Energy Storage and Distributed Energy Resources (ESDER) Stakeholder Initiative

Revised Straw Proposal

September 17, 2015

Table of Contents

Energy Storage and Distributed Energy Resource ("ESDER") Stakeholder Initiative

Revised Straw Proposal

1 Introduction

Enhancing the ability of grid-connected storage and the many examples of distribution-connected resources 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 straw proposals on the topics in the 2015 phase of the ESDER initiative. The 2015 scope comprises three topics: a limited set of enhancements to the ISO non-generator resources model ("NGR"), a limited set of enhancements to the ISO demand response participation models (proxy demand resource or "PDR" and reliability demand response resource or "RDRR"), and addressing questions associated with some non-resource adequacy multiple use applications. A more extensive set of issues will be addressed in the second phase of the ESDER initiative in 2016.

2 Summary of revisions to straw proposal and response to comments

In this revised straw proposal, the ISO has made several clarifications and revisions relative to the previous straw proposal paper based on stakeholder comments received and further consideration by the ISO. These revisions are summarized below.

Enhancements to the non-generator resources (NGR) model

<u>NGR documentation</u> – Stakeholders expressed strong support for updating the ISO BPMs with additional detail for NGRs. Some stakeholders requested that the ISO create a document or 'primer' specific to NGR participation. Others have requested a

consolidated summary of the NGR model and its associated requirements to help facilitate better understanding. The ISO proposes to add further documentation to ISO BPMs as further explained in section 5.2.1.

Clarification about how the ISO uses "state of charge" in the market optimization – Stakeholder comments showed detailed interest in understanding how the ISO utilizes state of charge (SOC) for storage devices. Several stakeholders have requested areas of SOC clarification to be included in the updated NGR documentation being developed within the ISO BPMs and as further described in Section 5.2.2.

Allow initial state of charge as a bid parameter in the day-ahead market – Stakeholders agree with the ISO proposal to allow for a feature to submit a daily SOC bid parameter to reflect the starting SOC value in the day-ahead market process. Some stakeholders have expressed that they would prefer not a single day-ahead initial SOC value but an hourly SOC parameter that could more accurately reflect SOC across the entire day-ahead timeframe. Some stakeholders expressed that they would like an option to supply a minimum SOC parameter that the resource must have at the end of its awarded day-ahead schedule. The ISO proposes to allow resources under NGR to optionally provide a single day-ahead initial SOC value. The ISO does not propose hourly or desired minimum SOC values for day-ahead participation and provides its reasoning in section 5.2.3.

Allow an option to not provide energy limits or have the ISO co-optimize a NGR based on state of charge – Several stakeholders expressed that they would like to explore the possibility that some resources have a preference for managing their own SOC and energy limit constraints. Other stakeholders expressed that an option to not co-optimize the resource based on SOC and energy limit constraints will make it difficult for the scheduling coordinator to prevent infeasible dispatches when bidding into the real-time market. This is because bids into the real-time market must be submitted 75 minutes before the start of the trading hour and remain fixed for the duration of trading hour. While the ISO recognizes this difficulty, the reasoning for not utilizing SOC and energy constraints in the co-optimization is because resources will manage their own SOC within the energy limits and will manage their own risks of deviations based on capacity and energy limitations similar to how other resources manage their own physical constraints. The option to continue having the ISO utilize SOC and energy limit constraints will still exist for those that wish to utilize this feature. The ISO proposes to provide an option that allows resources to participate under NGR without utilizing SOC and energy limit constraints as described in section 5.2.4.

PDR/RDRR enhancements

Alternative performance evaluation methodology – The ISO includes in its revised straw proposal several performance evaluation options it is considering as described in section 6.3.1. While there is general stakeholder support for including a metering generator output (MGO) performance evaluation methodology, stakeholders raised several implementation concerns. Some stakeholders expressed concern that an MGO proposal may require complementary, or conflict with, local regulatory authority (LRA) rules and procedures. In response, the ISO points out that existing rules already require that meter standards comply with LRA requirements (see tariff section 10.3.7) and the ISO is not proposing to change this requirement. Certain stakeholders commented on the "frequent" generation issue and how an MGO proposal could discern true demand response from other uses such as retail rate arbitrage absent employing a baseline. The ISO is inviting stakeholders to comment on the need to employ a baseline with the MGO proposal, and if needed, how a MGO baseline would work. The ISO will hold an additional working group meeting in October to discuss stakeholder input and ideas and possible revisions to the ISO proposal to address whether and how performance from devices behind the meter that provide frequent response should be measured for demand response compensation purposes.

Baseline Type-II – The ISO includes in this revised straw proposal a proposal to support the use of statistical sampling 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, as described in section 6.3.2. There is general stakeholder support for the ISO's proposal. However, stakeholders asked for clarification on the definition of "interval metering" and how tariff section 10.1.7 is applied. The ISO provides further clarification in section 6.3.2 of this paper.

Multiple use applications. In this revised straw proposal the ISO addresses two broad types of multiple-use applications: (1) the DER aggregation (DERA) provides services to the distribution system and participates in the wholesale market; and (2) the DERA provides services to end-use customers and participates in the wholesale market. Both types are treated in the context where the DERA or a set-aside portion of its capacity is not providing resource adequacy capacity to a load-serving entity for the given month. For these applications the ISO revised straw proposal includes the following provisions:

1. The ISO will require settlement quality meter data (SQMD) from the SC for a DERA to be submitted on a daily basis in accordance with ISO settlement 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. PDR/RDRR resources will continue to provide SQMD and be settled through the ISO market in those intervals when a PDR/RDRR resource was dispatched by the ISO.
2. The ISO does not propose to establish priority rights to DER to address instances where service to the distribution system may conflict with an ISO dispatch instruction. The ISO will settle deviations by a DER from its dispatch instruction as uninstructed imbalance energy (UIE).
3. The ISO does not propose to implement provisions at this time to address potential "double payment" situations where a DER is compensated by the distribution utility for performance that aligns with the DER's response to an ISO dispatch instruction. The ISO believes it is not possible to address such situations concretely at this time because distribution system services by DER have not yet been defined.
4. The ISO does not propose to implement limitations on the provision of distribution system services by sub-resources of a DERA.
5. The ISO believes that the PDR/RDRR topic in this initiative deals with scenarios where DER provide services to end-use customers and participate in the ISO markets, and does not see a need to address any additional topics regarding multiple-use associated with the provision of distribution services at this time.

