California ISO California Independent System Operator Corporation

May 18, 2016

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. ER16- ___-000

Tariff Amendment to Implement Energy Storage 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 participation in the CAISO markets.[1] The CAISO proposes two enhancements herein: (1) allowing non-generator resources such as batteries to self-manage their state of charge and energy limits; and (2) implementing the three metering generator output methodologies developed by the North American Energy Standards Board ("NAESB") to calculate demand response performance. These proposed revisions result from the first phase of the CAISO's Energy Storage and Distributed Energy Resource ("ESDER") stakeholder initiative.[2]

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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.

[2] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_Distributed

I. Summary

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 a MWh constraint that limits the amount of energy they can store and produce. Currently, when a non-generator resource bids into the day-ahead market, the initial state of charge value[3] used by the CAISO's market processes for that trading day is the ending state of charge value from the previous day's market awards. However, when there are no previous day's awards, the market system assumes that the initial state of charge value for the resource is 50 percent of its maximum energy limit. The CAISO proposes to allow non-generator resources to submit their state of charge as a bid parameter in the day-ahead market. This will provide the CAISO with more accurate market information regarding the resource, and it will allow resource bids to better reflect actual conditions.

Non-generator resources also currently provide the CAISO with their energy limits through telemetry. Stakeholders requested the option to self-manage their energy limits similar to how traditional resources manage their physical constraints. The CAISO therefore proposes to allow non-generator resources to elect not to provide their energy limits through telemetry unless the CAISO determines that they are not self-managing within their energy limits properly.

Further, energy storage devices may 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.[4] The CAISO currently measures demand response performance (*i.e.*, demand reductions) by comparing actual consumption relative to a baseline of expected consumption, both based upon customer meter data at a registered location.[5]

EnergyResourcesphase1.aspx.

3 State of charge reflects the amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage.

4 For concision, this letter will simply refer to both as demand response resources.

5 Proxy demand resources and reliability demand response resources both can be individual loads at a single meter/location, or they can be aggregations of multiple loads at multiple meters/locations within a single Sub-LAP. A Sub-LAP is a defined subset of PNodes

When demand, however, is offset by a behind-the-meter generation device[6]—a storage resource, for example—and there is no sub-meter to separate consumption and energy produced on site, this approach fails to distinguish the cause of the demand response. The CAISO cannot tell whether the resource is curtailing consumption or serving its load from a behind-the-meter resource.

To accommodate the proliferation of behind-the-meter generation and storage devices involved in demand response resources, the CAISO worked with stakeholders to tailor the NASEB metering generator output measurement and verification methodologies for the CAISO markets. These performance methodologies will accommodate sub-metering and allow the CAISO to ascertain demand response performance based upon the gross load independent of behind-the-meter generation, the behind-the-meter generator output itself, or both.[7]

For the reasons explained below, the CAISO respectfully requests that the Commission approve the proposed revisions within 90 days, with an effective date of October 1, 2016.

II. Background

The California Public Utilities Commission ("CPUC") has directed California investor-owned utilities to procure 1,325 MW of energy storage (excluding pumped hydro storage) by 2020.[8] The total procurement target is broken down into three locational categories requiring 700 MW of energy storage interconnected to the transmission system, 425 MW interconnected to the distribution system, and 200 MW from retail customers. As of March 31, 2016,

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within a default load aggregation point.

6 The CAISO adopts the Commission's definition of "behind-the-meter generation," namely, generation "located behind the retail delivery point that can directly serve the host customer's electrical demand in lieu of or in addition to electricity the customer takes through the [] grid." *Demand Response Supporters v. New York Independent System Operator Inc.*, 155 FERC ¶ 61,151 at P 1 n.3 (2016).

7 *See Demand Response Supporters v. New York Independent System Operator Inc.*, 145 FERC ¶ 61,162 (2013); *reh'g denied*, 155 FERC ¶ 61,151 (2016) (finding that load curtailment or behind-the-meter generation provides demand response).

8 *See, e.g.,* CPUC/CAISO Issue Paper on Joint Workshop on Multiple-Use Applications and Station Power for Energy Storage, *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K876/159876453.PDF.

the CPUC had approved procurement contracts for 364 MW, with another126 MW submitted but awaiting CPUC approval.[9]

The CAISO already is experiencing the effects of this procurement directive. The CAISO generator interconnection queue currently has 36 interconnection requests for energy storage devices, comprising 3,093 MW.[10] These figures will increase dramatically when the CAISO finishes compiling the results of its annual generator interconnection application window, which closed on April 30, 2016.[11]

Accordingly, 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 by non-generator resources.[12] 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.[13]

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'

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9 *Id.*

10 https://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

11 The CAISO interconnection application window is open once annually from April 1 to April 30. Traditionally the CAISO receives over 90% of its applications on April 30.

12 *California Independent System Operator Corp.*, 132 FERC ¶ 61,211 (2010).

13 *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 in order 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.

interconnecting to the CAISO controlled grid.[14] 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 will allow such resources to participate in the wholesale market.[15] The CAISO submitted the resulting tariff revisions to the Commission on March 4, 2016.[16] Third, in collaboration 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.[17]

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 and demand response enhancements proposed herein, as well as clarifications on the rules for "multiple-use applications," namely resources capable of both providing service to end-use customers and participating in the wholesale electricity markets.[18] The CAISO currently is conducting Phase 2 of the ESDER initiative, which may result in further enhancements.[19]

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14 http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorageInterconnection.aspx.

15 https://www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx.

16 *California Independent System Operator Corp.*, Tariff Filing on Distributed Energy Resource Provider Initiative, Docket No. ER16-1085-000 (March 4, 2016).

17 https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf.

18 The examination of multiple-use application rules did not result in tariff revisions.

19 http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesphase2.aspx.

III. Proposed Tariff Revisions

A. Non-Generator Resource Enhancements

1. Background

The CAISO tariff defines non-generator resources as "resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume [or charge] Energy."[20] Non-generator resources include batteries and flywheels. Pumped hydro storage, on the other hand, has its own distinct participation model in the CAISO. As stated above, 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 by non-generator resources.[21] In 2011, the CAISO formally created the non-generator resource model, detailed the procedures for non-generator resource market participation, including the use of regulation energy management functionality.

The CAISO designed its non-generator resource model to support energy-constrained resources that can operate as positive generation, negative generation, or from positive to negative generation. The non-generator resource model allows the CAISO's market processes to recognize that a resource can operate seamlessly between positive and negative generation. For example, the CAISO's market processes can accommodate participation by a battery that can discharge energy in one interval as positive generation and charge in the next interval as negative generation. Current battery chemistries and storage control systems have demonstrated these resources can move nearly instantaneously between positive (discharging) and negative generation (charging), can have fast ramping rates, and can be controlled with high precision and performance accuracy. Although storage technology is an ideal candidate for the non-generator resource model, the model also may benefit other energy-constrained resources such as dispatchable demand response, aggregated distributed

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20 Appendix A to the CAISO tariff.

21 *California Independent System Operator Corp.*, 132 FERC ¶ 61,211 (2010). Specifically, the CAISO changed its minimum rated capacity from 1 MW to 500 kW, reduced minimum energy requirements for regulation and spin/non-spin, and clarified the minimum continuous energy measurement such that continuous energy is measured from the period that the resource reaches the awarded energy output; not at the end of a 10-minute ramp.

energy resources, or microgrid configurations that have limited ability to generate or consume energy continuously.

As designed and implemented, the non-generator resource model applies to energy-constrained resources. For a battery, the amount of a resource's available energy is a function of the resource's state of charge. Non-generator resources provide their state of charge to the CAISO through telemetry.[22] Although this approach works well in real-time, it does not provide scheduling coordinators with a usable bid parameter in the day-ahead market. Today, when a scheduling coordinator places bids in the day-ahead market on behalf of a non-generator resource, the CAISO assumes that the initial state of charge is the ending value from the previous day's day-ahead awards. Where there are none, the CAISO assumes that the initial state of charge to be 50 percent of the MWh limit, which non-generator resources provide to the CAISO's master file.

The CAISO also currently requires non-generator resources to provide energy limits in the CAISO master file.[23] These energy limits instruct the CAISO to avoid dispatching the resource above or below its MWh limits, namely, the optimal levels of charge for a battery. Non-generator resources also may use telemetry to provide the CAISO with different energy limits in real-time where desired.

2. *Proposed Tariff Revisions*

The CAISO proposes to revise the tariff to allow non-generator resources to reflect their state of charge and energy limits as part of economic bids. First, the CAISO will allow scheduling coordinators to submit state of charge as a bid parameter in the day-ahead market.[24] This will replace the current methodology of using the previous day's final state of charge or assuming a 50 percent state of charge. Replacing these assumed state of charge values by allowing scheduling coordinators to submit their actual state of charge as a bid parameter in the CAISO markets will provide the CAISO with more accurate market information regarding the resource, and it will allow resource bids to better reflect actual conditions.

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[22] Section A.1.22.4 of Appendix K to the CAISO tariff; Section 27.9 of the CAISO tariff.

[23] *Id*.

[24] Proposed Section 30.5.6 of the CAISO tariff. This section also will provide guidance on bid parameters for scheduling coordinators for non-generator resources.

Second, the CAISO proposes to provide non-generator resources the option to self-manage their energy limits and state of charge.[25] Non-generator resources choosing this option will self-manage their available energy within any energy limit constraints to avoid uninstructed imbalance energy settlements through bids. As such, instead of having the CAISO's market processes ensure that dispatch does not violate the non-generator resource's MWh constraint, the scheduling coordinator would instead manage the resource's energy limits or keep its state of charge at an optimal level through its own bidding strategy.[26] This option will allow resource owners to manage their resources' physical constraints based on any dynamic needs in real-time. It also will better align the non-generator resource model with the traditional generation models by allowing resource owners to manage the physical constraints of their battery or storage device. As such, the CAISO respectfully requests that the Commission accept these tariff revisions as requested by stakeholders and proposed by the CAISO here.

B. Demand Response Enhancements

1. Background

Consistent with Order Nos. 719 and 745, NAESB models, and other ISO/RTOs,[27] the CAISO's demand response program uses a standard "ten-in-ten" methodology to acquire relevant historical load meter data to establish a customer baseline.[28] The CAISO compares this baseline to the actual load meter data at the time of dispatch to calculate the customer's demand response

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[25] Proposed Section 27.9 of the CAISO tariff and Section A 1.2.2.4 of Appendix K to the CAISO tariff.

[26] These options would not be available for non-generator resources using regulation energy management because of the CAISO's need to maintain the resource's energy state and state of charge for continuous energy output.

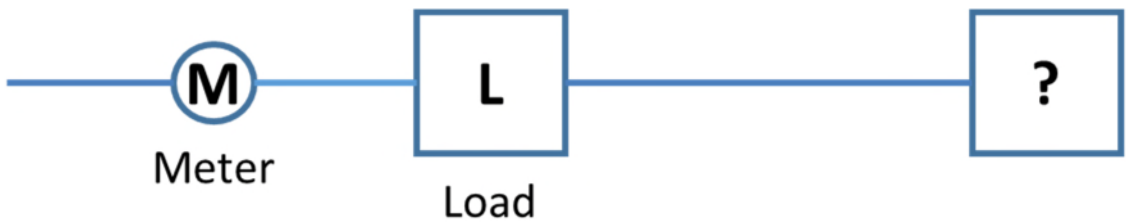
[27] *See, e.g., California Independent System Operator Corp.*, 132 FERC ¶ 61,045 at PP 8; 83 (2010) (implementing the proxy demand resource model for demand response); *California Independent System Operator Corp.*, 134 FERC ¶ 61,004 (implementing the proxy demand resource baseline); *California Independent System Operator Corp.*, 137 FERC ¶ 61,217 (2011) (implementing the net benefits test).

[28] Section 4.13.4.1 of the CAISO tariff. In simple terms, the baseline for the demand response resource is calculated using historical meter data from the facility with defined selection rules including a look-back window and exclusion days. The CAISO methodology examines up to 45 calendar days prior to the trade day to find a target number of "like" days and calculates an hourly average of the collected meter data to create a load profile, which is the baseline used to assess the event-day load response quantity.

energy, which is the value the CAISO uses for energy settlement purposes. Although this approach generally works well for traditional demand response resources that curtail consumption, it has limitations for demand response resources that incorporate energy storage resources or behind-the-meter generation to offset energy drawn from the grid.

As shown in Figure 1, a typical demand response resource comprises a physical meter connected to a load.

FIGURE 1



The load may be a pure load, or it may be offset by behind-the-meter generation or other devices, such as battery storage. With such a meter configuration—one that lacks separate metering of behind-the-meter generation—there is no way to separate the load from the generation or vice versa. The CAISO cannot distinguish the cause of demand response behind the meter.

2. Proposed Tariff Revisions

The CAISO proposes to revise its tariff to implement the "metering generator output" methodology developed by NAESB to acquire accurate meter data on demand response performance.[29] The metering generator output methodology requires a second meter, or "sub-meter," to isolate the output from any behind-the-meter generation, as shown in Figure 2.

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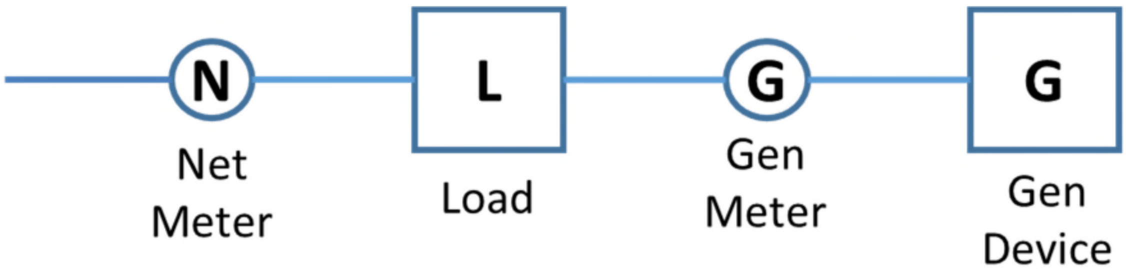
[29] *See* North American Electric Standards Board Inc., WEQ-015, Section 015-1.28 (Sep. 30, 2015).

FIGURE 2



Under this configuration, the overall demand response at the location can be separated into a pure demand response (from the facility) and behind-the-meter generation energy production.

The sub-meter provides demand response providers with three new ways they may elect to calculate their demand response performance.[30] First, demand response resources can elect to use the traditional ten-in-ten methodology, but the meter data to establish their baseline and actual output in an interval could consist of the gross consumption at the load location, rather than the netting any offsetting behind-the-meter generation.[31]

Second, sub-metering allows the demand response resource to calculate its baseline and actual output in an interval based upon the load curtailment provided by the behind-the-meter generation alone (*i.e.*, the gross generator output up to the facility load, but excluding load reduction due to reduced load consumption). The demand response resource would then be awarded in the market for load curtailment provided by the behind-the-meter generator in excess of what it generally provides to curtail facility load, namely, its generating

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30 Demand response providers also could continue to use the CAISO's existing ten-in-ten methodology. Although this methodology would net any behind-the-meter generation, it avoids the costs of sub-metering. Examples of each proposed methodology are available in the CAISO's Revised Final Draft Proposal, attached hereto as Attachment C.

