group on behalf of other DRPs. While matched control groups are subject to the same validation criteria as randomized control groups, the use of non-participants to develop a control group is of considerable interest to DRPs that wish to dispatch their entire enrolled population during an event. However, no recommendation has been developed that would allow DRPs access to non-participant data to develop the matched control group.

However, a few agreements were reached.

- DRPs with access to non-participant interval data may have the option to utilize matched control groups. The BAWG may choose to withhold the ability to create a matched control group if the access to non-participant data is not available to all parties. These matched control groups are subject to the same validation requirements as the randomly assigned control groups, as outlined above.
- The issue of access to non-participant data is broader than its use for settlement baselines and needs be worked out at the CPUC.
- The matched control group can be updated on a monthly basis but needs to be designated in advance. It cannot be changed once it is set for the month and cannot be changed after the fact.
- The matched control group assignment is subject to audit. The purpose of audits is to assure that baselines were properly calculated and control groups met precision and validation criteria. Audits may include delivery of customer interval data with the goal of recreating bias and precision metrics assessed in the validation process.

4.3 Using control groups with 5 minute data

The working group has not yet made a recommendation in this area. One alternative is to calculate the difference between the control group and the treatment group for each 5 minute interval. Another option would be to calculate hourly difference between treatment and control and to shape the baseline to 5 minute data as is currently done with the existing PDR baseline.

5 Baseline Process Discussion

The following additional process discussion points were addressed in meetings of the full working group.

- Allowing custom or alternate baselines: CAISO does not support any recommendation for new or custom baselines.
- Who will estimate the baselines: The BAWG recommends that DRPs estimate the baselines and provide them to CAISO. CAISO will have an annual process where the DRPs attest to the accuracy of the baselines and may also audit the accuracy of the baselines on an as-needed basis.
- Managing baselines for customer transitions: Further work in this area is needed. The registration process for new PDRs needs to be fully understood by the BAWG participants to ensure that the proper recommendation is developed. A suspension period for customers transitioning to a new settlement group may be necessary to ensure there are sufficient past candidate days to develop a baseline. A method of tracking past event days for customers who transition is also required.

Appendix A Applied Examples of Control Group Validation

A.1 Using Excel

Shown below are examples of how to demonstrate equivalence between treatment and control groups in Excel. As described above, the steps to performing this calculation are:

1. Identify a control pool of at least 100 customers to be selected via statistical matching or randomly withheld from the participant population. Create a dataset that has the form shown in Figure A-1 with control and participant's hourly usage by date from hours ending 1 through 24.

Table A-1: Base Dataset

Participant ID	Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
1	C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
1	C	Winter	1/1/2015	0.72	1.81	0.88	1.97	1.39	1.79		1.49	1.40
1	C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
1	C	Winter	1/3/2015	1.76	0.61	1.99	0.77	1.27	1.27		1.85	1.85
1	C	Winter	1/4/2015	1.60	0.66	1.55	1.08	1.86	1.57		0.68	0.83
1	C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
1	C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
2	T	Winter	12/31/2014	1.11	0.97	1.39	0.58	1.36	1.30		1.54	0.79
2	T	Winter	1/1/2015	0.65	1.04	1.38	1.31	0.81	1.68		0.80	1.47
2	T	Winter	1/2/2015	0.97	1.44	1.31	1.19	1.89	1.74		0.59	1.44
2	T	Winter	1/3/2015	1.16	1.59	1.70	1.25	1.11	1.63		0.79	0.97
2	T	Winter	1/4/2015	0.72	1.98	1.24	1.52	1.91	1.99		0.57	1.85
2	T	Winter	1/5/2015	0.56	1.20	1.19	1.34	1.33	0.50		1.23	1.38
2	T	Winter	1/6/2015	0.99	0.99	0.60	1.32	0.61	1.23		0.93	1.27
3	T	Winter	12/31/2014	1.59	1.81	0.58	1.69	1.49	1.15		0.55	1.81
3	T	Winter	1/1/2015	1.11	1.67	0.71	1.00	0.95	1.39		1.86	1.50
3	T	Winter	1/2/2015	1.71	1.54	1.26	1.40	1.67	1.52		1.90	1.67
3	T	Winter	1/3/2015	1.54	1.11	1.03	1.45	1.10	0.85		1.81	2.00
3	T	Winter	1/4/2015	1.13	0.67	1.25	0.83	1.96	1.58		0.78	0.64
3	T	Winter	1/5/2015	0.96	1.06	1.35	0.89	1.72	1.01		0.54	1.95
3	T	Winter	1/6/2015	0.99	1.35	1.32	0.75	0.82	1.16		1.08	1.11

2. Average the hourly load profile for all treatment group customers and all control group customers by day and hour.

Table A-2 Average Daily Treatment and Control Usage

Ineligible Day	Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
	C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
Holiday	C	Winter	1/1/2015	0.72	1.81	0.88	1.97	1.39	1.79		1.49	1.40
	C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
Weekend	C	Winter	1/3/2015	1.76	0.61	1.99	0.77	1.27	1.27		1.85	1.85
Weekend	C	Winter	1/4/2015	1.60	0.66	1.55	1.08	1.86	1.57		0.68	0.83
	C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
	C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
	T	Winter	12/31/2014	1.35	1.39	0.98	1.14	1.42	1.23		1.05	1.30
Holiday	T	Winter	1/1/2015	0.88	1.36	1.04	1.15	0.88	1.53		1.33	1.49
	T	Winter	1/2/2015	1.34	1.49	1.28	1.29	1.78	1.63		1.25	1.56
Weekend	T	Winter	1/3/2015	1.35	1.35	1.36	1.35	1.10	1.24		1.30	1.49
Weekend	T	Winter	1/4/2015	0.92	1.33	1.25	1.18	1.93	1.79		0.68	1.24
	T	Winter	1/5/2015	0.76	1.13	1.27	1.11	1.52	0.76		0.88	1.66
	T	Winter	1/6/2015	0.99	1.17	0.96	1.04	0.72	1.19		1.01	1.19

3. Flag and remove days in which the resource is not available and event days that the customers in the resource could have participated in.

Table A-3 Average Daily Treatment and Control Usage

Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
T	Winter	12/31/2014	1.35	1.39	0.98	1.14	1.42	1.23		1.05	1.30
T	Winter	1/2/2015	1.34	1.49	1.28	1.29	1.78	1.63		1.25	1.56
T	Winter	1/5/2015	0.76	1.13	1.27	1.11	1.52	0.76		0.88	1.66
T	Winter	1/6/2015	0.99	1.17	0.96	1.04	0.72	1.19		1.01	1.19

4. Arrange the data in the appropriate format.

Table A-4 Average Daily Treatment and Control Usage

Date	Hour	kWh_Treat	kWh_Control
12/31/2014	1	1.35	2.00
	2	1.39	1.11
	3	0.98	1.91
	4	1.14	1.29
	5	1.42	0.78
	6	1.23	1.25
	…		
	23	1.05	0.97
	24	1.30	1.44
1/2/2015	1	1.34	0.85
	2	1.49	0.59
	3	1.28	1.67
	4	1.29	0.64
	5	1.78	0.67
	6	1.63	1.04
	…		
	23	1.25	2.00
	24	1.56	1.42
1/5/2015	1	0.76	1.59
	2	1.13	1.32
	3	1.27	0.53
	4	1.11	1.32
	5	1.52	1.44
	6	0.76	0.88
	…		
	23	0.88	1.12
	24	1.66	1.18
1/6/2015	1	0.99	1.45
	2	1.17	1.63
	3	0.96	1.47
	4	1.04	1.50
	5	0.72	1.66
	6	1.19	0.98
	…		
	23	1.01	1.90
	24	1.19	0.66

5. Regress average treatment hourly load against average control hourly load during event hours with no constant by filling in the attached template and updating formulas in cells H20 and H24 to include the full range of the data added to columns B through E.

Randomization Validation Template.x

Figure A-1: Regression and Validation Template

Row	Date	Hour	Treatment kWh	Control kWh	Error Squared
3	12/31/2014	1	1.35	2.00	0.42250
4	12/31/2014	2	1.39	1.11	0.07840
5	12/31/2014	3	0.98	1.91	0.85008
6	12/31/2014	4	1.14	1.29	0.02449
7	12/31/2014	5	1.42	0.78	0.42055
8	12/31/2014	6	1.23	1.25	0.00046
9	12/31/2014	...			0.00000
10	12/31/2014	23	1.05	0.97	0.00562
11	12/31/2014	24	1.30	1.44	0.01960
12	1/2/2015	1	1.34	0.85	0.24010
13	1/2/2015	2	1.49	0.59	0.81000
14	1/2/2015	3	1.28	1.67	0.15016
15	1/2/2015	4	1.29	0.64	0.43296
16	1/2/2015	5	1.78	0.67	1.22545
17	1/2/2015	6	1.63	1.04	0.34928
18	1/2/2015	...			0.00000
19	1/2/2015	23	1.25	2.00	0.57003
20	1/2/2015	24	1.56	1.42	0.01823
21	1/5/2015	1	0.76	1.59	0.68558
22	1/5/2015	2	1.13	1.32	0.03648
23	1/5/2015	3	1.27	0.53	0.54834
24	1/5/2015	4	1.11	1.32	0.04182
25	1/5/2015	5	1.52	1.44	0.00601
26	1/5/2015	6	0.76	0.88	0.01525
27	1/5/2015	...			0.00000
28	1/5/2015	23	0.88	1.12	0.05452
29	1/5/2015	24	1.66	1.18	0.23136
30	1/6/2015	1	0.99	1.45	0.20794
31	1/6/2015	2	1.17	1.63	0.20931
32	1/6/2015	3	0.96	1.47	0.26317
33	1/6/2015	4	1.04	1.50	0.21716
34	1/6/2015	5	0.72	1.66	0.89114
35	1/6/2015	6	1.19	0.98	0.04623
36	1/6/2015	...			0.00000
37	1/6/2015	23	1.01	1.90	0.79477
38	1/6/2015	24	1.19	0.66	0.28037

1. Populate the values to the right with eligible (n
winter (perform these calculations in separate ta

2. Update the formulas in cells H20 and H24 (the E
500, for example, ensure that the formulas in H20

3. Make a scatterplot with control kWh as the X-a

4. Right click on the scatterplot data in the graph
options circled to the right, then click 'OK'
   a. Linear Regression Type
   b. Set Intercept = 0
   c. Display Equation on chart

BETA
0.999271146

Must be between 0.95 and 1.05

CVRMSE
4.84%

Margin of Error with 90% Confidence
8.0%

Must be less than 10%

6. The statistics of interest are in cells H20, H24, and H29.

A.2 Applied Example of Validation Required – Using Stata

Example code that performs the control group validation can be found here:

Stata Code to Validate Equivalence.do

The command to perform this regression is: *reg kWh_treat kWh_control, noconstant.* If using Stata, the validation statistics can be calculated easily using the two commands underlined in green. The coefficient β is the value circled in orange. The 90% limit on the CVRMSE can be calculated using the output (circled in blue) from the same two commands as shown in Figure 11.

Figure A-2: Stata Commands to Calculate Equivalence Statistics

```
          reg kwh_treat kwh_control, noconstant

      Source |       SS       df       MS              Number of obs =    5568
-------------+------------------------------           F(  1,  5567) =       .
       Model |  3792.8973     1  3792.8973             Prob > F      =  0.0000
    Residual |  10.197965  5567  .00183186             R-squared     =  0.9973
-------------+------------------------------           Adj R-squared =  0.9973
       Total | 3803.09527  5568  .683027167            Root MSE      =   .0428

------------------------------------------------------------------------------
   kwh_treat |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 kwh_control |    1.00539   .0006987   1438.93   0.000     1.004021     1.00676
------------------------------------------------------------------------------


          sum kwh_treat

    Variable |       Obs        Mean    Std. Dev.       Min        Max
-------------+--------------------------------------------------------
   kwh_treat |      5568    .7518921    .3430839   .1965188   3.313407


          di in red "the RMSE is " e(rmse)
the RMSE is .04280023

          di in red "the average treatment kWh is " r(mean)
the average treatment kWh is .75189212

          di in red "the 90% confidence limit of the CVRMSE is " 1.645 * (e(rmse)/r(mean)) * 100 "%"
the 90% confidence limit of the CVRMSE is 9.3638946%

          di in red "it can also be manually entered like this: " 1.645 * (.04280023/.75189212) * 100 "%"
it can also be manually entered like this: 9.3638936%
```

Appendix B Process to Calculate Participant-Weighted Weather

B.1 Mapping of NOAA Weather Stations to ZIP codes

Weather matching baselines require weather data in order to find similar non-event days. The BAWG found that participant-weighted weather, meaning an average hourly weather profile that is the weighted average of the geographic mix of resource participants, vastly outperforms using a single weather profile for each subLAP and resource. To facilitate this process, the BAWG has put together a mapping of NOAA stations to California zip codes.

The mapping was done using distance matching by finding the closest NOAA weather station by physical distance to the centroid of each zip code. For zip codes that did not have latitude and longitude values available (the metrics used to calculate distance from the stations), a matching process was used to find the weather stations of proximate surrounding zip codes, which was then used to fill in missing values. The full list of zip codes and their associated weather stations can be found here:

NOAA Station to Zip Mapping

The list above shall be updated by the IOUs for each of their respective territories and updated at the request of DRPs.

B.2 Calculating Participant-Weighted Weather

Once participants have been identified for a particular resource, their weather data can be compiled to calculate the participant-weighted average weather by day and hour. The process is as follows:

1. Determine the weather stations associated with the resource in question. For all the resource participants, collect their associated premise-level zip codes (ie the zip code associated with their physical location, not their billing location), and use the mapping listed above to generate a list of associated weather stations for each resource
2. Collect the last 90 days of weather data from NOAA from the weather stations in question.
   a. Data should be at the hourly level for all days and weather stations
3. Assemble the dataset of participants for the full baseline search period. The look-back period for weekday baselines is 90 days and 56 days (8 weeks) for weekend baselines. Each participant must have an associated premise zip code that indicates their physical (ie not billing) location.
4. Merge the customer-level dataset with the weather station mapping by zip code. In effect, ensure that each customer has a single weather station that is mapped to their zip code using the mapping attached above (or a subsequent update).

5. Now merge the weather data in to the customer-level dataset by weather station. This should yield a dataset that is unique by participant id, date and hour (if the dataset is long by hour).

6. Create the resource-average dataset by collapsing the participant-level dataset to an average by date and hour. No weighting is required if the dataset described in step 5 includes all the participants in the particular resource. Frequency weights should be applied to calculate the weighted average of all the weather stations in the resource (weighted by the total number of participants that are mapped to each weather station) if the dataset does not include all participants.

7. The dataset is participant-weighted and can be merged to the average hourly load data by date and hour to calculate weather-matching baselines.

Appendix C Detailed Day-Matching Calculation Process

A detailed example of how to calculate a day matching baseline is described in the attached Excel workbook. The steps are as follows:

Example_Day_Match
_Workbook.xlsx

0. Start with hourly interval data for all participants in the program, with at least 90 days of prior data. Note this is not shown in the attached example.

1. Collapse the data to the average hourly load by day for the full set of participants. The dataset should now look something like the example shown in Tab 1 of the attached document.

2. Clean the data by removing ineligible days (weekends and holidays, already excluded from this example) and other event days that the participants were dispatched for (highlighted in grey). The event day in this example, was September 10th, 2015, when the program was called between 4-7pm (hour ending 17 to hour ending 19). Note that this dataset is slightly smaller than the 90 days of eligible data, but it does not affect the calculations required for day matching.

    a. Generate the average event load. For each of the non-event days remaining in the dataset, average the hourly load for the event hours (in this case HE17-HE19) for each day.

3. Keep the last Y eligible days. The number Y refers to the denominator of the day matching baseline. If the baseline is a top 5/10, Y = 10. If the baseline is a top 3/5, as shown in the example workbook, Y = 5. These are your eligible days

4. Sort by the average event load in decreasing order, and pick the top X largest days. These are your baseline days. The X in this case refers to the numerator of the day matching baseline. For the two baseline examples listed in Step 3, X = 5 or X = 3, respectively. In the attached example, X = 3.

5. Generate the unadjusted baseline. Two options are presented in the attached example:

    a. Top 3/5 Unweighted: The three baseline days are simply averaged to generate the baseline.

    b. Top 3/5 Weighted: The closest day to the baseline receives a weight of 50%, the next closest receives a weight of 30% and the furthest receives a weight of 20%. Note that closest in this case refers to days closest to the event day, not by the average event load sorting that was done in Step 4. The weighting is applied by multiplying the % for each day to the hourly load profiles, then summing. This is a weighted average.

6. Perform the same-day adjustment as necessary.

   a. Define the adjustment window periods. In the example, the event occurs between HE17and HE19 (highlighted in blue in the example). For two-hour pre- and post-event adjustment windows with a two-hour buffer, the adjustment window hours (highlighted in orange in the example) are HE13, HE14, HE22, and HE23.

   b. Average the usage across those four hours for both the baseline and the event day observed load.

   c. Calculate the adjustment ratio by dividing the baseline average window value by the observed average window value. In the example, the baseline has an adjustment window value of 1.49kW and the event adjustment window value is 1.76. The ratio is then 1.18.

   d. Cap the ratio at the required level. If the cap is 1.4x, as in the example, the following logic applies:

      i. If the ratio is less than 1/1.4 = 0.71, the capped ratio is now set to 0.71.

      ii. If the ratio is between 0.71 and 1.4, the ratio remains as is.

      iii. If the ratio is greater than 1.4, the capped ratio is now set to 1.4.

   e. Apply the capped ratio to each hour of the baseline by multiplying the capped ratio by the hourly baseline values for each hour

   f. The profile obtained in step 6e is the baseline.

Appendix D Detailed Weather-Matching Calculation Process

A detailed example of how to calculate a weather matching baseline is described in the attached Excel workbook. The steps are as follows:

Example_Weather_Match_Workbook.xlsx

0. Start with hourly interval data for all participants in the program, with at least 90 days of prior data. Note this is not shown in the attached example.

1. Collapse the data to the average hourly load by day for the full set of participants. The dataset should now look something like the example shown in Tab 1 of the attached document.

2. Clean the data by removing ineligible days (weekends and holidays, already excluded from this example) and other event days that the participants were dispatched for (highlighted in grey). The event day in this example, was September 10th, 2015, when the program was called between 4-7pm (hour ending 17 to hour ending 19). Note that this dataset is slightly smaller than the 90 days of eligible data, but it does not affect the calculations required for day matching.

    a. Also generate the weather variable of interest for the baseline – either the maximum hourly temperature or the average daily temperature

    b. Drop any days that occur AFTER the event day for which the baseline is being calculated.

3. Sort the dataset by how similar the eligible days are to the event day, by calculating the absolute value of the difference between the event day average (or maximum) temperature and the eligible day's average (or maximum) temperature.

4. Sort by the weather variable absolute difference in decreasing order, and pick the top X largest days. These are your baseline days. The X in this case refers to number of days used to estimate the weather baseline. A 3 day weather matching baseline will have X = 3. A 5-day weather matching baseline will have X = 5.

5. Generate the unadjusted baseline by averaging the hourly kW values across the X baseline days.

6. Perform the same-day adjustment as necessary.

    a. Define the adjustment window periods. In the example, the event occurs between HE17and HE19 (highlighted in blue in the example). For two-hour pre- and post-event adjustment windows with a two-hour buffer, the adjustment window hours (highlighted in orange in the example) are HE13, HE14, HE22, and HE23.

b. Average the usage across those four hours for both the baseline and the event day observed load.

c. Calculate the adjustment ratio by dividing the baseline average window value by the observed average window value. In the example, the baseline has an adjustment window value of 1.64kW and the event adjustment window value is 1.76. The ratio is then 1.07.

d. Cap the ratio at the required level. If the cap is 1.4x, as in the example, the following logic applies:

    i. If the ratio is less than 1/1.4 = 0.71, the capped ratio is now set to 0.71.

    ii. If the ratio is between 0.71 and 1.4, the ratio remains as is.

    iii. If the ratio is greater than 1.4, the capped ratio is now set to 1.4.

e. Apply the capped ratio to each hour of the baseline by multiplying the capped ratio by the hourly baseline values for each hour

f. The profile obtained in step 6e is the baseline.

