Straw Proposal for Direct Participation of Proxy Demand Resource (PDR)

April 15, 2009

Straw Proposal for Direct Participation

Acronyms used in this proposal

TLA	Description	TLA	Description
ARC	Aggregator of Retail Customers	LSE	Load Serving Entity
CAISO, or ISO	California Independent System Operator	M&V	Measurement & Verification
CPUC	California Public Utility Commission	MAP	Markets & Performance
CSP	Curtailment Service Provider	MRTU	Market Redesign & Technology Upgrade
DR	Demand Response	NOPR	Notice of Proposed Rulemaking
ESP	Electric Service Provider	PL	Participating Load
FERC	Federal Energy Regulatory Commission	RTO	Regional Transmission Operator
ISO	Independent System Operator	SC	Scheduling Coordinator
LPPC	Large Public Power Council	TAPS	Transmission Access Policy Study Group

1. Introduction

To initiate the design of the Direct Participation functionality, the ISO published an Issue Paper on December 22, 2008, whose purpose is to identify the issues that the ISO recognizes and invite identification of additional issues that the ISO should address in its proposed market design enhancements to comply with Order 719. The Issue Paper was not intended to lay out specific modifications to the ISO's proposed market design enhancements, but rather to determine the scope of effort based on the identified issues, and if and how the issues impact the ISO's proposed market design enhancements. The ISO discussed the Issue Paper at a stakeholder conference call on January 5, 2009, and a stakeholder meeting on January 15. These materials, and stakeholder comments related to the Issue Paper, are available at

http://www.caiso.com/1893/1893e350393b0.html.

Based on comments received concerning the Issue Paper, the ISO prepared a Straw Proposal that was posted on March 5th as its proposed resolution of the issues for implementing Direct Participation as part of the market enhancements for DR. Stakeholders submitted comments to the Straw Proposal on March 20. The ISO is issuing this revised Straw Proposal to address recent policy changes and the need to reorganize the original Straw Proposal for clarity.

This Straw Proposal includes the following revisions from the March 5th version:

- The proposal for Proxy Demand Resource (PDR) was moved into a separate document which will represent the Draft Final Proposal for purposes of going to the Board in May.

- Clarifications to the proposal were added based on stakeholder comments received on March 20. Modifications were minimal since no stakeholder discussion has taken place since the Straw Proposal on these topics

- Since the ISO will not incorporate Direct Participation into the existing Participating Load model (DDR), Discussions pertaining to DDR in the document were removed.

This is not the final ISO proposal or recommendation, but rather is a means to focus discussion on workable resolutions of issues. The subsequent step in the ISO's stakeholder process is then the publication of a Draft Final Proposal, which is planned for late August or early September 2009 after the completion of the stakeholder process on Direct Participation.

The ISO's implementation of the conceptual design will be described in its Business Practice Manuals and Participating Load Users Guide. This practice is similar to a number of other aspects of MRTU, in which the tariff establishes overall authorities and responsibilities of the ISO and market participants, and further details are established by the Business Practice Manuals. In parallel, the CPUC and other Local Regulatory Authorities will likely consider these issues and their application to their jurisdictional entities.

The next section, "Impact of Direct Participation on Proxy Demand Resource "lays out each of the key issue areas the ISO determined are impacted by FERC Order 719. Generally, each topic begins with an overview discussion of the issues that the ISO identified in its Issue Paper and subsequent stakeholder discussions, followed by a summary of comments submitted by stakeholders that further describe the issues or that suggest alternative solutions, and finally by the ISO's initial proposed resolution of the issues. The stakeholder comments are summarized but the full comments are available on the ISO's web site at http://www.caiso.com/1893/1893e350393b0.html.

1.1. Design Features and Issues to be Resolved

In order to employ the Direct Participation of PDR in California's wholesale market, the ISO must address a range of related issues and assess their impacts on the ISO's systems, market design and business processes. Likewise, Market Participants will need to undertake a similar evaluation. The ISO identified the following seven categories as a framework to identify and resolve business issues and processes related to the Direct Participation directive in Order 719. The ISO shared this framework with stakeholders at the January 15 stakeholder meeting, and for consistency, organized this section of the proposal around these seven categories:

1. Qualification (program definition, participant and resource qualification)
2. Registration (resource characteristics, enrollment, transfers, testing & auditing)
3. Scheduling (system and resource forecasting, resource scheduling & bidding)
4. Notifications (market schedules & awards, RT dispatch, outages)
5. Metering and Telemetry (data availability, data exchange, data type & granularity)
6. Settlement (calculation of load changes, calculation of credits & charges)
7. Performance & Compliance Evaluation (resource, participant, program, and system performance evaluation, compliance monitoring)

These issues are individually examined in each subsection below. In each subsection, this document first describes the background for identifying and considering issues, then summarizes stakeholder comments received January through March and finally, presents a possible resolution of the issues for consideration and further discussion in working group meetings. In summarizing stakeholder comments, it has been necessary to identify the key points to maintain brevity, and to present the comments of diverse parties in a consistent format, but the intent is not to alter the substance of any comments that have been submitted. The full text of the stakeholder comments can be found at http://www.caiso.com/1893/1893e350393b0.html.