31 Proposed Sections 4.13.4.1(a) and 11.6.1. To make this load-based methodology and the traditional ten-in-ten methodology more clearly distinct from the proposed Metering Generator Output methodology described below, the CAISO proposes to refer to these methodologies as "Customer Load Baseline Methodologies." Maintaining the "ten-in-ten" shorthand could be confusing because the proposed Metering Generator Output methodology has a similar but distinct ten-in-ten lookback. The CAISO also proposes to revise its tariff such that references to baselines are either general (to apply to both Customer Load Baselines and Metering Generator Output Baselines by merely stating "performance evaluation methodologies") or specific to a particular baseline.

baseline.[32] This baseline is calculated in a similar, but distinct way from the load-based methodologies described above.[33] It is calculated by taking an average of the energy delivered by the generation device during a prescribed number of prior hours. Specifically, the metering generator output baseline consists of a 45-day lookback of meter data to find similar hours. The lookback requires these similar hours on similar day types, namely, business days or non-business days. When the lookback can find ten similar "non-event hours" on weekdays or four similar non-event hours on non-business days, the meter data is averaged to establish the baseline.[34] The baseline calculation would exclude meter data from any "event hour," that is, any trading hour in which the demand response resource was subject to an outage or provided demand response resources pursuant to a bid at or above the net benefits test price threshold.[35] This net benefits test establishes a price above which demand response resource bids are deemed cost effective. Because many of these behind-the-meter generating units will be batteries, the CAISO also proposes to consider their meter data set to zero in any interval in which the behind-the-meter generating unit is charging. This will avoid establishing a "negative" baseline for which any or even no output would exceed the baseline. Moreover, because the metering generating output methodology is for calculating demand response only, if the behind-the-meter generating device is capable of exporting energy onto the grid (*i.e.*, producing energy in excess of the on-site consumption), the CAISO will only consider output up to, but not including the output exceeding on-site consumption.[36]

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32 Using a metering generator output baseline removes energy delivered for retail load-modifying purposes, namely, energy not produced in response to a CAISO dispatch. Importantly, it mitigates issues of wholesale and retail service overlap and the potential for double compensation.

33 Examples of these methodologies are available in the CAISO's Revised Final Draft Proposal, attached hereto as Attachment C.

34 Similar to traditional customer load baseline methodologies, if it is not possible to collect meter data for the target number of hours, the meter data will include a minimum of five hours if the trading day is a business day or a minimum of four hours for a non-business day, and similar event hours on the same day type.

35 Section 30.6.3 of the CAISO tariff. The CAISO publishes the net benefits test price threshold on a monthly basis. A "non-event hour" is an hour that is not an "event hour," which is any trading hour in which the demand response resource was subject to an outage or provided demand response resources pursuant to a bid at or above the net benefits test price threshold.

36 The same rule would apply for actual output in the settlement interval as well.

Third, demand response resources could take advantage of both of the two new proposed methods simultaneously.[37] Under this approach, the demand response resource would have a separate baseline and actual demand curtailment value based on its gross facility demand, and a baseline and actual generator output based upon the behind-the-meter generation. The CAISO would then settle the resource on the sum of these two demand response energy measurements.[38] This methodology incentivizes demand curtailment from both traditional curtailment and behind-the-meter generation.

Finally, because the baseline and settlement methodologies proposed herein will be novel to scheduling coordinators, the CAISO proposes to include a tariff provision reiterating its rights to audit meter data submitted by scheduling coordinators for demand response providers to ensure accuracy and compliance with the CAISO tariff.[39]

The CAISO respectfully requests that the Commission approve these proposed tariff revisions as just and reasonable. They originate from NAESB models and represent the careful work of the CAISO and stakeholders to enable greater and more accurate participation in the CAISO markets from energy storage, load-curtailing, and behind-the-meter resources.[40]

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37 The first new methodology proposed here is an optional enhancement on the existing ten-in-ten methodology (gross instead of net consumption), and the second new methodology is metering generator output baseline methodology to determine the load curtailment provided by the behind-the-meter generation alone. The third is the combination of the two.

38 Proposed Section 11.6.3 of the CAISO tariff.

39 Proposed Section 10.3.6.6 of the CAISO tariff.

40 *See Demand Response Supporters v. New York Independent System Operator Inc.*, 145 FERC ¶ 61,162 (2013); *reh'g denied*, 155 FERC ¶ 61,151 (2016) (finding that load curtailment or behind-the-meter generation provides demand response).

IV. Stakeholder Process

The stakeholder process that resulted in this filing included:

- A series of six issue papers produced by the CAISO;
- A stakeholder working group devoted to working on the demand response baselines;[41]
- Seven stakeholder meetings and conference calls to discuss the CAISO papers and the draft tariff provisions; and
- Eight opportunities to submit written comments on the CAISO papers and the draft tariff provisions.[42]

The policies resulting in these proposed tariff revisions received broad stakeholder support. They were presented to the Board on February 3, 2016, where the Board voted unanimously to authorize this filing.[43]

V. Effective Date

The tariff revisions proposed herein require software development for the CAISO systems. Accordingly, the CAISO respectfully requests waiver of the Commission's notice requirements,[44] and that the Commission approve the proposed revisions within 90 days, with an effective date of October 1, 2016. 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 October 1. As such, good cause exists to grant waiver of the

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41 The working group itself held two public meetings and provided three opportunities for all stakeholders to provide written comments on its work.

42 All stakeholder materials are available on the CAISO website: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesphase1.aspx.

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

44 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).

Commission's notice requirements and approve the CAISO's requested effective date.

VI. Communications

Correspondence and other communications regarding this filing should be directed to:

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Sidney L. Mannheim
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* Individual designated for service pursuant to Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3)

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.

VIII. Contents of Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Revised draft final proposal

Attachment D	Board memorandum
Attachment E	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 October 1, 2016.

Respectfully submitted,

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

Counsel for the California Independent System Operator Corporation

Attachment A – Clean Tariff Records

Tariff Amendment to Implement Energy Storage Enhancements

California Independent System Operator Corporation

May 18, 2016

4.13.2 Applicable Requirements for RDRRs, PDRs and DRPs

A single Demand Response Provider must represent each Reliability Demand Response Resource or Proxy Demand Resource and may represent more than one (1) Reliability Demand Response Resource or Proxy Demand Resource. Each Reliability Demand Response Resource or Proxy Demand Resource that is not within a MSS must be associated with a single Load Serving Entity and a single Utility Distribution Company, and each Reliability Demand Response Resource or Proxy Demand Resource that is within a MSS must be associated with a single Load Serving Entity. A Demand Response Provider may be, but is not required to be, a Load Serving Entity or a Utility Distribution Company. Each Reliability Demand Response Resource or Proxy Demand Resource is required to be located in a single Sub-LAP. All underlying Locations of a Reliability Demand Response Resource or Proxy Demand Resource must be located in a single Sub-LAP. Each Demand Response Provider is required to satisfy registration requirements and to provide information to allow the CAISO to establish performance evaluation methodologies in accordance with Section 4.13.4 and the applicable Business Practice Manuals. Registration of a Location for participation in Reliability Demand Response Resources or Proxy Demand Resources requires the approval of the CAISO resulting from its registration process. As part of the submitted registration process, both the appropriately Demand Response Provider designated Load Serving Entity and Utility Distribution Company will have an opportunity to review the registration Location detail and provide comments with regard to its accuracy. Disputes regarding the acceptances or rejections of a registration of a Location shall be undertaken with the applicable Local Regulatory Authority and shall not be arbitrated or in any way resolved through a CAISO dispute resolution mechanism or process. A Location cannot be registered to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same Trading Day.

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4.13.4 Performance Evaluation Methodologies for PDRs and RDRRs

4.13.4.1 Customer Load Baseline Methodology

For each Proxy Demand Resource or Reliability Demand Response Resource, the CAISO will calculate the Customer Load Baseline as follows:

(a) The CAISO will collect 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 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 the calendar days for which the Meter Data will be collected, the CAISO 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 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 collecting Meter Data for this purpose if and when it is able to collect Meter Data for its target number of calendar days, which target number 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 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

Business Day or a minimum of four (4) calendar days if the Trading Day is a non-Business Day. If the CAISO is unable to collect Meter Data for the minimum number of calendar days described above, the CAISO will instead collect Meter Data 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 will calculate 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 will multiply 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 pursuant to Section 4.13.4.1(a). The 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 calculation will instead include Meter Data for the hours 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) 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, 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 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 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.

* * * *

10.3.2.1.1 Requirements for SCs Representing Demand Response Providers[1]

Each Scheduling Coordinator for a Demand Response Provider shall aggregate the Settlement Quality Meter Data of the underlying Proxy Demand Resource or Reliability Demand Response Resource to the level of the registration configuration of the Proxy Demand Resource or Reliability Demand Response Resource in the Demand Response System. Settlement Quality Meter Data for these Scheduling Coordinator Metered Entities shall be (1) an accurate measure of the actual consumption of Energy by each Scheduling Coordinator Metered Entity in each Settlement Period; (2) the resulting Demand Response Energy Measurement calculated using a performance evaluation methodology for Proxy Demand Resources or Reliability Demand Response Resources; or (3) statistically derived meter data pursuant to Section 10.1.7.

* * * *

10.3.6.5 Submission of Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for Reliability Demand Response Resources that Provide Demand Response Services in Real-Time

Each Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource that provides Demand Response Services only in Real-Time shall submit Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for the Reliability Demand Response Resource by noon of the fifth Business Day after the Trading Day (T+5B) on which the Demand Response Services were provided, including Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for a Demand Response Event and for the forty-five (45) calendar days preceding the Trading Day for use in the CAISO's calculation of the Customer Load Baseline pursuant to Section 4.13.4.

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[1] Text highlighted in grey is not currently effective tariff language, but has been proposed by the CAISO in FERC Docket No. ER16-1085-000.

10.3.6.6 Auditing by CAISO for Demand Response Providers

To ensure accuracy and compliance with the CAISO tariff, the CAISO will have the right to audit Meter Data submitted by Scheduling Coordinators to establish performance evaluation methodologies pursuant to Section 4.13.4 or Demand Response Energy Measurements pursuant to Section 11.6.

* * * *

11.6 Settlement of Transactions Involving PDRs or RDRRs

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 (i) the Customer Load Baseline for the Proxy Demand Resource or Reliability Demand Response Resource and (ii) either the actual underlying Load 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. For such Proxy Demand Resources or Reliability Demand Response Resources, the CAISO will calculate the 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.

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.

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.

* * * *

27.9 Non-Generator Resources MWh Constraints

Scheduling Coordinators may elect to provide the CAISO with Non-Generator Resources' MWh constraints. In such cases, the CAISO will observe Non-Generator Resources' MWh constraints in the IFM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in RUC as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Unit Commitment and FMM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management.

* * * *

30.5.6 Non-Generator Resource Bids

Scheduling Coordinators must ensure that Non-Generator Resource Bids contain the Bid components specified in this Section 30.5 based on how the Non-Generator Resource is then participating in the CAISO Markets, namely, whether it is providing Supply, Demand, and/or Ancillary Services Bids. In addition to the Bid components listed in this Section 30.5, Scheduling Coordinators representing Non-Generator Resources may submit Bids including the State of Charge for the Day-Ahead Market to indicate the forecasted starting physical position of the Non-Generator Resource. Scheduling Coordinators representing Non-Generator Resources using

Regulation Energy Management must submit Bids compliant with the requirements of Section 8.4.1.2.

* * * *

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.

* * * *

- Demand Response Energy Measurement

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.

* * * *

- 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.

* * * *

- State of Charge

The Energy available to CAISO Markets from a Non-Generator Resource or storage device.

* * * *

Appendix K

Ancillary Service Requirements Protocol (ASRP)

* * * *

A 1.2.2.4 Ancillary Service Providers for Non-Generator Resources (whether or not the resource uses Regulation Energy Management) shall provide CAISO the following additional telemetry data:

- Resource Ramp Rate when operating as Generation (MW/min);
- Resource Ramp Rate when operating as Load (MW/min);
- The maximum instantaneous ability to produce or consume Energy in MW; and
- The maximum capability to provide Energy as expressed in MWh over a fifteen (15) minute interval where the Scheduling Coordinator has elected to provide MWh constraints pursuant to Section 27.9 of the CAISO Tariff.

* * * *

Attachment B – Marked Tariff Records

Tariff Amendment to Implement Energy Storage Enhancements

California Independent System Operator Corporation

May 18, 2016

4.13.2 Applicable Requirements for RDRRs, PDRs and DRPs

A single Demand Response Provider must represent each Reliability Demand Response Resource or Proxy Demand Resource and may represent more than one (1) Reliability Demand Response Resource or Proxy Demand Resource. Each Reliability Demand Response Resource or Proxy Demand Resource that is not within a MSS must be associated with a single Load Serving Entity and a single Utility Distribution Company, and each Reliability Demand Response Resource or Proxy Demand Resource that is within a MSS must be associated with a single Load Serving Entity. A Demand Response Provider may be, but is not required to be, a Load Serving Entity or a Utility Distribution Company. Each Reliability Demand Response Resource or Proxy Demand Resource is required to be located in a single Sub-LAP. All underlying Locations of a Reliability Demand Response Resource or Proxy Demand Resource must be located in a single Sub-LAP. ~~The Meter Data for each Reliability Demand Response Resource or Proxy Demand Resource will be metered Load data.~~ Each Demand Response Provider is required to satisfy registration requirements and to provide information to allow the CAISO to establish ~~Customer Baselines~~performance evaluation methodologies in accordance with Section 4.13.4 and the applicable Business Practice Manuals. Registration of a Location for participation in Reliability Demand Response Resources or Proxy Demand Resources requires the approval of the CAISO resulting from its registration process. As part of the submitted registration process, both the appropriately Demand Response Provider designated Load Serving Entity and Utility Distribution Company will have an opportunity to review the registration Location detail and provide comments with regard to its accuracy. Disputes regarding the acceptances or rejections of a registration of a Location shall be undertaken with the applicable Local Regulatory Authority and shall not be arbitrated or in any way resolved through a CAISO dispute resolution mechanism or process. A Location cannot be registered to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same Trading Day.

* * * *

4.13.4 ~~Customer Baseline~~Performance Evaluation Methodologies for PDRs and RDRRs

4.13.4.1 ~~Ten in Ten Non-Event Day Selection Method~~Customer Load Baseline Methodology

For each Proxy Demand Resource or Reliability Demand Response Resource, the CAISO will calculate the Customer Load Baseline as follows:

(a) The CAISO will collect 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 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 the calendar days for which the Meter Data will be collected, the CAISO 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 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 collecting Meter Data for this purpose if and when it is able to collect Meter Data for its target number of calendar days, which target number 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 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 Business Day or a minimum of four (4) calendar days if the Trading Day is a non-Business Day. If the CAISO is unable to collect Meter Data for the minimum number of calendar days described above, the CAISO will instead collect Meter Data 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 will calculate 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 will multiply 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 pursuant to Section 4.13.4.1(a). The 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 calculation will instead include Meter Data for the hours 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) 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, 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 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 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.