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 aggregated distributed energy resources. In 2013, the CPUC established an energy storage procurement target of 1,325 MW by 2020. Energy storage developers responded by submitting many requests to interconnect to the ISO grid. Interconnection requests received in 2014 currently 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 interconnection rules accommodate the interconnection of storage to the ISO controlled grid.[3] However, the initiative identified 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.

---

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

[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

- 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.
  - 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 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. As an initial step, the ISO worked with stakeholders to develop a scope of issues in the ESDER initiative and a schedule for resolving them. The scope and schedule includes one set of issues to be addressed in 2015 and a second set of issues to be addressed in 2016 and beyond. On July 30 the ISO posted an issue paper and straw proposal on the issues in the 2015 scope. In this paper the ISO provides its revised straw proposal on the same set of issues.

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 and a proposed scope of issues for potential policy resolution in 2016 and beyond. 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 considered the July 25 scope and schedule final and used it as the work plan for this paper.

Although the ISO held no stakeholder web conference on the revised scope and schedule, the ISO invited interested stakeholders to submit written comments on the scope and schedule by July 2. The ISO 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, this revised straw proposal was developed. The next step will be to discuss this paper with stakeholders during a web conference scheduled for September 28 from 1:00 p.m. to 4:00 p.m. (Pacific). Following that, the ISO is inviting stakeholders to submit written comments to InitiativeComments@caiso.com by 5:00 p.m. (Pacific) on October 9.

The following table outlines the schedule for the policy development portion of this stakeholder initiative for those issues in the 2015 scope. The objective is to bring proposed resolutions to identified policy issues in the 2015 scope to the Board by December 2015 (i.e., for those proposals requiring tariff changes). This schedule does not include implementation steps including development and filing of tariff amendments, changing relevant business process manuals, and making and implementing changes to market system software and models.

Stakeholder Process Schedule
(for the scope of issues identified for potential policy resolution in 2015)

Step	Date	Activity
Initial proposed scope and	May 13	Post initial proposed scope and schedule (posted in presentation format rather than a paper)

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

Stakeholder Process Schedule (for the scope of issues identified for potential policy resolution in 2015)		
Step	**Date**	**Activity**
schedule	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 straw proposal	July 30	Post issue paper and straw proposal
	August 6	Stakeholder web conference
	August 18	Stakeholder comments due
Revised straw proposal	September 17	Post revised straw proposal
	September 28	Stakeholder web conference
	October 9	Stakeholder comments due
Draft final proposal	November 2	Post draft final proposal
	November 9	Stakeholder web conference
	November 20	Stakeholder comments due
Board approval	December 17-18, 2015	ISO Board meeting

Regarding the proposed scope of issues for potential policy resolution in 2016 and beyond, the ISO intends to delay work on these issues until early 2016. Taking this approach will maximize the potential for bringing proposed resolutions to the 2015 scope of issues to the Board by December 2015 (again, for those proposals requiring tariff changes).

5 Non-generator resource (NGR) model enhancements

5.1 Background on the NGR model

As early as 2007, the ISO launched stakeholder initiatives that began 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, Preventing Undue Discrimination and Preference in Transmission Service, 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 made the following changes to 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 non-generator 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 where operation could be modeled on the positive generation side, the negative generation side, or from positive to negative generation. The NGR model allowed smaller, energy-constrained resources to be treated on a comparable basis to traditional generation resources in qualifying for day-ahead capacity and continuous energy output when providing regulation services.

The NGR model recognizes that a resource can operate seamlessly between positive and negative generation. For example, battery storage is a resource which 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, have fast ramping rates, and can be controlled to 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 is also envisioned by the ISO as the model best suited for smaller, distribution connected resources, which when aggregated, demonstrate the ability to operate across negative and positive generation ranges.

5.2 Revised Straw Proposal

5.2.1 NGR documentation

Feedback from the April education forums suggests that the educational forum included material and information not previously available about the NGR model and its capabilities. Because the ISO introduced the NGR model almost 3 years ago and because few energy storage projects have yet reached commercial operation, the adoption rate has been slow.[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. Thus, the timing is right for the ISO to review and enhance NGR documentation in anticipation of more storage devices participating in the ISO market as NGRs.

The ISO proposes to follow the established method of utilizing Business Practice Manuals (BPMs) to provide detailed rules, procedures and examples for the administration, operation, planning and accounting requirements of NGRs participating in the ISO market, consistent with the ISO tariff. The ISO does not create stand-alone, model specific documentation, but instead relies on BPMs to provide information on participation in the ISO markets.

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). The SOC is utilized for market resource co-optimization, real-time dispatch feasibility, and automatic generation control (AGC) signaling. For the ISO to

[6] Although there are many projects under development 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.

observe this energy constraint, the resource's SOC must be provided to the ISO through telemetry. Telemetry plays an essential role in market optimization of awards, AGC signaling, and market dispatch.

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 by updating ISO BPMs with 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 supplied 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.

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 for 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 that are modeled for the resource, a desired ending SOC parameter is not a physical constraint, but more of 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

---

[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

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 suggested that NGR resources should not 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. While the intent behind requiring the SOC value is to allow 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 also 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 comprises an aggregation of resources where the SOC becomes variable.

The ISO recognizes that in some cases, NGRs may have difficulty providing a SOC value based solely on ISO market participation. This may be especially true for sub-resource aggregations which may be composed of multiple types of resources or for resources constantly changing based on aggregations where sub-resources may enter or departing the resource aggregation.

For these cases, the ISO proposes to allow an option for NGRs to be modeled similar to other resources which manage participation within their energy constraints. 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

- Provides required feedback to scheduling coordinators concerning bids and trades that have been submitted.

values and energy limits are not provided, the ISO would assume that the NGR did not have these constraints.

Resources modeled under NGR REM would not be allowed 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.

6 PDR/RDRR enhancements

6.1 Background on performance evaluation methodologies

A commonly used performance evaluation methodology for demand response is a "baseline." A baseline calculates a "counter-factual" value, a theoretical measure of how much energy a customer would have consumed had there not been a demand response event. The baseline calculation compares the customer's counter-factual energy use to actual energy use during the demand response event. The difference between the two are the "nega-watts" a demand response resource delivered during the event. Since 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.[8]

[8] A baseline calculation is necessary when the load-serving and demand response roles are independent of one another. If load is being scheduled and served by one entity while another entity is taking demand response actions on that load, then a baseline calculation is needed. There is only a meter to record load consumption; there is no meter to record the demand response event. This "pay to not consume" construct is in contrast to price-responsive demand, where, for example, an entity in the wholesale market can procure energy in the day-ahead market and then sell that energy back in real-time, by not consuming that energy, if and when advantageous to do so.