Attachment F – Nexant: California ISO Baseline Accuracy Assessment

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

CALIFORNIA ISO BASELINE ACCURACY ASSESSMENT

November 20, 2017

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Figures

Tables

1 Introduction

Historically, California has been a leader in the use of Demand Response and dynamic pricing to offset the need for additional peaking generation capacity, which is driven by system peak loads. A large share of DR resources, totaling roughly 1,700 MW, are enrolled in programs and contracts administered via the three California investor owned utilities – Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE). The market for demand response and battery storage is changing in three fundamental ways. First, the level of participation by third-parties (non-utilities) is expected to increase. Second, to receive credit for peaking capacity – also known as resource adequacy – DR resources must be bid into the CAISO markets. Third, the need for resources is increasingly becoming bidirectional; resources are needed to reduce demand (or inject power) during peak periods and to increase demand (or reduce power production) during periods when there is a surplus of power.

A key issue for incorporating DR resources into markets is accurate measurement of demand reductions for settlement. Measurements for settlement and operations need to be conducted much faster than traditional program evaluations, which are conducted on an annual basis. Settlements must also be transparent, relatively easy to understand, and simple to implement.

To estimate demand reductions, it is necessary to estimate what energy consumption would have been in the absence of DR dispatch — a baseline or counterfactual. The change in energy use is calculated as the difference between the baseline and consumption during the event. There are a variety of approaches for measuring the magnitude of curtailments with different degrees of complexity. While highly accurate results are desirable, there is often a tradeoff between simplicity and incremental accuracy.

Before 2017, settlement of DR resources at CAISO was based on using the same hour average for the 10 non-event weekdays immediately prior to dispatch of the resource – an approach known as a 10 of 10 baseline with a 20% adjustment cap – which was developed primarily based on analysis of large and mid-large non-residential customers. Prior baseline research has shown that the 10 of 10 baseline works reasonably well for the large and medium commercial customers who are not highly weather sensitive. However, research has also shown that the current baseline significantly underestimates residential demand response resources and non-residential weather sensitive customers. In addition, little research has been done on the performance of the current 10 of 10 baselines for customers participating in emergency demand response programs such as the Baseline Interruptible Program and Agricultural Pump load control.

Because the CAISO performs settlement by product type in specific geographic areas – known as sub Load Aggregation Points (subLAPs), it is critical to understand the extent to which the number of participants enrolled influence the accuracy and precision of settlements. Just as important is effect of more frequent event days, which reduce the number of control days that can be used to develop baselines.

The purpose of this study is to assess different baseline alternatives and rules that allow for accurate estimates of broad range of DR resources, including weather sensitive and less weather sensitive resources. A key outcome from this study is baseline proposal – subject to FERC approval – that allows a broader range of demand response programs/products to be bid into the CAISO market and be settled accurately. As part of the study, we obtained input regarding baseline variations to asses for accuracy from stakeholders, including from CAISO, PG&E, SCE, SDG&E and demand response and battery storage third party vendors. The three California utilities allowed the use of hourly smart meter or interval data from over 500,000 sites enrolled in eight distinct DR programs for the baseline accuracy assessment.

1.1 Key Research Questions

The study addresses several research questions, including:

- What are the most accurate and precise baselines by program type and customer class?
- How accurately and precisely do the best baselines perform?
- How much variation is there in accuracy and precision across geographic areas?
- Does the accuracy and precision vary depending on the number of customers (sample size) or event days?
- What is the effect of various baseline adjustments rules on the accuracy and precision of baseline estimates?
- Are approaches relying on control groups feasible and accurate and, if so, what are the implications of more granular sample sizes?

1.2 Aggregated versus Customer Specific Baselines

The settlement with CAISO is implemented at the resource level. Aggregator and utilities pool customers into a resource which delivers a specific product in a predefined area and bid the resource in to the CAISO market. Individual customer loads for events and non-event days are aggregated to the resource level before the baselines are calculated. While some jurisdictions estimate baselines for individual customer accounts first and then aggregate the resources to the resource level, this is not the case at CAISO. In this report, all accuracy and precision metrics are for baselines calculated for aggregated resources.

1.3 Baselines Included in Testing

At a high level, the baseline settlement methods tested for accuracy can be classified under three broad categories:

- Control Groups — An ideal control group has nearly identical load patterns in aggregate and experiences the same weather patterns and conditions. The only difference is that on some days, one group curtails demand while the control group does not. The control group is used to establish the baseline of what load patterns would have been absence the curtailment event. This approach is the primary method for settlement of residential AC cycling and thermostat programs by Texas' system operator, ERCOT.

- Day Matching — Day-matching baselines estimate what electricity use would have been in the absence of curtailment by relying on electricity use in the days leading up to the event. It does not include information from a control group that did not experience an event. The process involves setting rules for the eligible days and rules for how the days used to estimate the baseline are selected from the eligible days. A subset of non-event days in close proximity to the event day are identified and averaged to produce baselines.

- Weather Matching — The process for weather matching baselines is similar to day-matching except that the baseline load profile is based on non-event days with similar temperature conditions. In general, weather matching tends to include a wider range of eligible baseline days, which are narrowed to the ones with weather conditions closest to those observed during events.

A total of 23 day-matching, 12 weather-matching, and randomly assigned control groups were included in the accuracy assessment, for a total of 36 different baseline types.

Error! Reference source not found. and **Error! Reference source not found.** provide additional details about the baselines tested. These baselines were identified by reviewing the best performing baselines for past studies, inside and outside of California, for residential, industrial, and commercial loads. For each baseline, a number of baseline rules were tested for using existing customers in the BIP, Agricultural pumping, residential air conditioner, and commercial air conditioner customers. These rules include various combinations of baseline adjustment hours, adjustments caps and, when possible, assessment of accuracy and precision for actual event days (if large control groups were available) and for non-event days when net CAISO loads were high – proxy event days where the actual loads in the absence of demand response were known.

Table 1-1: Baselines Tested and Compared: Weekday

Control group	Day Matching	Weather Matching
1. Comparison of means	2. Average 3 of last 3 eligible days 3. Use 3 of last 3 eligible days; more recent days receive higher weight 4. Average the top 3 of the last 5 eligible days 5. Use top 3 of the last 5 eligible days; more recent days receive higher weight 6. Average 3 of last 5 eligible days and adjust upward by 5% for all customers 7. Average top 4 of the last 5 eligible days 8. Average top 5 of the last 5 eligible days 9. Average top 3 of the last 10 eligible days 10. Average top 5 of the last 10 eligible days 11. Average 10 of the last 10 eligible days 12. Average top 3 of the last 20 eligible days 13. Average top 5 of the last 20 eligible days 14. Average top 10 of the last 20 eligible days	15. Average 3 days with most similar weather during the last three months 16. Average 4 days with most similar weather during the last three months 17. Average 5 days with similar weather during the last three months 18. Assign days with high temperatures exceeding 80°F to 3 bins based on maximum temperature; baseline equals the average peak-period load on non-event days in a similar bin 19. Assign days with high temperatures exceeding 80°F to 3 bins based on CDD for the day; baseline equals the average peak-period load on non-event days in a similar bin 20. Assign days with high temperatures exceeding 80F to 3 bins based on the total CDH for the day; baseline equals the average peak-period load on non-event days in a similar bin

Table 1-2: Baselines Tested and Compared: Weekend

Control Group	Day Matching	Weather Matching
▪ Comparison of means	▪ 1/1 ▪ 1/2, 2/2 ▪ 1/3, 2/3, 3/3, 3/3 weighted ▪ 1/4, 2/4, 3/4, 4/4, ▪ 1/5, 2/5, 3/5, 3/5 weighted, 4/5, 5/5	▪ Matching baselines based on: – average temperature – sumCDH – maximum temperature ▪ Match on 1-5 days out of 8 prior weekend lookback

1.4 Baseline Rules, Frequency, and Aggregation included in Testing

There several rules regarding baselines and option in the accuracy assessment which influence accuracy and precision. These include:

- Limits on baseline adjustments – Baseline adjustments are calculated by comparing actual loads and unadjusted baselines during non-event periods and using that information to calibrate the baseline. If the difference between the unadjusted baseline and the actual load is truly due to baseline estimation error, the adjustment process reduces those errors. Typically baseline adjustments are limited. As part the assessment, 10 baseline adjustments, including unlimited adjustment and no adjustments were tested.

- Adjustment buffers - To avoid contamination of the baseline with intentional changes to loads, a buffer period between adjustment periods and event dispatch hours is typically employed. Buffer periods reduce the risk of this contamination by allowing pre-cooling and snapback to occur in the hours directly before and after the event without using those hours to adjust the baseline. The default buffer is two hours before and after and event, but as part of the assessment, the use of buffer or 1, 2, and 3 hours was tested for residential air conditioner programs.

- Use of hours before and after the event in the baseline adjustment calculation. Historically, baseline adjustments have been calculated using only pre-event hours. At the request of a stakeholder, the study assessed the inclusion of hours before and after the events to calculate the baseline adjustment. This was done only for residential air conditioner programs where results for large control groups were available.

- The number of event days called. When more events are called, it limits the days available for baseline calculations. The sole exception is control groups, which are unaffected by frequent events. To assess the impact of event days on baseline accuracy, the study assessed baseline accuracy when 3, 5, 10, or 15 events were called per summer.

- How many sites are aggregated into a resource. More aggregation of diverse resources tends to smooth out idiosyncrasies, leading to more accurate baselines. The less resources are aggregated, the lower the accuracy of baselines. To assess the impact of aggregation, the baseline accuracy was assessed using different amount of aggregation. For mass market programs such as air conditioner cycling or connected loads and agricultural pumps, the accuracy was estimated for resources of 200, 500, 1,000 and 2,000 sites. For large C&I customers, the accuracy was estimate for resources of 20, 50, 100, 200, and 300 sites.

- The timing of the event. The assessment analyzed events starting at 2 pm, 3 pm, and 5 pm and lasting four hours each.

When combined with the baselines, over 12,000 combinations of baselines, adjustment rules, aggregation, and event dispatch were tested for each of the program types included in the assessment.

1.5 Baseline Accuracy versus Demand Response Accuracy

To assess the accuracy of the estimated values, one needs to know the correct values. When the correct answers are known, it is possible to assess if each alternative settlement option correctly measures the demand reduction and, if not, by how much it deviates from the known values. There are two basic approaches:

- Assess the accuracy of baselines themselves — This involves estimating the baseline and comparing it to actual unperturbed load during non-event days. While this is useful for identifying the best performing baseline, it is not a direct assessment of how accurately the signal—the demand reduction—is measured. An emphasis on baseline accuracy is analogous to assessing which method is better at reducing noise.
- Assess the accuracy of the demand reductions produced by the baseline — Baselines are simply a means to produce demand reductions estimates. They are tools to filter out noise (or explain variation) and allow the effect or impact to be more easily detected. The focus, however, is on how accurately the demand reductions are detected. If actual demand reductions are 20%, a baseline that is biased by 2% will estimate demand reductions of 22%, or estimate 110% of the actual demand reductions. Accuracy of baselines is clearly different than the accuracy of the demand reductions estimated by baselines.

Throughout this report, the focus of the analysis is on the accuracy of the baselines. For individual market participants, accuracy of settlement will depend on the amount of resources aggregated, the diversity of those resources (i.e., whether or not a single participant dominates results), and the percent demand reduction delivered.

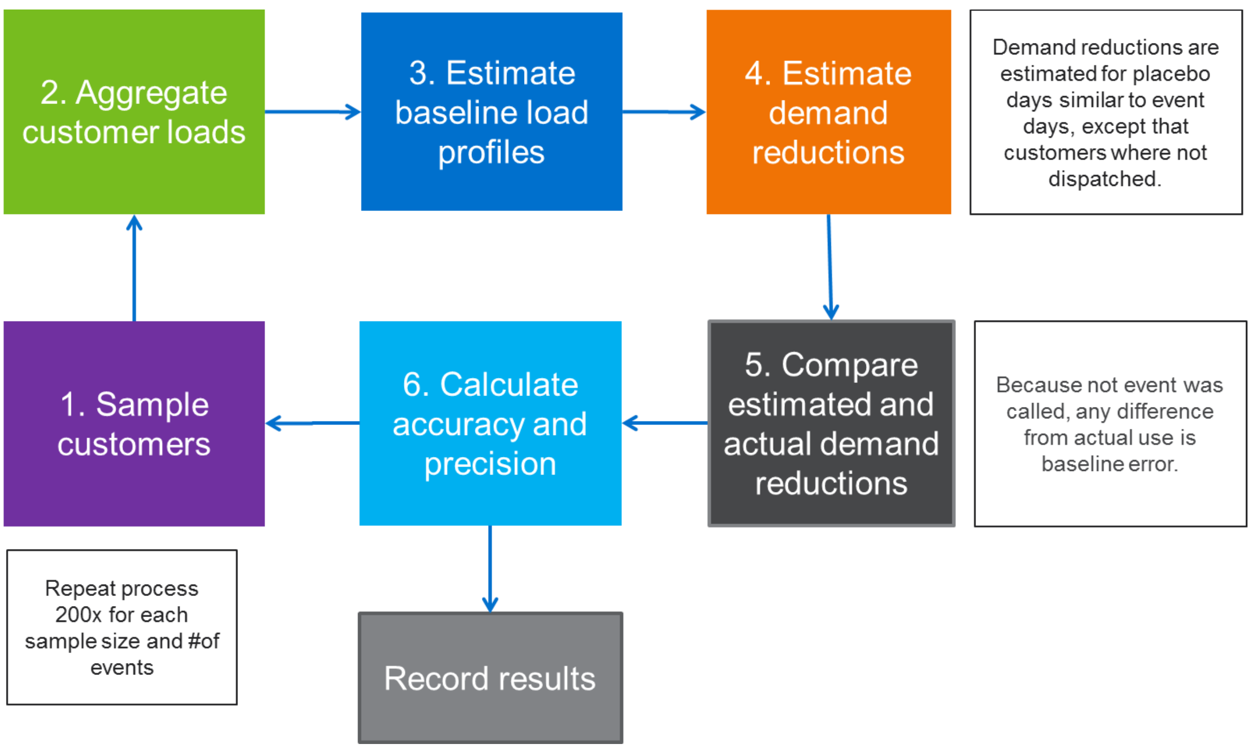
2 Methodology

2.1 Assessing Baseline Error

To assess the baseline error, one needs to know the correct values. When the correct answers are known, it is possible to assess if each alternative settlement option correctly measures the demand reduction and, if not, by how much it deviates from the known values. Figure 2-1 summarizes the approach for assessing accuracy and precision.

The objective is to test different baselines with different samples of participants using actual data from participants in order to identify the most accurate analysis method. Baseline accuracy is assessed on placebo days, which are treated as event days. Because no event was called, any deviation between the baseline and actual loads is due to error.

Figure 2-1: Method for Testing Baseline Accuracy



The process is repeated hundreds of times, using slightly different samples – a procedure known as bootstrapping – to construct the distribution of baseline errors. In addition, the accuracy of the baselines is tested at granular geographic levels, such as subLAPs, to mimic market settlement. A key question is the degree to which more or less aggregation influences the accuracy and precision of the estimates. This is assessed by repeating the below process using different subsets of customers so the relationship between the amount of aggregation and baseline accuracy is quantified.

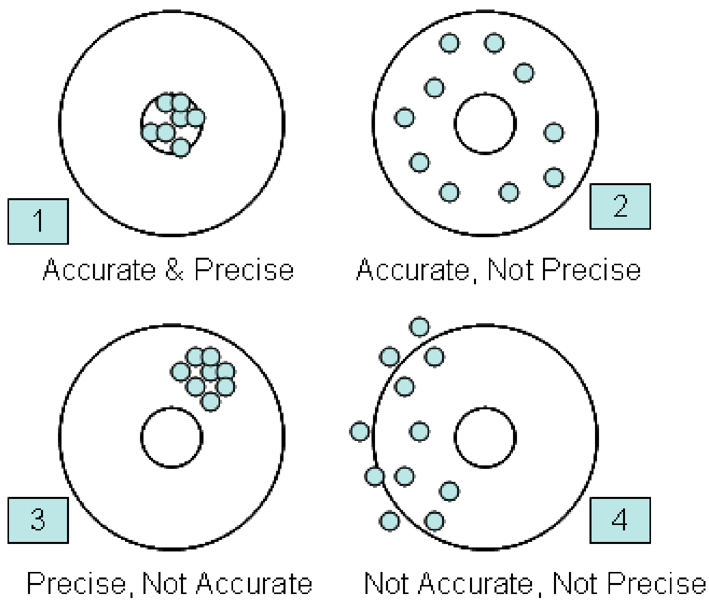
The only instance where placebo events were not used was in assessing the use of both pre and post event hours in the baseline adjustment calculation. The analysis was implemented using an air conditioner cycling program residential sample and actual event days when load was expected to be higher after events due to snapback. Because PG&E withholds a large randomly assigned control group of over 14,000 customers for each of its events, the control group estimate of the counterfactual is highly precise and nearly error free, providing a basis against which day and weather matching baselines could be compared.

2.2 Accuracy and Precision Metrics

The terms accuracy and precision have a very specific meaning to statisticians and data scientists. Accuracy refers to metrics for bias; the tendency to over or under predict. Precision refers to metrics for how close typical predictions are to actual answers.

The figure below illustrates the difference between accuracy and precision. An ideal model is both accurate and precise (example #1). Baselines can be accurate but imprecise when errors are large but cancel each other out (#2). They can also exhibit false precision when the results are very similar for individual events but are biased (#3). The worst baselines are both imprecise and inaccurate (#4)

Figure 2-2: Precision versus Accuracy (Lack of Bias)



Throughout this report, the performance of baseline rule options was summarized using two metrics: one for accuracy (or bias) and one for precision (or goodness-of-fit). The equations and formal description are included in the methodology section, but it is important to understand how to interpret these metrics.

Table 2-1 summarizes metrics for accuracy (bias) and precision (goodness-of-fit) that were produced to assess the different baseline alternatives. Bias metrics measure the tendency of different approaches to over or under predict (accuracy or lack of bias) and are measured over multiple days. The BAWG used the mean percent error since it describes the relative magnitude and direction of the bias. A negative value indicates a tendency to under-predict and a positive value indicates a tendency to over-predict. This tendency is best measured using multiple days. Baselines that exhibit substantial bias were eliminated from consideration.

Precision metrics describe the magnitude of errors for individual events days and are always positive. The closer they are to zero, the more precise the results. The primary metric for precision was CVRMSE, or normalized root mean squared error. Among baselines which exhibit little or no bias, more precise metrics will be favored. Last, but not least, multiple baselines can prove to be both relatively accurate and precise. In which case, the BAWG has submitted its recommendation based on practical considerations such ease of implementation or potential for gaming.