* * * *

10.3.2.1.1 Requirements for SCs Representing Demand Response Providers[1]

Each Scheduling Coordinator for a Demand Response Provider shall aggregate the Settlement Quality Meter Data of the underlying Proxy Demand Resource or Reliability Demand Response Resource to the level of the registration configuration of the Proxy Demand Resource or Reliability Demand Response Resource in the Demand Response System. Settlement Quality Meter Data for these Scheduling Coordinator Metered Entities shall be ~~either~~ (1) an accurate measure of the actual consumption of Energy by each Scheduling Coordinator Metered Entity in each Settlement Period; (2) the resulting Demand Response Energy Measurement calculated using a performance evaluation methodology for Proxy Demand Resources or Reliability Demand Response Resources; or (3~~2~~) statistically derived meter data pursuant to Section 10.1.7.

* * * *

10.3.6.5 Submission of Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for Reliability Demand Response Resources that Provide Demand Response Services in Real-Time

Each Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource that provides Demand Response Services only in Real-Time shall submit Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for the Reliability Demand Response Resource by noon of the fifth Business Day after the Trading Day (T+5B) on which the Demand Response Services were provided, including Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data for a Demand Response Event and for the forty-five (45) calendar days preceding the Trading Day for use in the CAISO's calculation of the Customer Load Baseline pursuant to Section 4.13.4.

[1] Text highlighted in grey is not currently effective tariff language, but has been proposed by the CAISO in FERC Docket No. ER16-1085-000.

10.3.6.6 Auditing by CAISO for Demand Response Providers

To ensure accuracy and compliance with the CAISO tariff, the CAISO will have the right to audit Meter Data submitted by Scheduling Coordinators to establish performance evaluation methodologies pursuant to Section 4.13.4 or Demand Response Energy Measurements pursuant to Section 11.6.

* * * *

11.6 Settlement of Transactions Involving PDRs or RDRRs

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 (i) the Customer Load Baseline for the Proxy Demand Resource or Reliability Demand Response Resource and (ii) either the actual underlying Load 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. For ~~each~~ such Proxy Demand Resources or Reliability Demand Response Resources, the CAISO will calculate the 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.

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.

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.

* * * *

27.9 Non-Generator Resources MWh Constraints

~~**THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.**~~

Scheduling Coordinators may elect to provide the CAISO with Non-Generator Resources' MWh constraints. In such cases, ~~T~~the CAISO will observe Non-Generator Resources' MWh constraints in the IFM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in RUC as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Unit Commitment and FMM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management.

* * * *

30.5.6 Non-Generator Resource Bids

Scheduling Coordinators must ensure that Non-Generator Resource Bids contain the Bid components specified in this Section 30.5 based on how the Non-Generator Resource is then participating in the CAISO Markets, namely, whether it is providing Supply, Demand, and/or Ancillary Services Bids. In addition to the Bid components listed in this Section 30.5, Scheduling Coordinators representing Non-Generator Resources may submit Bids including the State of Charge for the Day-Ahead Market to indicate the forecasted starting physical position of the Non-

Generator Resource. Scheduling Coordinators representing Non-Generator Resources using Regulation Energy Management must submit Bids compliant with the requirements of Section 8.4.1.2.

* * * *

Appendix A

Master Definition Supplement

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- Customer Load Baseline

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

* * * *

- Demand Response Energy Measurement

The resulting Energy quantity calculated by comparing the ~~Customer Baseline~~applicable performance evaluation methodology of a Proxy Demand Resource or Reliability Demand Response Resource against its actual underlying ~~Load~~ performance for a Demand Response Event.

* * * *

- Generator Output Baseline

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

* * * *

- State of Charge

The Energy available to CAISO Markets from a Non-Generator Resource or storage device.

* * * *

Appendix K

Ancillary Service Requirements Protocol (ASRP)

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A 1.2.2.4 Ancillary Service Providers for Non-Generator Resources (whether or not the resource uses Regulation Energy Management) shall provide CAISO the following additional telemetry data:

- Resource Ramp Rate when operating as Generation (MW/min);
- Resource Ramp Rate when operating as Load (MW/min);
- The maximum instantaneous ability to produce or consume Energy in MW; and
- The maximum capability to provide Energy as expressed in MWh over a fifteen (15) minute interval where the Scheduling Coordinator has elected to provide MWh constraints pursuant to Section 27.9 of the CAISO Tariff.

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Attachment C – Revised Draft Final Proposal

Tariff Amendment to Implement Energy Storage Enhancements

California Independent System Operator Corporation

May 18, 2016

Energy Storage and Distributed Energy Resources (ESDER) Stakeholder Initiative

Revised Draft Final Proposal

December 23, 2015

Table of Contents

Energy Storage and Distributed Energy Resource (“ESDER”) Stakeholder Initiative

Revised Draft Final Proposal

1 Introduction

Enhancing the ability of transmission grid-connected storage and the many examples of distribution-connected resources (i.e., distributed energy resources or “DER”) to participate in the ISO market is the central focus of the ISO’s energy storage and distributed energy resources (ESDER) stakeholder initiative.

In this paper, the ISO presents its revised draft final proposals on the topics in scope for the 2015 phase of the ESDER initiative. The 2015 scope comprises three topic areas:

1. Enhancements to the ISO non-generator resources model (“NGR”);
2. Enhancements to demand response performance measures and statistical sampling for the ISO proxy demand resource (PDR) and reliability demand response resource (RDRR) market participation models; and,
3. Clarifications to rules for non-resource adequacy multiple-use applications (provision of retail, distribution and wholesale services by the same resource).

The ISO plans to address additional topic areas during the second phase of the ESDER initiative in 2016.

2 Summary of clarifications and/or revisions to draft final proposal

In this revised draft final proposal, the ISO makes clarifications and/or revisions to its proposals in topic area 2, and to a lesser extent in topic area 1, to incorporate stakeholder comments and further ISO considerations. Topic area 3 remains unchanged.

2.1 Enhancements to NGR

Stakeholders generally support the ISO's proposals in this topic area as described in the draft final proposal and the ISO views its proposals as complete. However, the ISO is taking this opportunity to clarify certain aspects of its proposal in section 5.2.4 to allow an option to not provide energy limits or have the ISO co-optimize an NGR based on the "state of charge". This paper also provides clarification on the tariff changes the ISO intends to make to implement the proposed NGR enhancements (see section 5.2.5).

2.2 Enhancements to demand response performance measures and statistical sampling for PDR/RDRR

2.2.1 Alternative performance evaluation methodology

Many stakeholders are supportive of the ISO's proposal for a metering generator output (MGO) performance evaluation methodology, while some stakeholders are either not supportive or request that the ISO continue discussions with stakeholders to refine the proposal. After considering this feedback and exploring potential revisions, the ISO's proposal remains unchanged in this paper. However, the ISO does use this opportunity to clarify certain aspects of its proposal.

2.2.2 Statistical sampling

There is general stakeholder support for the ISO's proposal on the use of statistical sampling. However, based on stakeholder feedback, the ISO has revised its proposal to clarify where hourly interval meter data would be "unavailable" to meet ISO meter data submission deadlines. This clarification also results in the ISO confirming that provisions under tariff section 10.1.7 apply.

The ISO's revisions include the additional use of statistical sampling to derive settlement quality meter data (SQMD) in the following cases:

- For day-ahead participation, when hourly interval metering is not installed at all underlying resource locations.
- For day-ahead participation, when hourly interval-capable meters are installed but RQMD is not derived from the hourly interval meter data (e.g., where load profiling is used to develop ISO submitted load settlement quality meter data).

2.3 Multiple-use applications

Because of the scope of this topic, planned tariff revisions in the Expanded Metering and Telemetry Options / Distributed Energy Resources Provider (EMTO/DERP) stakeholder initiative, and the considerations discussed in section 7 of this paper, no changes to the draft final proposal or ISO tariff are needed at this time for this topic. Most stakeholders support the ISO's proposed resolution of the issues in scope regarding non-resource adequacy multiple-use applications (provision of retail, distribution and wholesale services by the same resource) as presented in the draft final proposal. For stakeholders who do not support the currently proposed resolution, the ISO anticipates further discussion of multiple-use applications in phase 2 of ESDER in 2016. The ISO therefore views its proposals in this topic area complete and does not make any revisions in this paper.

3 Background

Energy storage connected directly to the ISO grid and resources connected directly to the distribution grid (distributed energy resources or "DER") are growing and will represent an increasingly important part of the future resource mix.[1] Integrating these resources will help lower carbon emissions and can offer operational benefits.

California is taking several steps to facilitate market participation of storage and distributed energy resources. In 2013, the CPUC established an energy storage

[1] Distributed energy resources are those resources on the distribution system such as rooftop solar, energy storage, plug-in electric vehicles, and demand response.

procurement target of 1,325 MW by 2020. Energy storage developers responded by submitting many requests to interconnect to the ISO grid in the spring of 2014. Interconnection requests received in 2014 include approximately 780 MW of energy storage (13 projects), while the 2015 interconnection requests as of June 2015 included approximately 7,300 MW of energy storage (66 projects), a jump of nearly 1000%.[2]

In 2013, the ISO conducted an effort to clarify interconnection rules for storage. This effort concluded in 2014 and found that existing ISO interconnection rules accommodate the interconnection of storage to the ISO controlled grid.[3] However, in reaching this conclusion the ISO and stakeholders identified several non-interconnection related issues that should also be addressed. To address these issues, the ISO collaborated with the CPUC and CEC to publish the California Energy Storage Roadmap in late 2014.[4]

The 2014 roadmap identified a broad array of challenges and barriers confronting energy storage and aggregated distributed energy resources. The roadmap also identified needed actions to address these challenges, including several high priority action items assigned to the ISO. These are listed below:

- Rate treatment: Clarify wholesale rate treatment and ensure that the ISO tariff and applicable BPMs and other documentation provide sufficient information.
- Market participation:
    - Clarify existing ISO requirements, rules and market products for energy storage to participate in the ISO market.
    - Identify gaps and potential changes or additions to existing ISO requirements, rules, market products and models.

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[2] Queue clusters 7 and 8 include interconnection requests received in April 2014 and April 2015, respectively. The latest ISO generator interconnection queue is available on the ISO website at http://www.caiso.com/participate/Pages/Generation/Default.aspx.

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

[4] http://www.caiso.com/informed/Pages/CleanGrid/EnergyStorageRoadmap.aspx

– Where appropriate, expand options to current ISO requirements and rules for aggregations of distributed storage resources.

The ISO action plan for carrying out these items comprises two parts. The first part is to help inform stakeholders on existing ISO requirements, rules, market products and models for energy storage and aggregated DER. The ISO accomplished this first part by developing a special purpose education forum and hosting it on two dates – April 16 and 23, 2015. The forums were a success: Over 200 stakeholders attended and the feedback received was positive.

The second part of the ISO action plan is to conduct a stakeholder initiative to identify and consider potential enhancements to existing requirements, rules, market products and models for energy storage and DER market participation. The ESDER is that initiative.

4 Stakeholder process

The ISO published an initial proposed scope and schedule for the ESDER initiative on May 13, 2015. This effort identified candidate issues and divided them into two groups – a proposed scope of issues for potential policy resolution in 2015 (phase 1) and a proposed scope of issues for potential policy resolution in 2016 and beyond (phase 2). A stakeholder web conference was held on May 21 and written stakeholder comments were received on or about May 29. Based on a consideration of the stakeholder comments received, the ISO developed the revised scope and schedule and posted that on July 25.[5] The ISO invited interested stakeholders to submit written comments on the scope and schedule by July 2 and addressed these comments in its issue paper and straw proposal posted on July 30. The ISO discussed the July 30 paper with stakeholders during a web conference held on August 6 and invited stakeholders to submit written comments on the paper by August 18. Based on a review of the stakeholder comments received and further consideration by the ISO, the ISO developed its revised straw

[5] All documents for the ESDER initiative are available on the ISO's website at: http://www.caiso.com/Documents/RevisedScopeSchedule-EnergyStorageDistributedEnergyResources.pdf

proposal and posted that on September 17. This was followed by a stakeholder web conference on September 28 and written comments were received on or around October 9. The ISO then held two working group meetings in October focused on the PDR/RDRR enhancements and received written stakeholder comments following these meetings.

After considering the stakeholder input received, the ISO posted its draft final proposal on November 2, hosted a stakeholder web conference on November 9 and invited stakeholders to submit written comments by November 20. Based on a review of the stakeholder comments received on the November 2 paper, the ISO opted to produce a revised draft final proposal in order to consult with stakeholders again on its proposal for a MGO performance evaluation methodology and to use the opportunity to make further refinements and/or clarifications to its other proposals. The ISO will hold a stakeholder web conference on January 7 to discuss this paper and is inviting written comments by January 14.

The following table outlines the schedule for the policy development portion of this stakeholder initiative for those issues in the ESDER phase one scope. This schedule does not include implementation steps that may be necessary including development and filing of tariff amendments, changing business process manuals, and making and implementing changes to market system software and models.

Stakeholder Process Schedule (Phase 1 scope of issues)		
Step	**Date**	**Activity**
Education Forum	April 16 & 23	Hold education forums
Initial Proposed Scope and Schedule	May 13	Post initial proposed scope and schedule (posted in presentation format rather than a paper)
	May 21	Stakeholder web conference
	May 28	Stakeholder comments due
Revised Scope and Schedule	June 25	Post revised scope and schedule
	July 2	Stakeholder comments due
Issue Paper and	July 30	Post issue paper and straw proposal

Stakeholder Process Schedule (Phase 1 scope of issues)		
Step	**Date**	**Activity**
Straw Proposal	August 6	Stakeholder web conference
	August 18	Stakeholder comments due
ESDER Working Group	August 27	ESDER working group web conference
	September 3	Stakeholder comments due
Revised Straw Proposal	September 17	Post revised straw proposal
	September 28	Stakeholder web conference
	October 9	Stakeholder comments due
ESDER Working Group	October 12	ESDER working group meeting
	October 19	Stakeholder comments due
ESDER Working Group	October 27	ESDER working group web conference
	October 29	Stakeholder comments due
Draft Final Proposal	November 2	Post draft final proposal
	November 9	Stakeholder web conference
	November 20	Stakeholder comments due
Revised Draft Final Proposal	December 23	Post revised draft final proposal
	January 7	Stakeholder web conference
	January 14	Stakeholder comments due
Board approval	February 3-4, 2016 (tentative)	ISO Board meeting

5 NGR enhancements

5.1 Background on the NGR model

As early as 2007, the ISO launched stakeholder initiatives to lay the foundation to allow non-traditional generator resources to participate in the ISO wholesale market. These initiatives were largely in response to FERC Order Nos. 719 and 890. FERC Order No. 719 directed the ISO to allow demand response resources to participate in ancillary service markets where the resources could technically provide the ancillary service within response times and other reasonable requirements adopted by the ISO.