The North American Energy Standards Board (NAESB), responsible for developing and promoting industry standards, published a standard for DR performance evaluation methodologies.[9] It provided standard terminology and identified five broad types of performance evaluation methodologies:

1) Baseline Type-I: use of historical interval meter data for calculation of a baseline performance;
2) Baseline Type-II: use of statistical sampling to estimate the usage of an aggregated DR where interval metering is not available for all aggregated customers;
3) Maximum Base Load (MBL): the ability of DR resource to keep its usage at or below a level that typically is determined based on historical peak usage;
4) Meter Before/Meter After (MB/MA): usage during dispatch period is compared to a prescribed period of time before dispatch; and
5) Metering Generator Output (MGO): output of generator behind load is metered directly and used as demand reduction.

The ISO tariff provides for use of 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"). For this discussion, this paper refers to these as "ISO Type I" and "ISO Type 2" respectively to help clarify the relationship.

ISO Type 1 is the most commonly used baseline method for performance measurement of DR resources among ISOs and regional transmission organizations (RTOs). This method uses historical meter data from the facility to calculate the baseline for the

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

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 I uses the 10-in-10 non-event day methodology as described in section 4.13.4.1 of the tariff utilizing 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 then used as the baseline 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 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 readily available for the entire population. ISO Type 2 is described in section 10.1.7 of the tariff and allows for the submittal of settlement quality meter data 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.

Stakeholders have expressed concern there may be ambiguity as to the precise meaning of "where interval metering is not available" as stated in the tariff. It is generally accepted that while there may be interval metering installed for the entire population of a demand resource, meter data cannot be provided in either the interval level needed for some levels of ISO participation (i.e. 15 minute granularity) or may not be available within the timeframe that it is need to produce and submit settlement quality meter data for the entire population to meet the ISO submittal deadlines. To facilitate the use of ISO Type 2, stakeholders have requested that the ISO develop a "representative sample" technique based on an ISO defined set of statistical sampling principles including, but not limited to, establishing precision and accuracy requirements. The ISO's proposal below contains both clarification on applicability and provision of detail on a proposed ISO statistical sampling method that would provide an approved statistical sampling methodology for settling demand response resource participation in the ISO market under section 10.1.7 of the ISO tariff.

Stakeholders have also requested clarification regarding use of a control group to establish a statistical basis for a resource's performance measurement. However, since this topic is not specifically addressed by section 10.1.7 and since for ISO Type 2 the 2015 scope of ESDER is limited to clarifying existing tariff rules rather than creating new tariff rules, the ISO is not proposing to address the use of a control group here.

6.2 Stakeholder interest in alternative performance evaluation methodologies

Under the umbrella of the California Public Utilities Commission (CPUC) Demand Response OIR[10], a Supply Integration Working Group (SIWG) was established to: (1) identify areas where requirements for integrating supply resource demand response in the ISO market may add cost and complexity, determine whether these requirements can be simplified or changed without creating operational problems, prioritize these possible changes, and resolve them and (2) identify program modifications and operational techniques to make demand response programs more suitable and successful as supply resources. The ISO was a participant in the SIWG.

The SIWG filed a report with the CPUC on June 30, 2015, which identified the need for the ISO to expand its support of NAESB approved DR performance evaluation methodologies including the metering generator output (MGO) methodology, to develop a process for adding "custom baselines," and to address perceived gaps regarding the ISO Type 2 baseline methodology in its BPMs.

Based on a consideration of the SIWG report, the ISO recognizes the need to expand the available approved performance evaluation methodologies to accommodate more demand response use cases. Through the ESDER initiative the ISO is considering MGO as a new ISO-approved performance evaluation methodology and is developing

[10] D.14-12-024.

additional detail for an approved ISO Type 2 sampling methodology that will be documented in a BPM.

The ISO will address two of the three recommendations of the SIWG discussed above. Developing a process for the request and approval of additional "custom baselines" will be deferred until 2016. However, the ISO is drafting business requirement specifications (BRS) are for the Demand Response System (DRS) replacement in such a way as to establish the capability for ISO's systems supporting demand response resource participation to allow for ISO Type 1 baseline parameters to be configurable. This allows the ISO to support new and possibly customized Type 1 baselines if and when justified.

The ISO has asked the SIWG members to continue their exploration of alternative performance evaluation methodologies by participating in the ESDER stakeholder initiative through an ESDER working group where their momentum and participant expertise could be leveraged in further development of its demand response enhancement proposals. The ISO held a working group meeting (via web conference) on August 27 to solicit stakeholder feedback on its DR baseline proposals. The feedback received is reflected in the ISO's revised straw proposal in this paper.

In developing and considering alternative baseline methodologies, the ISO will apply the following principles:

1) Accuracy – alternate baselines must provide a more accurate estimate of the performance compared to existing ISO Type 1 and ISO Type 2 methodologies for the use case in consideration.

2) Auditability – alternate baselines must provide the ability for the ISO to audit fundamental parameters upon which the baseline is established.

3) Ease of Implementation – ISO systems and processes must be able to implement the alternate baseline.

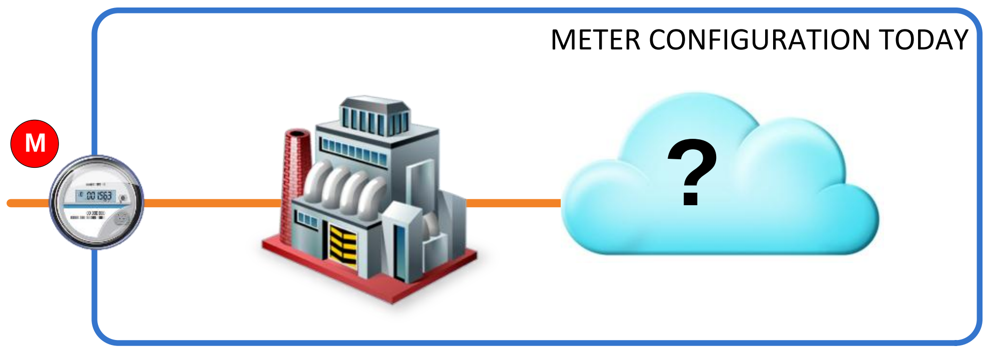
4) Compliance with NAESB standards – alternate baselines must comply with NAESB standards and exist within NAESB approved parameters.