Table 2-1: Accuracy and Precision Metrics Used to Identify Best Performing Baselines

Type of Metric	Metric	Description	Mathematical Expression
Accuracy (Bias)	Mean Percent Error (MPE)	Indicates the percentage by which the measurement, on average, over or underestimates the true demand reduction.	$MPE = \frac{\frac{1}{n}\sum_{i=1}^{n}(\hat{y}_i - y_i)}{\bar{y}}$
Precision (Goodness-of-Fit)	Mean Absolute Percentage Error (MAPE)	Measures the relative magnitude of errors across event days, regardless of positive or negative direction.	$MAPE = \frac{1}{n}\sum_{i=1}^{n}\left\lvert\frac{\hat{y}_i - y_i}{y_i}\right\rvert$
	CV(RMSE)	This metric normalizes the RMSE by dividing it by the average of the actual demand reduction.	$CV(RMSE) = \frac{RMSE}{\bar{y}}$

2.3 Data Sources

Table 2-2 summarizes the data provide by PG&E, SCE, and SDG&E for the baseline accuracy assessment. In total, hourly data over 2 years from nearly 104,000 customers was used for the baseline accuracy assessment. All sites were current or recent participants in utility programs and, in nearly all cases, the full population of participants was employed in the analysis.

Table 2-2: Data Sources for Analysis

Program Type	Utility Program	Number of accounts	Time frame
Weather Sensitive	PG&E Residential AC cycling	84,159	Jan 2015 to Oct 2015
	SDG&E Residential AC cycling (100%)	1,064	Jan 2015 to Oct 2015

	SDG&E Residential AC Cycling (50%)	1,110	Jan 2015 to Oct 2015
	SCE Commercial AC cycling	10,760	Jan 2015 to Oct 2015
	SDG&E Commercial AC Cycling	4,467	Aug 2015 to Oct 2015
Industrial and Agricultural	PG&E Baseline Interruptible Program	299	Nov 2013 to Sep 2015
	SCE Baseline Interruptible program	633	Nov 2013 to Sep 2015
	SCE Agricultural pumps	1,285	Nov 2013 to Sep 2015

2.4 Selection of Placebo Event Days

Baseline accuracy was assessed on placebo days. Because no event was called, any deviation between the baseline and actual loads is due to error. Actual event days were removed from the analysis datasets to ensure the baselines calculation did not include days where customers were delivering demand reductions.

The placebo events were based high net loads to better account for the high penetration of utility scale renewables in California, which is affecting when, how often, and for how long resources are needed. Different frequency of events was simulated, from as little as 3 events per year to as many as 15 events per year, in order to assess if the frequency of dispatch influenced the accuracy of baselines - with high frequency dispatch, fewer days are available to baseline settlement calculations.

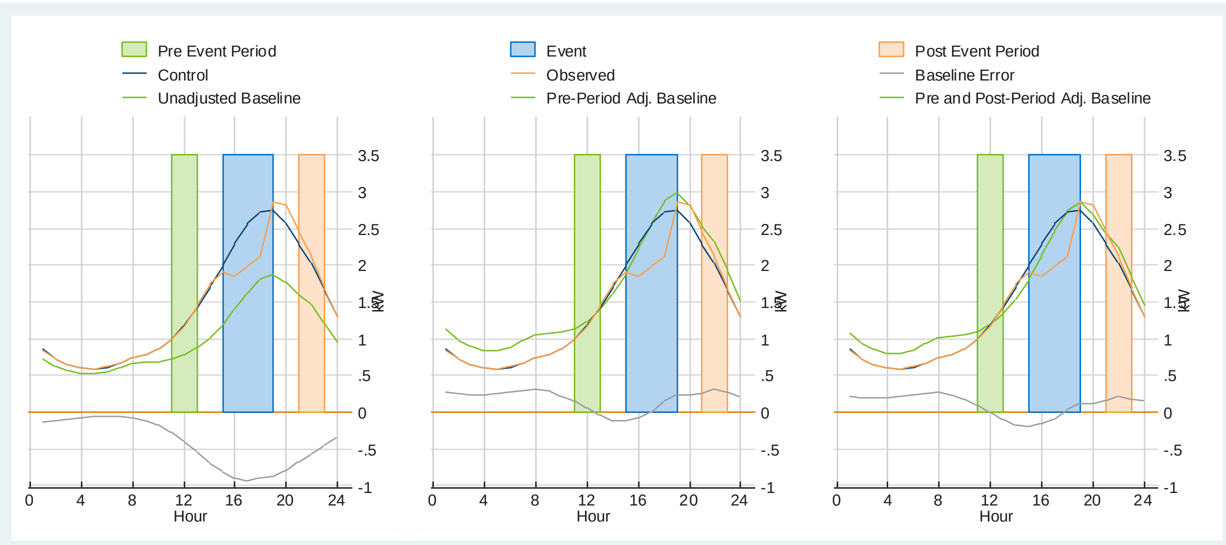
2.5 Baseline Adjustments

Another key issue is the use of baseline adjustments – are they used and, if so, what are the rules for around those adjustments? The concept relies on comparing actual loads and unadjusted baselines during non-event periods and using that information to calibrate the baseline. The underlying assumption is that differences during non-event periods are due to measurement error. That is, if the difference between the unadjusted baseline and the actual load is truly due to baseline estimation error, the adjustment process reduces those errors.

Baseline estimates of electricity use during an event period can be adjusted up or down based on electricity use patterns during the hours leading up to an event or during both pre- and post-event hours. If, during non-event adjustment hours, the baseline is less than the actual load, it is adjusted upwards. Similarly, if the baseline is above the actual load in the non-event adjustment hours, it is adjusted downwards. To avoid contamination of the baseline with perturbed event hours, a buffer period between adjustment periods and event dispatch hours is typically employed. Buffer periods reduce the risk of this contamination by allowing pre-cooling and snapback to occur in the hours directly before and after the event without using those hours to adjust the baseline. Same-day adjustments are often capped to reduce the variance of estimates and to limit the potential for manipulation of loads to influence baselines.

Error! Reference source not found. illustrates the concept of baseline adjustments. In the example, the event occurs from 3 PM to 6PM. With two hour buffers both before and after the event, the adjustment windows are 11AM-1PM and 8PM-10PM. The green line in each graph is the baseline, unadjusted, adjusted with the pre-event period only or adjusted with both the pre- and post-event period. The orange line is the observed load on the event day, while the black line indicates the counterfactual (modeled here by a large control group). The ratio of the observed (orange) loads during the pre-event adjustment window is applied to the baseline in the center graph, while the ratio of the average observed compared to baseline loads for both the pre- and post-event periods is shown in the rightmost graph. The graph on the left shows the unadjusted result.

Figure 2-3: Example of Baseline Same-day Adjustment



3 Results

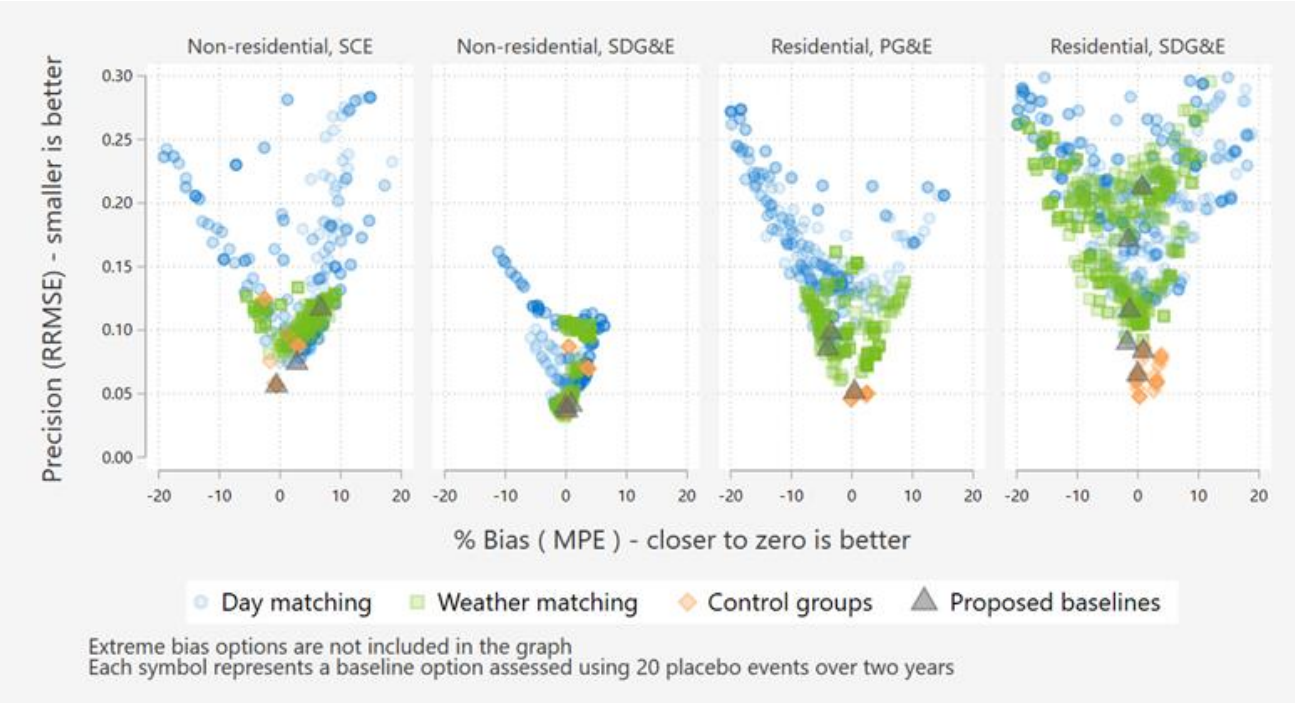
The goal of this study was to assess different baseline alternatives and rules and identify options that accurately estimate impacts of a broad range of DR resources, including weather sensitive and less weather sensitive resources. Over 120,000 combinations of baselines, adjustment rules, aggregation level, and event dispatch frequency and timing were tested on each of eight utility programs. Due to the volume, the results are presented in a summary format holding the number of events (20 over 2 years), timing of events (3 pm to 7 pm), and aggregation level (100 or 500 sites for commercial and residential types, respectively) constant, and assuming baseline adjustments are based on pre-treatment data. The effect the number of events and the amount of resource aggregation on the accuracy of baselines is presented separately. Unless otherwise indicated, accuracy was assessed using placebo event days – event like days when resources where not dispatched – allowing error to be calculated by comparing baselines against actual loads. For more detailed results, please refer to Appendix E, where the top ten best baselines for each program, utility and baseline type are listed, along with their bias and precision metrics.

A key finding of the analysis is that multiple baseline rules can deliver sufficiently unbiased and precise baselines. The proposed baselines were arrived at based on input from CAISO, third party stakeholders, and the three investor owned utilities in California.

3.1 Accuracy and Precision Metrics for Existing Programs

Figure 3-1 summarizes the baseline accuracy results for the weather sensitive air conditioner programs analyzed. Each symbol represents the bias and precision of a baseline rule option assessed over 20 placebo events over the course of two years. The best approaches have little or no bias – the tendency to over or under predict on average – and are more precise – the typical magnitude of errors for individual events periods is smaller. On the graph, the best baselines are at the bottom of the “V” shape.

Figure 3-1: Bias and Precision for Weather Sensitive Residential and Non-Residential Customers



Control groups methods consistently outperformed weather matching and day matching baselines, delivering baselines that were unbiased and more precise. Overall, weather matching methods typically outperformed day matching baselines. The chart also shows the proposed baselines. The chart does not show the degree to which inclusion of post event hours in the baseline adjustment improves the accuracy of results (it does). Because this analysis was implemented on a subset of data, it is discussed separately in section 3.2.

Figure 3-2 shows the baseline accuracy results for the Baseline Interruptible Program, which is mainly comprised of large industrial customers, and for agricultural pumps. Control groups were not assessed for these options since they are fewer in number and loads vary more widely across customers. The results are shown using the same scale as the weather sensitive loads to allow direct comparisons. While loads for these customers can be seasonal (particularly for agricultural pumps), they are less sensitive to day to day variation in weather conditions. In general, baselines for less weather sensitive customers are more precise.

Figure 3-2: Bias and Precision for Industrial (BIP) and Agricultural Customers

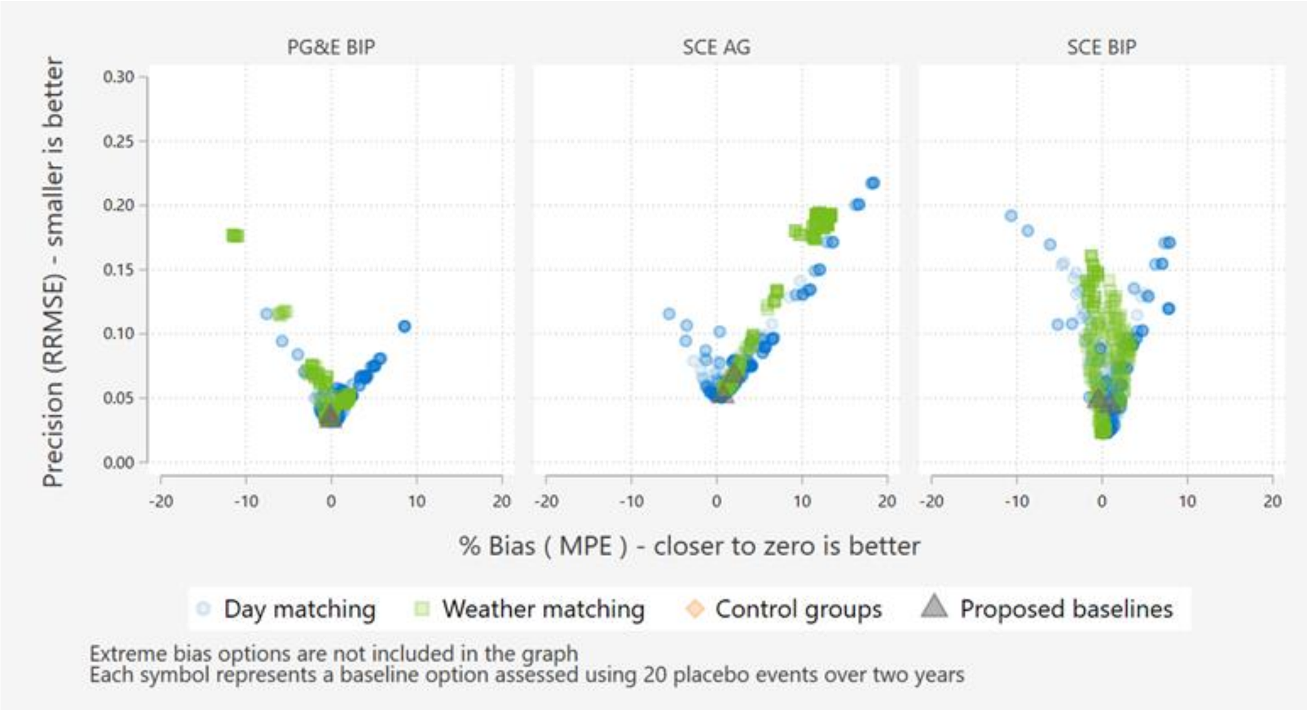


Table 3-1 shows the bias and precision metrics for the proposed and current baselines for each program assessed. For residential weather sensitive programs as whole, the current baseline is downwardly biased by 12% to 14% and event to event magnitude of errors is sufficiently large to occasionally nullify actual reductions. The proposed baselines reduce the tendency to under predict and improve precision for dispatch hours. As discussed later, the baselines of weather sensitive customers are improved further by including post event hours in the baseline adjustment calculation. For commercial customers, the existing baseline performed relatively well but can be improved on, especially by using control groups.

Table 3-1: Bias and Precision for Proposed and Current Baselines

Program Type	Utility Program	Baseline type	Proposed		Current Baseline	
			Bias (MPE)	Precision (CVRMSE)	Bias (MPE)	Precision (CVRMSE)
Weather Sensitive	PG&E Residential AC cycling	Day matching	-4.0%	0.086	-13.1%	0.179
		Weather matching	-3.4%	0.098		
		Control group	0.4%	0.051		
	SDG&E Residential AC cycling (100%)	Day matching	-1.5%	0.171	-12.7%	0.240
		Weather matching	0.7%	0.212		
		Control group	0.9%	0.084		
	SDG&E Residential AC Cycling (50%)	Day matching	-1.8%	0.090	-13.7%	0.205
		Weather matching	-1.4%	0.116		

		Control group	-0.1%	0.065		
	SCE Commercial AC cycling	Day matching	2.8%	0.074	2.8%	0.074
		Weather matching	6.7%	0.117		
		Control group	-0.6%	0.056		
	SDG&E Commercial AC Cycling	Day matching	0.9%	0.041	0.9%	0.041
		Weather matching	-0.1%	0.040		
		Control group	0.1%	0.037		
Industrial and Agricultural (not weather sensitive)	PG&E Baseline Interruptible Program	Day matching	-0.1%	0.032	-0.1%	0.032
		Weather matching	-0.2%	0.036		
	SCE Baseline Interruptible program	Day matching	0.9%	0.044	0.9%	0.044
		Weather matching	-0.4%	0.048		
	SCE Agricultural pumps	Day matching	0.7%	0.051	0.7%	0.051
		Weather matching	2.0%	0.068		

3.2 Inclusion of Post Event Hours in the Baseline Adjustments

Historically, baseline adjustments for day and weather matching baselines have been calculated using only pre-event hours. At the request of a stakeholder, the study assessed the use of hours before and after the events to calculate baseline adjustments. The drier California weather leads to limited use of air conditioning until the late afternoon and evening hours. As result, post event hours can include information useful for calibrating the baselines that is not available during pre-event hours.

The impact of including post event hours in the baseline calculation was studied using actual events and data from PG&E and SDG&E, both of which rely on control groups to estimate the baseline. Actual event days were employed to account for small increases in load that occur when control of air conditioners is released – a phenomenon known as snapback. The baselines were compared to the control group loads. While this is technically a comparison of one estimate – a baseline – to another – the counterfactual produced by the control group – the control groups used were large enough that any sampling error was minimal.