1.2. Qualification

1.2.1. Background

A fundamental issue is who is eligible to directly participate in the ISO markets on behalf of PDRs. FERC has identified a new market participant that it refers to as an "Aggregator of Retail Customers", but because direct access retail end-use customers are aggregated for purposes of scheduling energy usage by Electric Service Providers, the ISO finds that a parallel term, "Curtailment Service Provider" (CSP), which is used in some other organized markets, clarifies what is being aggregated. The term CSP highlights some of its roles and responsibilities, i.e., that this entity bids DR into the ISO's markets on behalf of end-use customers, separately from the LSE's scheduling of the energy that the end-use customers consume.

Remaining issues involve the eligibility of PDR to participate in ISO markets, and these have been addressed in stakeholder comments.

1.2.2. Stakeholder Comments

EnerNOC identifies several types of entities and programs who could potentially be eligible to directly participate in DR programs, including Load Serving Entities (LSEs), Utility Distribution Companies (UDCs), Electric Service Providers (ESPs), Curtailment Service Providers (CSPs), end-use customers, distributed generators, and permanent load shift and energy efficiency resources. EnerNOC suggests that the registration for a CSP might not require becoming or interfacing with a Scheduling Coordinator. EnerNOC suggests that the minimum resource size might be 0.1 MW, and that eligible programs include DA, RT, and price-responsive. Issues include whether customers can participate in more than one program, which programs will be eligible to participate in which ISO markets (energy, capacity, ancillary services), and which programs provide an RA credit. DR resources can have differing availability requirements, with variation in being summer only or annual programs, hours per year of availability, number of events, hours per event, different event-initiation triggers, price, demand levels, operating reserve levels and/or emergency protocols. EnerNOC asks, as an issue, how the administrative costs associated with DR programs are administered. (DO: Are DA, RT, and RA defined somewhere?)

North America Power Partners LLC (NAPP) states that all California customers located within the ISO managed region should be allowed to participate as DR resources in the ISO markets, whether they are IOU or non-IOU customers, including participation by aggregated loads as small as 100 kW in all ISO markets (DA and RT energy and ancillary services), which would be managed as a "portfolio" for purposes of assessing performance. NAPP disagrees with the tentative conclusion of the ISO Issue Paper that a DR resource may only be registered to one CSP, noting that different CSPs may focus on different markets (e.g., one CSP for Ancillary Services and another CSP for other markets), and that a limitation to one CSP per DR resource may not lead to the most efficient use of DR resources. NAPP suggests that the ISO should allow DR aggregations that CSPs are operating within the utilities' DR programs to be bid by CSPs for delivery periods that are outside of IOU contract delivery periods. NAPP also suggests that if customers who participate in DR programs maintain back-up generators or on site "behind-the-meter" generation, these generators might be able to participate in some of the ISO markets.

Southern California Edison (SCE) agrees with using the term "Curtailment Service Provider" to represent an aggregator of retail customers as the new market participant. SCE suggests that CPUC tariff allowances for dual participation in DR programs should be explicitly addressed. For example, if the LSE's interruptible tariff allows a customer to also participate in other DR programs, it needs to be determined whether a resource is eligible to be registered with more than one CSP or LSE at a time, and whether dual participation in multiple programs (rather than specific DR events) will be accommodated. SCE states that while defining the roles of LSEs and CSPs, the ISO needs to make liability assignments between counter parties very clear, through details in the Business Practice Manuals.

AReM proposed in comments that the ISO require agreement by the LSE as a pre-condition to qualify a DR resource. The CSP would be obligated to submit written agreements with the affected LSEs specifying that the LSE has given approval for the end use customers to participate in the CSP's DR program.

The CPUC pointed out in their comments that some of the issues discussed in this section are at least in part CPUC jurisdictional issues, (i.e. RA credits) but welcomes the discussion both within the CAISO's current and CPUC's upcoming stakeholder processes in order to have the fullest discussion possible. The CPUC also commented that they understand that Investor Owned Utilities may seek tariff changes to allow them to act as CSPs and bid their own DR into the markets. This topic will likely be addressed in a CPUC proceeding.