6.3 Revised Straw Proposal

6.3.1 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 device, such as battery storage. The presence of such a load offsetting device is depicted in the Figure 1 below as a cloud labeled with a question mark to illustrate that under such a metering configuration both its presence and composition are unknown to the ISO.

Figure 1



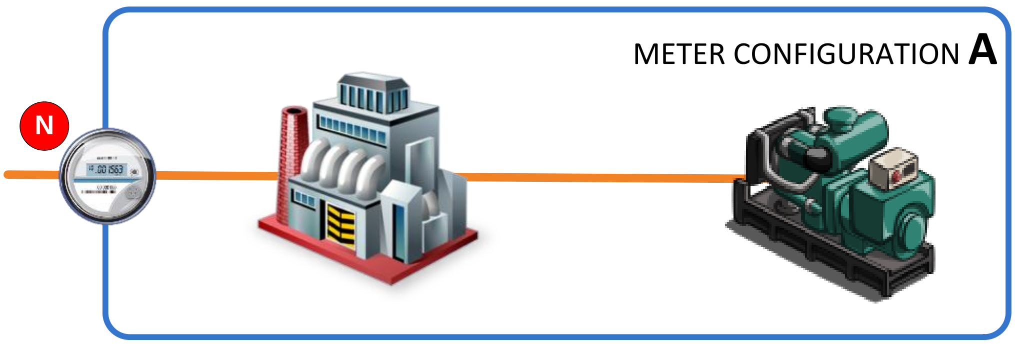
With such a metering configuration, there is no way to separate the load from the generation or vice versa. The ISO cannot distinguish the cause of demand response behind the meter. Some stakeholders have asked about an alternative performance evaluation methodology that directly meters the behind-the-meter device to measure the demand response provided by the device separate from the facility load.

NAESB's Metering Generator Output (MGO) model was established to allow for a back-up generator 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 describe the options the ISO is considering, the ISO has developed metering configurations A, B, and C. These are used throughout the remainder of this discussion to illustrate different demand response scenarios.

Consider meter configuration A illustrated in Figure 2 below. This is essentially identical to today's PDR/RDRR configuration other than the generation being formally recognized and the meter (M) has been relabeled as (N) to recognize it as a net meter representing the net effect of the load being offset by the behind-the-meter generation. But 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).

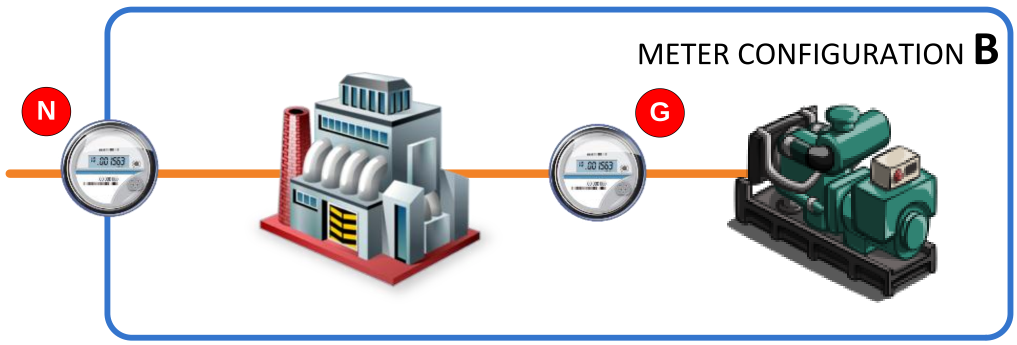
Figure 2



This configuration is supported by current ISO rules which establish a baseline using the physical meter (N) 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 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 can be identified), 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 impossible to model; electric vehicle charging (or discharging) whenever the homeowner plugs the vehicle into a home charging station.

Now consider meter configuration B as illustrated in Figure 3 below. Meter configuration B adds a generation meter to the diagram so the pure load may be derived as the difference (N-G)[11] between the net meter (N) and the generation or device meter (G).

Figure 3



Under this configuration, the overall demand response at the location could be separated into a pure load response and a generator or device 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-G as a derived "virtual" meter quantity, whereas the load consumption offset by the generation or device would use the MGO method using the physical meter G to directly measure its performance. As an example, if N = 8 MWh and G = -2 MWH, the virtual load meter quantity would be L = (N-G) = 10 MWh, where a metered quantity is assumed positive for load (consuming energy) and negative for generation (producing energy). The L = 10 MWh would be the calculated quantity used to develop a baseline and performance evaluation for the traditional load response, while the directly

[11] In this discussion we follow the sign convention that a load or the output of a charging storage device is expressed as a positive quantity, whereas the output of a generator or a discharging storage device is a negative quantity. Thus the true end-use load under configuration B would be (N-G).

measured metered quantity G = -2MWh would be the metered quantity used to establish the MGO demand response performance evaluation.

Further, the ISO is considering three possible PDR/RDRR participation options under meter configuration B, each with its own performance evaluation methodology. To be clear, the ISO is still considering whether it is appropriate to offer all of these options. We are discussing them here and request stakeholder input regarding their preferences and any concerns about any of the options. These are described:

- Option B1 – Load Reduction Only. Under this option only the load would be registered in the PDR/RDRR and 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 in response to an ISO dispatch would then be the baseline B minus the quantity (N_t - G_t) for the dispatch interval: demand reduction = (B - (N_t - G_t)).
- Option B2 – Generation Offset Only. Under this option only the generation device would be registered in the PDR/RDRR and the demand response performance would be evaluated based on the physical meter G_t for the dispatch interval. This is MGO. An issue with this option is that it may not be possible to distinguish between the generation device's retail activities (*e.g.,* generating to offset some portion of the load's consumption to reduce the load's peak demand charges) and its wholesale activities (*i.e.,* receiving a PDR/RDRR dispatch instruction from the ISO). It would be problematic for the wholesale market to pay for demand response when the resource is generating to reduce a customer's demand charges because the grid would experience no true demand response/load modification and no difference in day-to-day or interval-to-interval power flow because of ISO dispatch. One possible solution to keep these separate is to require that the generation device "reserve" a portion of its capacity for retail activities and the remaining portion for wholesale purposes. The ISO requests stakeholder input on how the generator or device under option B2 could participate in the ISO market using MGO in a manner that separates the generator's normal use from its wholesale market use to provide demand response. Stakeholders are encouraged to provide input on how a resource adequacy qualifying generator or device that modifies load could operate for the

provider's own purposes (e.g., retail TOU rate arbitrage, demand charge management, etc.) while also responding to ISO market dispatches and complying with resource adequacy must offer obligations.