Figure 3-3: Effect of Including Post Event Hours in Baseline Adjustment Calculation

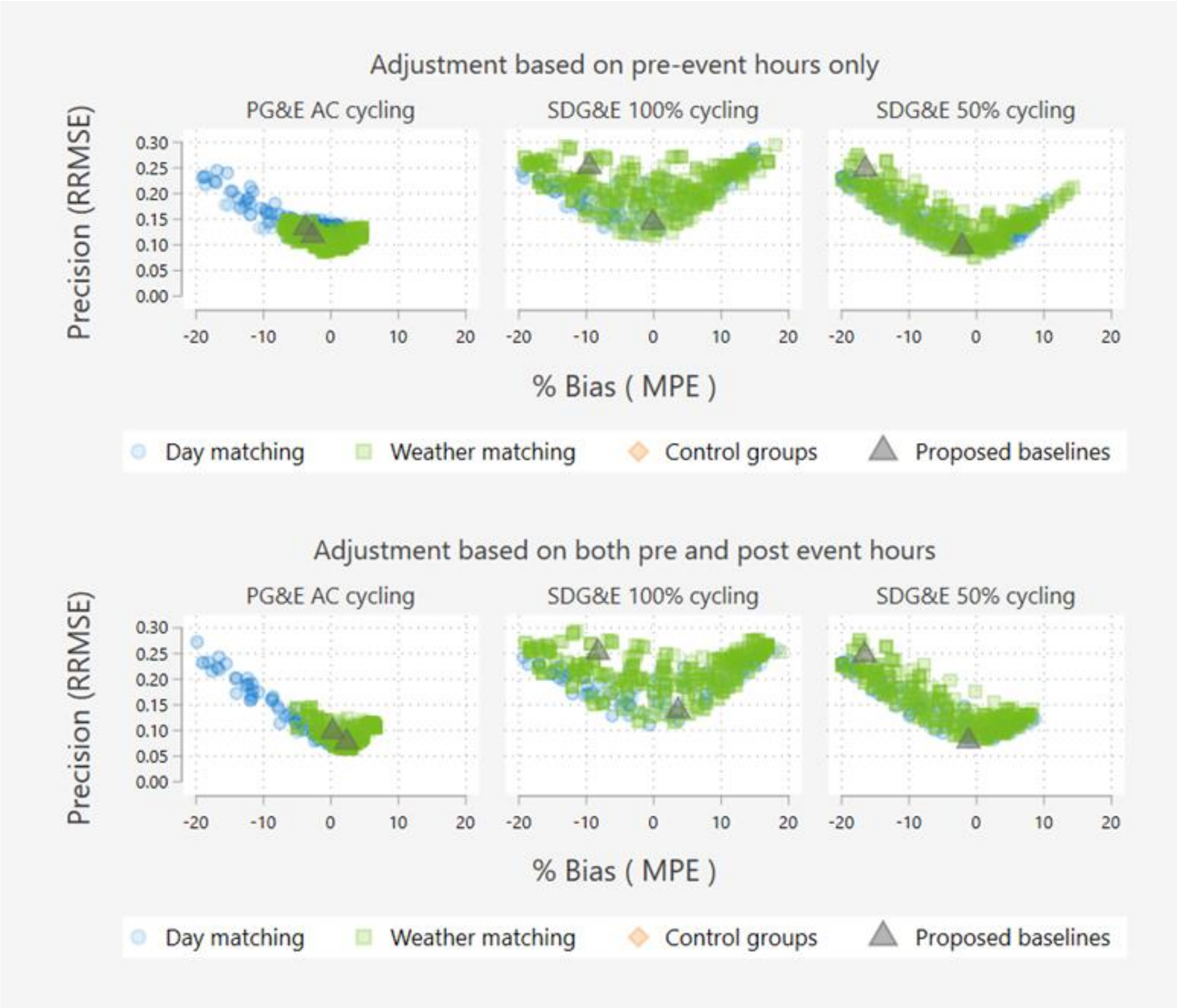
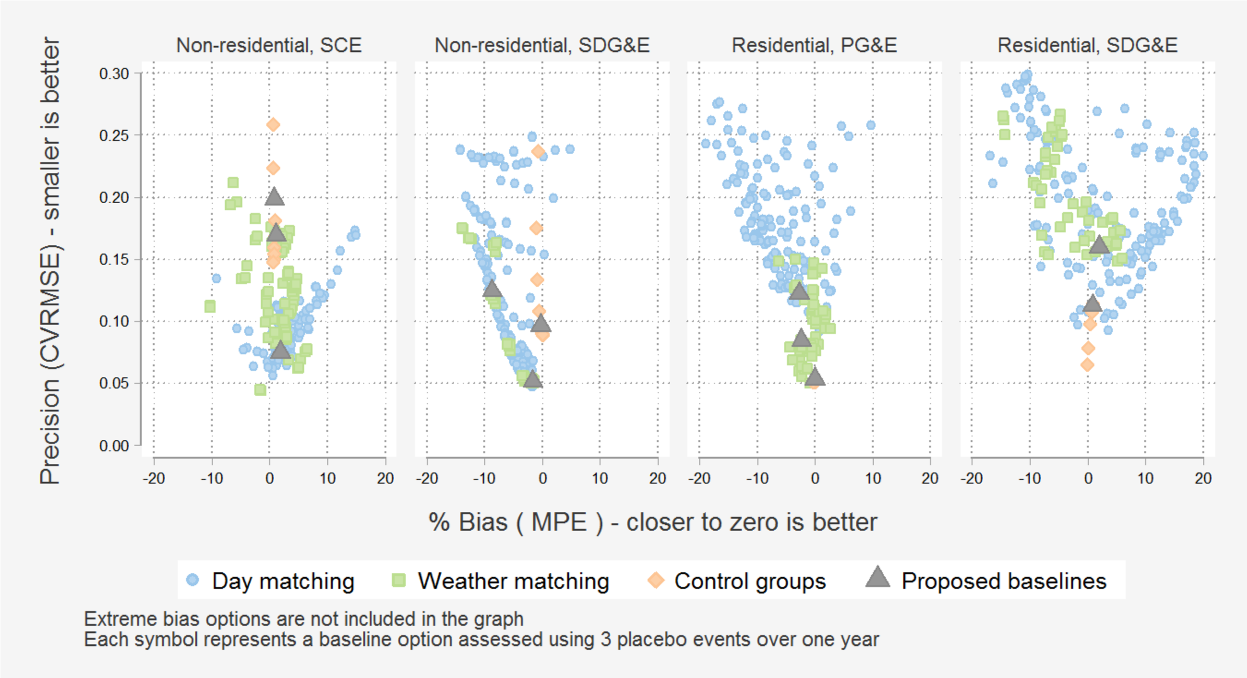


Figure 3-3compares the baselines with and without the inclusion of the post event hours in the baseline calculation. Adding the post-event hours to the baseline adjustment, reduced bias and improves the precision of the impacts for nearly all baselines tested, however the improvement is slight, compared to the improvements seen with including a pre-event adjustment at all.

3.3 Accuracy, Precision, and Post Event Hours for Weekends

Figure 3-4 summarizes the baseline accuracy results for weather sensitive air conditioner programs analyzed on weekends. The proposed weekend baselines differ from the proposed weekday baselines because the patterns of weekend use may differ substantially from weekdays. Using weekday use to predict weekend use for customer classes that vary in loadshape across days of week would substantially reduce the accuracy of the baseline. The results below are shown using the same scale as the weekday baselines to allow direct comparisons. Unlike weekday results which were simulated using ten placebo events, the weekend baselines were calculated using 3 placebo event days over the course of one year.

Figure 3-4: Bias and Precision for Weather Sensitive Residential and Non-Residential Customers on Weekends



As with weekdays, control groups consistently delivered less biased baselines. Overall, weather matching baselines typically outperformed day matching baselines, consistent with the weekday results. Since no events were called on weekends for the programs and summers of data available, there was no additional analysis on how the inclusion of post-event hours in the baseline adjustment improves the accuracy of results for weekends, nor on how the proposed baselines performed during actual events

Figure 3-5 shows the baseline accuracy results for agricultural customers and customers enrolled in the Baseline Interruptible Program on weekends. As with weekdays, control groups were not assessed for these options since they are fewer in number and loads vary more widely across customers. The results are shown using the same scale as the weather sensitive and weekday groups to allow direct comparison. As these customers are generally less weather-sensitive with more stable loads, both weather and day-matching methods performed similarly.

Figure 3-5: Bias and Precision for Industrial (BIP) and Agricultural Customers on Weekends

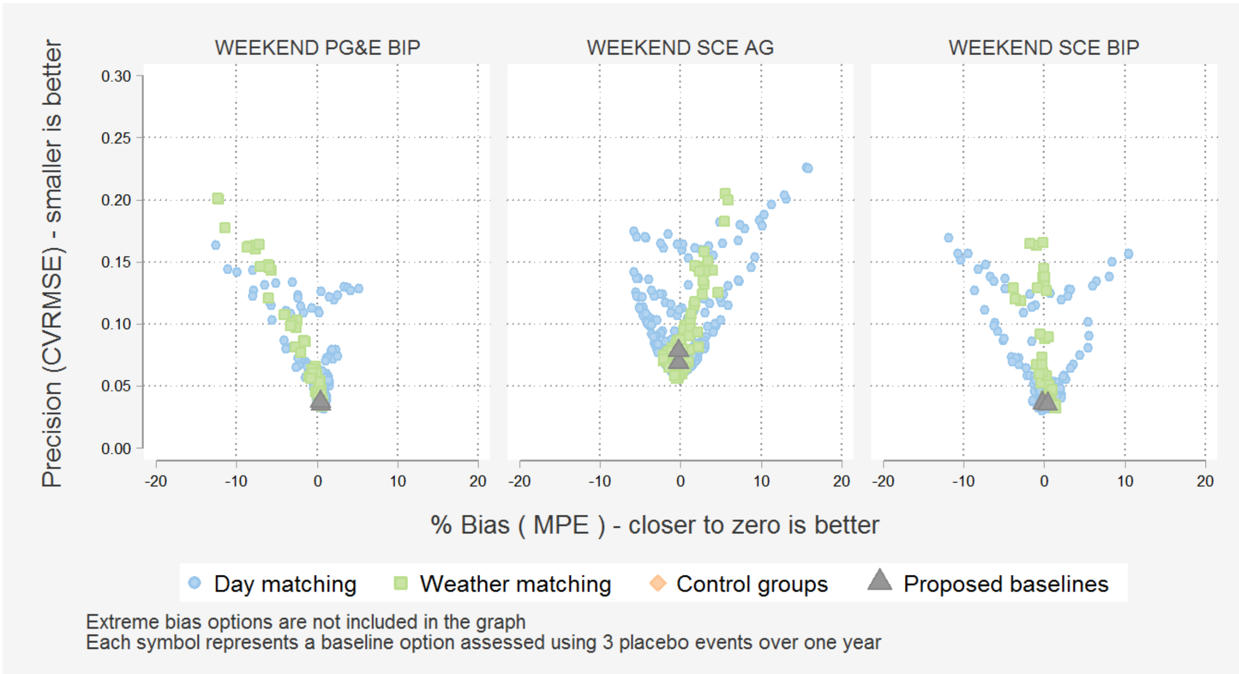


Table 3-2 shows the bias and precision metrics for the proposed and current weekend baselines for each program assessed. For residential weather sensitive programs as whole, the current baseline is downwardly biased by 6% and upwardly biased to 9% and event to event magnitude of errors is sufficiently large to occasionally nullify actual reductions. The proposed baselines reduce the tendency to over or under predict and improve precision for dispatch hours. For commercial customers, the existing baseline performed relatively well but can be improved on, especially by using control groups.

Table 3-2: Bias and Precision for Proposed and Current Baselines

Program Type	Utility Program	Baseline type	Proposed		Current Baseline	
			Bias (MPE)	Precision (CVRMSE)	Bias (MPE)	Precision (CVRMSE)
Weather Sensitive	PG&E Residential AC cycling	Day matching	-2.7%	0.122	-5.7%	0.172
		Weather matching	-2.4%	0.084		
		Control group	0.02%	0.053		
		Weather matching	2.0%	0.160		
		Control group	0.8%	0.112		
	SDG&E Residential AC Cycling	Day matching	22.5%	0.248	8.8%	0.126
		Weather matching	-2.0%	0.160		
		Control group	0.8%	0.112		
	SCE Commercial AC	Day matching	1.8%	0.075	1.8%	0.060

	cycling	Weather matching	1.1%	0.169		
		Control group	-0.8%	0.199		
	SDG&E Commercial AC Cycling	Day matching	-8.6%	0.124	-8.6%	0.124
		Weather matching	-1.6%	0.051		
		Control group	-0.3%	0.096		
Industrial and Agricultural (not weather sensitive)	PG&E Baseline Interruptible Program	Day matching	0.4%	0.036	0.4%	0.036
		Weather matching	0.4%	0.037		
	SCE Baseline Interruptible program	Day matching	-0.2%	0.036	-0.2%	0.036
		Weather matching	0.3%	0.035		
	SCE Agricultural pumps	Day matching	-0.2%	0.078	-0.2%	0.078
		Weather matching	-0.3%	0.068		

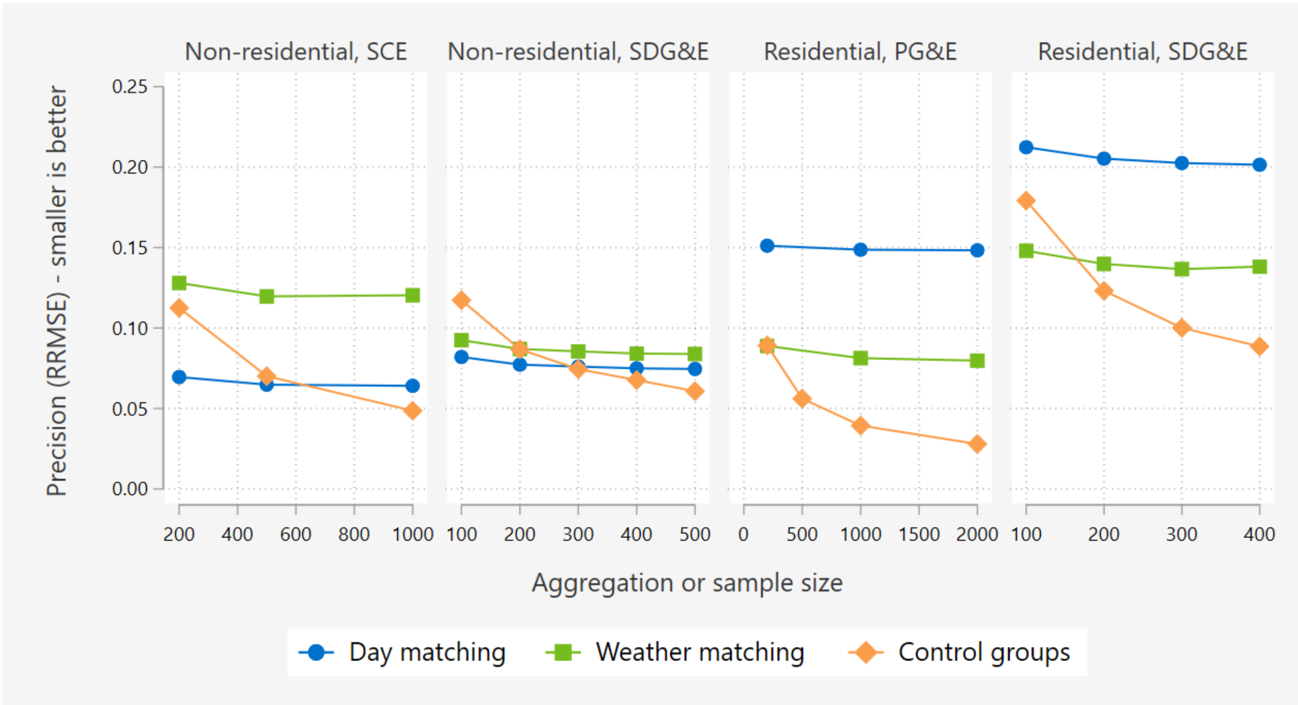
3.4 Impact of Aggregation on the Precision of Baselines

Baseline methods perform better when there are larger numbers of customers and those customers are diverse. This is true both for methods that rely exclusively on non-event data and for baselines that rely on a control group. Baselines tend to perform more poorly when there are fewer participants or when loads and demand reductions are highly concentrated on a handful of customers.

Because the focus is on settlement by product type in specific geographic areas, it is critical to understand the extent to which the number of participants enrolled influence the precision of settlements. While baselines that reply on a control groups are generally more precise, they require withholding some customers from event dispatch. The question is how many. For newer market participants, it may require a considerable share of their resources, especially because the sample sizes need to be adequate with each of the 20 geographic settlement areas

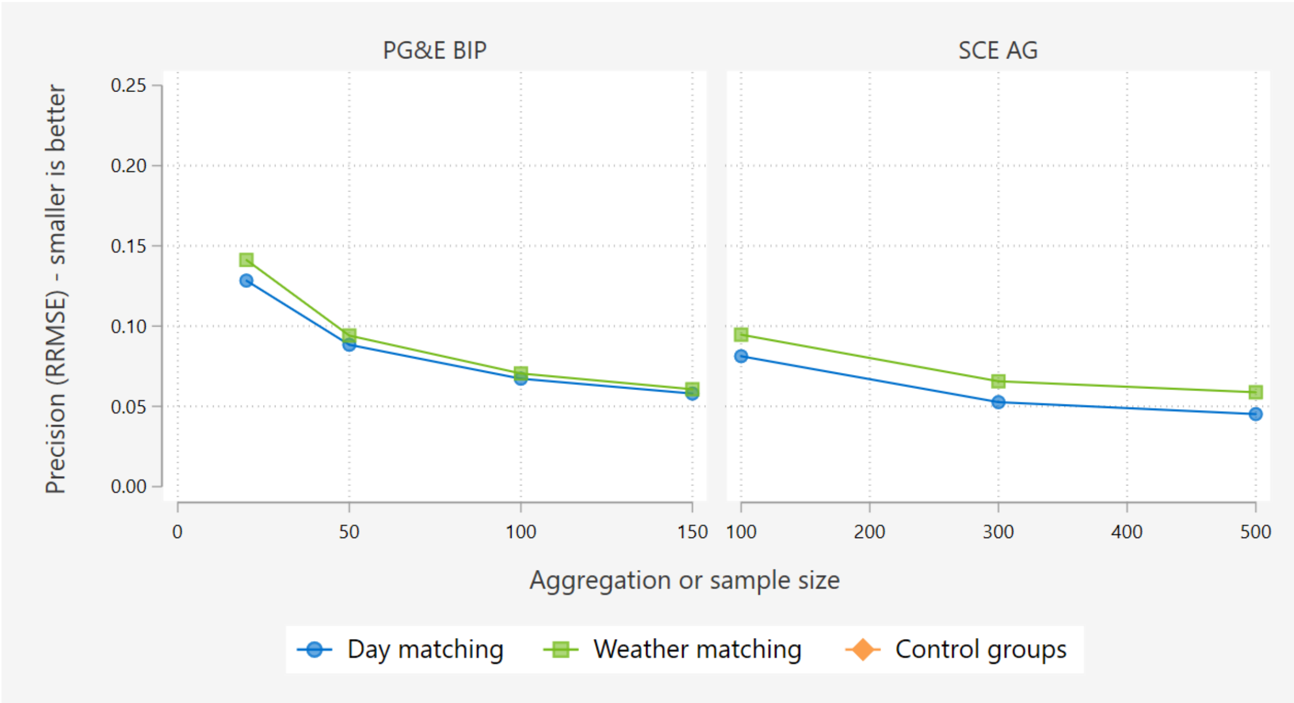
Figure 3-6 and Figure 3-7 show how the precision of baseline methods improves with aggregation or, in the case of control groups, the sample size. The aggregation levels tested for the different programs varied due to the available data, but some patterns emerge.

Figure 3-6: Effect of Aggregation or Sample Size on Precision for Weather Sensitive Customers



Day and weather matching baselines perform better for non-residential customers than for residential ones. Once control group sizes exceed approximately 200 customers, they outperform weather and day matching methods. The larger the control group, the more precise estimates produced. With 500 customers, control groups are more than twice as precise as day and weather matching baselines. However, day and weather matching methods are typically more precise than control groups when control groups are less than 200. We also observe that aggregation leads to improvement in precision for day and weather matching methods, especially with smaller groups. However, the gains of more aggregation are more pronounced with control groups.

Figure 3-7: Effect of Aggregation or Sample Size for Industrial (BIP) and Agricultural Customers



4 Recommendations

Table 4-1 shows the recommended baselines for residential and non-residential loads. Randomized control groups consistently outperformed day and weather matching baselines. With large enough sample sizes, between 200 and 400 participants, they were more precise than day or weather matching baselines. For this reason, control groups are recommended as a settlement options for both residential and non-residential customers. However, a day matching and a weather matching baseline are also options available to demand response providers who may lack a sufficiently large customer base to develop a control group. The baseline option for any portfolio of resources needs to be specified for the month, in advance, and cannot be modified after the fact.

Table 4-1: Recommended Baselines for CAISO Settlement[1]

Customer Segment[2]	Weekday	Baselines Recommended	Adjustment Caps
Residential	Weekday	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 5/10 day matching	+/- 40%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		Highest 3/5 weighted day matching	+/- 40%
Non-residential	Weekday	Control Group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		10/10 day matching	+/- 20%
	Weekend	Control group	+/- 40%
		4 day weather matching using maximum temperature	+/- 40%
		4 eligible days immediately prior (4/4)	+/-20%

Baseline calculations require multiple steps and definition of rules. For clarity, this section presents the baseline calculation processes and rules for control groups, weather matching baselines, and day matching baselines. Appendix A provides an applied example of control group validation and an example of how the baseline is calculated with a control group. 0 includes an applied example of a day matching baseline (the weekend residential baseline). Appendix D provides an applied example of a weather matching baseline.