FERC Order No. 890 required that non-generation resources such as demand response must be evaluated comparably to services provided by generation resources in the areas of meeting mandatory reliability standards, providing ancillary services, and planning the expansion of the transmission grid.

Because of these initiatives, in 2010, the ISO changed its tariff for ancillary service wholesale participation:

- Removed resource type restrictions and reduced minimum rated capacity to 500 kW from 1 MW
- Reduced the minimum continuous energy requirement from 2 hours to:
  - Day-Ahead Regulation Up/Down: 60 minutes
  - Real-Time Regulation Up/Down: 30 minutes
  - Spin and Non-Spin: 30 minutes
- Clarified the minimum continuous energy measurement such that continuous energy is measured from the period that the resource reaches the awarded energy output; not at the end of a 10-minute ramp.

In broader context, these initiatives were a catalyst for developing new market opportunities and modeling techniques that recognized that a growing number of participating resources no longer fit the traditional generator or load models. Non-generator resources such as demand response and storage have unique energy use and production characteristics that have spawned the development of new wholesale participation models that recognize the unique attributes of these resources.

In 2012, the ISO introduced the non-generator resource (NGR) model to better accommodate energy-constrained resources that can both consume and produce energy. The NGR model was designed for energy-constrained resources to be modeled on the positive generation side, the negative generation side, or from positive to negative generation. The NGR model also allowed smaller, energy-constrained resources to be treated comparably to traditional generation resources in qualifying for day-ahead capacity and continuous energy output when providing regulation services.

The NGR model thus recognizes that a resource can operate seamlessly between positive and negative generation. For example, battery storage is a resource that can discharge energy in one interval as positive generation and consume energy in the next interval as negative generation. Current battery chemistries and storage control systems have demonstrated these resources can move nearly instantaneously between positive and negative generation, can have fast ramping rates, and can be controlled with high precision and performance accuracy. While storage technology is an ideal candidate for the NGR model, the model may also benefit other energy-constrained resources such as dispatchable demand response or microgrid configurations that have limited ability to generate or consume energy continuously and can be directly metered. The NGR model also is envisioned by the ISO as the model best suited for aggregations of distributed energy resources.

5.2 Revised Draft Final Proposal

Stakeholders generally support the ISO's proposals in this topic area as described in the draft final proposal. The ISO therefore views its proposals in this topic area complete and does not make any revisions in this paper. However, the ISO is taking this opportunity to clarify certain aspects of its proposal in section 5.2.4 to allow an option to not provide energy limits or have the ISO co-optimize an NGR based on the "state of charge". Subsection 5.2.5 provides clarification on the tariff changes the ISO intends to make to implement the proposed NGR enhancements.

5.2.1 NGR documentation

Feedback from the April education forums suggests that the forum included material and information not previously available about the NGR model and its capabilities. Although the ISO introduced the NGR model almost 3 years ago, the adoption rate has been slow because few energy storage projects have yet reached commercial operation.[6] However, the adoption rate is likely to increase with the advent of energy storage procurement targets for utilities, storage original equipment manufacturers (OEMs) reducing costs, and developers bringing projects to market. The timing is right for the ISO to review and enhance its NGR documentation in the appropriate Business Practice Manuals (BPMs) consistent with the ISO tariff, in anticipation of more storage devices participating in the ISO market as NGRs. BPM updates will include content that distinguishes differences in requirements between resources participating as NGR from NGR participating under the Regulation Energy Management (REM) option and provide additional detail on NGR participation as load or generation resources. Multiple BPMs – including but not limited to Market Operations, Market Instruments, Direct Telemetry, Metering, Outage Management, Reliability Requirements, and Settlements and Billing – will be reviewed and updated where appropriate to reflect the most up-to-date information related to NGR requirements and operation.

5.2.2 Clarification about how the ISO uses "state of charge" in the market optimization

As designed and implemented, the NGR model applies to continuous energy constrained resources. The amount of a resource's available energy is a function of the resource's state of charge (SOC). SOC is provided to the ISO through telemetry and is utilized for market resource co-optimization, real-time dispatch feasibility, and automatic generation control (AGC) signaling.

[6] Although there are many projects in the development pipeline that could ultimately use the NGR model, they are not yet in commercial operation and thus are not available to participate in the ISO market and utilize the NGR model.

Stakeholders have expressed the need to have more detail on how SOC influences model optimization and how it affects the mathematical formulation of economic dispatch. Several stakeholders requested numerical examples that describe how SOC affects the interplay between capacity and energy in sequential hours, and, information on how SOC is used in real-time AGC calculations for NGRs participating under the regulation energy management (REM) option under both normal and stressed grid conditions. Stakeholders also requested documentation that helps them understand the interplay and timing of when a particular four-second telemetered SOC value is used in the real-time market processes, which operate at different time intervals from AGC telemetry.

The ISO proposes to address the stakeholder need for clarity in SOC utilization through updates to applicable BPMs. This may include information that describes how SOC influences model optimization, impacts to mathematical formulation of economic dispatch, examples of how SOC impacts the interplay of capacity and energy over several market intervals, examples of how SOC is used in AGC calculations for resources under NGR REM, and the market interval timing between telemetered SOC values and actual market system use of the telemetered SOC value.

5.2.3 Allow initial "state of charge" as a bid parameter in the day-ahead market

Stakeholders point out that because the ISO assumes that the initial SOC value is 50% in the day-ahead market, the resource owner must manage the resource in a way to ensure that the initial day-ahead SOC is at this value or risk being awarded bids that create infeasible dispatches in the trading day. This could be especially difficult if there is significant real-time activity.

Under current rules, when an NGR bids into the day-ahead market, the initial SOC value used for that trading day is the ending SOC value from the previous day's day-ahead awards. When there are no previous day's day-ahead awards, the market system assumes that the initial SOC value for the resource is 50% of the maximum energy (MWh) limit, which is a parameter defined when the ISO models the resource in its network model. While the current approach is to begin day-ahead participation at an actual resource SOC of 50%, participants have suggested that another approach would be for the ISO to allow the initial day-ahead SOC value to be provided as a daily bid component with the day-ahead bid schedule.

With the option of providing an initial SOC parameter, stakeholders would like the ISO to clarify how the daily bid SOC value is reconciled with the real-time SOC value passed in real-time telemetry and clarify day-ahead and real-time settlement rules when day-ahead SOC parameter values differ from real-time operation. Stakeholders have also asked the ISO to clarify if there would be any restrictions on the value of the initial SOC, or on any requirements to be at (or close to) that SOC value. The ISO does not propose to monitor the accuracy of day-ahead initial SOC bid parameter. The ISO believes that the resource owner will ensure this value will be accurate to maximize the value of the resource while participating in the market and to avoid uninstructed imbalance energy (UIE) settlement and infeasible dispatch situations (i.e., the resource owner/operator takes on the UIE risk).

While some stakeholders have commented that providing an hourly SOC value would provide more benefit than an initial daily value, the ISO is not considering an option to provide an hourly starting bid parameter for day-ahead participation. The ISO suggests that an option for NGRs that does not utilize SOC within energy limit constraints may be a better solution (see section 5.2.4 below).

Some stakeholders have asked the ISO to provide an option to supply a minimum SOC parameter that the resource must have at the end of its awarded day-ahead schedule. While the ISO will observe physical constraints modeled for the resource, a desired ending SOC parameter is not a physical constraint, but an operational strategy determined by the resource owner. In these cases, the resource owner would alter their bidding strategy to affect the desired ending SOC. The ISO does not propose providing a minimum SOC parameter that the resource must have at the end of its awarded day-ahead schedule within this stakeholder process.

The ISO proposes to allow the ability to submit a daily SOC bidding parameter to initialize the ISO day-ahead market system. This option will include updates to the ISO's scheduling infrastructure business rules (SIBR)[7] system that would allow scheduling coordinators to submit a daily bid parameter for NGR SOC in both the SIBR user interface and the SIBR application programming interface (API). Rules must be established in the SIBR application such that the SOC parameter is used only on the first interval of participation for the trading day.

5.2.4 Allow an option to not provide energy limits or have the ISO co-optimize an NGR based on the "state of charge"

Stakeholders have requested that NGR resources have the option to self-manage their SOC rather than be required to provide energy limits or have the ISO co-optimize the resource based on SOC values. This request may be due in part to the lack of wholesale market participation experience with the NGR model and uncertainty of how SOC is used within the ISO co-optimization calculations and market dispatches. Under current requirements, SOC must be provided to the ISO through telemetry to enable the ISO to maximize the value of this resource in the wholesale markets and to ensure that the resource is not given an infeasible dispatch or AGC signal. The ISO recognizes there may be circumstances or conditions where the benefits of SOC co-optimization by the ISO may not materialize based on multiple use scenarios or where the SOC is derived from the SOC of many resources that may or may not always be actively participating in an aggregation.

In response to stakeholder requests, the ISO proposes to allow an option for NGRs to be modeled similar to resources that manage participation within their energy constraints.

[7] SIBR is an ISO application that provides scheduling coordinators access to the ISO market systems. SIBR functionality includes:

- Accepts bids and trades for energy and energy-related commodities from scheduling coordinators that are certified to interact with the ISO;
- Ensures that those bids and trades are valid and modified bids for correctness when necessary;
- Enters those bids and trades into a database for processing by other components of ISO's management systems; and
- Provides required feedback to scheduling coordinators concerning bids and trades that have been submitted.

This means that the scheduling coordinator would manage the SOC constraint and actively manage resource bids in the ISO real-time market in line with the resources ability to avoid non-performance conditions. Without SOC or energy limits, the ISO co-optimization process would not use these values when determining awards. If SOC values and energy limits are not provided, the ISO would assume that the NGR did not have these constraints.

Under this option:

- NGRs that do not have SOC energy limits or choose to self-manage the SOC within resource energy limit constraints may choose to not use energy limit constraints and SOC in co-optimization or dispatch.
- NGR resource owners will self-manage the resource's available energy within any energy limit constraints to avoid uninstructed imbalance energy settlements.

Although under this option an NGR would not be required to provide its SOC to the ISO through telemetry, it would have to provide all other telemetry data required by the tariff and as specified in applicable BPMs. If the ISO determines that resources under this option are not self-managing their NGR resource within energy limit constraints, the ISO reserves the right to require SOC telemetry.

Resources modeled under NGR REM are not allowed to utilize this option given the need for the ISO to maintain the resource's energy state and SOC for continuous energy output. Without real-time telemetered SOC and energy limit constraints, the ISO could not manage continuous energy requirements.

5.2.5 Tariff amendments and BPM changes

Section 30.5 of the CAISO tariff provides the bidding rules for market participants, including, among others, the common elements for supply bids (30.5.2.1), ancillary service bids (30.5.2.6), and demand bids (30.5.3). It also provides the available bid components for the different subsets of supply, such as participating generators, system resources, and metered subsystems. Because this phase of the ESDER initiative seeks to create SOC as an available bid component and to provide additional clarity on NGR bidding rules, the CAISO plans to create a new subsection within Section 30.5 that will provide both the required and optional bid components for NGRs.

In amending the tariff to include NGR bid components, the CAISO intends to continue to provide NGRs with the bid flexibility their unique nature requires. As such, many of the available bid components listed for NGRs in the tariff will be optional rather than required. Moreover, the CAISO does not intend to re-visit NGR bid components in this phase of this initiative. Instead, as part of the tariff development process in this initiative, the CAISO plans to work with stakeholders to develop NGR tariff language consistent with section 30.5 of the tariff and the NGR bid component table in section 4.1.1 of the BPM for Market Instruments, with the addition of SOC.

6 Enhancements to demand response performance measures and statistical sampling for PDR/RDRR

6.1 Background on performance evaluation methodologies

Demand response is a reduction in consumption relative to expected consumption. A baseline is an estimate of the expected consumption – i.e., the electricity that would have been consumed – had there not been a demand response event. The difference between the baseline and the actual consumption is the "nega-watts" delivered, i.e., the actual energy reduction a demand response resource delivered during the event. Because only the physical load can be metered (and not the demand response quantity), the result of the baseline calculation compared against the actual load during the ISO dispatch time horizon serves as the demand response energy measurement used by the ISO to financially settle the energy delivered (i.e., energy not consumed) from a demand response resource.

The North American Energy Standards Board (NAESB), responsible for developing and promoting industry standards, published a standard for demand resource performance evaluation methodologies.[8] It provided standard terminology and identified five broad types of performance evaluation methodologies:

1) Baseline Type-I: A baseline performance evaluation methodology based on historical interval meter data for a demand resource that may include other parameters such as weather and calendar data;
2) Baseline Type-II: A baseline performance evaluation methodology that uses statistical sampling to estimate the electricity usage of an aggregated demand resource where interval metering is not available on the entire population;
3) Maximum Base Load (MBL): A baseline performance evaluation methodology based solely on the ability of a demand resource to maintain its electricity usage at or below a specified level during a response event;
4) Meter Before/Meter After (MB/MA): A baseline performance evaluation methodology in which electricity demand over a prescribed period of time prior to resource deployment is compared to similar readings during the sustained response period; and
5) Metering Generator Output (MGO): A performance evaluation methodology in which the demand reduction value is based on the output of generator located behind the revenue meter for the demand resource.

The ISO tariff currently provides for two of these five NAESB-approved performance evaluation methodologies: Baseline Type-I and Baseline Type-II. NAESB standards, including WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response, are included in the ISO tariff by reference in section 7.3.3; however, the NAESB naming terminology is not replicated in the ISO tariff. The ISO tariff addresses the equivalent of the NAESB Baseline Type-I in tariff section 4.13.4 (“Customer Baseline Methodologies for PDR/RDRRs and RDRRs”) and NAESB Baseline Type-II in tariff section 10.1.7 (“Provision of Statistically Derived Meter Data”). This paper refers to these as “ISO Type 1” and “ISO Type 2” respectively to help clarify the relationship.

[8] Measurement and Verification of Wholesale Electricity Demand Response – NAESB WEQ-015; July 31, 2012.

ISO Type 1 is the most commonly used baseline method for performance measurement of demand response resources among ISOs and regional transmission organizations. This method uses historical meter data from the facility to calculate the baseline for the demand response resource with defined selection rules including baseline window and exclusion days. It employs an adjustment method for aligning the preliminary baseline with observed load prior to the event to minimize baseline errors. The adjustment uses actual load data in the hours preceding the event to adjust the baseline to better reflect the variables that may not be represented in the historical data (e.g., the impact of weather on load). ISO Type 1 uses the 10-in-10 non-event day methodology as described in section 4.13.4.1 of the tariff, which utilizes both baseline selection and exclusion rules. Under this methodology, the ISO examines up to 45 days prior to the trade day to find ten "like" days. The ISO then calculates a simple hourly average of the collected meter data to create a load profile, which is the baseline used to assess the event-day load response quantity. A day-of adjustment capped at ± 20 % is applied based on an adjustment window preceding the resource dispatch.