- Option B3 – Load and Generation. Under this option both the load and the generation device would be registered in the PDR/RDRR resource and the demand response performance would be evaluated using both a baseline determined by N-G and the physical meter G. The ISO sees two possible variants of this option and requests that stakeholders comment on them. For both variants, the baseline B for the end-use load would be determined based on (N-G) calculations for comparable non-event days/hours.
    - Under variant B3-1 the demand reduction during dispatch interval t would be the sum of the load-only response plus the generator output. Thus demand reduction = $(B – (N_t – G_t) + G_t)$.
    - Under variant B3-2 the demand reduction during dispatch interval t would be the load-only response minus the generator output. Thus demand reduction = $(B – (N_t – G_t) – G_t) = (B – N_t)$. Note that with this variant the formula for measuring demand reduction looks the same as the formula used with configuration A. There is an important difference however because the baseline for configuration A is determined from a sequence of N values, whereas for configuration B it is determined from a sequence of (N-G) values.

Since net exporting of power at a location is not allowed under PDR/RDRR the ISO will need to establish rules around or provisions to require the performance of an export check to ensure that net exporting is not occurring for those periods of ISO participation, *i.e.,* to confirm that the metered quantity at N is always positive (consuming energy). In both metering configurations A and B, including all three performance evaluation options under B, the ISO proposes that the location, and all underlying chosen performance methodologies used for that location, be assigned to a single resource associated to a single Demand Response Provider (DRP).

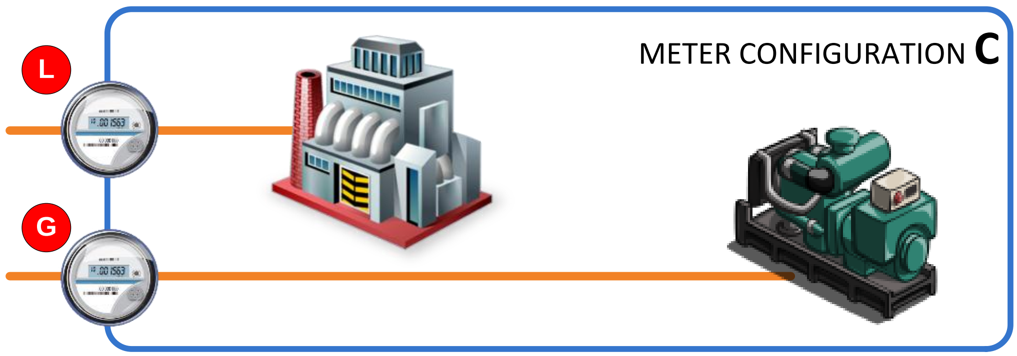
Table 1 below summarizes the ISO proposal for meter configurations A and B and the three options for configuration B. As stated above, the ISO has not yet concluded that all of these options should be provided, and seeks stakeholder input regarding their preferences and any concerns about any of the options.

Table 1

	Meter Configuration A	**Meter Configuration B**		
		B3 – Load and Generation	**B1 – Load Only**	**B2 – Generation Only**
Demand Response Providers	Single DRP	Single DRP	Single DRP	Single DRP
Resources	Single PDR/RDRR	Single DRP	Single PDR/RDRR	Single PDR/RDRR
Registrations	Net Facility	(1) Load (2) Generation	Load	Generation
Locations (SANs)	Net Facility	(1) Load (2) Generation	Load	Generation
Performance Calculation	(B-N)	(B-N) or (B-(N-G)+G)	(B-(N-G))	(G)
Performance Evaluation Methodology	Baseline (N)	Baseline (N-G) plus MGO (G)	Baseline (N-G)	MGO (G)
Export Check	All Intervals N ≥ 0	All Intervals N ≥ 0	All Intervals N ≥ 0	All Intervals N ≥ 0

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



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. Since 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 Providers	Single DRP (May be different from generation owner)	Cannot be PDR/RDRR but would participate in the ISO market as a non-generator

	Meter Configuration C	
	Load Only	**Generation Only**
Resources	Single PDR/RDRR	resource (NGR) or participating generator (PG).
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 due to the current one registration to one resource limitation. In summary, the ISO is considering offering each of the following performance measurement options understanding that 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:

- Meter configuration A
- Meter configuration B Option B1 – Load Only
- Meter configuration B Option B2 – Generation Only
- Meter configuration B Option B3 – Load and Generation
- Meter configuration C – Load Only

Under PDR/RDRR, a resource and its underlying locations cannot export to the grid. Current metering business practice requires that the meter data submitted for the resource represents load at all locations. Therefore, the meter data for that location must be "zero" for any interval in which there is exporting of energy under meter configuration A and meter configuration B. Additionally, this will apply under meter configuration B for any interval where the output of the behind the meter generator or device exceeds the retail load at the location.

The ISO understands that a provider with a generator or device behind-the-meter may want to use the device to provide other demand management services for the load it is serving. This scenario raises important issues that merit further discussion with stakeholders. Should information about performance of the resource behind the retail meter in intervals prior to being dispatched as a PDR/RDRR be available to measure the actual PDR/RDRR response? Another approach could be to reserve or set aside a resource's capacity dedicated to retail demand management services with the remainder eligible for wholesale participation and resource adequacy qualification. The ISO invites stakeholders to comment on these questions. The ISO will hold a working group session in October to discuss possible revisions to ISO proposal to address these questions.

6.3.2 Baseline Type-II

The authority for the use of statistical sampling to estimate load meter data submitted to the ISO and used in developing a baseline to evaluate the performance of an ISO dispatched demand response resource (PDR/RDRR, 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. [emphasis added]

Stakeholders have asked for clarification on the definition of "interval metering is not available" as it pertains to the applicability of this option. The vast majority of residential and small-commercial customers have hourly interval metering installed that can provide interval data in a granularity that would support ISO day-ahead market participation but availability of the data is in question by demand response providers. To participate in ISO real-time and ancillary services markets, a maximum of 15 minute interval metering is required as 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 (section 12.5). Therefore, hourly interval metering could not be used to meet this requirement. In all ISO participation cases, revenue quality meter data (RQMD), as required by the local regulatory authority (LRA), is required to create settlement quality meter data (SQMD) for ISO PDR and RDRR settlements. The ISO does not want to preclude participation of residential or small-commercial customer because this data is “unavailable” to meet either ISO required submittal timelines or granularity.

Therefore, to expedite demand response participation in wholesale markets, including resource adequacy, the ISO proposes to support the use of statistical sampling in the following case:

- 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 this is supported in the language as written in section 10.1.7 of the ISO Tariff.