1.2.3. Discussion

The comments by EnerNOC and NAPP address a broad range of issues. Addressing the requirements for enabling a new type of entity to participate in the ISO markets, within the short timeframe before the Order 719 compliance filing, requires limiting the issues that are resolved through this stakeholder process to only those that are required. As noted in section 1, the ISO markets have included PL functionality since the ISO started operations in 1998, and this continues in MRTU Release 1. To the extent that mechanisms already exist to support PL, this Straw Proposal does not seek to reinvent them. Also, the ISO is a market operator that interacts with business entities that represent suppliers and end-use customers, and is not an operator of (a) specific DR programs that directly enroll end-use retail customers, or (b) operate other market resources that would compete with market participants' resources.

All market participants that buy or sell in the ISO markets either provide or purchase products that involve financial obligations, and it should not be surprising that market participants must formally agree to these obligations. The means of agreeing to these obligations is to become a Scheduling Coordinator, and therefore all market participants must either be or be represented by a Scheduling Coordinator. Executing the agreements to be a Scheduling Coordinator is not onerous or restrictive, and the agreements simply obligate the market participant to understand and agree to the provisions of the ISO tariff. Additional obligations such as metering depend on the types of resources that the Scheduling Coordinator offers in the market. Although the ISO assists all market participants in bringing their resources into the ISO markets, the ISO does not fund the administrative costs of any market participant.

In the context of PDR, the ISO's role is to implement market structures that allow market participants' DR programs to participate in the ISO's markets on a comparable basis as other resources. The ISO's markets are founded on bidding in DA and RT market timeframes, using hourly or sub-hourly time intervals, and recognize resources' operational constraints as well as grid operational constraints.[1] Thus, the ISO's market operations provide the mechanisms for market participants to describe their resources' operational constraints as part of their bid submission using PDR, but the ISO does not determine the resources' operational constraints. For example, the ISO's PDR designs already allow DR aggregations to be as small as 0.1 MW, but do not create the aggregations, since that is the CSP's role. The utilities' retail programs include reliability-based/emergency response programs such as interruptible tariffs, but the ISO's markets do not have emergency response products. Instead, the ISO is aware of the utilities' reliability-based/emergency response programs, and coordinates with the utilities when those programs are needed to maintain system reliability. The ISO tariff already limits the participation of the same end-use customers in emergency response programs and PL resources, and the ISO does not see the addition of CSPs to the market as changing the existing tariff provisions. The ISO does not currently operate a market for resource adequacy capacity, and instead, works with Local Regulatory Authorities (LRA, such as the CPUC) to develop RA requirements that market participants must meet, with the LRAs defining which and how resources qualify as RA capacity.

For these reasons, the ISO does not find it necessary to either broaden its role beyond that of market operator, or to relax the requirements for representation by Scheduling Coordinators. Conversely, no comments have suggested that the requirements for representation by Scheduling Coordinators, as currently defined, are not sufficient to cover the new roles of CSPs. Thus, the ISO concludes that CSPs must be or be represented by a Scheduling Coordinator, but does not see need for extensive revisions to the tariff provisions governing Scheduling Coordinators.

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1 Resources that are not scheduled on hourly or sub-hourly time intervals, such as permanent load shifting or energy efficiency, have roles in LSEs' overall resource planning but are not participants in ISO markets.

The current Scheduling Coordination Certification requirements may be found at the ISO website at:

http://www.caiso.com/docs/2005/10/05/2005100520241822328.html

One necessary requirement is that when seeking to qualify a PDR, the CSP must certify to the ISO that participation by its resource is not precluded by the Local Regulatory Authority, e.g., the CPUC. This is a FERC Order 719 requirement and reasons for making a resource ineligible would be determined by the Local Regulatory Authority. In other ways, the eligibility of the PDR themselves does not seem to be affected by whether they are operated by a CSP that is the same entity as the LSE, or by an independent CSP, through Direct Participation.

The ISO will address with stakeholders through the stakeholder process additional requirements that may be needed as part of the ISO's process for qualifying a PDR such as signed agreements between the LSE and CSP as proposed by AReM.

A final issue for this section is whether multiple CSPs can represent the same end-use customer. At this point, the ISO recommends allowing only a single CSP to represent an end-use customer, although the end-use customer may participate in multiple programs with that CSP. However, once the market gains more experience with Direct Participation this provision could be relaxed. .