ISO Type 2 provides for statistical sampling of a demand response resource's energy usage data to derive the settlement quality meter (SQMD) data submitted to the ISO representing the total energy usage, in aggregate, for the demand response resource. It is best used for large, direct load control aggregations (e.g., residential A/C cycling) that are homogeneous, exhibit similar behavior, and where interval meter data is not available across the entire population. ISO Type 2, as described in section 10.1.7 of the tariff, allows for the submittal of SQMD for the aggregated resource to be estimated based on a representative sample of interval meter data scaled to represent the entire population of underlying service accounts.

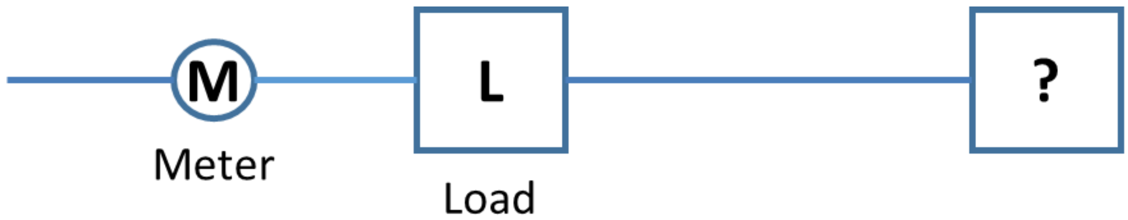
6.2 Revised Draft Final Proposal

6.2.1 Alternative performance evaluation methodology

Today, a typical PDR/RDRR resource comprises a physical meter (labeled as M in figure 1 below) connected to a load. The load may be a pure load, or it may be offset by "behind-the-meter" generation or other devices, such as battery storage. The presence of such a load-offsetting device is depicted in the figure with a question mark to illustrate that under such a metering configuration both its presence and composition are unknown to the ISO.

Figure 1

Meter Configuration Today



With such a meter configuration, there is no way to separate the load from the generation or vice versa. The ISO cannot distinguish the cause of demand response behind the meter. Some stakeholders have asked about an alternative performance evaluation methodology that directly meters the behind-the-meter device to measure the demand response provided by the device separate from the facility load. These stakeholders believe that a new methodology is needed to support the development of new use cases and configurations, especially those involving storage.

NAESB's Metering Generator Output (MGO) model was established to allow for back-up generation to offset load and serve as demand response. Per NAESB, MGO is "a performance evaluation methodology used when a generation asset is located behind the Demand Resource's revenue meter, in which the Demand Reduction Value is based on the output of the generation asset."

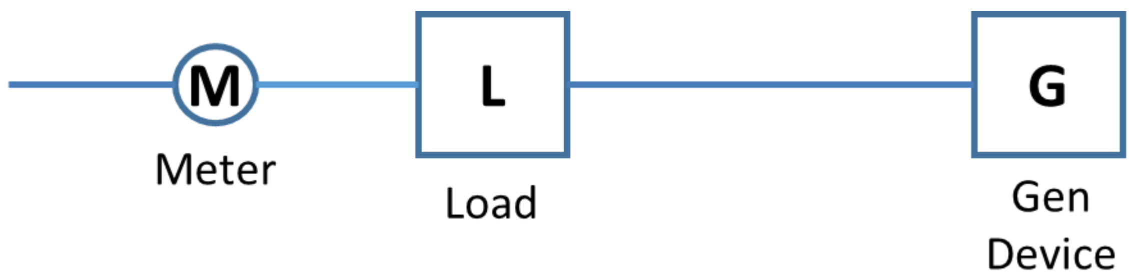
To illustrate the options the ISO is proposing, the ISO has developed metering configurations A, B, and C.

6.2.1.1 Meter Configuration A

Consider meter configuration A illustrated in Figure 2 below. This is essentially identical to today's PDR/RDRR configuration other than the generation is recognized. However, just as with today's PDR/RDRR configuration depicted in Figure 1, the performance cannot be separated into the two response methods (i.e., actual load reduction versus load consumption offset by output from a behind-the-meter generator or device).

Figure 2

Meter Configuration A



Current ISO rules support this configuration, which establishes a baseline using the physical meter (M) usage data. One issue with this configuration is that a PDR/RDRR resource that relies on a behind-the-meter generator or device used frequently such as an energy storage unit may have an unpredictable load shape and therefore an inability to derive a reasonable, predictable baseline-load profile to derive performance during a demand response dispatch event. If one excludes days with frequent generation from the baseline calculation (assuming they are identifiable), the number of available days for evaluation could become small and make it difficult to find ten comparable non-event days. It is reasonable to presume that a battery may charge every night and discharge every day based on many external variables and incentives not captured in existing performance evaluation methods. Some devices may be more difficult to model: electric vehicle charging (or discharging) whenever the homeowner plugs the vehicle into a home charging station, for example.

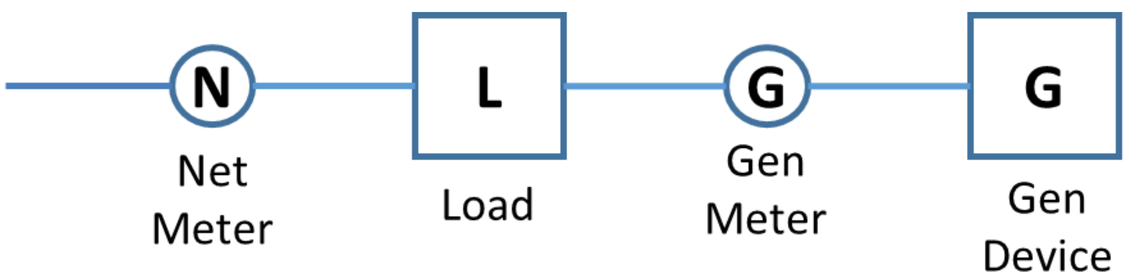
PDR and RDRR are load curtailment resources. The resource's measured performance is in aggregate based on individual location load curtailment only and must not include measured export of energy from any of the resources underlying locations. To resolve instances when M is a negative value[9] (occurring when the generation device more than offsets the load), any negative M metered quantity is set to zero (0) by the scheduling coordinator prior to summing individual location meter data in the development of the aggregated settlement quality meter data SQMD submitted to the CAISO for that PDR or RDRR.

6.2.1.2 Meter Configuration B

Now consider meter configuration B as illustrated in Figure 3 below. Meter configuration B adds a generation meter to the diagram so pure load can be derived as the difference between the net meter (N) and the generation or device meter (G).

Figure 3

Meter Configuration B



[9] For purposes of this discussion, the ISO uses the sign convention that load is a positive quantity and the output of a generation device – or energy storage in discharging mode – is a negative quantity. This sign convention does not necessarily reflect a metering sign convention in which load and generation are distinguished by metering channel.

Under this configuration, the overall demand response at the location can be separated into a pure load (facility) response and a behind-the-meter generation device's response. Measurement of the location's reduction in consumption through traditional load response would employ a standard ISO type 1 baseline and performance evaluation method using N minus G for time interval t, or N(t) – G(t), as a derived "virtual" meter quantity. Measurement of the load consumption offset by the behind-the-meter generation device would use the MGO method using the physical meter G to directly measure its response to an ISO market award/dispatch and derive its performance. As an example, if N(t) = 8 MWh and G(t) = -2 MWh, the virtual load meter quantity at time interval t would be L(t) = N(t) – G(t) = 10 MWh, where a metered quantity is assumed positive for load (consuming energy) and negative for generation (producing energy). The L(t) = 10 MWh would be the calculated quantity used to develop a baseline and performance evaluation for the traditional load response. However, rather than simply using the directly measured metered quantity G(t) to establish the MGO demand response performance evaluation, the ISO proposes to require an adjustment to the directly measured metered quantity G(t) to mitigate issues of wholesale and retail service overlap and the potential for double compensation or excess value assessment.

The ISO is offering three possible PDR/RDRR participation options under meter configuration B, each with its own application of Baseline Type-I and the adjusted MGO performance evaluation methodology. The proposals developed reflect refinements to address concerns the ISO and stakeholders have expressed about how to distinguish between the quantity of energy delivered from a device in response to a PDR/RDRR wholesale dispatch from a quantity of energy delivered to beneficially modify load for retail purposes. The ISO's three proposed options are as follows:

Option B1 – Load Reduction Only. This option would apply in instances where only the facility load is registered in the PDR/RDRR. The demand response performance would be evaluated using a baseline (B) determined from N-G values for comparable non-dispatch hours. The actual demand reduction of the load in response to an ISO dispatch interval (t) would be calculated as:

$$DR_{LOAD}(t) = B_{N\text{-}G}(t) - [N(t) - G(t)]$$

A net export rule does not apply in the B1 case since $DR_{LOAD}(t)$ is derived based on true load measurements (N-G) that will never be less than zero. In cases where the resource's calculated $DR_{LOAD}(t) < 0$, indicating that the actual load was higher than the baseline and that there was no response to an ISO PDR/RDRR dispatch, the performance measurement is set to zero for ISO settlement purposes. Application of this "non-negative" condition is at the resource level represented as:

$$DR_{LOAD}(t) = \max \{ B_{N\text{-}G}(t) - [N(t) - G(t)], 0\}$$

Option B2 – Generation Offset Only. This option would apply in instances where only the behind-the-meter device is registered in the PDR/RDRR (not the facility load as in B1). The demand response performance, referred to as $DR_{SUPPLY}(t)$ for purposes of this proposal, is the demand reduction resulting from the output of the behind-the-meter generation device for dispatch interval t. The demand response performance $DR_{SUPPLY}(t)$ would be evaluated based on the physical meter generator output G for dispatch interval t or G(t), adjusted by a quantity G_{LM} which represents an estimate of the typical energy output used for retail load modifying purposes and benefits. The calculated value, G_{LM}[10], would appropriately remove an estimated quantity of energy delivered by the device to the facility for its retail load modifying purposes, i.e. energy not produced in response to an ISO PDR/RDRR dispatch. The performance evaluation introduces an adjusted MGO value calculated by taking the difference between G(t) and G_{LM}, where the demand response performance attributed to a PDR/RDRR supply dispatch would be calculated as:

$$DR_{SUPPLY}(t) = -[G(t) - G_{LM}]$$

The adjustment for typical retail load modifying behavior, or G_{LM}, is established through a look back of metered generator output values during similar ISO non-event hours using a 10-in-10 non-event hour selection method on similar day types, i.e. comparing weekday event hours to weekday non-event hours, and weekend and holiday event hours to weekend and holiday non-event hours. For purposes of determining G_{LM}, an "event hour" is any ISO market award, dispatch or outage recorded for the PDR/RDRR that occurs during an ISO Hour Ending (HE) interval, be it the full hour or a 5-minute

[10] $G_{Load\ Modifying}$ or G_{LM} is an ISO term used to represent an estimated value of the typical retail load modifying behavior of the behind the meter generating device.

interval in that hour. G_{LM} is calculated by looking back as far as 45 calendar days and calculating the simple average energy delivered during the 10 most recent non-event hours for the same day type and for the same event hour when the PDR/RDRR dispatch event occurred.

Following are the rules the ISO will employ to calculate G_{LM} (note these rules closely align with the ISO's existing rules for ISO Type 1 baseline calculations):

- A 10-in-10 non-event hour selection method is used.
- A look back window will be 45 calendar days from which the target number of non-event hours for the same day type and for the same event hour is used to determine the G_{LM} quantity beginning with the most recent days prior to the occurrence of the ISO market award/dispatch.
- Two different day-types are recognized: Weekday (Monday through Friday), Weekend/Holiday (Saturday, Sunday, or any NERC holiday).
- An event hour is an hour when there was an ISO PDR or RDRR dispatch, or the hours when a PDR or RDRR has an outage recorded in OMS. Charging a device used for MGO is not categorized as an event.[11]

The selection of non-event hours in establishing the G_{LM} quantity is performed by iterating backward up to 45 calendar days to find the target number of non-event hours for the same event hour and same day type. Once the target number of hours is reached, selection ends. If the target number of hours is not reached, but the minimum number of hours is reached, the baseline is calculated on the selected hours. The current target and minimum hours used for the ISO Type 1: 10-in-10 baseline methodology is as follows:

- Weekdays = 10 hour target; 5 hour minimum

[11] For reference, a detailed table specifying under which conditions a PDR or RDRR is considered to have an "event day" can be found on page 47 of the Demand Response User Guide located at http://www.caiso.com/participate/Pages/Load/Default.aspx.

- Weekends/Holidays = 4 hour target; 4 hour minimum

Example: If only 8 non-event hours for a week day for the applicable event hour can be found across a 45-calendar day look back, then those set of 8 non-event hours will be averaged to determine the G_{LM}.

If in the 45-calendar day look back period, the minimum number of non-event hours cannot be reached, then G_{LM} should be set to zero. It is reasonable to assume that, upon exhaustion of a 45-calendar day search to obtain a similar non-event hour, there is no typical energy output for retail load modifying purposes and that the generator is being used solely in response to ISO wholesale participation.

In calculating G_{LM}, the ISO is only interested in the average energy output (not input) across the target or minimum number of hours required for that day type. Thus the metered quantity for any interval in which a generation device is in charging mode shall be set to zero (0) when developing the non-event hour value used in developing G_{LM} .

PDR and RDRR are load curtailment resources. The resource's measured performance is in aggregate based on individual location load curtailment only and must not include measured export of energy from any of the resource's underlying locations. Meter data in which there is a net export of energy (i.e., where in any interval the meter output of the behind-the-meter device is greater than the facility load) at any underlying PDR or RDRR location, must be set to zero (0).

Option B2 employs a net export rule, such that, if $N < 0$ then the MWh amount settled in that interval is the MWh delivered up to $N = 0$. This net export rule is applied at the location level, not at the PDR/RDRR aggregate level.

To recognize inclusion of the net export rule application at the location level, the DR_{SUPPLY} equation is rewritten to reflect this adjustment requirement:

$$DR_{SUPPLY}(t) = \max\{ -[G(t)^{nx} - G_{LM}(t)], 0\}$$

Where the net export adjusted generation quantity $G(t)^{nx}$ is calculated as:

$$G(t)^{nx} = \sum_{i=1}^{n} G(i,t) - \min\{0, N(i,t)\}$$

When, *i* = 1,2,…*n* denotes the location, G(i,t) is the generator/device metered output at location *i* during dispatch interval t, and N(i,t) is the net meter quantity at location I during dispatch interval t.

The ISO retains the authority to audit both the N and G meter data values to evaluate the accuracy of settlement quality meter data, representing the resources performance measurement, submitted by the scheduling coordinator to ensure compliance with this net export rule.