At this time the ISO has reservations in supporting the use of statistical sampling in the following case:

For day-ahead participation, when hourly interval metering is installed at all underlying resource locations but RQMD is not available or accessible to demand response providers or their scheduling coordinators, for all underlying locations, in the established timelines required to meet ISO settlement quality meter data (SQMD) submission timelines.

The ISO will continue to determine if this tariff section may need to be expanded to include circumstances when interval metering is installed at all underlying resource locations but RQMD is not available or accessible to DRPs for wholesale market participation. However, the ISO is unclear why tariff expansion is needed given the ISO settlement timeline and meter data submission requirements for PDR/RDRR.

There are two key dates for the submittal of the meter data per the ISO settlement timeline: (1) T+8B and (2) T+48B. For the T+8B meter data submittal, Section 10.3.6.2 of the ISO tariff states "Scheduling Coordinators can submit **Estimated** Settlement Quality Meter Data for Demand Reponses Resources" [emphasis added]. RQMD meter data is not a necessity at the T+8B submittal deadline and it is not clear to the ISO why RQMD would not be available by the T+48B meter data submittal date as required by Section 10.3.6.3 of the ISO tariff given today all load serving entities are submitting SQMD by T+48B, which could be made available to demand response providers under provisions approved by the CPUC.

The ISO is concerned with how this may conflict with the responsibilities of a scheduling coordinator to comply with standards established by the LRA and must further contemplate this expansion in relation to Section 10.3.7 of the Tariff which states:

> Each Scheduling Coordinator, in conjunction with the relevant Local Regulatory Authority, shall ensure that each of its Scheduling Coordinator Metered Entities connected to and served from the Distribution System of a UDC shall be metered by a revenue meter complying with any standards of the relevant Local Regulatory Authority or, if no such standards have been set by that Local Regulatory Authority, the metering standards set forth in this CAISO Tariff and as further detailed in the Business Practice Manuals.

The ISO invites stakeholder feedback on these ISO concerns and their relationship to the ISO extending the use of statistical sampling for customers with installed hourly interval metering including stakeholders view on the necessity of such an extension if RQMD is not available.

The ISO recognizes there is considerable effort being made to accommodate the provision of RQMD to 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. Therefore, the ISO will re-visit the applicability proposed above upon implementation of resulting technical and process solutions that solves either one or both unavailability issues identified by participants. The ISO also proposes to define the use of ISO type 2 to derive SQMD from a sample based on using RQMD, collected at the required interval granularity, for all customers identified in the sample set.

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 termed 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 be selected with no 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: $e_{REL} = Relative\ Precision\ Level$

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

$p = True\ Population\ Proportion$

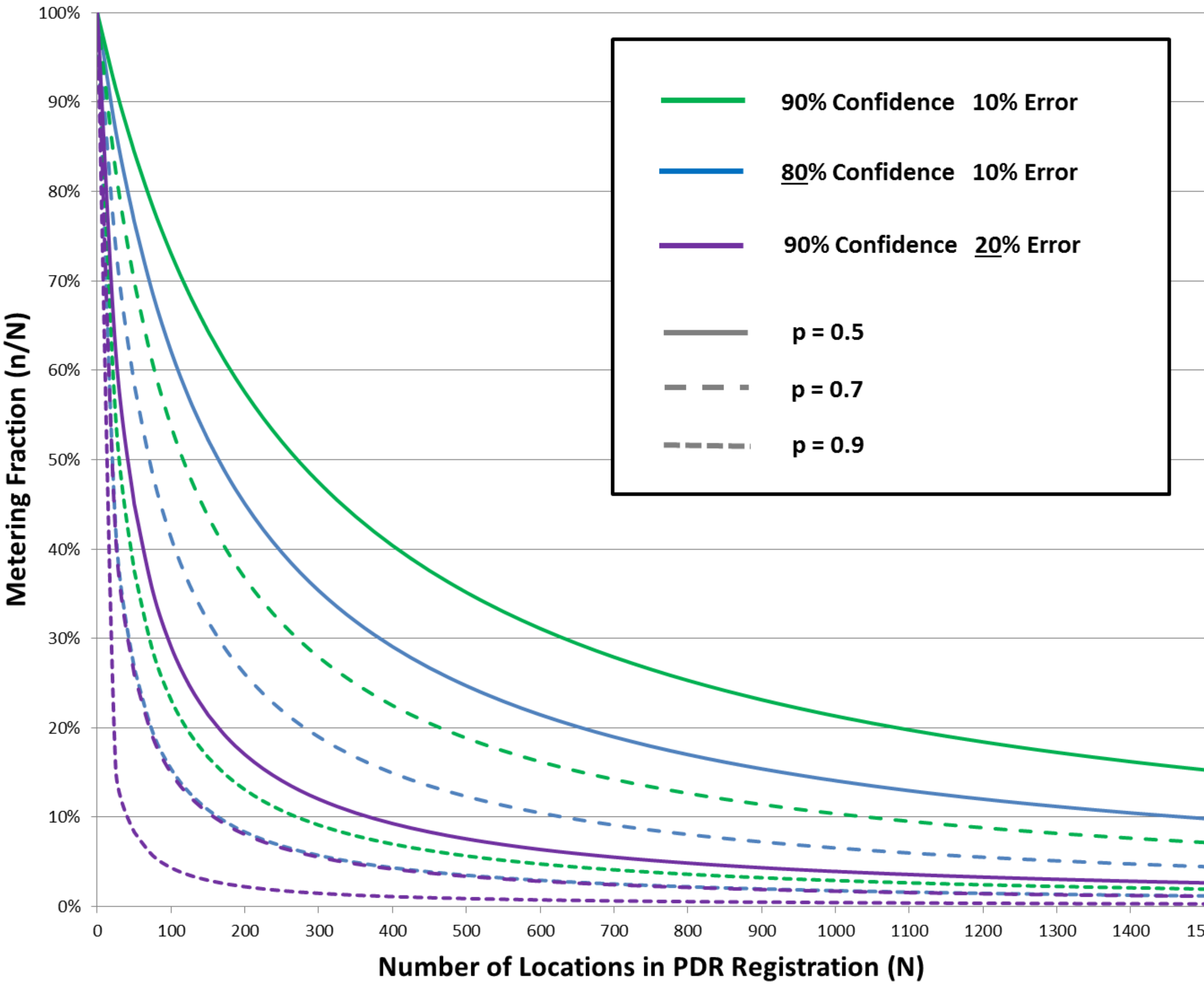
Many ISOs and RTOs use this formulation. The following table summarizes some samples:

	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:

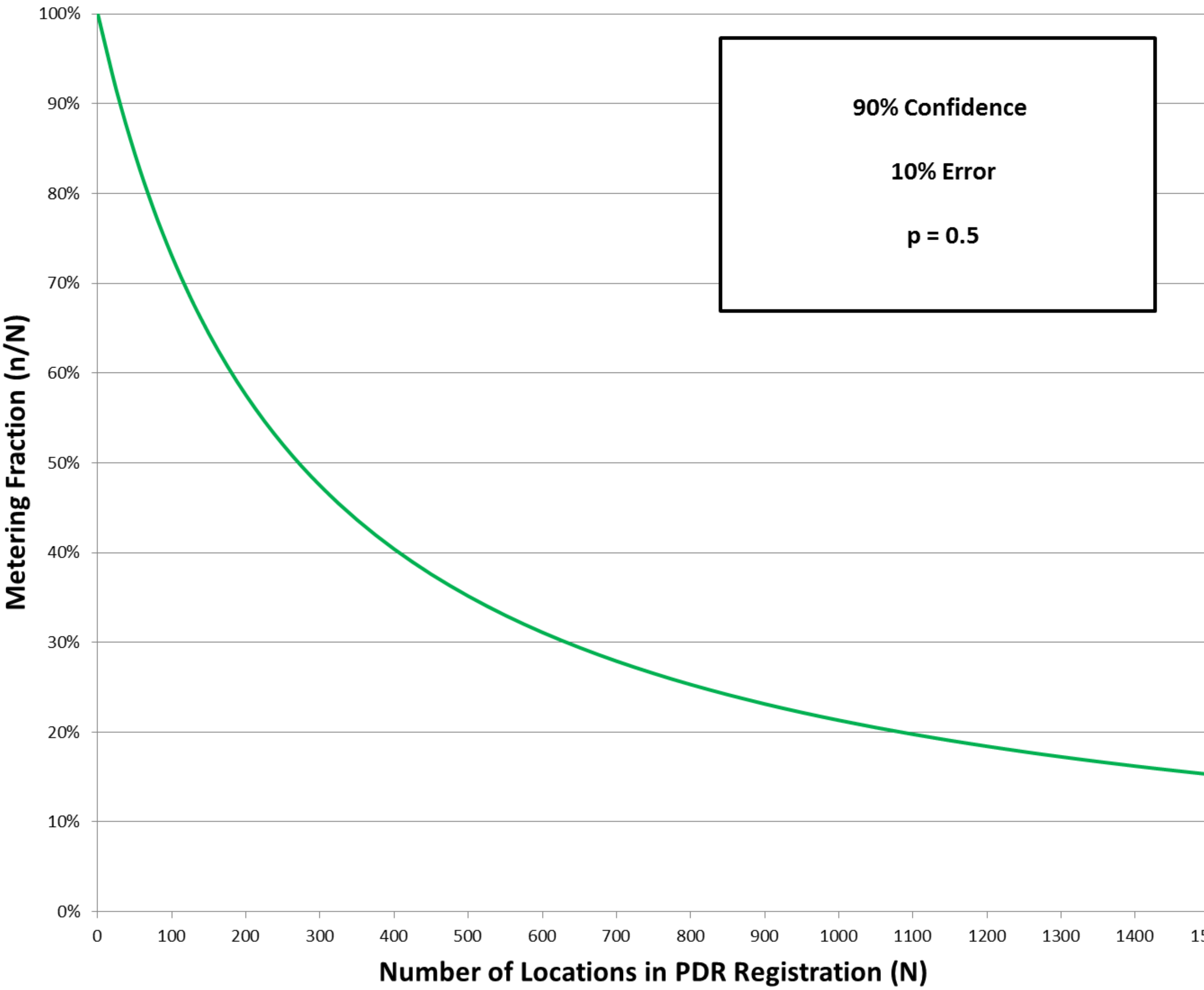
$$\frac{n}{N} = \frac{n'}{N + n'}$$

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:



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 80%, which results in a z of 1.645 [12]. 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: $n' = 271$.

[12] 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 reevaluated and the sample size adjusted accordingly. Except for the SC 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 should it deem that the data being submitted is questionable.

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

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 is not included in a load-serving entity's RA plan for the given month.

7.2 Assumptions underlying this revised straw proposal

The first assumption is that ESDER should be consistent with the DERP[13] regarding multi-pnode DER aggregations (DERA). In the DERP the ISO is considering relaxing the 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 considering instead to impose the requirement – which has been the underlying concern all along – that (b) the net movement 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 movement 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.

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.[14] 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

---

[13] "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 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. The ISO is currently preparing draft tariff language for the DERP initiative to be filed at FERC, and will post draft tariff language for stakeholder comment in the near future.

[14] 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.

ISO, but resources participating under the DERP construct will not.

7.3 Revised Straw Proposal – ISO's proposed positions on questions posed in the Straw Proposal

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?

Revised Straw 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.

Many stakeholders 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?

Revised Straw 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. This topic may or may not be ripe for consideration in the 2016 ESDER initiative.

Question 3: 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?

Revised Straw Proposal: In contrast to the ISO's position in the prior Straw Proposal, the ISO now proposes not to impose any such limitations. The current position is based on the provisions for DER aggregations (DERA) that will be filed at FERC in the near future to implement the DERP proposal approved by the ISO Board in July. 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

As the ISO stated in the prior Straw Proposal, we do 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 that were not addressed and should be included in the 2016 ESDER scope.

7.4 Responses to stakeholder comments

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

Question 1: Conflicting real-time needs

Comments: One theme stakeholders raised was the need 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.

Comments: Many 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.

Comments: One party suggested that the distribution system operator (DSO) should manage any conflicting needs between the distribution system and ISO, potentially by optimizing the resource for distribution needs and offering the remaining services to the ISO. One party suggested the resource itself could resolve a conflict by sending the dispatch to another resource to meet the ISO dispatch. Others said there should be clear priority rights established; the ISO might even establish super-priority rights for certain situations.

Some parties said conflicts would be a rare occurrence because the distribution system needs arise only when there is a local need. Some said distribution reliability should be the first priority for certain DER types, specifically EV chargers. Others said distribution priority should apply if there is a grid emergency.