1.2.4. Other Issues: Credit Requirements

The ISO establishes credit requirements for participation in ISO markets in order to ensure that each market participant adequately secures its financial transactions with the ISO. Credit requirements apply to Scheduling Coordinators who represent Supply resources, including PLs. Any financial penalties triggered during the delivery period would accrue through the ISO settlement system to the relevant SC. Based on the provisions of this Straw Proposal, and review of the existing credit requirements for Supply resources, the ISO has concluded that the exposure of CSPs is within what has already been established for Supply resources.[2] Thus, the ISO's preliminary analysis is that the CSP should simply be subject to the same, existing credit requirements as other Supply resources.[3]

In the event that financial penalties are adopted to protect against non-performance or under-performance by CSPs, the ISO should have assurance that it will receive payment. Each CSP's liability would need to be evaluated and a credit requirement developed, if financial penalties are adopted.

1.3. Registration

1.3.1. Background

The Issue Paper identified three distinct registration functions that need to be addressed:

2 SCE's comments suggest that the credit requirements for CSPs should be the same as for LSEs and Community Choice Aggregators. However, CSPs do not take on the primary role of providing energy, and instead are included in the ISO tariff's definition of supply resources.

3 At the January 15 stakeholder meeting, the ISO identified a potential issue as to whether CSPs' bidding of increases in energy consumption needs to be limited or adds other requirements. The ISO offered examples that a CSP that manages an end-use customer's thermal energy storage system would bid to buy economical energy in off-peak hours in order to reduce demand during peak hours, and may result in a net increase in MWh over the course of a day, but that this seems to be a legitimate role for a CSP. However, a CSP taking over a significant fraction of an end-use customer's energy procurement may be beyond the appropriate role of a CSP that is not also the customer's LSE. Stakeholders have not submitted written comments on these issues, and the issues do not seem to clearly define new requirements at this time, either as credit requirements or restrictions on bidding by the CSP.

- New end-use customer that will participate as a PDR wishing to register with a CSP / LSE,
- Existing end use customer participating as a PDR is registered with a CSP / LSE who wishes to change to a different CSP / LSE, and
- Existing end use customer that is participating as a PDR is registered with a CSP / LSE that wishes to withdraw from the DR market.

Within these three scenarios, to make the PDR market effective, the Issue Paper suggested needs for a series of controls / checks and balances to ensure appropriate scheduling of PDRs. The ISO will establish necessary overall rules in its tariff to ensure the integrity of registering and scheduling PDRs, and further detail the supporting processes in its Business Practice Manuals and Participating Load Users Guide through a working group and stakeholder process that will follow the Order 719 compliance filing. The Issue Paper suggested that the appropriate provisions for PDR appear to be that:

- A PDR is served by one CSP and may consist of multiple end use customers from one or more LSEs
- An end use customer that is participating as a PDR can be registered to one CSP and one LSE at a time on any given trading day.
- The end use customer that is participating as a PDR is registered to the correct CSP / LSE
- All registered end use customers that comprise a PDR are aware that they are registered with a specific CSP / LSE
- Confirmation of any change of CSP / LSE is communicated to the end use customer that is participating as a PDR and the end use customer that is participating as a PDR affirmatively confirms that change
- An end use customer that is participating as a PDR who wishes to leave the PDR resource pool confirms that it has been removed
- The CSP / LSE's report to the ISO of DR capability is accurate and reflects the registered PDR capacities.

A variety of implementation details will need to be resolved through the working group and stakeholder process following the ISO's Order 719 compliance filing. Customer migration will need to be tracked as end-use customers enroll in and discontinue their participation in DR programs, and move between LSEs (including direct access Electric Service Providers), particularly if the end-use customers' migration between CSPs and LSEs do not occur at the same time. Registration of a PL resource needs to ensure that the end-use customers that comprise the resource are located within the designated areas. The ISO's PDR model requires the aggregation of end-use customers within CLAPs that are no larger than the ISO defined Sub-LAPs for PDR. Customer migration will require updating of the aggregation data that underlie the submission of Schedules and Bids by LSEs and CSPs, as well as the operational characteristics of PDR (available capacity, loss factors, etc.), to ensure that correct prices are applied in settlements. If customer migration results in changes to the products (e.g., Ancillary Services) that are bid into ISO markets, Schedule 1 of the Participating Load Agreement will require updating, and updates to the PL's implementation plan will track other resource attributes such as available capacity.