4.1 Control Group Baselines

Control groups involve using a set of customers who did not experience events to establish a baseline. A control group should be made of customers who have nearly identical load patterns and experience the

[1] In the case of PDR resources that combine residential and non-residential customers, the aggregate baselines for the two customer groups should be calculated separately using the appropriate baseline for residential and non-residential customers, then added together to represent the full resource. This subdivision is not necessary if the baseline method for both residential and non-residential customers is the same, as is the case for the current recommended weather matching baselines.

[2] Residential and non-residential designations are based on customer rate class from that customer's local distribution company. That is, if a customer is served under a non-residential rate from it's LDC, that customer is classified as a non-residential customer.

same weather patterns and conditions as the resource's customers who are dispatched. During event days, the difference is that one group, known as the treatment group, experienced event dispatch while the control group did not.

Table 4-2 summarizes the control group process and rules. The process and baseline rules are identical for residential and non-residential customers and for weekdays and weekends. Section 6 includes additional discussion regarding the implementation of control group baselines. Instructions for demonstrating control group equivalence, with applied examples, are also included in the appendix to this document.

Table 4-2: Control Group Baseline Process and Rules

Component	Explanation
Baseline process	1. Determine the method for developing the control group 2. Identify the control group customers 3. Narrow data to hours and days required for validation checks (see validation options) 4. Calculate average customer loads for each hour of each day 5. Drop CAISO event days and utility program event days for programs the resource or control customers participate in. 6. Validate on the schedule described in 'Validation Options' below. Conduct validation checks and ensure all of the following requirements are met for: a. Sufficient sample size – 150 customer or more b. Lack of bias - see Section 6 c. Precision – see Section 6 7. Submit information about which sites designated as a control group and which sites will be dispatched to CAISO in advance. 8. Submit the validation checks to CAISO. 9. For event days: a. Calculate the control group average customer load for each hour of event day b. Calculate the dispatch group average customer load for each hour of the event day c. Subtract the control group load (a) from the treatment group load (b) for each hour of the event day. The difference is the change in energy use for the average customer attributable to the event response, known as the load impact. d. Multiply the load impact for each hour by the number of customers controlled or dispatched. 10. Submit summary results to CAISO and store code, analysis datasets, and results datasets. 11. Update control group validation for changes in the resource customer mix of more than +/-10% or to remain compliant with seasonal or rolling window validation requirements.
Event period	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.
Method for control group development	List the method used to develop the control group – random assignment of site, random assignment of clusters, matched control group, or other. For random assignment, please retain the randomization code and set a random number generator seed value.
Replication and Audit	Control group equivalence and event days calculation are subject to audit. The results must be reproducible. The underlying customer level data, randomization files, and validation code, and event day analysis code must be retained for 3 years and be made available the CAISO within 10 business days of a request. In the case where the California ISO deems it necessary, DRPs will be required to securely provide the control and treatment

Component	Explanation
	group's interval data to recreate the bias regression coefficient and CVRMSE to ensure they meet the criteria
Validation options	Validation is performed by the DRP and subject to audit by CAISO. The validation method uses 75-day lookback period with a 30-day buffer. Validation is required as described in note e, below. The 75 days selected for validation should be chosen such that the validation is complete prior to finalizing the control group to act as the designated baseline method for that resource. a. 30 days used to collect and validate the groups b. Prior 45 days used for the validation (t-31 to t-75) c. Candidate validation days used to establish control group similarity are either non-event weekdays (if the resource is dispatched only on weekdays) or all non-event days (if the resource can be dispatched on any day) d. A minimum of 20 candidate days are required to be in the validation period. If there are not 20 non-event validation days, extend the validation period backwards (t-76 and further) until there are 20 candidate days in the validation period. e. Requires validation check updates every other month if the number of accounts in the resource does not change more than ± 10%. If the number of accounts changes by more than ± 10%, the control group must be validated monthly. f. If the validation fails, the control group method is unavailable for that resource unless the control group is updated and revalidated. Control groups may be updated monthly. g. 90% of the population must be in both the validation period and the active period
Aggregation of Control Groups across Sub Load Aggregation Points (subLAPs)	Aggregation of control groups is permissible across different subLAPs; however the same performance on intra-subLAP equivalence checks must be demonstrated. While sourcing a control group from a region with similar weather and customer mix conditions is not explicitly mandated, considerations for these attributes that affect load may help in developing an appropriate control group.
Rotation of control groups	The assignment to treatment and control groups can be updated on a monthly basis; however this assignment must be completed prior to any events. Validation of new control groups must also be completed prior to any events in concurrence with any new control group development. The assignment cannot be changed once set for the month and cannot be changed after the fact

4.2 Weather Matching Baselines

Weather-matching baselines estimate what electricity use would have been in the absence of dispatch (the baseline) by relying exclusively on electricity use data for customers who were dispatched. The load patterns during a subset of non-event days with the most similar weather conditions are used to estimate the baseline for the event day. Weather matching baselines do not include information from an external control group.

Table 4-3: Residential Weather Matching Baseline Process and Rules

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an event 2. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 3. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 4. Select the baseline days out of the pool of eligible days 5. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 6. Calculate the same-day adjustment ratio based on the adjustment period hours. 7. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 8. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 9. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	1. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 2. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 3. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

Table 4-4: Non-Residential Weather Matching Baseline Process and Rules

	Weekday Baseline 4 Day Matching Using Daily Maximum Temperature	Weekend Baseline 4 Day Matching Using Daily Maximum Temperature

Baseline calculation process	10. Identifying eligible baseline days that occurred prior to an event 11. Calculate the aggregate hourly participant load on the event day and on each eligible baseline day during the event period hour. 12. Calculate the resource's participant weighted temperatures for each hour of each event day and eligible baseline day 13. Select the baseline days out of the pool of eligible days 14. Average hourly customer loads across the baseline days to generate the unadjusted baseline. 15. Calculate the same-day adjustment ratio based on the adjustment period hours. 16. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 17. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 18. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour	
Eligible baseline days	Weekdays, excluding event days and federal holidays, in the 90 days immediately prior to the event.	Weekends and federal holidays, excluding event days, in the 90 days immediately prior to the event
Baseline day selection criteria	Rank eligible days based on how similar daily maximum temperature is to the event day	Rank eligible days based on how similar daily maximum temperature is to the event day
Number of days selected to develop baseline	4 days with the closest daily maximum temperature	4 days with the closest daily maximum temperature
Calculation of temperatures	4. Map the resource sites to pre-approved National Oceanic Atmospheric Association weather station based on zip code and the mapping included as Appendix B 5. Calculate the participant-weighted weather for each hour of each event and eligible baseline day. That is the weather for each relevant weather station is weighted based on the share of participant associated with the specific weather station. 6. Calculate the average temperature or daily maximum temperatures across all 24 hours in both the event day and eligible baseline days.	
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $$\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$$	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

4.3 Day Matching Baselines

Day-matching baselines also estimate what electricity use would have been in the absence of dispatch (the baseline) by relying exclusively on electricity use data for customers who were dispatched. The load patterns during a subset of non-event days are used to estimate the baseline for the event day.

Table 4-5: Residential Day Matching Baseline Process and Rules

	Weekday Baseline Highest 5 of 10	Weekend Baseline Highest 3 of 5 weighted
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an event 2. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day 3. Calculate total MWh during the event period for each eligible baseline day 4. Rank the baseline days from largest to smallest based on MWh consumed over the event period 5. Select the baseline days out of the pool of eligible days 6. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate. 7. Calculate the same-day adjustment ratio based on the adjustment period hours. 8. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 9. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 10. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.	
Eligible baseline days	10 weekdays immediately prior to event, excluding event days and federal holidays	5 weekend days, including federal holidays, immediately prior to the event
Baseline day selection criteria	Rank days for largest to smallest based on MWh over the event period, pick the top 5 days	Rank days for largest to smallest based on MWh over the event period, pick the top 3 days
Application of weights (if needed)	Not applicable	1. 50% - Highest load day 2. 30% - 2nd Highest load day 3. 20% - 3rd Highest load day
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The weighted hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.4x. If the ratio is larger than 1.4, limit it to 1.4. If the ratio is less than 1/1.4 = 0.71, limit it to 0.71	Cap the ratio between +/- 2x. If the ratio is larger than 2.0, limit it to 2.0. If the ratio is less than 1/2 = 0.50, limit it to 0.50
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

Table 4-6: Non-Residential Day Matching Baseline Process and Rules

	Weekday Baseline Highest 10 of 10	Weekend Baseline Highest 4 of 4
Baseline calculation process	11. Identifying eligible baseline days that occurred prior to an event 12. Calculate the aggregate hourly participant load for the event day and for each eligible baseline day 13. Calculate total MWh during the event period for each eligible baseline day 14. Rank the baseline days from largest to smallest based on MWh consumed over the event period 15. Select the baseline days out of the pool of eligible days 16. Average hourly customer loads across the baseline days to generate the unadjusted baseline. Apply weighted average, if appropriate. 17. Calculate the same-day adjustment ratio based on the adjustment period hours. 18. If the same day adjustment ratio exceeds adjustment limit, limit the adjustment ratio to the cap. 19. Apply the same day adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline. Application of the baseline adjustment is not optional. It must be employed to calibrate the unadjusted baseline. 20. Calculate the demand reduction as the difference between the adjusted baseline and actual electricity use for each event hour.	
Eligible baseline days	10 weekdays immediately prior to event, excluding event days and federal holidays	4 weekend days, including federal holidays, immediately prior to the event
Baseline day selection criteria	Keep all 10 eligible days	Keep all 4 eligible days
Application of weights (if needed)	Not applicable	Not applicable
Event	Per CAISO, the event period includes any phase-in or phase-out ramp defined by the schedule coordinator, in addition to hours where the resource is dispatched.	
Unadjusted baseline	The weighted hourly average of the resource's electric load during baseline days. The unadjusted baseline includes all 24 hours in day.	
Adjustment hours	Two hours immediately prior to the event period with a two hour buffer before the event and two hours after the event with a two hour buffer. For example, if an event went from 1pm to 4pm, the adjustment hours would be 9am-11am and 6-8pm.	
Same day adjustment ratio	Calculate the ratio between the resources load and the unadjusted baseline during the adjustment hours. $\text{Adjustment ratio} = \frac{\text{Total kWh during adjusment hours}}{\text{Unadjusted baseline kWh over adjustment hours}}$	
Adjustment Limit	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83	Cap the ratio between +/- 1.2x. If the ratio is larger than 1.2, limit it to 1.2. If the ratio is less than 1/1.2 = 0.83, limit it to 0.83
Adjusted baseline	Apply the capped same day adjustment ratio to the unadjusted baseline to calculate the final adjusted baseline. The ratio is applied to all 24 hours of the unadjusted baseline	

5 Implementation of Control Group Settlement Methodology

Randomized control groups consistently outperformed day and weather matching baselines for residential and commercial AC cycling programs during testing. With large enough sample sizes, between 200 and 400 participants, they were more precise than day or weather matching baselines.

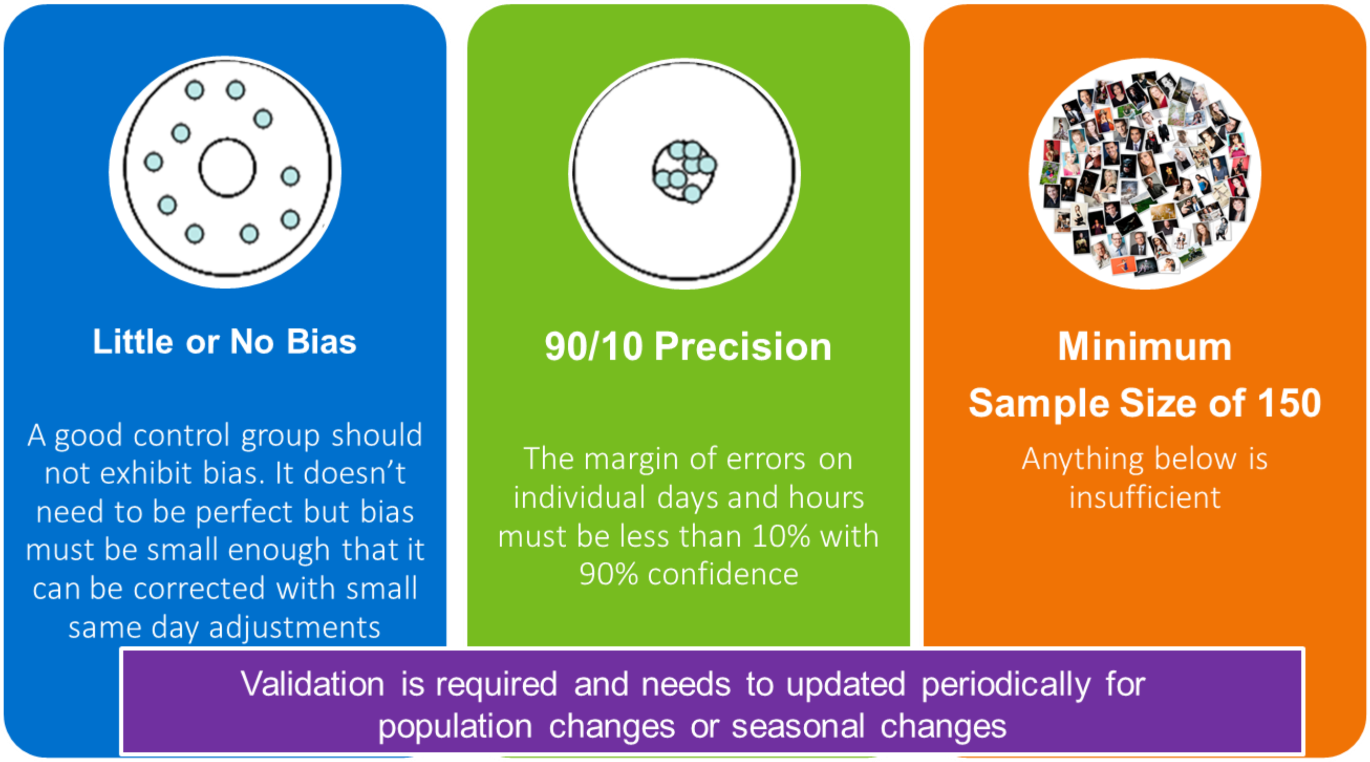
Control groups involve using a set of customers who did not experience events to establish a baseline. A control group should be made of customers who are statistically indistinguishable from the participant group on non-event days to act as a comparison on event days, instead of relying on participants' past performance. There are many ways to develop a control group, including random assignment and statistical or propensity score matching. The rules were intentionally developed so as not preclude use of alternate methods for selecting a control group. There are, however, multiple issues surrounding the development of matched control groups (e.g. data security, equal access to non-participant data, legality, and cost) that were outside of the BAWG scope. Currently, all demand response providers are able to establish a control group by randomly assigning and withholding a subset of participant resource sites from dispatch. However, not all demand response providers have equal access to utility smart meter data for non-participants, which is necessary for development of matched control groups.

The best approach for developing a valid control group is to randomly assign a subset of customers in a resource portfolio to serve as the control group. This requires withholding a subset of participants from event dispatch, thus establishing the baseline. Because of random assignment, there are no systematic differences between the group that is dispatched and the control group, except the event dispatch. With sufficient sample sizes, differences due to random chance are minimized and the control group becomes statistically indistinguishable from the treatment group. This then means that any difference in load profiles on event days can be attributed to the effect of treatment, and that any difference between the two groups on non-event days should be negligible.

However, before a control settlement methodology can be employed it is necessary to demonstrate that the energy use of the control group is an accurate predictor of the energy use of the participants. Three high level requirements for demonstrating the validity of a control group are shown below. Instructions for demonstrating control group equivalence follow, with applied examples in the appendix to this document. Once a suitably accurate and precise baseline has been developed, it can be adjusted using same-day adjustments as described at the end of this section. However, it is the unadjusted baseline that must meet the accuracy, precision and sample size criteria.

Figure 5-1 demonstrates the three key principles for the development and validation of control groups. They must exhibit little or no bias, must be sufficiently precise, and be large enough to represent the treatment population.

Figure 5-1: Control Group Requirements



5.1 Statistical Checks Necessary to Demonstrate Control Group Validity

Demand response providers will need to demonstrate that the control group reflects the electricity use patterns of customers curtailed (validation). The process for demonstrating equivalence is outlined below. It is the responsibility of the demand response provider to develop the control group and demonstrate equivalence. The control group(s) developed are subject to audit by the CAISO.

1. The demand response provider identifies a control pool of at least 150 customers to be selected via statistical matching or randomly withheld from the participant population. A single control group may be used for multiple subLAP settlement groups; however, equivalence, using the procedure outlined below, must be demonstrated for each of the treatment groups against the control group. For example, if there are five subLAPs, five equivalence checks must be completed to show that the control customers are equivalent to treatment customers in subLAPs A, B, C, D and E. Use of a different control group for each subLAP is also permitted and will be necessary if there are significant differences in weather sensitivity or other characteristics among treatment groups in different subLAPs. In those cases, equivalence must be demonstrated only between the treatment group and the control group for which it is acting as control.

2. For each resource ID, look back 75 days from when the validation occurs, and pull hourly data from the 45 earliest days (t-31 to t-75). The days included in the validation must be in this t-31 to t-75 range, excluding any days that an event has been called for this resource. If the resource is

only dispatched on weekdays, the candidate weekend days may be ignored. If the resource can be dispatched on weekdays and weekends/holidays, all non-event days must be included in the validation period. In addition, exclude event days that the customers in the resource could have participated in. If customers are dually participating in utility load modifying programs, event days of the load modifying resource may also be excluded. If there are not at least 20 available candidate days, continue looking further back (t-76 to t-85 for example) to find additional candidate days until 20 days are available for validation.

3. Average the hourly load profile for all treatment group customers and all control group customers by day and hour.

4. Filter to the appropriate hours and days. Validation is only done on the hours 12-9pm but does include weekdays, weekends, and holidays if the resource can be dispatched on those days.

5. Arrange the data in the appropriate format. For most statistical packages and Excel, regressions are easiest to perform when data is in a long format by date and hour and wide by treatment status. Note that the datasets should be separate for each treatment/control group pairing to be tested.

6. Regress average treatment hourly load against average control hourly load during event hours with no constant. This can be done in a statistical package like R or Stata, or within an Excel file or other spreadsheet application. The functional form of this model should be

$$y_{i,h}^{T} = \beta y_{i,h}^{C} + \varepsilon_{i,h}$$

Where $y_{i,h}^{T}$ is the average kW across all treatment customers for the non-event day i and hour h, and $y_{i,h}^{C}$ is the average kW across all control customers for that same hour and day. The coefficient,β, represents the bias that exists in the control group; that is, the percent difference between the average treatment kW and the average control kW across all days and event hours. A coefficient of 1.05 means that the treatment group demand is on average 5% higher than that of the control group. Similarly, a coefficient of 0.86 means that the control group load is 86% that of the treatment group. Note that this model explicitly excludes a constant term from the regression.

7. To demonstrate lack of bias, the coefficient β should be between 0.95 and 1.05, minimizing the unadjusted absolute bias from the treatment group.

8. To demonstrate that the control group has sufficient precision, the value of the normalized root mean squared error at the 90% confidence level should be less than 10%. The normalized root mean squared error, or CVRMSE, is calculated according to

$$CV(RMSE) = \frac{\sqrt{\frac{\sum_{i,h}(y_{i,h}^{C} - y_{i,h}^{T})^2}{n}}}{(1/n)\sum_{i,h} y_{i,h}^{T}}$$

In this equation, the squared difference between treatment and control for each event hour and day is summed over all event hours and days, and then divided by the total number of event hours and days (n). The square root of that value is divided by the average treatment load across all event hours and days to normalize the error. Under the assumption that the CVRMSE is normally distributed, the 90% confidence level for this statistic is 1.645 times the CVRMSE. For example, if the CVRMSE is 0.86%, the 90% confidence level for the statistic is 1.414%.