ISO response: The ISO believes that developing dispatch priorities as stakeholders have suggested should not be necessary for the non-RA cases being considered at this time, and if undertaken now would add more complexity than can be resolved by the end of 2015. For purposes of the 2015 initiative the ISO believes it is sufficient to use the UIE settlement provisions for cases where DERA deviate from ISO dispatch instructions to serve distribution needs.

Question 2: Double payment

Comments: Stakeholders were divided on the question of whether there is a concern about double payment to a resource when its performance meets a need of the distribution system and also responds to an ISO dispatch. Several stakeholders said this is not a problem while others said it is a concern. One said double payment (in the Type 1 category) would occur only if the UDC and ISO both pay for energy. Another said that the ISO should provide examples and a formal definition of double payment.

ISO response: The ISO believes this matter cannot be addressed concretely until there is more definition of the distribution system services DER can provide and how those services would be procured, utilized and compensated. The ISO anticipates that the needed service definitions, etc., will be considered in CPUC proceedings including the distributed resources plan proceeding (DRP) and the integration of distributed energy resources proceeding (IDSR).[15]

---

[15] R.14-08-013 and R.14-10-003, respectively.

Question 3: Restrictions on sub-resources of an aggregation providing distribution services

Comments: Several stakeholders said there is no need for restrictions on provision of distribution services by DER resources, or if some restrictions are needed, they should not interfere with ability of resources to participate in multiple revenue streams. Some said the ISO has no jurisdiction to prevent DER providing services to distribution.

In addition to responses to the three questions, some stakeholders pointed to a need to resolve jurisdictional issues related to Type 1 dual participation, but explained no specific issues.

ISO response: The ISO is not currently proposing any restrictions on the provision of distribution system services by sub-resources of a DERA, as long as the DERA complies with the requirement that the net response of sub-resources at each pnode be in the same direction as the ISO dispatch instruction and in proportion to the distribution factors.

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

Comments: Some stakeholders offered a perspective here that is analogous to their point on Type 1 above: DER should be able to participate voluntarily in the ISO market and should not be settled by the ISO for their performance when they are not under an ISO dispatch. One exception suggested in the comments was that a resource connected on the utility side of the meter should be a full-time ISO participant. Also DER should be able to partly bid into the ISO market.

ISO response: As noted above, PDR/RDRR resources can choose when to participate in the ISO market and will be settled through the ISO only for intervals in which they are issued ISO dispatch instructions. Other models for DERA participation, such as NGR, are viewed as participating and will be settled through the ISO in all hours.

Comments: Some stakeholders supported the sufficiency of the existing PDR/RDRR framework for resources that don't export onto the grid, and the NGR framework for resources that may both inject and consume at different times. One party said that a PDR/RDRR-NGR hybrid is needed for resources to support wholesale market operations part-time. Also that a PDR/RDRR resource should be allowed to respond to a negative ISO dispatch (i.e., to increase load) without requiring a WDAT interconnection.

ISO response: In this year's initiative the ISO cannot address any modifications to the PDR/RDRR and NGR models other than the topics already in scope of this initiative. Additional modifications to these models are potential topics for the 2016 ESDER initiative.

Comments: Some stakeholders said that DER should be able provide service to customers, distribution needs, and ISO needs in descending order.

Some parties raised double payment issues in this category. Some said that DER should not be paid for state programs (such as NEM) and also receive ISO market payments; i.e., NEM customers, or storage devices that rely on NEM generation to charge, should not be permitted to participate in ISO market. Others disagree about NEM resources and say they should be allowed to participate in the wholesale market. More generally, some parties emphasized the need to resolve questions about when retail versus wholesale rates apply. One concern is that energy storage may charge at the wholesale rate and use the stored energy to provide service to the end-use customer.

ISO response: If energy storage is behind the customer meter and participates in a PDR/RDRR resource, it will pay the retail rate for charging as part of the customer load at that meter. If the energy storage participates in an NGR, then it is metered and settled as a separate wholesale resource in all operating hours.

Comments: One party argued for DER to have requirements comparable to other wholesale resources for participating in the ISO markets, including all registration, metering and verification, transparency and accountability, non-performance penalties and any other applicable tariff obligations. Retail products should not participate in wholesale markets.

ISO response: The ISO agrees that DER should be treated comparably, as far as possible, to other resources with respect to wholesale market participation, and believes that this revised straw proposal is consistent with that principle.

Comments: Finally some parties called for greater clarification of jurisdictional lines between federal and state, retail and wholesale, and distribution and transmission.

Some also stated that ISO and CPUC need to coordinate on a number of issues related to cost recovery, interconnection and metering; the CPUC Energy Storage OIR Track 2 was suggested as an appropriate venue.

ISO response: The ISO is coordinating closely with CPUC staff on ISO initiatives involving DER and on ISO involvement in CPUC proceedings related to DER.

7.5 Demand forecasting considerations

The ISO recognizes that the expansion of DER in the electric system introduces new and significant complications into the demand forecasting process. Some stakeholders have raised questions about demand forecasting in their comments and suggested that this ESDER initiative address them. The ISO does not by any means minimize the importance of these questions, but does believe that ESDER is not the appropriate venue to address them. In particular, although DER participation in the ISO markets represents one of the complications, there are DER-related forecasting questions to be addressed whether or not the DER participate in the ISO markets. Therefore, we suggest that these issues be taken up under the framework of the CEC's IEPR proceeding, perhaps through one or more of the Demand Analysis Working Group (DAWG) subgroups.

The demand forecasting approach used in the IEPR process involves first developing forecasts of gross demand based on economic and demographic drivers, and then adjusting these forecasts to reflect "load modifiers" such as energy efficiency and behind-the-meter (BTM) distributed generation. Gross demand is the actual energy usage of end-use customers for their underlying residential, commercial and other purposes, unaffected by any installed devices that may offset some of that usage. If, for example, customers have BTM solar PV that offsets some load, it is possible to estimate the gross load statistically from solar PV penetration (MW installed capacity) and weather conditions for the climate zone to adjust the end-use meter data to obtain what the load would have been absent the PV generation.

Now consider the scenario where energy storage devices are installed behind the end-use customer meter for managing the customer's load shape and demand charges. Assume for simplicity there is no BTM solar PV to further complicate the scenario. The BTM storage scenario introduces a complication right away, before any consideration of

ISO market participation, because unlike solar PV it is not obvious how to estimate the activity of the BTM storage based on observable variables such as installed capacity and weather. The ISO suggests that this and other DER scenarios need to be addressed first in the absence of DER participation in the ISO market and responses to ISO dispatch instructions, and only then can we develop ways to account for the effects of ISO dispatches in the demand forecasting process.