Option B3 – Load and Generation. This option would apply in instances where both the load and the behind-the-meter device together are registered as the PDR/RDRR resource. Under this option, the demand response performance would be the combined demand response performance attributed to $DR_{LOAD}(t)$ and $DR_{SUPPLY}(t)$, as previously detailed under options B1 and B2 respectively, resulting in a total demand response reduction calculated as:

$$DR_{TOTAL}(t) = DR_{LOAD}(t) + DR_{SUPPLY}(t)$$

Consider the following example where N(t) = 15, G(t) = - 7, $B_{N-G}(t)$ = 25 and $G_{LM}(t)$ = - 3. In this example, the total performance evaluation would be:

$DR_{LOAD}(t) = B_{N-G}(t) - [N(t) - G(t)] = 3$ **and** $DR_{SUPPLY}(t) = -[G(t) - G_{LM}(t)] = 4$

Therefore, $DR_{TOTAL}(t) = 7$

When deriving $DR_{TOTAL}(t)$, the "non-negative" applicability must be applied to $DR_{LOAD}(t)$ consistent with Option B1 in addition to the application of the net export rule to $DR_{SUPPLY}(t)$ consistent with option B2.

Table 1 below summarizes the ISO proposal for meter configurations A and B and the three options for configuration B.

Table 1

	Meter Configuration A	Meter Configuration B		
		B1 Load Only	B2 Supply Only	B3 Load & Supply
Demand Response Providers (DRP)	Single DRP	Single DRP	Single DRP	Single DRP

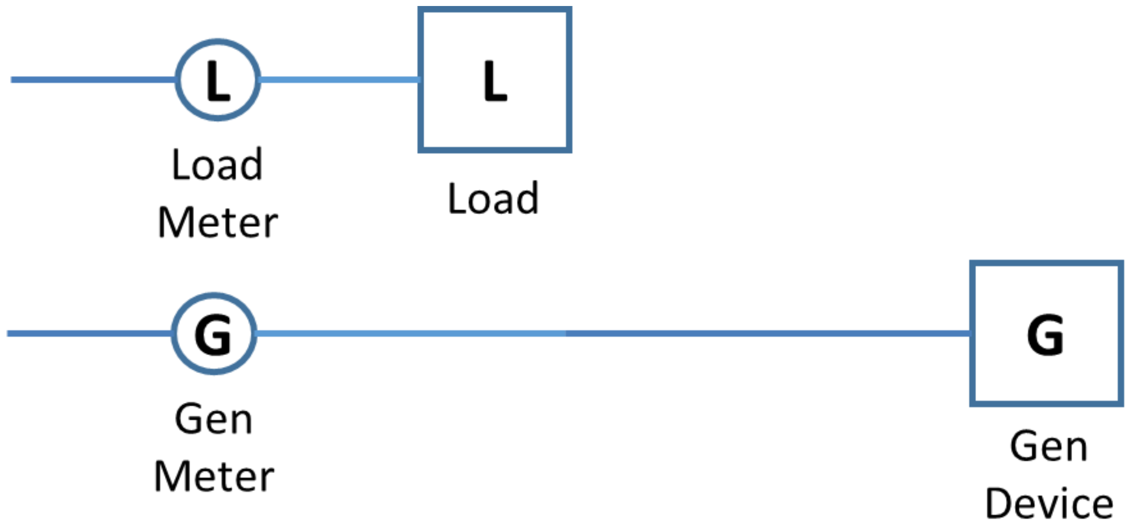
	Meter Configuration A	Meter Configuration B		
		B1 Load Only	B2 Supply Only	B3 Load & Supply
Resources	Single PDR/RDRR	Single PDR/RDRR	Single PDR/RDRR	Single DRP
Registrations	Net Facility	Load	Supply	(1) Load (2) Generation
Locations (SANs)	Net Facility	Load	Supply	(1) Load (2) Supply
Performance Evaluation Methodology	BN(t) – N(t)	B_{N-G}(t) – N(t) + G(t)	G_{LM}(t) – G(t)	DR_{TOTAL}(t) = DR_{LOAD}(t) + DR_{SUPPLY}(t)

6.2.1.3 Meter Configuration C

Lastly, consider meter configuration C illustrated in Figure 4 below. Here it is assumed that the utility has provided a separate service account for the generator or device, leaving the load independently measured.

Figure 4

Meter Configuration C



This meter configuration provides the same information as meter configuration B, only with N-G replaced by the physical meter L. However, this configuration is required if separate participants are managing the load and the generation independent of one another. Because the load is not combined or affected by the generator or device as in meter configuration B, the generator or device alone cannot be a PDR/RDRR; it must be a Non-Generator Resource (NGR) or a Participating Generator (PG). A summary of rules for Meter Configuration C is provided in Table 2 below.

Table 2

	Meter Configuration C	
	Load Only	**Generation Only**
Demand Response	Single DRP	Cannot be PDR/RDRR but

	Meter Configuration C	
	Load Only	**Generation Only**
Providers (DRP)	(May be different from generation owner)	would participate in the ISO market as a non-generator resource (NGR) or participating generator (PG).
Resources	Single PDR/RDRR	
Registrations	Load	
Locations (SANs)	Load	
Performance Evaluation Methodology	ISO Type 1 Baseline (L)	

Current demand response system design accommodates a single performance evaluation method for a resource. There may be limitations imposed on stakeholders until such time that the system, and processes associated with its use, can accommodate many registrations to one resource. The ISO's proposed performance measurement options for meter configurations A and B will remain subject to development limitations.

Additionally, the current ISO demand response registration system (DRRS) redesign scope does not contain specifications that can automatically calculate the MGO variations being proposed under B2 and B3. ISO Type 1 baseline and performance measurement calculations for the load portion of the above scenarios will continue to be calculated by the ISO using actual or derived SQMD for metering configurations A and B1. Performance calculations for resources using the "supply only" and "supply and load" options, utilizing proposal options B2 and B3, will be done by the scheduling coordinator and submitted to the ISO as SQMD by the scheduling coordinator.

6.2.2 Statistical Sampling (Baseline Type-II)

The ability to use statistical sampling to estimate load meter data submitted to the ISO to evaluate the performance of an ISO dispatched demand response resource (PDR/RDRR) is described in section 10.1.7 of the ISO tariff:

10.1.7 Provision of Statistically Derived Meter Data

A Demand Response Provider representing a Reliability Demand Response Resource or a Proxy Demand Resource may submit a written application to the CAISO for approval of a methodology for deriving Settlement Quality Meter Data for the Reliability Demand Response Resource or Proxy Demand Resource that consists of a statistical sampling of Energy usage data, ***in cases where interval metering is not available for the entire population*** of underlying service accounts for the Reliability Demand Response Resource or Proxy Demand Resource. As specified in the Business Practice Manual, the CAISO and the Demand Response Provider will then engage in written discussion which will result in the CAISO either approving or denying the application.

Stakeholders have asked for clarification on when "interval metering is not available." While the vast majority of residential and small-commercial customers have hourly interval metering installed that could provide interval data in a granularity that would support ISO day-ahead market participation, the ISO understands there are cases in which hourly interval meter data is not used for a significant percentage of customers' retail billing or load serving entities' (LSE) default LAP settlement. While hourly interval meter data is required for day ahead market participation, the ISO can accommodate up to 15-minute interval metering to participate in the ISO real-time and ancillary services markets.[12] In all ISO participation cases, revenue quality meter data (RQMD), as specified by the local regulatory authority (LRA), is required to create settlement quality meter data (SQMD) for ISO PDR and RDRR settlements. However, the ISO does not want to preclude participation of residential or small-commercial customers because the ISO's required submittal timelines or granularity are interpreted too narrowly.

[12] The ISO allows meter data to be created by parsing 15-minute recorded interval meter data into three equal 5-minute intervals per BPM for metering (see section 12.5).

Accordingly, to expedite demand response participation in wholesale markets (including providing resource adequacy), the ISO is proposing to support the use of statistical sampling in the following cases:

- For day-ahead energy participation only, when hourly interval metering is not installed at all underlying resource locations. Not applicable for ancillary service participation.
- For day-ahead energy participation only, when hourly interval metering is installed at all underlying resource locations but RQMD is not derived using the hourly interval meter data for settlement purposes, but is developed using load profiles. Not applicable for ancillary service participation.
- For real-time and ancillary services participation when interval metering installed at all underlying resource locations is not recorded in 5- or 15-minute intervals

The ISO believes the use of statistical sample is applicable for these cases and is supported by section 10.1.7 of the ISO tariff. It was always the ISO's intent to allow broad participation among small resources consistent with the LSEs' commercially reasonable data collection and settlement processes. This interpretation is consistent with that intent.

The ISO recognizes the IOUs are expending considerable effort to accommodate the RQMD data needs of demand response providers in both the timelines and interval granularity required for wholesale market participation through multiple CPUC proceedings including Customer Data Access and Rule 24. The ISO will re-visit the applicability for use of statistical sampling proposed upon implementation of resulting technical and process solutions that will be in place to solve unavailability issues identified.

Finally, the ISO Type 2 proposal is intended to be used, and its use will be identified as such, for a demand resource participating under PDR and RDRR. Any other use of ISO Type 2 to derive SQMD for any other form of ISO participation under this proposal would be prohibited.

The ISO tariff provision to statistically derive meter data was included to accommodate participation of an aggregated PDR/RDRR comprising several locations, some of which are interval metered and have revenue quality meter data available, and with the condition that the balance of locations would mimic the metered random sample. Once the randomly sampled fraction of revenue quality meter data is converted to settlement quality meter data (SQMD), the sum is then scaled to derive the SQMD sized for the PDR/RDRR. This scaled SQMD value is called the **Virtual** SQMD and is calculated as:

$$m_{VIRTUAL} = \frac{N}{n} \cdot \sum_{i=1}^{n} m_i$$

where: $N = Total\ Number\ of\ Locations\ Participating$

$n = Number\ of\ Metered\ Locations$

$m_i = SQMD\ for\ Location\ i$

$n \in N\ (Metered\ Locations\ are\ a\ subset\ of\ Locations\ Participating)$

It is critical that the members of the sample (n) be selected at random from within the population (N). This means that sample members must be selected without bias to any factor such as size, location, or customer type. The participant may be required to demonstrate that each PDR/RDRR sample was selected at random.

Determining the minimum number of metered locations providing RQMD is based on statistical sampling principles. For an infinite population, the required sample size is given as:

$$n' = \left(\frac{z}{e_{REL}}\right)^2 \cdot \left(\frac{1-p}{p}\right)$$

Where: $e_{REL} = Relative\ Precision\ Level$

$z = Value\ based\ on\ Level\ Of\ Confidence$

$p = True\ Population\ Proportion$

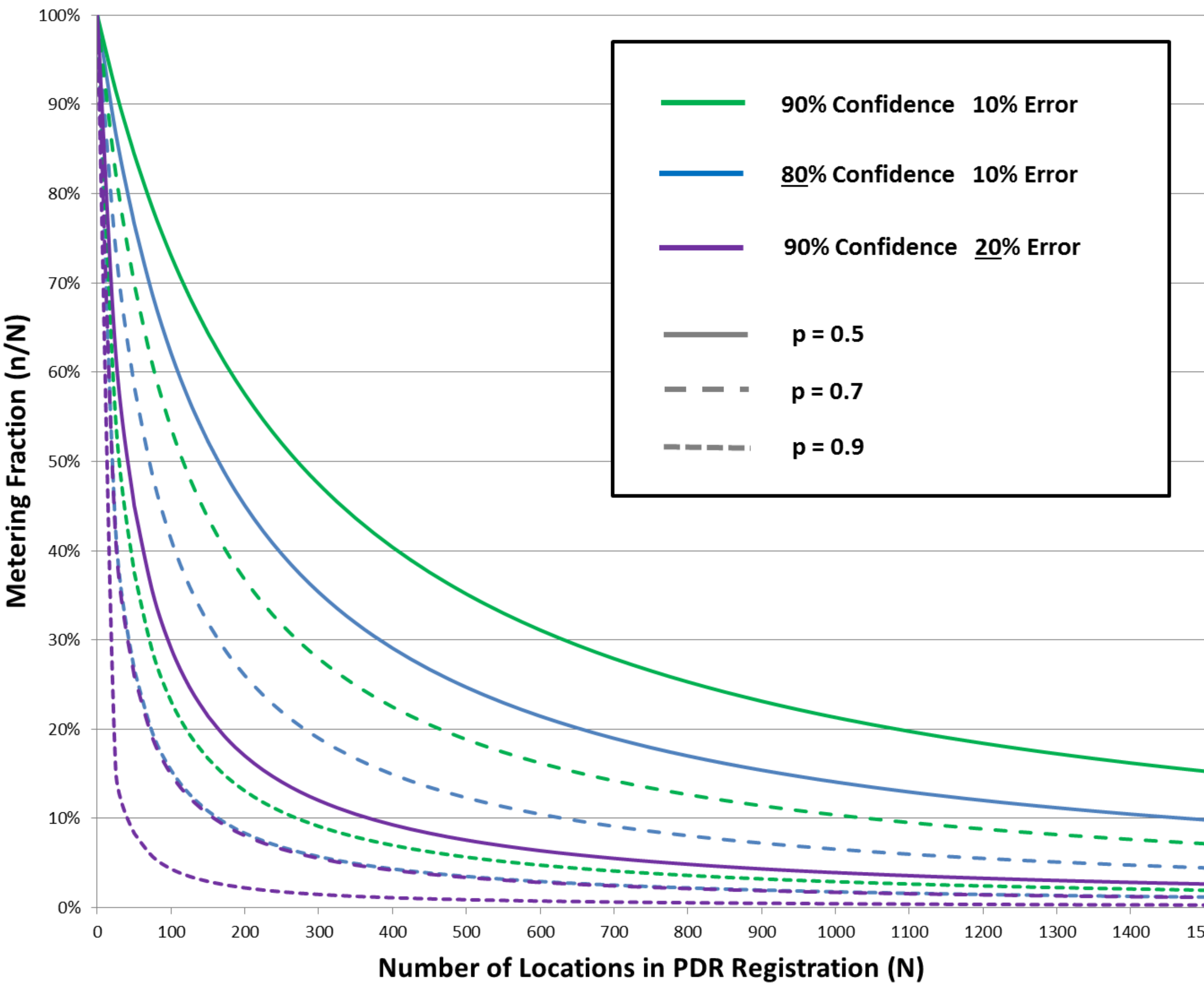
Many ISOs and RTOs use this formulation. The following table summarizes some samples:

	Relative Precision Level	Level Of Confidence
PJM	10%	90% (z=1.645)
ISO New England	10%	80% (z=1.282)
NYISO	10%	90% (z=1.282)

For a finite population, the sample fraction can be calculated as:

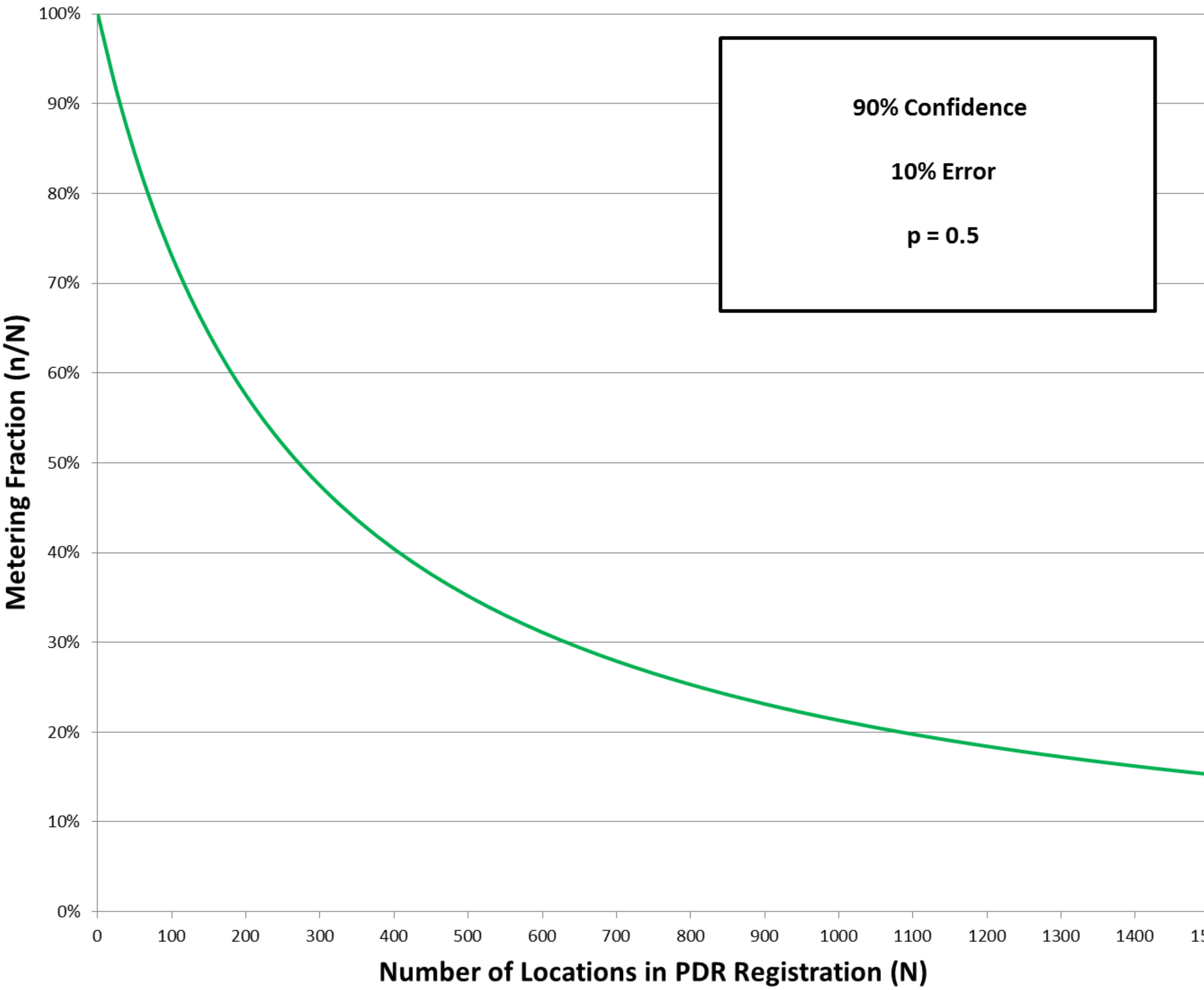
$$\frac{n}{N} = \frac{n'}{N + n'}$$

This yields several different Metering Fraction curves as a function of the two variables to be fixed,in addition to the population size (N) and the True Population Proportion (p) as shown on the following page:


100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Metering Fraction (n/N)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
15
Number of Locations in PDR Registration (N)
90% Confidence 10% Error
80% Confidence 10% Error
90% Confidence 20% Error
p = 0.5
p = 0.7
p = 0.9

The following figure shows the resulting curve based on the ISO's decision to set the Relative Precision Level to 10% and the Level of Confidence to 90%, which results in a z of 1.645 [13]. Since the True Population Proportion is difficult to calculate, a value of p = 0.5 is chosen, similar to other ISOs and RTOs. The sample size for an infinite population with these requirements is therefore: $n' = 271$.

[13] The value of z is derived from a distribution of samples with 10% of the high samples and 10% of the low samples in the two respective tails of a Gaussian distribution.


90% Confidence
10% Error
p = 0.5
Metering Fraction (n/N)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
Number of Locations in PDR Registration (N)

The ISO proposes to require that every resource employing ISO Type 2 have a sample fraction:

$$f = \frac{n}{N} = \frac{n'}{N + n'} = \frac{271}{N + 271}$$

The following table shows a number values for the fraction based on the number of locations:

PDR Locations	Minimum Sample Fraction
10	96%
25	92%
50	84%
75	78%
100	73%
125	68%
150	64%
175	61%
200	58%
250	52%
300	47%
350	44%
400	40%
500	35%
750	27%
1000	21%
1500	15%
2000	12%

Should the size of the population increase or decrease over time, the sample fraction must be re-evaluated and the sample size adjusted accordingly. Except for the scheduling coordinator submitting SQMD for a derived virtual metering data based on statistical sampled physical metering rather than physical metering data for all locations, a PDR/RDRR utilizing ISO Type 2 provisions (NAESB Baseline Type-II) is treated identical to NAESB Baseline Type-I from an ISO demand response system processing perspective.

Market participants with aggregated PDR/RDRRs may be requested to comply with ISO information requests to audit the meter data collection process and the virtual meter scaling process.

As a final note, a long-standing ISO philosophy regarding PDR and RDRR is to focus initial implementations on features that achieve as many of the business goals as practical while keeping the processes simple and rules straight forward. As this applies to allowing for statistical sampling of meter data (ISO Type 2), the CAISO position is to formalize a well-defined and easy-to-understand rule that applies to all market participants as outlined in this proposal. This proposal is consistent with other markets, and errs on the side of a more conservative approach.

The ISO will continue to explore further enhancements to ISO Type 2. For example, additional logic that would allow for a sampling method that may be biased by existing installations of 15-minute interval data meter equipment and a process for demonstrating that PDR/RDRR constituent locations are more homogenous than average in order to qualify for a smaller sampling fraction.

7 Non-resource adequacy (non-RA) multiple-use applications

Because of the scope of this topic, planned tariff revisions in the DERP stakeholder initiative, and the considerations discussed in section 7 of this paper, no changes to the draft final proposal or ISO tariff are needed at this time for this topic. Most stakeholders support the ISO's proposed resolution of the issues in scope regarding non-resource adequacy multiple-use applications (provision of retail, distribution and wholesale services by the same resource) as presented in the draft final proposal. For stakeholders who do not support the currently proposed resolution, the ISO anticipates further discussion of multiple-use applications in phase 2 of ESDER in 2016. The ISO therefore views its proposals in this topic area complete and does not make any revisions in this paper. The remainder of this section is mostly identical to the same section in the draft final proposal, except for the addition of new stakeholder comments opposing the ISO's proposal at the end of the section.

7.1 Background

Multiple-use applications are those where an energy resource or facility provides services to and receives compensation from more than one entity. The ISO, CPUC and Energy Commission 2014 Energy Storage Roadmap identified "Define and develop models and rules for multiple-use applications of storage" as a medium-priority action item. The present initiative addresses two broad categories or types of multiple-use applications that the Energy Storage Roadmap identified for storage and extends them here to include more general DER aggregations (DERA): (1) the DERA provides reliability services to the distribution grid and services to the wholesale market; and (2) the DERA provides services such as demand management to end-use customers while participating in the wholesale market.

Consistent with previous papers issued as part of this initiative, the treatment of these multiple-use applications is limited to circumstances where the resource either is not providing resource adequacy (RA) capacity or can set aside a portion of its installed capacity not providing RA capacity. The criterion "not providing RA capacity" is intended to apply on a monthly basis for purposes of this initiative; i.e., the capacity in question that capacity is not included in a load-serving entity's RA plan for the given month.

7.2 Assumptions underlying this revised draft final proposal

The first assumption is that ESDER should follow the DERP[14] proposal regarding multi-pricing node (pnode) DER aggregations. In the DERP the ISO is proposing to relax the

[14] "DER provider" or "DERP" refers to an entity that aggregates individual DER sub-resources to create an aggregate resource called a "DER aggregation" or "DERA" for participation in the ISO markets. The DERP

original requirement for multi-pnode DERAs that (a) all sub-resources must be of the same type and move in the same direction in response to an ISO dispatch of the DERA. The ISO is proposing instead to impose the requirement – which has been the underlying concern all along – that (b) the net movement or net response at each pnode must be in the same direction as the dispatch and in alignment with the distribution factors (DFs) used in the dispatch. Under requirement (b) the ISO will not require the underlying sub-resources to be of the same type, or even that they all move in the same direction, but only that the net response of all sub-resources at each pnode that comprises the DERA be in the direction of the dispatch and in the same relative proportions as the DFs. Moreover, the SC for the DERA may bid the DFs in each hour, so the DFs need not be fixed. But whatever DFs the SC bids for the DERA will be used in the dispatch, so the ISO will expect the resource to move in accordance with the bid DFs if it is dispatched.[15]

The second assumption is that the ISO will require settlement quality meter data (SQMD) from the SC for a DERA, to be submitted on a daily basis following ISO submittal timelines, and will settle the DERA based on that SQMD, for all market intervals, not just those intervals in which the DERA was issued an ISO schedule or dispatch instruction.[16] PDR and RDRR resources will continue to have the ability to provide SQMD and be settled through the ISO market only for intervals in which they were dispatched by the ISO, but resources participating under the DERP construct will not.

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initiative, which was approved by the ISO Board of Governors in July 2015, will create a pro forma "DERP agreement" or "DERPA" that will be the contractual relationship between the DERP and the ISO.

[15] These proposed enhancements were approved by the ISO Board of Governors on December 18, 2015, and will be included in the draft tariff language currently being prepared in the EMTO/DERP initiative to be filed at FERC.

[16] A multi-pnode DERA will be settled at an aggregated pnode (APnode) price that is the average of the pnode prices at pnodes included in the DERA, weighted by the distribution factors (DFs) for the DERA that either were submitted by the SC in the bid for the relevant interval or are on file as default DFs for intervals in which the SC does not bid DFs.

7.3 Revised Draft Final Proposal – ISO's proposed positions on questions posed in this initiative

Type 1. DER provide services to the distribution system and participate in the wholesale market

Question 1: If a DER is procured by the distribution utility to provide a grid service and bids into the ISO market, how should conflicting real-time needs of the distribution utility and the ISO be managed?

Draft Final Proposal: The ISO proposes to settle a DER dispatch in the same manner as other generating resources are settled. If the DER deviates from an ISO dispatch instruction to provide service to the distribution system or for another reason, its deviation will be settled as uninstructed imbalance energy.

Stakeholders generally support this approach, and the ISO agrees this approach is appropriate for DER capacity not serving as RA capacity. In the 2016 phase of ESDER when we consider DER capacity that is subject to RA offer obligations, we will explore what modifications to this approach may be appropriate for RA resources.

Question 2: Is there a concern about double payment to a DER for any market interval in which the DER follows an ISO dispatch instruction that aligns with the service the same DER is providing to the distribution utility? If so, how should the ISO address this concern?

Draft Final Proposal: The ISO proposes not to implement any provisions at this time to address potential double payment situations where a DER is compensated by the distribution utility and is also settled through the ISO market for responding to an ISO dispatch or for UIE. The ISO may reconsider this position in the future, but for now the issue is not yet ripe for resolution because distribution-level services have not yet been defined. The ISO's position is that concerns about double payment from both the distribution utility for distribution-level services and the ISO for market participation need to be based on an understanding of the specific distribution-level services involved and how they are procured, utilized and compensated by the distribution utility. These questions are being considered in CPUC proceedings[17] and may or may not be ripe for consideration by the ISO in the 2016 ESDER initiative.

<u>Question 3:</u> Should there be limitations on the provision of distribution-level services by a multi-pnode DER aggregation or the sub-resources of a single-pnode or multi-pnode DER aggregation that is an ISO market participating resource? If so, what limitations are appropriate?

<u>Draft Final Proposal:</u> The ISO proposes not to impose any such limitations. This follows the first assumption described in section 7.2 above regarding the provisions for DER aggregations (DERA) that will be filed at FERC in the near future. Specifically, under the DERP proposal, the ISO will not require any specific performance by sub-resources that comprise either a multi-node or single-note DERA. The requirement is that when the ISO issues a dispatch instruction to a DERA, the net response at each constituent pnode be in the direction of the dispatch and that the net responses across constituent pnodes be in proportion to the distribution factors for the DERA. As long as the DERA complies with this requirement, the operational behavior of individual sub-resources will not be subject to ISO requirements. Thus an individual sub-resource could respond to the needs of the distribution system as long as the DERP who operates the DERA delivers the net response at the associated pnode that is in the same direction as the dispatch instruction and aligns with the distribution factors for the DERA.

Type 2. DER provide services to end-use customers and participate in the wholesale market

Consistent with the Revised Straw Proposal, the ISO does not believe there are issues that need to be addressed at this time on this topic, beyond the issues being addressed under the PDR/RDRR topic. The PDR/RDRR topic in this initiative deals with scenarios where DER provide services to end-use customers and participate in the wholesale market. The ISO believes that those elements of the present initiative should be resolved, at which time we can better assess whether there are additional issues regarding this category of multiple-use applications that were not addressed and should

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[17] See in particular the CPUC Distribution Resources Plan (DRP) proceeding (R.14-08-013) and the Integration of Distributed Energy Resources (IDER) proceeding (R.14-10-003).

be included in the 2016 ESDER scope.

7.4 Responses to stakeholder comments

Stakeholder comment: One theme many stakeholders raised was the desire for rules that allow a resource to choose not to participate in the ISO markets in all hours. Stakeholders propose that the SC for the resource could choose to submit a bid only for hours when the resource wants to participate, and for other hours the resource would have no obligation to participate and would not be settled by the ISO for its activity during those hours. The ISO would settle the resource's performance only for hours in which the ISO issued the resource dispatch instructions, not for hours the SC submitted a bid for the resource and it was not dispatched.

ISO response: Only resources using the PDR or RDRR model have this flexibility today. Under the NGR model or other models for DERA participation, the resource is subject to all the normal provisions that apply to resources in the ISO markets. In particular, although a DERA is able to be a scheduling coordinator metered entity (SCME), it will be required to provide SQMD in accordance with ISO submittal timelines and will be subject to ISO settlement for all hours regardless of whether it submitted a bid and was dispatched. The ISO will not revisit this requirement on NGR in the 2105 ESDER scope, but recognizes that there is wide support among stakeholders for a variant of NGR that allows the resource to elect when to participate in the wholesale market and be settled accordingly, and will consider including this in the 2016 scope of the ESDER initiative.

Type 1. DER provide services to the distribution system and also participate in the wholesale markets.

Question 1: Conflicting real-time needs

Comments: Most stakeholders support relying on uninstructed imbalance energy (UIE) settlement for deviations of the resource from ISO dispatch. For hours where the SC does submit a bid and the ISO dispatches the resource, the resource would be settled in the normal way based on its response to the ISO dispatch, with deviations from the dispatch – for example, in cases where the resource responded instead to a distribution system need – settled as UIE.