Appendix A Applied Examples of Control Group Validation

A.1 Using Excel

Shown below are examples of how to demonstrate equivalence between treatment and control groups in Excel. A template for performing this calculation can be found in the file called ‘Randomization Validation Template.xlsx’. As described above, the steps to performing this calculation are:

1. Identify a control pool of at least 100 customers to be selected via statistical matching or randomly withheld from the participant population. Create a dataset that has the form shown in Figure A-1 with control and participant’s hourly usage by date from hours ending 1 through 24.

Table A-1: Base Dataset

Participant ID	Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
1	C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
1	C	Winter	1/1/2015	0.72	1.81	0.88	1.97	1.39	1.79		1.49	1.40
1	C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
1	C	Winter	1/3/2015	1.76	0.61	1.99	0.77	1.27	1.27		1.85	1.85
1	C	Winter	1/4/2015	1.60	0.66	1.55	1.08	1.86	1.57		0.68	0.83
1	C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
1	C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
2	T	Winter	12/31/2014	1.11	0.97	1.39	0.58	1.36	1.30		1.54	0.79
2	T	Winter	1/1/2015	0.65	1.04	1.38	1.31	0.81	1.68		0.80	1.47
2	T	Winter	1/2/2015	0.97	1.44	1.31	1.19	1.89	1.74		0.59	1.44
2	T	Winter	1/3/2015	1.16	1.59	1.70	1.25	1.11	1.63		0.79	0.97
2	T	Winter	1/4/2015	0.72	1.98	1.24	1.52	1.91	1.99		0.57	1.85
2	T	Winter	1/5/2015	0.56	1.20	1.19	1.34	1.33	0.50		1.23	1.38
2	T	Winter	1/6/2015	0.99	0.99	0.60	1.32	0.61	1.23		0.93	1.27
3	T	Winter	12/31/2014	1.59	1.81	0.58	1.69	1.49	1.15		0.55	1.81
3	T	Winter	1/1/2015	1.11	1.67	0.71	1.00	0.95	1.39		1.86	1.50
3	T	Winter	1/2/2015	1.71	1.54	1.26	1.40	1.67	1.52		1.90	1.67
3	T	Winter	1/3/2015	1.54	1.11	1.03	1.45	1.10	0.85		1.81	2.00
3	T	Winter	1/4/2015	1.13	0.67	1.25	0.83	1.96	1.58		0.78	0.64
3	T	Winter	1/5/2015	0.96	1.06	1.35	0.89	1.72	1.01		0.54	1.95
3	T	Winter	1/6/2015	0.99	1.35	1.32	0.75	0.82	1.16		1.08	1.11

2. Average the hourly load profile for all treatment group customers and all control group customers by day and hour.

Table A-2: Average Daily Treatment and Control Usage

Ineligible Day	Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
	C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
Holiday	C	Winter	1/1/2015	0.72	1.81	0.88	1.97	1.39	1.79		1.49	1.40
	C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
Weekend	C	Winter	1/3/2015	1.76	0.61	1.99	0.77	1.27	1.27		1.85	1.85
Weekend	C	Winter	1/4/2015	1.60	0.66	1.55	1.08	1.86	1.57		0.68	0.83
	C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
	C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
	T	Winter	12/31/2014	1.35	1.39	0.98	1.14	1.42	1.23		1.05	1.30
Holiday	T	Winter	1/1/2015	0.88	1.36	1.04	1.15	0.88	1.53		1.33	1.49
	T	Winter	1/2/2015	1.34	1.49	1.28	1.29	1.78	1.63		1.25	1.56
Weekend	T	Winter	1/3/2015	1.35	1.35	1.36	1.35	1.10	1.24		1.30	1.49
Weekend	T	Winter	1/4/2015	0.92	1.33	1.25	1.18	1.93	1.79		0.68	1.24
	T	Winter	1/5/2015	0.76	1.13	1.27	1.11	1.52	0.76		0.88	1.66
	T	Winter	1/6/2015	0.99	1.17	0.96	1.04	0.72	1.19		1.01	1.19

3. Flag and remove days in which the resource is not available and event days that the customers in the resource could have participated in.

Table A-3: Average Daily Treatment and Control Usage

Treat	RA Season	Date	kWh1	kWh2	kWh3	kWh4	kWh5	kWh6	…	kWh23	kWh24
C	Winter	12/31/2014	2.00	1.11	1.91	1.29	0.78	1.25		0.97	1.44
C	Winter	1/2/2015	0.85	0.59	1.67	0.64	0.67	1.04		2.00	1.42
C	Winter	1/5/2015	1.59	1.32	0.53	1.32	1.44	0.88		1.12	1.18
C	Winter	1/6/2015	1.45	1.63	1.47	1.50	1.66	0.98		1.90	0.66
T	Winter	12/31/2014	1.35	1.39	0.98	1.14	1.42	1.23		1.05	1.30
T	Winter	1/2/2015	1.34	1.49	1.28	1.29	1.78	1.63		1.25	1.56
T	Winter	1/5/2015	0.76	1.13	1.27	1.11	1.52	0.76		0.88	1.66
T	Winter	1/6/2015	0.99	1.17	0.96	1.04	0.72	1.19		1.01	1.19

4. Arrange the data in the appropriate format.

Table A-4: Average Daily Treatment and Control Usage

Date	Hour	kWh_Treat	kWh_Control
12/31/2014	1	1.35	2.00
	2	1.39	1.11
	3	0.98	1.91
	4	1.14	1.29
	5	1.42	0.78
	6	1.23	1.25
	…		
	23	1.05	0.97
	24	1.30	1.44
1/2/2015	1	1.34	0.85
	2	1.49	0.59
	3	1.28	1.67
	4	1.29	0.64
	5	1.78	0.67
	6	1.63	1.04
	…		
	23	1.25	2.00
	24	1.56	1.42
1/5/2015	1	0.76	1.59
	2	1.13	1.32
	3	1.27	0.53
	4	1.11	1.32
	5	1.52	1.44
	6	0.76	0.88
	…		
	23	0.88	1.12
	24	1.66	1.18
1/6/2015	1	0.99	1.45
	2	1.17	1.63
	3	0.96	1.47
	4	1.04	1.50
	5	0.72	1.66
	6	1.19	0.98
	…		
	23	1.01	1.90
	24	1.19	0.66

5. Regress average treatment hourly load against average control hourly load during event hours with no constant by filling in the attached template and updating formulas in cells H20 and H24 to include the full range of the data added to columns B through E.

Figure A-1: Regression and Validation Template

Row	Date	Hour	Treatment kWh	Control kWh	Error Squared
3	12/31/2014	1	1.35	2.00	0.42250
4	12/31/2014	2	1.39	1.11	0.07840
5	12/31/2014	3	0.98	1.91	0.85008
6	12/31/2014	4	1.14	1.29	0.02449
7	12/31/2014	5	1.42	0.78	0.42055
8	12/31/2014	6	1.23	1.25	0.00046
9	12/31/2014	...			0.00000
10	12/31/2014	23	1.05	0.97	0.00562
11	12/31/2014	24	1.30	1.44	0.01960
12	1/2/2015	1	1.34	0.85	0.24010
13	1/2/2015	2	1.49	0.59	0.81000
14	1/2/2015	3	1.28	1.67	0.15016
15	1/2/2015	4	1.29	0.64	0.43296
16	1/2/2015	5	1.78	0.67	1.22545
17	1/2/2015	6	1.63	1.04	0.34928
18	1/2/2015	...			0.00000
19	1/2/2015	23	1.25	2.00	0.57003
20	1/2/2015	24	1.56	1.42	0.01823
21	1/5/2015	1	0.76	1.59	0.68558
22	1/5/2015	2	1.13	1.32	0.03648
23	1/5/2015	3	1.27	0.53	0.54834
24	1/5/2015	4	1.11	1.32	0.04182
25	1/5/2015	5	1.52	1.44	0.00601
26	1/5/2015	6	0.76	0.88	0.01525
27	1/5/2015	...			0.00000
28	1/5/2015	23	0.88	1.12	0.05452
29	1/5/2015	24	1.66	1.18	0.23136
30	1/6/2015	1	0.99	1.45	0.20794
31	1/6/2015	2	1.17	1.63	0.20931
32	1/6/2015	3	0.96	1.47	0.26317
33	1/6/2015	4	1.04	1.50	0.21716
34	1/6/2015	5	0.72	1.66	0.89114
35	1/6/2015	6	1.19	0.98	0.04623
36	1/6/2015	...			0.00000
37	1/6/2015	23	1.01	1.90	0.79477
38	1/6/2015	24	1.19	0.66	0.28037

1. Populate the values to the right with eligible (n
winter (perform these calculations in separate ta

2. Update the formulas in cells H20 and H24 (the E
500, for example, ensure that the formulas in H20

3. Make a scatterplot with control kWh as the X-a

4. Right click on the scatterplot data in the graph
options circled to the right, then click 'OK'
  a. Linear Regression Type
  b. Set Intercept = 0
  c. Display Equation on chart

BETA
0.999271146

Must be between 0.95 and 1.05

CVRMSE
4.84%

Margin of Error with 90% Confidence
8.0%

Must be less than 10%

6. The statistics of interest are in cells H20, H24, and H29.

A.2 Applied Example of Validation Required – Using Stata

Example code that performs the control group validation can be found in the Stata do file named 'Stata Code to Validate Equivalence.do'.

The command to perform this regression is: *reg kWh_treat kWh_control, noconstant.* If using Stata, the validation statistics can be calculated easily using the two commands underlined in green. The coefficient β is the value circled in orange. The 90% limit on the CVRMSE can be calculated using the output (circled in blue) from the same two commands as shown in Figure A-2.

Figure A-2: Stata Commands to Calculate Equivalence Statistics

```
          reg kwh_treat kwh_control, noconstant

      Source |       SS       df       MS              Number of obs =    5568
-------------+------------------------------           F(  1,  5567) =       .
       Model |  3792.8973     1  3792.8973             Prob > F      =  0.0000
    Residual |  10.197965  5567  .00183186             R-squared     =  0.9973
-------------+------------------------------           Adj R-squared =  0.9973
       Total | 3803.09527  5568  .683027167            Root MSE      =   .0428

------------------------------------------------------------------------------
   kwh_treat |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
 kwh_control |    1.00539   .0006987  1438.93   0.000     1.004021     1.00676
------------------------------------------------------------------------------


          sum kwh_treat

    Variable |       Obs        Mean    Std. Dev.       Min        Max
-------------+--------------------------------------------------------
   kwh_treat |      5568    .7518921    .3430839   .1965188   3.313407


          di in red "the RMSE is " e(rmse)
the RMSE is .04280023

          di in red "the average treatment kWh is " r(mean)
the average treatment kWh is .75189212

          di in red "the 90% confidence limit of the CVRMSE is " 1.645 * (e(rmse)/r(mean)) * 100 "%"
the 90% confidence limit of the CVRMSE is 9.3638946%

          di in red "it can also be manually entered like this: " 1.645 * (.04280023/.75189212) * 100 "%"
it can also be manually entered like this: 9.3638936%
```

Appendix B Process to Calculate Participant-Weighted Weather

B.1 Mapping of NOAA Weather Stations to ZIP codes

Weather matching baselines require weather data in order to find similar non-event days. The BAWG found that participant-weighted weather, meaning an average hourly weather profile that is the weighted average of the geographic mix of resource participants, vastly outperforms using a single weather profile for each subLAP and resource. To facilitate this process, the BAWG has put together a mapping of NOAA stations to California zip codes.

The mapping was done using distance matching by finding the closest NOAA weather station by physical distance to the centroid of each zip code. For zip codes that did not have latitude and longitude values available (the metrics used to calculate distance from the stations), a matching process was used to find the weather stations of proximate surrounding zip codes, which was then used to fill in missing values. The full list of zip codes and their associated weather stations can be found in the Excel workbook 'NOAA Station to Zip Mapping.xlsx'. This list above shall be updated by the IOUs for each of their respective territories and updated at the request of DRPs.

B.2 Calculating Participant-Weighted Weather

Once participants have been identified for a particular resource, their weather data can be compiled to calculate the participant-weighted average weather by day and hour. The process is as follows:

1. Determine the weather stations associated with the resource in question. For all the resource participants, collect their associated premise-level zip codes (ie the zip code associated with their physical location, not their billing location), and use the mapping listed above to generate a list of associated weather stations for each resource

2. Collect the last 90 days of weather data from NOAA from the weather stations in question.

    a. Data should be at the hourly level for all days and weather stations

3. Assemble the dataset of participants for the full baseline search period. The look-back period for weekday baselines is 90 days and 56 days (8 weeks) for weekend baselines. Each participant must have an associated premise zip code that indicates their physical (ie not billing) location.

4. Merge the customer-level dataset with the weather station mapping by zip code. In effect, ensure that each customer has a single weather station that is mapped to their zip code using the mapping attached above (or a subsequent update).

5. Now merge the weather data in to the customer-level dataset by weather station. This should yield a dataset that is unique by participant id, date and hour (if the dataset is long by hour).

6. Create the resource-average dataset by collapsing the participant-level dataset to an average by date and hour. No weighting is required if the dataset described in step 5 includes all the participants in the particular resource. Frequency weights should be applied to calculate the

weighted average of all the weather stations in the resource (weighted by the total number of participants that are mapped to each weather station) if the dataset does not include all participants.

7. The dataset is participant-weighted and can be merged to the average hourly load data by date and hour to calculate weather-matching baselines.

Appendix C Detailed Day-Matching Calculation Process

A detailed example of how to calculate a weather matching baseline is described in the Excel workbook named 'Example_Day_Match_Workbook.xlsx'. The steps are as follows:

0. Start with hourly interval data for all participants in the program, with at least 90 days of prior data. Note this is not shown in the attached example.

1. Collapse the data to the average hourly load by day for the full set of participants. The dataset should now look something like the example shown in Tab 1 of the attached document.

2. Clean the data by removing ineligible days (weekends and holidays, already excluded from this example) and other event days that the participants were dispatched for (highlighted in grey). The event day in this example, was September 10th, 2015, when the program was called between 4-7pm (hour ending 17 to hour ending 19). Note that this dataset is slightly smaller than the 90 days of eligible data, but it does not affect the calculations required for day matching.

    a. Generate the average event load. For each of the non-event days remaining in the dataset, average the hourly load for the event hours (in this case HE17-HE19) for each day.

3. Keep the last Y eligible days. The number Y refers to the denominator of the day matching baseline. If the baseline is a top 5/10, Y = 10. If the baseline is a top 3/5, as shown in the example workbook, Y = 5. These are your eligible days

4. Sort by the average event load in decreasing order, and pick the top X largest days. These are your baseline days. The X in this case refers to the numerator of the day matching baseline. For the two baseline examples listed in Step 3, X = 5 or X = 3, respectively. In the attached example, X = 3.

5. Generate the unadjusted baseline. Two options are presented in the attached example:

    a. Top 3/5 Unweighted: The three baseline days are simply averaged to generate the baseline.

    b. Top 3/5 Weighted: The closest day to the baseline receives a weight of 50%, the next closest receives a weight of 30% and the furthest receives a weight of 20%. Note that closest in this case refers to days closest to the event day, not by the average event load sorting that was done in Step 4. The weighting is applied by multiplying the % for each day to the hourly load profiles, then summing. This is a weighted average.

6. Perform the same-day adjustment as necessary.

a. Define the adjustment window periods. In the example, the event occurs between HE17and HE19 (highlighted in blue in the example). For two-hour pre- and post-event adjustment windows with a two-hour buffer, the adjustment window hours (highlighted in orange in the example) are HE13, HE14, HE22, and HE23.

b. Average the usage across those four hours for both the baseline and the event day observed load.

c. Calculate the adjustment ratio by dividing the baseline average window value by the observed average window value. In the example, the baseline has an adjustment window value of 1.49kW and the event adjustment window value is 1.76. The ratio is then 1.18.

d. Cap the ratio at the required level. If the cap is 1.4x, as in the example, the following logic applies:

    i. If the ratio is less than 1/1.4 = 0.71, the capped ratio is now set to 0.71.

    ii. If the ratio is between 0.71 and 1.4, the ratio remains as is.

    iii. If the ratio is greater than 1.4, the capped ratio is now set to 1.4.

e. Apply the capped ratio to each hour of the baseline by multiplying the capped ratio by the hourly baseline values for each hour

f. The profile obtained in step 6e is the baseline.

7. DR Energy Measurements are calculated as the difference between the baseline and the observed load, which have already been decomposed to the 5-minute increment level, such that load reductions relative to the baseline are positive. Load increases, when the baseline is less than the observed load, should be set to 0 for settlement purposes.

Appendix D Detailed Weather-Matching Calculation Process

A detailed example of how to calculate a weather matching baseline is described in the Excel workbook named 'Example_Weather_Match_Workbook.xlsx'. The steps are as follows:

0. Start with hourly interval data for all participants in the program, with at least 90 days of prior data. Note this is not shown in the attached example.
1. Collapse the data to the average hourly load by day for the full set of participants. The dataset should now look something like the example shown in Tab 1 of the attached document.
2. Clean the data by removing ineligible days (weekends and holidays, already excluded from this example) and other event days that the participants were dispatched for (highlighted in grey). The event day in this example, was September 10th, 2015, when the program was called between 4-7pm (hour ending 17 to hour ending 19). Note that this dataset is slightly smaller than the 90 days of eligible data, but it does not affect the calculations required for day matching.
    a. Also generate the weather variable of interest for the baseline – either the maximum hourly temperature or the average daily temperature
    b. Drop any days that occur AFTER the event day for which the baseline is being calculated.
3. Sort the dataset by how similar the eligible days are to the event day, by calculating the absolute value of the difference between the event day average (or maximum) temperature and the eligible day's average (or maximum) temperature.
4. Sort by the weather variable absolute difference in decreasing order, and pick the top X largest days. These are your baseline days. The X in this case refers to number of days used to estimate the weather baseline. A 3 day weather matching baseline will have X = 3. A 5-day weather matching baseline will have X = 5.
5. Generate the unadjusted baseline by averaging the hourly kW values across the X baseline days.
6. Perform the same-day adjustment as necessary.
    a. Define the adjustment window periods. In the example, the event occurs between HE17and HE19 (highlighted in blue in the example). For two-hour pre- and post-event adjustment windows with a two-hour buffer, the adjustment window hours (highlighted in orange in the example) are HE13, HE14, HE22, and HE23.
    b. Average the usage across those four hours for both the baseline and the event day observed load.

c. Calculate the adjustment ratio by dividing the baseline average window value by the observed average window value. In the example, the baseline has an adjustment window value of 1.64kW and the event adjustment window value is 1.76. The ratio is then 1.07.

d. Cap the ratio at the required level. If the cap is 1.4x, as in the example, the following logic applies:

   i. If the ratio is less than 1/1.4 = 0.71, the capped ratio is now set to 0.71.

   ii. If the ratio is between 0.71 and 1.4, the ratio remains as is.

   iii. If the ratio is greater than 1.4, the capped ratio is now set to 1.4.

e. Apply the capped ratio to each hour of the baseline by multiplying the capped ratio by the hourly baseline values for each hour

f. The profile obtained in step 6e is the baseline.

7. DR Energy Measurements are calculated as the difference between the baseline and the observed load such that load reductions relative to the baseline are positive. Load increases, when the baseline is less than the observed load, should be set to 0 for settlement purposes.