In some ISO markets, the ISO has the responsibility of managing the registration / confirmation process. How this will be managed within the scope of the DR program under MRTU is among the questions addressed below, and will be among the topics of ongoing discussions. Two of the alternatives are: (1) the ISO could actively manage the registration and confirmation process, by constructing and maintaining large databases of end-use customer registrations and assignments to

CSPs and LSEs, or (2) market participants could be responsible for managing end-use customer registrations, pursuant to rules and processes that the ISO and CPUC would establish. Discussion during the current stakeholder process, and the working group and stakeholder process that will follow the Order 719 compliance filing may identify additional options that are between these two fundamental options, or that are hybrids of them.

1.3.2. Stakeholder Comments

EnerNOC suggests that the ISO will need to register resources (customer locations) with a specific resource ID. The aggregator would submit the list of resources that are behind the load reduction bid that will respond when DR events are initiated. EnerNOC identifies issues as being how resources are identified with a CSP, and how new customers are registered in the program.

NAPP proposes that the ISO should maintain central databases that support the registration and settlements of market resources and transactions, which would allow the EDC(?), LSE, CSP and ISO to enter, review and approve each DR resource registration, transaction and settlement. Metering would be maintained outside of the ISO system and reported to the ISO by the corresponding DR resource aggregator or provider.

SCE identifies communications among the various market participants as an important issue requiring a set of standards/protocols, with respect to specific customer account program enrollments, changes as customers move in and out of programs, and event participation. AReM also identifies “customer migration” as an issue with Direct Participation that needs further discussion.

PG&E suggests that the ISO should require the CSP to notify the LSE soon after enrollment when a customer of the LSE is enrolled in the CSP’s DR program, before bids by the CSP are scheduled or dispatched, and require the CSP to notify the LSE when the CSP’s DR resource is scheduled or dispatched for an LSE’s customer.

1.3.3. Discussion

After discussion at the January 15 stakeholder meeting and review of stakeholder comments, the ISO continues to see the principles outlined above in section 1.3.1, “Background”, to be appropriate as requirements for Direct Participation. As noted in section 1.3.1, the ISO will establish the overall rules in its tariff that are necessary to ensure the integrity of registering and scheduling PDR. Details of the supporting processes will be described in the ISO’s Business Practice Manuals and Participating Load Users Guide, to be developed through a working group and stakeholder process that will follow the Order 719 compliance filing. There is no doubt that developing details of these processes will require time for open discussion, and first establishing the fundamental requirements will then help to focus the subsequent discussion of the details that are required for implementation.

As documented in the MRTU Release 1 Participating Load User Guide, the Participating Load Agreement (PLA) establishes the roles and responsibilities for being a PL in the ISO markets, and Schedule 1 of the PLA describes its participating resources in general terms. The Participating Load Implementation Plan and Resource Data Template are less formal documents that certify resource capabilities. Once resource characteristics are established through these documents, market bids describe the day to day (and hour to hour) availability of resources. These documents provide a flexible structure for managing PDRs, and provide the ISO with the information it needs to manage its markets without excessive needs for the ISO to track individual end-use customers. Tracking the individual customers that make up PL resources is the responsibility of the CSP that bids the resource.[4]

The ISO recognizes that LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. LSEs will base their load schedules on the actual usage of the customers who they serve, and lack of knowledge about DR schedule changes affecting their customers could cause error in their forecasts. Thus, the ISO agrees with SCE and PG&E that LSEs should be informed of DR enrollments and schedule changes. The ISO's tariff will need to establish the principles for this data exchange, followed by development of implementation details in the Business Practice Manuals and Participating Load Users Guide.

1.4. Scheduling

1.4.1. Background

Once a CSP becomes certified for participation in ISO markets and registers its resources, actual participation proceeds with the submission of bids for energy and/or capacity products (e.g., Ancillary Services). The CSP's preparation of markets bids involves collection of aggregated data for its end-use customers, and forecasting the availability of price responsive resources for the operating day, as well as business decisions such as determining its bid price.

1.4.2. Stakeholder Comments

NAPP suggests that DR resources should be allowed to participate using Firm Service Level (making a minimum threshold usage commitment) or Guaranteed Load Drop (committing that they will shed a specific amount of load at the time of the call event). EnerNOC states that an issue to be addressed is how DR is offered into the ISO markets.

PG&E suggests in their comments that the CSP inform the LSE and CAISO simultaneously regarding the allocation of MW between LSEs. This will enable the LSE to validate these numbers when the CAISO posts them in the settlement process.