ISO response: The ISO agrees and proposes to use the UIE settlement provisions for deviations from DERA schedules and ISO dispatches. UIE settlement will also apply to intervals where the DERA operates without an ISO schedule or dispatch.

Type 2. DER provide services to end-use customers and participate in the wholesale market.

Comments: Several stakeholders commented on the need to expand the capabilities under the PDR model to allow bi-directional ISO dispatch (i.e., a dispatch instruction to increase consumption, for example to relieve excess supply on the grid) and to provide regulation service, as long as the resource satisfies the PDR requirement not to export energy across the end-use meter onto the distribution grid.

ISO response: In the 2015 scope the ISO cannot address any modifications to the PDR model other than the topics already in scope of this initiative. Modifications such as those suggested in the comments will be considered as potential topics for the 2016 ESDER initiative.

Comments: Some stakeholders expressed the view that storage resources located behind the end-use customer meter and serving retail load should be considered retail assets. As such, "the process for rates, interconnection procedures and metering cost responsibility must be clearly defined, and opportunities for wholesale/retail 'gaming' should be eliminated in order to avoid shifting grid service costs to other customers," in particular with regard to such resources participating in the wholesale market under the NGR model. A related issue that was raised is the question of whether the ISO has the authority to directly meter and control non-WDAT resources, and the need to resolve this jurisdictional issue and address its potential implications (such as possible double payment for the same service) before any rules are put in place for non-WDAT multiple-use applications.

ISO Response: As noted at the beginning of this section, the ISO is not proposing to put any new rules in place for the multiple-use applications considered under the narrow scope of the present initiative. The ISO anticipates that some of these issues will be included in the scope of Track 2 of the CPUC's energy storage proceeding, in which the ISO will fully participate, as well as considering them in a parallel and coordinated fashion in the 2016 phase of ESDER.

Attachment D – Board Memorandum

Tariff Amendment to Implement Energy Storage Enhancements

California Independent System Operator Corporation

May 18, 2016

Memorandum

To: ISO Board of Governors

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

Date: January 27, 2016

Re: **Decision on energy storage and distributed energy resources proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Energy storage connected directly to the ISO grid, and distributed energy resources connected directly to the distribution grid, are growing and will represent an increasingly important part of the future generation resource mix available to the ISO. Integrating these resources into the ISO market will help lower carbon emissions and can offer operational benefits. Enhancing the ability of these resources to participate in the ISO market is the central focus of the ISO's energy storage and distributed energy resources stakeholder initiative.

Through this initiative, Management has developed a proposal to increase the flexibility for these resources to participate in the ISO market. This proposal involves several enhancements to existing market design rules. These include two proposed enhancements to the market participation model for storage and one proposed enhancement to demand response performance measures. The storage-related enhancements for resources participating in the ISO market under the non-generator resources model would (1) allow such a resource the ability to submit a daily state of charge bidding parameter and (2) have the option to self-manage limits and state of charge. The demand response-related enhancement would provide three performance evaluation methods for resources participating in the ISO market as either a proxy demand resource or reliability demand response resource with behind-the-meter generation devices.

Management recommends the following motion:

> **Moved, that the ISO Board of Governors approves the proposal for the non-generator resources model and demand response performance measures, as described in the memorandum dated January 27, 2016; 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

<u>Proposed enhancements to the market participation model for storage</u>

In 2012, the ISO introduced the non-generator resource model to better accommodate energy-constrained resources that can operate seamlessly between positive and negative generation. For example, battery storage is a resource that can discharge energy in one interval as positive generation and consume energy in the next interval as negative generation. The ISO also considers this model as best suited for aggregations of distributed energy resources to participate in the ISO market. Although the ISO introduced the model three years ago, the adoption rate has been slow because few energy storage projects have reached commercial operation. However, the adoption rate is likely to increase dramatically in the near future as the many projects in the development pipeline reach commercial operation. The timing is right to review and enhance the model in anticipation of more storage devices participating in the ISO market as non-generator resources.

Management proposes two enhancements. First, we propose to allow a storage resource participating as a non-generator resource to submit a daily state of charge bidding parameter in the day-ahead market. Under current rules, when a non-generator resource bids into the day-ahead market, the initial state of charge value used for that trading day is the ending state of charge value from the previous day's day-ahead awards. However, when there are no previous day's day-ahead awards, the market system assumes that the initial state of charge value for the resource is fifty percent of the maximum energy limit. As an alternative, stakeholders have requested that the ISO allow the initial day-ahead state of charge value to be provided as a daily bid component with the day-ahead bid schedule.

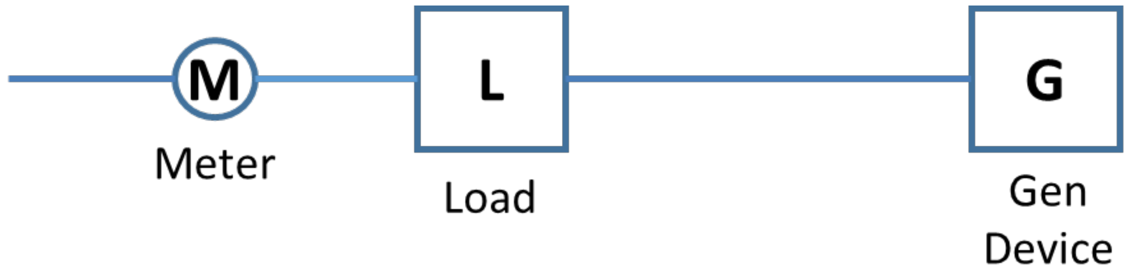
Second, we propose to provide non-generator resources with the option to self-manage their energy limits and state of charge. Under current rules, state of charge must be provided to the ISO through telemetry to enable the ISO to maximize the value of the resource in the wholesale market, and to ensure that the resource is not given an infeasible dispatch. As an alternative, stakeholders have requested that non-generator resources have the option to self-manage their state of charge rather than be required to provide energy limits or have the ISO co-optimize the resource based on state of charge values. Under Management's proposal, non-generator resources that do not have state of charge energy limits or prefer to self-manage the state of charge within resource energy limit constraints may choose to not use energy limit constraints and state of charge in co-optimization or dispatch. Non-generator resources choosing this option will self-manage their available energy within any energy limit constraints to avoid uninstructed imbalance energy settlements. Although under this option a non-generator resource would not be required to provide its state of charge to the ISO through telemetry, it would still be required to provide all other telemetry data required by the tariff and as specified in applicable business practice manuals. If the ISO determines that resources under this option are not self-managing their resource within energy limit constraints, the ISO reserves the right to require state of charge telemetry. Non-generator resources modeled as regulation energy management resources are not allowed to utilize this option, given the need for the ISO to maintain the resource's energy state and state of charge for continuous energy output. In this latter case, without real-time telemetered state of charge and energy limit constraints, the ISO could not manage continuous energy requirements.

Proposed enhancements to demand response performance measures

Demand response is a reduction in actual consumption relative to expected consumption. A baseline is an estimate of the expected consumption – that is, the electricity that would have been consumed had there not been a demand response event. Because only physical load can be metered and not the demand response quantity, the result of the baseline calculation compared against the actual load during the ISO dispatch interval serves as the demand response energy measurement used by the ISO to financially settle the energy delivered (that is, energy not consumed) from a demand response resource.

Today, a proxy demand resource or a reliability demand response resource[1] participating in the ISO market comprises a physical meter connected to a load. The load may be a pure load, or it may be offset by "behind-the-meter" generation or other devices as depicted in the following diagram. The presence of such a load-offsetting device is unknown to the ISO under this configuration. With such a meter configuration – that is one lacking a sub-meter separately measuring the performance of the behind-the-meter generation device – there is no way to separate the load from the generation or vice versa.

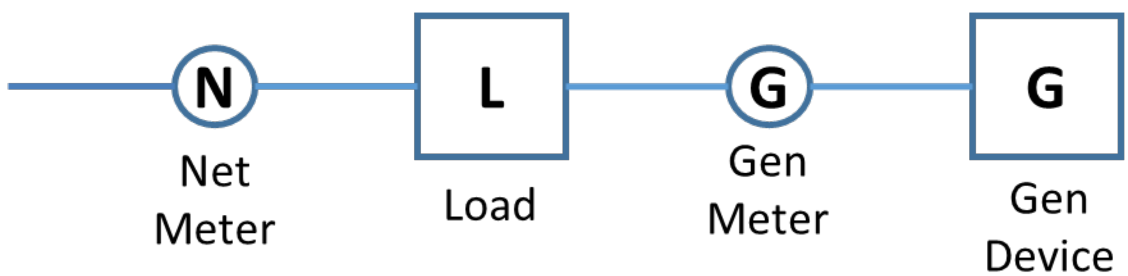
[1] Loads or aggregation of loads capable of measurably and verifiably providing demand response services pursuant to a demand response provider agreement with the ISO.



Under current rules, proxy demand resources and reliability demand response resources participating in the ISO market use a baseline method to estimate expected consumption which is compared to actual consumption to measure performance. The baseline for the demand response resource is calculated using historical meter data from the facility with defined selection rules including a look-back window and exclusion days. The ISO methodology examines up to 45 calendar days prior to the trade day to find a target number of “like” days and calculates an hourly average of the collected meter data to create a load profile, which is the baseline used to assess the event-day load response quantity. This method cannot distinguish the cause of demand response – that is, whether it is actual load reduction versus load consumption offset by the output of a behind-the-meter generation device – because there is no way to separately measure the amount of consumption offset by the output of the generator or device.

To accommodate the proliferation of behind-the-meter generation devices involved in demand response, stakeholders have requested an alternative performance evaluation methodology that directly meters the behind-the-meter generation device to measure the demand response provided by the device separate from the facility load.

The following illustration reflects the addition of a generation meter to the current configuration, enabling the overall demand response at the location to be separated into a pure load (facility) response and a behind-the-meter generation device’s response or contribution.



Management proposes three performance evaluation methods to support this meter configuration.

The first method would apply in instances where only the facility load is registered in the proxy demand resource or reliability demand response resource. In this instance, the demand response performance would be calculated by subtracting the actual demand (represented by the N minus G values for the dispatch interval) from a standard baseline (represented by an average of N minus G values for comparable non-dispatch hours selected in the look-back).

The second method would apply in instances where only the behind-the-meter generation device is registered in the proxy demand resource or reliability demand response resource and not the facility load as in the first method. In this instance, the demand response performance is the demand reduction resulting from the output of the behind-the-meter generation device for the dispatch interval. It would be evaluated based on the physical meter generator output for the dispatch interval and reduced by an estimate of the typical energy output of the device used for retail load-modifying purposes and benefits. This adjustment would appropriately remove an estimated quantity of energy delivered by the device to the facility for its retail load-modifying purposes, i.e., energy not produced in response to an ISO dispatch. The adjustment is intended to mitigate issues of wholesale and retail service overlap and the potential for double compensation. It is calculated by taking an average of the energy delivered by the generation device during a prescribed number of prior non-event hours. To identify non-event hours, Management's proposal originally defined an event hour as any hour when there was an ISO market award or dispatch or outage recorded. In its comments, Southern California Edison proposed a modification to this definition to include as non-event hours those hours in which the generation device received an ISO award/dispatch but had submitted a bid below the applicable ISO net benefits test price threshold published by the ISO on a monthly basis. The ISO net benefits test establishes a price threshold above which demand response resource bids are deemed cost effective. Thus, under SCE's proposed modification, an event hour is any hour when there was an ISO market award or dispatch at or above the demand response net benefits test price threshold or outage recorded. Management has incorporated this modification into its proposal, as it appears reasonable and is supported by stakeholders.

The third method would apply in instances where both the load and the behind-the-meter generation device together are registered in the proxy demand resource or reliability demand response resource. Under this method, the demand response performance would be the combined demand response performance detailed under the previous two methods.

POSITIONS OF THE PARTIES

Stakeholders broadly support Management's proposed enhancements to the market participation model for storage.

On Management's proposed enhancements to demand response performance measures, Southern California Edison proposed a minor modification that affects the definition of an event hour for purposes of estimating the typical retail behavior of a behind-the-meter generation device. As previously discussed, Management has incorporated the modification into its proposal because it appears to represent a slight improvement and most stakeholders support it.

Management more fully addresses stakeholder's comments in Attachment A.

CONCLUSION

Management recommends that the Board approve the proposed enhancements to the market participation model for storage and demand response performance measures described in this memorandum. Management's proposal will increase the flexibility for these resources to participate in the ISO market.

Attachment E – List of Key Dates in Stakeholder Process

Tariff Amendment to Implement Energy Storage Enhancements

California Independent System Operator Corporation

May 18, 2016

List of Key Dates in the Stakeholder Process for this Tariff Amendment[1]

Date	Event
May 13, 2015	CAISO publishes Initial Scope and Schedule
May 21, 2015	CAISO hosts stakeholder conference call and web conference on Initial Scope
May 29, 2015	Stakeholders submit written comments on Initial Scope
June 25, 2015	CAISO publishes Revised Scope and Schedule
July 6, 2015	Stakeholders submit written comments on Revised Scope
July 30, 2015	CAISO publishes Issue Paper and Straw Proposal
August 6, 2015	CAISO hosts stakeholder conference call and web conference on Issue Paper
August 20, 2015	Stakeholders submit written comments on Issue Paper
August 27, 2015	Stakeholder working group meeting and web conference on demand response baseline
Sept. 4, 2015	Stakeholders submit written comments on demand response working group
Sept. 17, 2015	CAISO publishes Revised Straw Proposal
Sept. 28, 2015	CAISO hosts stakeholder conference call and web conference on Revised Straw Proposal
Oct. 9, 2015	Stakeholders submit written comments on Revised Straw Proposal
Oct. 12, 2015	Stakeholder working group meeting on alternate performance evaluation methodologies
Oct. 22, 2015	Stakeholders submit written comments on performance evaluation methodology working group
Oct. 27, 2015	Stakeholder web conference on performance evaluation methodologies
Oct. 29, 2015	Stakeholders submit written comments on alternate performance evaluation methodology working group
Nov. 2, 2015	CAISO publishes Draft Final Proposal
Nov. 9, 2015	CAISO hosts stakeholder conference call and web conference on Draft Final Proposal
Nov. 17, 2015	Stakeholders submit written comments on Draft Final Proposal
Dec. 23, 2015	CAISO publishes Revised Draft Final Proposal
Jan. 7, 2016	CAISO hosts stakeholder conference call and web conference on Revised Draft Final Proposal
Jan. 15, 2016	Stakeholders submit written comments on Revised Draft Final Proposal
Feb. 3, 2016	CAISO Board of Governors approves proposal

[1] *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesphase1.aspx for links to all documents.

April 11, 2016	CAISO posts draft tariff language
April 20, 2016	Stakeholders submit written comments on draft tariff language
April 25, 2016	CAISO hosts stakeholder conference call and web conference on draft tariff language