Appendix E Best Baseline Results by Program and Utility

Results shown here are the top 10 baselines by utility, program, and baseline category, chosen by finding baselines with absolute bias less than 10%, and then sorted by low CVRMSE. For consistency, all results shown here are for events with the following features:

- Event window from HE16-HE19 (or as close as possible to this for event-based results).
- Residential programs use samples of 500 customers, and commercial programs use 100
- Simulated over 10 events per summer for proxy weekday results and 3 events for proxy weekend results
- All post-event adjustments include a 2-hour buffer between the end of the event and the post-adjustment period.

Table A-5: Proxy Weekday Results

Program	Baseline Category	Type	Adjustment Cap	Adjustment Type	MPE (%)	CVRMSE (%)	Recommended
PG&E BIP	Day matching	10/20	+/-1.4x	No Post Adjustment	0.53	3.20	
		10/20	Unlimited	No Post Adjustment	0.53	3.20	
		10/20	+/-1.5x	No Post Adjustment	0.53	3.20	
		10/20	+/-2x	No Post Adjustment	0.53	3.20	
		10/20	+/-1.3x	No Post Adjustment	0.54	3.20	
		10/10	+/-1.5x	No Post Adjustment	-0.11	3.22	Same Type as Proposed
		10/10	+/-1.4x	No Post Adjustment	-0.11	3.22	Same Type as Proposed
		10/10	+/-2x	No Post Adjustment	-0.11	3.22	Same Type as Proposed
		10/10	Unlimited	No Post Adjustment	-0.11	3.22	Same Type as Proposed
		Bottom 10/10	+/-1.5x	No Post Adjustment	-0.11	3.22	
	Weather matching	Bins based on CDD	Unlimited	No Post Adjustment	-0.42	3.29	
		Bins based on CDD	+/-2x	No Post Adjustment	-0.42	3.29	
		Bins based on CDD	+/-1.5x	No Post Adjustment	-0.43	3.30	
		Bins based on Sum of CDH	+/-2x	No Post Adjustment	-0.65	3.41	
		Bins based on Sum of CDH	Unlimited	No Post Adjustment	-0.65	3.41	
		Bins based on Max Temp	Unlimited	No Post Adjustment	-0.67	3.41	
		Bins based on Max Temp	+/-2x	No Post Adjustment	-0.67	3.41	
		5 Day Match on Sum of CDH	+/-1.3x	No Post Adjustment	-0.13	3.41	
		5 Day Match on Sum of CDH	+/-2x	No Post Adjustment	-0.13	3.41	
		5 Day Match on Sum of CDH	+/-1.5x	No Post Adjustment	-0.13	3.41	
PG&E Res AC Cycling	Control group	Control group	+/-1.1x	Pre & Post Adjustment	0.21	3.84	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	0.21	3.86	Proposed

		Control group	+/-1.3x	Pre & Post Adjustment	0.21	3.86	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	0.21	3.86	Same Type as Proposed
		Control group	Unlimited	Pre & Post Adjustment	0.21	3.86	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	0.21	3.86	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	0.21	3.86	Same Type as Proposed
		Control group	+1.1x	Pre & Post Adjustment	1.65	4.31	Same Type as Proposed
		Control group	+1.3x	Pre & Post Adjustment	1.66	4.32	Same Type as Proposed
		Control group	+1.4x	Pre & Post Adjustment	1.66	4.32	Same Type as Proposed
	Day matching	5/20	+/-1.4x	Pre & Post Adjustment	-0.50	5.21	
		5/20	Unlimited	Pre & Post Adjustment	-0.51	5.21	
		5/20	+/-1.5x	Pre & Post Adjustment	-0.51	5.21	
		5/20	+/-2x	Pre & Post Adjustment	-0.51	5.21	
		3/20	+/-1.5x	Pre & Post Adjustment	-0.08	5.36	
		3/20	+/-2x	Pre & Post Adjustment	-0.08	5.36	
		3/20	Unlimited	Pre & Post Adjustment	-0.08	5.36	
		5/20	+/-1.3x	Pre & Post Adjustment	-0.20	5.37	
		3/20	+/-1.4x	Pre & Post Adjustment	0.04	5.40	
		10/20	+/-1.5x	Pre & Post Adjustment	-1.93	5.49	
	Weather matching	5 Day Match on CDD	+/-1.1x	Pre & Post Adjustment	-2.38	5.39	
		4 Day Match on Sum of CDH	+/-1.1x	Pre & Post Adjustment	-1.58	5.39	
		5 Day Match on Sum of CDH	+/-1.1x	Pre & Post Adjustment	-1.66	5.51	
		3 Day Match on Sum of CDH	+/-1.1x	Pre & Post Adjustment	-1.45	5.74	
		4 Day Match on CDD	+2x	Pre & Post Adjustment	2.23	5.77	
		4 Day Match on CDD	+1.5x	Pre & Post Adjustment	2.23	5.77	
		4 Day Match on CDD	+1.3x	Pre & Post Adjustment	2.23	5.77	
		4 Day Match on CDD	+1.4x	Pre & Post Adjustment	2.23	5.77	
		4 Day Match on CDD	+1.2x	Pre & Post Adjustment	2.23	5.77	
		5 Day Match on CDD	+2x	Pre & Post Adjustment	2.32	5.80	
SCE Agricultural	Day matching	Bottom 10/10	+/-1.4x	No Post Adjustment	0.51	5.05	
		10/10	+/-1.4x	No Post Adjustment	0.51	5.05	Same Type as Proposed
		Bottom 10/10	+/-1.5x	No Post Adjustment	0.50	5.05	
		10/10	+/-1.5x	No Post Adjustment	0.50	5.05	Same Type as Proposed
		Bottom 10/10	Unlimited	No Post Adjustment	0.50	5.05	
		Bottom 10/10	+/-2x	No Post Adjustment	0.50	5.05	
		10/10	+/-2x	No Post Adjustment	0.50	5.05	Same Type as Proposed
		10/10	Unlimited	No Post Adjustment	0.50	5.05	Same Type as Proposed
		Bottom 10/10	+/-1.3x	No Post Adjustment	0.55	5.06	
		10/10	+/-1.3x	No Post Adjustment	0.55	5.06	Same Type as Proposed
	Weather	Bins based on Sum of CDH	+/-2x	No Post Adjustment	0.81	5.64	

	matching	Bins based on Sum of CDH	Unlimited	No Post Adjustment	0.81	5.64	
		5 Day Match on CDD	+/-2x	No Post Adjustment	1.06	5.66	
		5 Day Match on CDD	Unlimited	No Post Adjustment	1.06	5.67	
		5 Day Match on Sum of CDH	+/-2x	No Post Adjustment	1.04	5.69	
		5 Day Match on Sum of CDH	Unlimited	No Post Adjustment	1.03	5.69	
		Bins based on CDD	+/-2x	No Post Adjustment	0.99	5.75	
		Bins based on CDD	Unlimited	No Post Adjustment	0.99	5.75	
		5 Day Match on Max Temp	+/-2x	No Post Adjustment	1.11	5.76	
		4 Day Match on CDD	+/-2x	No Post Adjustment	1.15	5.76	
SCE BIP	Day matching	Bottom 10/20	+/-2x	No Post Adjustment	0.16	2.22	
		Bottom 10/20	Unlimited	No Post Adjustment	0.16	2.22	
		Bottom 5/20	Unlimited	No Post Adjustment	-0.03	2.28	
		Bottom 5/20	+/-2x	No Post Adjustment	-0.03	2.28	
		Bottom 3/3	+/-1.4x	No Post Adjustment	0.61	2.32	
		Bottom 3/3	Unlimited	No Post Adjustment	0.61	2.32	
		Bottom 3/3	+/-2x	No Post Adjustment	0.61	2.32	
		3/3	+/-1.4x	No Post Adjustment	0.61	2.32	
		3/3	Unlimited	No Post Adjustment	0.61	2.32	
		3/3	+/-2x	No Post Adjustment	0.61	2.32	
	Weather matching	Bins based on CDD	+/-2x	No Post Adjustment	-0.08	2.31	
		Bins based on CDD	Unlimited	No Post Adjustment	-0.08	2.31	
		Bins based on Max Temp	Unlimited	No Post Adjustment	-0.13	2.34	
		Bins based on Max Temp	+/-2x	No Post Adjustment	-0.13	2.34	
		Bins based on CDD	+/-1.5x	No Post Adjustment	-0.09	2.34	
		Bins based on Sum of CDH	Unlimited	No Post Adjustment	0.08	2.37	
		Bins based on Sum of CDH	+/-2x	No Post Adjustment	0.08	2.37	
		5 Day Match on Max Temp	Unlimited	No Post Adjustment	0.15	2.40	
		5 Day Match on Max Temp	+/-2x	No Post Adjustment	0.15	2.40	
		Bins based on Max Temp	+/-1.5x	No Post Adjustment	-0.17	2.43	
SCE Comm AC Cycling	Control group	Control group	+/-1.5x	Pre & Post Adjustment	-0.18	4.24	Same Type as Proposed
		Control group	Unlimited	Pre & Post Adjustment	-0.18	4.24	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	-0.18	4.24	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	-0.17	4.25	Proposed
		Control group	+/-1.3x	Pre & Post Adjustment	-0.21	4.29	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	-0.54	4.78	Same Type as Proposed
		Control group	+/-1.3x	No Post Adjustment	-0.66	5.64	Same Type as Proposed
		Control group	+/-2x	No Post Adjustment	-0.59	5.64	Same Type as Proposed
		Control group	Unlimited	No Post Adjustment	-0.59	5.64	Same Type as Proposed
		Control group	+/-1.5x	No Post Adjustment	-0.59	5.64	Same Type as Proposed

	Day matching	3/20	Unlimited	Pre & Post Adjustment	-0.41	6.79	
		5/20	Unlimited	Pre & Post Adjustment	0.39	6.94	
		5/20	+/-2x	Pre & Post Adjustment	0.42	6.95	
		10/20	Unlimited	Pre & Post Adjustment	1.57	6.96	
		10/20	+/-2x	Pre & Post Adjustment	1.57	6.96	
		10/20	+/-1.5x	Pre & Post Adjustment	1.58	6.96	
		10/10	+/-1.2x	Pre & Post Adjustment	1.09	7.11	Proposed
		Bottom 10/10	+/-1.2x	Pre & Post Adjustment	1.09	7.11	
		10/20	+/-1.4x	Pre & Post Adjustment	1.81	7.11	
		10/10	+/-1.2x	No Post Adjustment	2.79	7.43	Proposed
	Weather matching	Bins based on Max Temp	+/-1.3x	Pre & Post Adjustment	0.29	7.55	
		Bins based on Max Temp	+/-1.4x	Pre & Post Adjustment	0.98	7.82	
		Bins based on Max Temp	+/-1.5x	Pre & Post Adjustment	1.01	7.84	
		Bins based on Max Temp	+/-2x	Pre & Post Adjustment	1.01	7.84	
		Bins based on Max Temp	Unlimited	Pre & Post Adjustment	1.01	7.84	
		3 Day Match on Max Temp	+/-1.3x	Pre & Post Adjustment	2.80	7.85	
		Bins based on CDD	+/-1.3x	Pre & Post Adjustment	1.25	7.86	
		Bins based on Max Temp	+/-1.3x	No Post Adjustment	0.57	7.94	
		3 Day Match on Max Temp	+/-1.2x	Pre & Post Adjustment	1.83	7.96	
		Bins based on Max Temp	+/-1.2x	Pre & Post Adjustment	-0.54	8.02	
SDG&E Comm AC Cycling	Control group	Control group	+/-1.3x	Pre & Post Adjustment	0.08	2.98	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	0.08	2.99	Same Type as Proposed
		Control group	Unlimited	Pre & Post Adjustment	0.08	2.99	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	0.08	2.99	Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	0.08	2.99	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	0.08	3.10	Same Type as Proposed
		Control group	+/-2x	No Post Adjustment	0.14	3.69	Same Type as Proposed
		Control group	Unlimited	No Post Adjustment	0.14	3.69	Same Type as Proposed
		Control group	+/-1.4x	No Post Adjustment	0.14	3.69	Proposed
		Control group	+/-1.5x	No Post Adjustment	0.14	3.69	Same Type as Proposed
	Day matching	5/10	+/-1.5x	Pre & Post Adjustment	-0.25	3.59	
		5/10	+/-2x	Pre & Post Adjustment	-0.25	3.59	
		5/10	Unlimited	Pre & Post Adjustment	-0.25	3.59	
		5/10	+/-1.4x	Pre & Post Adjustment	-0.25	3.59	
		Bottom 4/5	+/-1.2x	Pre & Post Adjustment	-0.86	3.63	
		5/10	+/-1.3x	Pre & Post Adjustment	-0.14	3.66	
		Bottom 10/20	+/-1.2x	Pre & Post Adjustment	-1.05	3.67	
		3/5 weighted	+/-1.3x	No Post Adjustment	-0.54	3.67	
		3/5 weighted	+/-2x	Pre & Post Adjustment	-0.31	3.68	
		3/5 weighted	+/-1.5x	Pre & Post Adjustment	-0.31	3.68	

		5 Day Match on Sum of CDH	+/-1.4x	No Post Adjustment	-0.18	3.18	
		5 Day Match on Sum of CDH	Unlimited	Pre & Post Adjustment	-0.36	3.19	
		5 Day Match on Sum of CDH	+/-2x	Pre & Post Adjustment	-0.36	3.19	
		5 Day Match on Sum of CDH	+/-1.5x	Pre & Post Adjustment	-0.36	3.19	
	Weather matching	5 Day Match on Sum of CDH	+/-1.4x	Pre & Post Adjustment	-0.35	3.20	
		5 Day Match on CDD	Unlimited	Pre & Post Adjustment	-0.62	3.28	
		5 Day Match on CDD	+/-1.5x	Pre & Post Adjustment	-0.62	3.28	
		5 Day Match on CDD	+/-2x	Pre & Post Adjustment	-0.62	3.28	
		5 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	-0.61	3.28	
		4 Day Match on Sum of CDH	+/-1.4x	No Post Adjustment	-0.09	3.35	
		Control group	+/-1.1x	Pre & Post Adjustment	-0.27	5.29	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	-0.26	5.32	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	-0.26	5.32	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	-0.26	5.32	Same Type as Proposed
	Control group	Control group	Unlimited	Pre & Post Adjustment	-0.26	5.32	Same Type as Proposed
		Control group	+/-1.3x	Pre & Post Adjustment	-0.26	5.32	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	-0.26	5.32	Proposed
		Control group	+1.1x	Pre & Post Adjustment	1.49	5.56	Same Type as Proposed
		Control group	+2x	Pre & Post Adjustment	1.53	5.58	Same Type as Proposed
		Control group	+1.2x	Pre & Post Adjustment	1.53	5.58	Same Type as Proposed
		3/5 weighted	+1.5x	Pre & Post Adjustment	4.24	12.76	
		3/5 weighted	+2x	Pre & Post Adjustment	4.29	12.80	
		3/5 weighted	+1.4x	Pre & Post Adjustment	2.70	13.10	
SDG&E Res 100% AC Cycling		3/5 weighted	+/-1.5x	Pre & Post Adjustment	3.28	13.32	
	Day matching	3/5 weighted	+/-2x	Pre & Post Adjustment	3.33	13.36	
		3/5 weighted	Unlimited	Pre & Post Adjustment	3.33	13.36	
		3/5 weighted	+/-1.4x	Pre & Post Adjustment	1.75	13.65	
		3/3 weighted	+2x	Pre & Post Adjustment	3.63	13.77	
		3/3 weighted	Unlimited	Pre & Post Adjustment	2.73	14.32	
		3/3 weighted	+/-2x	Pre & Post Adjustment	2.73	14.32	
		4 Day Match on CDD	+/-1.1x	Pre & Post Adjustment	-2.59	15.94	
		5 Day Match on CDD	+/-1.1x	Pre & Post Adjustment	-2.34	16.08	
		Bins based on Max Temp	+1.5x	Pre & Post Adjustment	-5.44	16.23	
		Bins based on Max Temp	+/-1.5x	Pre & Post Adjustment	-5.44	16.23	
	Weather matching	4 Day Match on CDD	+1.1x	Pre & Post Adjustment	-1.67	16.25	
		5 Day Match on CDD	+1.1x	Pre & Post Adjustment	-1.17	16.33	
		Bins based on CDD	+1.5x	Pre & Post Adjustment	-0.20	16.54	
		Bins based on CDD	+2x	Pre & Post Adjustment	-0.18	16.54	
		Bins based on CDD	+/-1.5x	Pre & Post Adjustment	-0.26	16.55	

		Bins based on CDD	+/-2x	Pre & Post Adjustment	-0.24	16.55	
SDG&E Res 50% AC Cycling	Control group	Control group	+/-1.1x	Pre & Post Adjustment	0.04	4.19	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	0.02	4.23	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	0.02	4.23	Proposed
		Control group	Unlimited	Pre & Post Adjustment	0.02	4.23	Same Type as Proposed
		Control group	+/-1.3x	Pre & Post Adjustment	0.02	4.23	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	0.02	4.23	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	0.02	4.23	Same Type as Proposed
		Control group	+1.1x	Pre & Post Adjustment	1.85	4.66	Same Type as Proposed
		Control group	+1.2x	Pre & Post Adjustment	1.89	4.68	Same Type as Proposed
		Control group	+2x	Pre & Post Adjustment	1.89	4.68	Same Type as Proposed
	Day matching	3/5 weighted	+2x	Pre & Post Adjustment	2.81	8.20	
		3/5 weighted	+1.5x	Pre & Post Adjustment	2.59	8.38	
		4/5	Unlimited	Pre & Post Adjustment	1.23	8.50	
		4/5	+/-2x	Pre & Post Adjustment	1.23	8.50	
		3/5 weighted	+/-2x	Pre & Post Adjustment	1.65	8.55	
		3/5 weighted	Unlimited	Pre & Post Adjustment	1.65	8.55	
		4/5	+2x	Pre & Post Adjustment	1.47	8.58	
		3/5	Unlimited	Pre & Post Adjustment	2.34	8.62	
		3/5	+/-2x	Pre & Post Adjustment	2.34	8.62	
		3/5 - +5%	Unlimited	Pre & Post Adjustment	2.34	8.62	
	Weather matching	Bins based on CDD	+/-2x	Pre & Post Adjustment	-1.57	8.26	
		Bins based on CDD	Unlimited	Pre & Post Adjustment	-1.57	8.26	
		Bins based on CDD	+2x	Pre & Post Adjustment	-1.56	8.26	
		Bins based on CDD	+/-1.5x	Pre & Post Adjustment	-1.59	8.28	
		Bins based on CDD	+1.5x	Pre & Post Adjustment	-1.58	8.28	
		4 Day Match on CDD	+/-1.5x	Pre & Post Adjustment	-1.38	8.78	
		4 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	-1.38	8.78	
		4 Day Match on CDD	+/-1.3x	Pre & Post Adjustment	-1.38	8.78	
		4 Day Match on CDD	+/-2x	Pre & Post Adjustment	-1.38	8.78	
		4 Day Match on CDD	Unlimited	Pre & Post Adjustment	-1.38	8.78	

Table A-6: Event Day Results

Program	Baseline Category	Type	Adjustment Cap	Adjustment Type	MPE (%)	CVRM SE (%)	Recommended
PG&E Res AC Cycling	Day matching	10/20	Unlimited	Pre & Post Adjustment	0.66	6.84	
		10/20	+/-2x	Pre & Post Adjustment	0.66	6.84	
		10/20	+2x	Pre & Post Adjustment	0.66	6.84	
		10/20	+/-1.5x	Pre & Post Adjustment	0.52	6.89	