1.4.3. Discussion

As the ISO discussed in the January 15, 2009, stakeholder meeting, the scheduling functions summarized in section 1.4 do not appear to be changed by the addition of the CSP as a market participant that is separate from the LSE. As a general rule, when the LSE and CSP are separate entities, scheduling functions that would be performed to schedule demand that if it were not participating in DR would remain with the LSE, but functions that exist because of participation in a DR program would be the CSP's responsibility. The proposed respective roles of the CSP and LSE are shown in following table:

4 In determining whether additional data are needed to track individual customers, an analogous situation could be the tracking of load migration between LSEs so that Congestion Revenue Rights (CRRs) can be reassigned to the LSEs that serve end-use customers in each month. Because the ISO allocates CRRs to LSEs to manage congestion costs that the LSEs incur in serving their customers, the ISO needs to maintain as much precision as possible in its allocation of CRRs. Nevertheless, the information that the ISO tracks for the reallocation of CRRs from month to month is limited, consisting of data such as account number, customer class, and approximate usage for individual customers over one MW in size. That is, extensive databases about end-use customers have not been required. In contrast, each CSP is responsible for managing its DR resources and will see the financial impacts of any mismanagement in its final settlements. While the LSE can receive CRRs for serving load, CSPs are not awarded CRRs for managing DR. The number of individual customers who participate in DR programs could be quite large for programs that serve small customers. Therefore, there appears to be no need for the ISO to develop complex systems for tracking individual end-use customers to actively manage the registration and confirmation process. Instead, market participants should be responsible for managing end-use customer registrations, pursuant to rules and processes that the ISO and CPUC will establish.

Who develops pilot program and applies to PUC for approval?	CSP [5]
Who markets program and enrolls customers?	CSP
Who pays customers capacity payment to participate?	CSP
Who procures, installs, reads and maintains metering, telemetry and auto DR equipment at customer sites?	CSP
Who registers participant load with ISO as a new Resource ID?	CSP
Who coordinates PDR acceptance and certification test?	CSP
Who forecasts hourly energy usage for each Resource ID?	N/A [6]
Who submits energy bid for Resource ID in DA market?	CSP
Who forecasts available load reduction capacity that can be bid in RT?	CSP
Who models actual load response (if necessary) when ISO dispatches PDR in RT market?	CSP
Model output assumed to be integrated with meter data and communicated with ISO.	CSP
Who submits RTEM bids?	CSP
How are Imbalance Energy bid levels decided?	M&V vs Baseline [7]
Who receives ADS dispatch for Imbalance Energy?	CSP
Who activates load reduction via auto DR?	CSP
Who measures and verifies load reduction?	CSP (recommend that LSE, ISO verify also) [8]

The details of these roles will be discussed and detailed out further through stakeholder process on Direct Participation. The ISO notes that the LSE needs to have metering compliant with CPUC standards for all of its retail end-use customers, and that the assignment of the metering and telemetry role discussed in this table concerns any additional needs for PLs, which are discussed in section 1.6 of this Straw Proposal.

Among the key issues to be addressed at this point of completing the ISO's proposal is who is responsible for measuring and verifying load reductions. The ISO anticipates that all entities that are affected by PDR resources (including the ISO, CSP, and LSE) will actively monitor load reductions, and the question is whose calculations form the basis of financial settlements. The ISO proposes that settlements will be the most transparent to market participants and will function more smoothly, if the ISO takes on this responsibility.

Some retail DR programs include performance characteristics such as Firm Service Level and Guaranteed Load Drop, which are referred to in NAPP's comments. Except for RT response to the dispatch of energy from ancillary service and RUC capacity, these concepts do not apply in the

5 By including this row, the ISO is not making any determination whether independent CSPs must apply to the CPUC for program approval.

6 The ISO's understanding is that this proposal at the working group meeting includes each LSE and CSP preparing its own load forecast.

7 The ISO's understanding is that this proposal at the working group meeting places responsibility for both measurement and verification, and baseline, calculations on the CSP.

8 This table entry reflects SCE's suggestion. See the text of this section for the ISO's assessment of who should measure and verify load reductions.

ISO's markets. For ancillary services and RUC, the ISO must know that it has a specific amount of capacity available that will be available when needed in RT operations. Other sources of ancillary services (i.e., generation and imports) provide this operational certainty of having a specific amount of capacity available when needed, and RUC resources similarly offer specific capacity to RTM. To be comparable to the other sources of ancillary services and RUC capacity, so that capacity can be awarded using the same market mechanisms, PLs must also provide a specific amount of capacity. CSPs may include Firm Service Level and Guaranteed Load Drop commitments in contractual arrangements with their end-use customers, and if honoring these commitments results in deviations from schedules issued by the ISO, the difference will be settled as RT imbalance energy – the same as other sources of RT imbalances.

1.5. Notifications

1.5.1. Background

After Scheduling Coordinators submit their bids into the ISO's RT markets, the ISO runs its market software to determine final schedules. At the completion of DAM, the ISO publishes DA prices as public market information, and publishes schedules separately to each Scheduling Coordinator. While running RTM, the ISO uses the Automated Dispatch System (ADS) to communicate resource-specific dispatches, and publishes RT prices as public market information. In the Issue Paper, the ISO indicated that it sees little if any change in mechanisms for communicating schedules and dispatch due to adding Direct Participation to the PDR design. The ISO identified issues and invited stakeholder comments regarding whether the LSE needs a copy of schedule changes and dispatches resulting from CSP's bids, to be sent by the ISO, and whether the CSP needs a copy of the LSE's scheduled energy, to be sent by the ISO.

The ISO has previously indicated that it sees no need to track outages for DR, other than unavailability of awarded AS capacity. The Issue Paper suggested that there is no apparent need to change this conclusion due to Direct Participation.

1.5.2. Stakeholder Comments

PG&E suggests that the ISO should require the CSP to notify the LSE when the CSP's DR resource is scheduled or dispatched for an LSE's customer, as well as to require the CSP to notify the LSE when the CSP enrolls a customer of the LSE in the CSP's DR program. PG&E also commented that there are concerns about LSE bid confidentiality and the fact that LSE's would not normally be forecasting load for individual customers or DR aggregations of customers.

EnerNOC identifies issues of how events are triggered, what minimum types of communication equipment the CSP and its customers will have to install in order for communications from the ISO to be received to alert of DR events, how the event notification is transmitted to the CSP and/or customers of the CSP, and what response time is required after notification is received.

Multiple market participants stated in their March 20 comments that they believe the ISO must take an active role in managing the communications required regarding customer participation in PDR between the LSE and the CSP and should adopt clear and enforceable rules for communication.

1.5.3. Discussion

The ISO recognizes that LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. LSEs will base their load schedules on the actual usage of the customers who they serve, and lack of knowledge about DR schedule changes affecting their customers could cause error in their forecasts. Thus, the ISO agrees that LSEs should be informed of DR enrollments and schedule changes. In addition, there must be a process for the CSP to inform the ISO how to allocate the DR MWs that are part of a PDR bid between LSE's in the PDR model.

Exchanging data about MW quantities does not need to include data about bid prices, or quantities that were included in bids but not scheduled or dispatched by the ISO, which a market participant may consider confidential. The ISO's tariff will need to establish the principles for this data exchange, followed by development of implementation details in the Business Practice Manuals and Participating Load Users Guide.

Regarding the mechanics of schedule and dispatch notifications, the ISO has existing mechanisms for communicating schedules in the DA market, and dispatches in the RT market. These mechanisms and their timing requirements are documented in the User Guide. Other than to communicate MW quantities of demand schedules and dispatches to both the CSP and LSE, the ISO has identified no need to change the existing notification mechanisms, and plans to continue to use the existing mechanisms.

1.6. Metering and Telemetry

1.6.1. Background

The Issue Paper addressed two types of issues: existing tariff impediments that will require clarification, and metering requirements for DR participation in the ISO markets.

One issue for tariff clarification is the provision in MRTU Tariff section 4.5.1.1.3 that only one Scheduling Coordinator may register at any point in time to represent the same meter point for a ISO Metered Entity. This tariff provision is discussed in detail in the Issue Paper, and that discussion does not require repeating here. The discussion's fundamental conclusion is that the ISO tariff does not fundamentally prohibit the situation where one SC schedules demand while another SC submits demand curtailment bids, particularly when the end-use customer is a SC Metered Entity. The issue of how the CSP may participate in ISO markets is the general topic of this Straw Proposal, and section 4.5.1.1.3 can ultimately be clarified to reflect the final policy resolution. However, the MRTU Tariff does not currently have provisions to address dual bids by the CSP and LSE, and in particular does not address how to allocate the value of a dispatched Demand curtailment between two Scheduling Coordinators representing the CSP and the LSE (and the underlying interests that they represent), and a substantive policy decision needs to be formulated about how any allocation should be made. The financial settlements issue of how to allocate revenues between the CSP and LSE is addressed in section 1.7 of this proposal.

The other issue identified in the Issue Paper for tariff clarification involves the definition of ISO Metered Entity, which states that an ISO Metered Entity is one of several types of entities, one of which is "a Participating Load". The ISO will clarify the tariff definitions to reflect that a PL is not necessarily an ISO Metered Entity. On these two tariff issues, the Issue Paper has established a sufficient background to develop the needed tariff clarifications.