		10/20	+1.5x	Pre & Post Adjustment	0.52	6.89	
		5/10	Unlimited	Pre & Post Adjustment	1.60	7.13	Same Type as Proposed
		5/10	+/-2x	Pre & Post Adjustment	1.60	7.13	Same Type as Proposed
		5/10	+2x	Pre & Post Adjustment	1.76	7.31	Same Type as Proposed
		5/20	+/-1.4x	Pre & Post Adjustment	2.59	7.36	
		5/20	Unlimited	Pre & Post Adjustment	2.59	7.36	
	Weather matching	Bins based on Sum of CDH	+/-1.4x	Pre & Post Adjustment	1.06	7.37	
		Bins based on Sum of CDH	Unlimited	Pre & Post Adjustment	1.06	7.37	
		Bins based on Sum of CDH	+/-1.5x	Pre & Post Adjustment	1.06	7.37	
		Bins based on Sum of CDH	+/-2x	Pre & Post Adjustment	1.06	7.37	
		Bins based on Sum of CDH	+/-1.3x	Pre & Post Adjustment	1.06	7.38	
		Bins based on Max Temp	+/-1.3x	Pre & Post Adjustment	2.40	7.40	
		Bins based on Max Temp	+/-1.5x	Pre & Post Adjustment	2.27	7.42	
		Bins based on Max Temp	+/-2x	Pre & Post Adjustment	2.27	7.42	
		Bins based on Max Temp	+/-1.4x	Pre & Post Adjustment	2.27	7.42	
		Bins based on Max Temp	Unlimited	Pre & Post Adjustment	2.27	7.42	
SDG&E Res 100% AC Cycling	Day matching	10/20	+1.4x	No Post Adjustment	-0.76	10.50	
		10/20	+/-1.4x	No Post Adjustment	-0.76	10.51	
		10/20	+/-1.4x	Pre & Post Adjustment	0.06	10.89	
		10/20	+1.4x	Pre & Post Adjustment	0.06	10.89	
		10/20	+1.5x	No Post Adjustment	3.80	11.49	
		10/20	+/-1.5x	No Post Adjustment	3.80	11.49	
		5/20	+/-1.3x	No Post Adjustment	1.67	11.93	
		5/20	+1.3x	No Post Adjustment	2.02	12.04	
		10/20	+/-1.5x	Pre & Post Adjustment	4.99	12.11	
		10/20	+1.5x	Pre & Post Adjustment	4.99	12.11	
	Weather matching	Bins based on CDD	+1.5x	No Post Adjustment	2.24	15.68	
		Bins based on CDD	+1.4x	No Post Adjustment	-0.14	16.26	
		5 Day Match on CDD	+/-1.4x	No Post Adjustment	-0.83	17.04	
		5 Day Match on CDD	+1.4x	No Post Adjustment	-0.83	17.04	
		5 Day Match on CDD	+1.4x	Pre & Post Adjustment	0.22	17.35	
		5 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	0.22	17.35	
		Bins based on CDD	+1.3x	No Post Adjustment	-3.14	17.52	
		5 Day Match on CDD	+1.5x	No Post Adjustment	3.12	17.56	
		5 Day Match on CDD	+/-1.5x	No Post Adjustment	3.12	17.56	
		5 Day Match on CDD	+/-1.5x	Pre & Post Adjustment	4.31	17.95	
SDG&E Res 50% AC Cycling	Day matching	5/10	+1.4x	Pre & Post Adjustment	-0.52	7.69	Same Type as Proposed
		5/10	+/-1.4x	Pre & Post Adjustment	-0.64	7.74	Proposed
		5/20	+1.3x	Pre & Post Adjustment	-1.54	8.36	
		5/20	+/-1.3x	Pre & Post Adjustment	-1.84	8.37	

Program	Baseline Category	Type	Adjustment Cap	Adjustment Type	MPE (%)	CVRM SE (%)	Recommended
		5/20	+1.4x	Pre & Post Adjustment	2.89	8.41	
		5/20	+/-1.4x	Pre & Post Adjustment	2.59	8.42	
		5/20	+1.4x	No Post Adjustment	2.63	8.60	
		10/20	+1.5x	Pre & Post Adjustment	0.12	8.65	
		10/20	+/-1.5x	Pre & Post Adjustment	0.12	8.65	
		3/20	+/-1.3x	Pre & Post Adjustment	1.21	8.66	
	Weather matching	4 Day Match on CDD	+1.4x	No Post Adjustment	-0.01	8.71	
		4 Day Match on CDD	+/-1.4x	No Post Adjustment	-0.13	8.89	
		4 Day Match on CDD	+1.4x	Pre & Post Adjustment	0.15	9.12	
		4 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	0.15	9.12	
		3 Day Match on CDD	+1.4x	No Post Adjustment	-0.52	9.79	
		5 Day Match on CDD	+/-1.5x	Pre & Post Adjustment	0.36	9.88	
		5 Day Match on CDD	+1.5x	Pre & Post Adjustment	0.36	9.88	
		4 Day Match on CDD	+1.3x	No Post Adjustment	-4.59	10.07	
		4 Day Match on CDD	+/-1.3x	No Post Adjustment	-4.72	10.23	
		3 Day Match on CDD	+/-1.4x	No Post Adjustment	-1.00	10.26	

Table A-7: Proxy Weekend Results

Program	Baseline Category	Type	Adjustment Cap	Adjustment Type	MPE (%)	CVRM SE (%)	Recommended
PG&E BIP	Day matching	5/5	+/-1.8x	Pre & Post Adjustment	0.26	2.99	
		5/5	+/-1.4x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-2x	Pre & Post Adjustment	0.26	2.99	
		5/5	+/-1.9x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-1.5x	Pre & Post Adjustment	0.26	2.99	
		5/5	+/-2x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-1.9x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-1.8x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-1.7x	Pre & Post Adjustment	0.26	2.99	
		Bottom 5/5	+/-1.6x	Pre & Post Adjustment	0.26	2.99	
	Weather matching	5 Day Match on Sum CDH	+/-1.8x	Pre & Post Adjustment	-0.06	3.00	
		5 Day Match on Sum CDH	+/-1.7x	Pre & Post Adjustment	-0.06	3.00	
		5 Day Match on Sum CDH	+/-1.9x	Pre & Post Adjustment	-0.06	3.00	
		5 Day Match on Sum CDH	+/-1.6x	Pre & Post Adjustment	-0.06	3.00	
		5 Day Match on Sum CDH	+/-2x	Pre & Post Adjustment	-0.06	3.00	
		5 Day Match on Sum CDH	+/-1.5x	Pre & Post Adjustment	-0.07	3.03	
		5 Day Match on CDD	+/-1.6x	Pre & Post Adjustment	-0.02	3.04	
		5 Day Match on CDD	+/-2x	Pre & Post Adjustment	-0.02	3.04	
		5 Day Match on CDD	+/-1.8x	Pre & Post Adjustment	-0.02	3.04	

		5 Day Match on CDD	+/-1.7x	Pre & Post Adjustment	-0.02	3.04	
PG&E Res AC Cycling	Control group	Control group	+/-1.1x	Pre & Post Adjustment	-0.13	4.14	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	-0.13	4.16	Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.8x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.6x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.7x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.9x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.3x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	-0.13	4.16	Same Type as Proposed
	Day matching	1/4	+/-1.4x	No Post Adjustment	-0.68	7.84	
		1/4	+/-1.7x	No Post Adjustment	-0.69	7.84	
		1/4	+/-2x	No Post Adjustment	-0.69	7.84	
		1/4	+/-1.5x	No Post Adjustment	-0.69	7.84	
		1/4	+/-1.9x	No Post Adjustment	-0.69	7.84	
		1/4	+/-1.8x	No Post Adjustment	-0.69	7.84	
		1/4	+/-1.6x	No Post Adjustment	-0.69	7.84	
		1/5	+/-1.8x	No Post Adjustment	-0.46	7.98	
		1/5	+/-1.9x	No Post Adjustment	-0.46	7.98	
		1/5	+/-2x	No Post Adjustment	-0.46	7.98	
	Weather matching	3 Day Match on Max Temp	+/-1.2x	No Post Adjustment	-0.88	5.02	
		5 Day Match on Max Temp	+/-1.2x	No Post Adjustment	-2.21	5.51	
		5 Day Match on Max Temp	+/-1.2x	Pre & Post Adjustment	1.64	5.87	
		5 Day Match on Max Temp	+/-2x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.7x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.9x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.3x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.6x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.4x	Pre & Post Adjustment	1.70	5.88	
		5 Day Match on Max Temp	+/-1.5x	Pre & Post Adjustment	1.70	5.88	
SCE Agricultural	Day matching	5/5	+/-1.6x	No Post Adjustment	-0.60	6.02	
		Bottom 5/5	+/-1.6x	No Post Adjustment	-0.60	6.02	
		5/5	+/-1.7x	No Post Adjustment	-0.64	6.02	
		Bottom 5/5	+/-1.7x	No Post Adjustment	-0.64	6.02	
		Bottom 5/5	+/-1.9x	No Post Adjustment	-0.67	6.03	
		5/5	+/-1.9x	No Post Adjustment	-0.67	6.03	
		5/5	+/-1.8x	No Post Adjustment	-0.66	6.03	
		Bottom 5/5	+/-1.8x	No Post Adjustment	-0.66	6.03	
		5/5	+/-2x	No Post Adjustment	-0.68	6.03	
		Bottom 5/5	+/-2x	No Post Adjustment	-0.68	6.03	

	Weather matching	Bins based on CDD	+/-2x	Pre & Post Adjustment	-1.10	5.30	
		Bins based on CDD	+/-1.9x	Pre & Post Adjustment	-1.10	5.30	
		Bins based on CDD	+/-1.8x	Pre & Post Adjustment	-1.10	5.31	
		Bins based on CDD	+/-1.7x	Pre & Post Adjustment	-1.09	5.31	
		Bins based on CDD	+/-1.6x	Pre & Post Adjustment	-1.09	5.31	
		Bins based on CDD	+/-1.5x	Pre & Post Adjustment	-1.06	5.32	
		Bins based on CDD	+/-1.4x	Pre & Post Adjustment	-0.98	5.36	
		Bins based on CDD	+/-1.3x	Pre & Post Adjustment	-0.74	5.52	
		Bins based on Sum of CDH	+/-2x	No Post Adjustment	-0.49	5.56	
		Bins based on Sum of CDH	+/-1.9x	No Post Adjustment	-0.49	5.56	
SCE BIP	Day matching	Bottom 5/5	+/-2x	Pre & Post Adjustment	-0.05	2.07	
		Bottom 5/5	+/-1.9x	Pre & Post Adjustment	-0.05	2.07	
		Bottom 5/5	+/-1.8x	Pre & Post Adjustment	-0.05	2.07	
		5/5	+/-1.6x	Pre & Post Adjustment	-0.05	2.07	
		5/5	+/-1.5x	Pre & Post Adjustment	-0.05	2.07	
		Bottom 5/5	+/-1.7x	Pre & Post Adjustment	-0.05	2.07	
		Bottom 5/5	+/-1.6x	Pre & Post Adjustment	-0.05	2.07	
		5/5	+/-2x	Pre & Post Adjustment	-0.05	2.07	
		5/5	+/-1.8x	Pre & Post Adjustment	-0.05	2.07	
		Bottom 5/5	+/-1.5x	Pre & Post Adjustment	-0.05	2.07	
	Weather matching	Bins based on Max Temp	+/-1.6x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-2x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-1.7x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-1.9x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-1.5x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-1.8x	Pre & Post Adjustment	-0.73	2.05	
		Bins based on Max Temp	+/-1.4x	Pre & Post Adjustment	-0.72	2.05	
		Bins based on CDD	+/-1.4x	Pre & Post Adjustment	-0.71	2.06	
		Bins based on CDD	+/-1.7x	Pre & Post Adjustment	-0.71	2.06	
		Bins based on CDD	+/-1.9x	Pre & Post Adjustment	-0.71	2.06	
SCE Comm AC Cycling	Control group	Control group	+/-2x	Pre & Post Adjustment	0.91	11.72	Same Type as Proposed
		Control group	+/-1.9x	Pre & Post Adjustment	1.02	12.19	Same Type as Proposed
		Control group	+/-1.8x	Pre & Post Adjustment	1.12	12.85	Same Type as Proposed
		Control group	+/-1.7x	Pre & Post Adjustment	1.25	13.71	Same Type as Proposed
		Control group	+/-2x	No Post Adjustment	0.65	14.77	Same Type as Proposed
		Control group	+/-1.6x	Pre & Post Adjustment	1.38	14.84	Same Type as Proposed
		Control group	+/-1.9x	No Post Adjustment	0.71	15.01	Same Type as Proposed
		Control group	+/-1.8x	No Post Adjustment	0.75	15.41	Same Type as Proposed
		Control group	+/-1.7x	No Post Adjustment	0.81	15.98	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	1.52	16.43	Same Type as Proposed

	Day matching	Bottom 2/4	+/-1.1x	Pre & Post Adjustment	0.79	4.75	
		Bottom 3/4	+/-1.8x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.9x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.5x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.6x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.7x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-2x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.4x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.3x	Pre & Post Adjustment	1.40	4.76	
		Bottom 3/4	+/-1.2x	Pre & Post Adjustment	1.44	4.79	
	Weather matching	Bins based on Sum of CDH	+/-1.2x	Pre & Post Adjustment	0.91	3.35	
		Bins based on Sum of CDH	+/-1.6x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.7x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.4x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.3x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.8x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-2x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.9x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Sum of CDH	+/-1.5x	Pre & Post Adjustment	0.95	3.37	
		Bins based on Max Temp	+/-1.2x	Pre & Post Adjustment	0.92	3.37	
SDG&E Comm AC Cycling	Control group	Control group	+/-2x	Pre & Post Adjustment	0.23	7.35	Same Type as Proposed
		Control group	+/-1.9x	Pre & Post Adjustment	0.22	7.35	Same Type as Proposed
		Control group	+/-1.8x	Pre & Post Adjustment	0.21	7.39	Same Type as Proposed
		Control group	+/-1.7x	Pre & Post Adjustment	0.14	7.42	Same Type as Proposed
		Control group	+/-1.6x	Pre & Post Adjustment	0.03	7.51	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	-0.09	7.75	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	-0.26	8.36	Proposed
		Control group	+/-2x	No Post Adjustment	0.06	8.83	Same Type as Proposed
		Control group	+/-1.9x	No Post Adjustment	0.04	8.86	Same Type as Proposed
		Control group	+/-1.8x	No Post Adjustment	0.01	8.89	Same Type as Proposed
	Day matching	3/4	+/-1.5x	No Post Adjustment	-1.78	4.72	
		3/4	+/-1.6x	No Post Adjustment	-1.60	4.78	
		3/4	+/-1.7x	No Post Adjustment	-1.60	4.78	
		3/4	+/-1.8x	No Post Adjustment	-1.60	4.78	
		3/4	+/-1.9x	No Post Adjustment	-1.60	4.78	
		3/4	+/-2x	No Post Adjustment	-1.60	4.78	
		2/4	+/-1.4x	No Post Adjustment	-2.09	4.84	
		2/4	+/-1.5x	No Post Adjustment	-1.34	4.88	
		2/4	+/-1.6x	No Post Adjustment	-1.30	4.89	
		2/4	+/-1.8x	No Post Adjustment	-1.30	4.89	

	Weather matching	5 Day Match on CDD	+/-1.8x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-2x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.5x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.6x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.9x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.7x	Pre & Post Adjustment	-1.20	3.82	
		5 Day Match on CDD	+/-1.3x	Pre & Post Adjustment	-1.50	4.07	
		4 Day Match on CDD	+/-1.7x	Pre & Post Adjustment	-1.27	4.09	
		4 Day Match on CDD	+/-1.4x	Pre & Post Adjustment	-1.27	4.09	
SDG&E Res AC Cycling	Control group	Control group	+/-1.1x	Pre & Post Adjustment	-0.04	6.00	Same Type as Proposed
		Control group	+/-1.6x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.2x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.4x	Pre & Post Adjustment	0.02	6.17	Proposed
		Control group	+/-1.9x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-2x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.5x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.3x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.8x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
		Control group	+/-1.7x	Pre & Post Adjustment	0.02	6.17	Same Type as Proposed
	Day matching	Bottom 4/5	+/-1x	Pre & Post Adjustment	3.56	9.26	
		Bottom 4/5	Unadjusted	No Post Adjustment	3.56	9.26	
		Bottom 4/5	+/-1x	No Post Adjustment	3.56	9.26	
		Bottom 4/5	Unadjusted	Pre & Post Adjustment	3.56	9.26	
		4/4	+/-1.3x	Pre & Post Adjustment	0.44	9.63	
		Bottom 4/4	+/-1.3x	Pre & Post Adjustment	0.44	9.63	
		Bottom 3/4	+/-1.1x	Pre & Post Adjustment	-1.63	9.71	
		Bottom 3/4	+/-1.1x	No Post Adjustment	-1.63	9.71	
		Bottom 2/3	+/-1.2x	Pre & Post Adjustment	2.32	9.78	
		5/5	+/-1.2x	Pre & Post Adjustment	3.85	9.79	
	Weather matching	5 Day Match on Sum CDH	+/-1.2x	No Post Adjustment	5.24	14.83	
		5 Day Match on Sum CDH	+/-1.3x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.5x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.6x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.8x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.9x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-2x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.7x	No Post Adjustment	6.05	15.05	
		5 Day Match on Sum CDH	+/-1.4x	No Post Adjustment	6.05	15.05	
		5 Day Match on Max Temp	+/-1.4x	No Post Adjustment	-0.07	15.35	

Attachment G – List of Key Dates in Stakeholder Process

Energy Storage and Distributed Energy Resources Enhancements Phase 2

California Independent System Operator Corporation

List of Key Dates in the Stakeholder Process for this Tariff Amendment[1]

Date	Event
March 22, 2017	CAISO publishes issue paper
April 4, 2017	CAISO hosts stakeholder conference call and web conference on issue paper
April 19, 2017	Stakeholders submit comments on issue paper and straw proposal
May 24, 2017	CAISO publishes straw proposal
May 31, 2017	CAISO hosts stakeholder conference call and web conference on straw proposal
June 10, 2017	Stakeholders submit comments on straw proposal
July 21, 2017	CAISO publishes revised straw proposal
July 28, 2017	CAISO hosts stakeholder conference call and web conference on revised straw proposal
August 12, 2017	Stakeholders submit comments on revised straw proposal
September 19, 2017	CAISO publishes second revised straw proposal
September 27, 2017	CAISO hosts stakeholder conference call and web conference on second revised straw proposal
October 12, 2017	Stakeholders submit comments on second revised straw proposal
November 20, 2017	Baseline Accuracy Work Group publishes initial assessment
April 4, 2017	Baseline Accuracy Work Group publishes final proposal
April 17, 2017	CAISO publishes third revised straw proposal
May 203, 2017	CAISO hosts joint public workshop with California Public Utilities Commission
May 4, 2017	CAISO hosts stakeholder conference call and web conference on third revised straw proposal
May 22, 2017	Stakeholders submit comments on third revised straw proposal
June 2, 2017	CAISO hosts joint public workshop with California Public Utilities Commission
June 12, 2017	CAISO publishes draft final proposal
June 15, 2017	CAISO hosts stakeholder conference call and web conference on draft final proposal
June 27, 2017	Stakeholders submit comments on draft final proposal
November 17, 2017	CAISO publishes draft tariff revisions

[1] Meetings for the Baseline Accuracy Work Group and the Customer Partnership Group, a public stakeholder group that tracks the CAISO's technology and implementation process, are not listed here. *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx for links to all documents.

December 11, 2017	Stakeholders submit comments on draft tariff revisions
December 12, 2017	CAISO hosts stakeholder conference call and web conference on draft tariff revisions
April 9, 2018	CAISO publishes revised draft tariff revisions
April 19, 2018	Stakeholders submit comments on revised draft tariff revisions