An additional clarification that will be needed is that the current tariff does not define when a PL must be a ISO Metered Entity[9] or a SC Metered Entity[10]. As a Straw Proposal for further discussion, the

[9] An ISO Metered Entity is defined for this purpose as a PDR that represents a Load that is directly connected to the CAISO Controlled Grid or representing a Load or Loads that are otherwise required to provide Meter Data to the CAISO through CAISO certified metering directly polled by the CAISO.

[10] An SC Metered Entity for this purpose is defined as a PDR that is not an ISO Metered Entity

ISO proposes that a PDR that connects to the ISO Controlled Grid without other loads being served from the same grid takeout point must be a ISO Metered Entity, and otherwise PDRs would be SC Metered Entities.

Substantive issues that need to be addressed further involve the specification of meter data for DR, and the responsibilities for meeting these requirements, when there are separate LSEs and CSPs. The current Metering Protocol and Tariff requirements may be found at the ISO website at:

http://www.caiso.com/docs/2005/10/01/2005100116065757 62.html

PLs and their Scheduling Coordinators must provide revenue quality metering data to the ISO. PLs and their SCs must ensure that revenue Meter Data is made available to the ISO in accordance with the ISO tariff and Metering Protocol. The specific requirements for ISO Metered Entities (if applicable) and details regarding the ISO certified meter, including the ISO's standards for the certification of a "Load-only" meter, can be found in the metering section on the ISO Home Page at http://www.caiso.com/docs/2005/10/01/2005100114481329995.html.

For all Loads of PLs, Sections 2.2.3 and 2.3.4 of the Metering Protocol of the ISO tariff require that revenue meter data must be recorded and submitted at 5-minute intervals for purposes of financial settlements. Pursuant to that requirement, ordinarily all Loads participating in ISO markets, including AS and RT Imbalance Energy markets, must have revenue quality metering equipment that records data at intervals no longer than five minutes. For the MRTU Release 1 and thereafter, the 5 minute interval reading may be constructed by dividing a 15-minute interval reading into three equal values.

Among the issues to be considered is whether the same meter is applicable for settlement and validating compliance of services provided by the LSE (i.e., Energy) and the CSP (e.g., Ancillary Services). As discussed in the User Guide that is being developed for PL resources in MRTU Release 1, a separate set of measurements is already required as telemetry for PLs that provide Ancillary Services, while Settlement Quality Meter Data are used for Energy settlement. Whether there are needs for the LSE and CSP to maintain separate metering (rather than both entities using a common meter), whether it would be technically feasible for telemetered meters to be registered to the Scheduling Coordinator for the DR Participant, whether the data from such meters could be used for some settlement purposes, and the technical and financial feasibility of installing independent meters to be registered to the CSP's Scheduling Coordinator are all issues for consideration.

Also to be considered are the roles and responsibilities around meter data management, data access needs between the LSE and CSP, and data and process flows specific to meter settlements data.

1.6.2. Stakeholder Comments

Blue Point Energy suggests that when AMI meters are present, both local aggregated net load and local aggregated resource load reductions should be reported to the ISO by the aggregator on a 5 minute basis. This assumes that the AMI will make net load information available to the aggregator on a 5 minute basis. This data would be subject to metering requirements similar to the current requirements for PL, and aggregation detail would need to be submitted on a daily or weekly basis. Blue Point Energy states that aggregators are already able to monitor their own load reductions, that their metering could be enhanced to perform in the proposed environment, and that utilities are rolling out AMI and could provide appropriate data without substantial investment.

EnerNOC identifies several issues for consideration, including: (1) minimum metering requirements (requirements for interval meters, or acceptability of load profiling for small customers), (2) timing requirements for providing meter data to the ISO after DR operations, (3) establishing measurement and verification protocols, (4) establishing a baseline methodology for measuring DR, and

(5) performance measurement, possibly using the resolution of issues in a current CPUC proceeding for current utility programs.

NAPP suggests that the ISO should recognize the large investment by California utilities in Advanced Metering Infrastructure (AMI), and allow AMI metering solutions as a proxy for telemetry. NAPP suggests that the requirements energy or "capacity" resources should allow standard hourly or 15 minute interval data, whereas the ancillary services market should require metering solutions that provide actual 1-minute interval data. NAPP suggests that remote control and telemetry requirements can be barriers to participation and should not be a requirement for participation.

SCE states that the ISO has correctly articulated the issues related to metering, meter data management, and telemetry when the party serving the load and the party providing the DR are not the same entity, and that these issues will require significant stakeholder discussions including consensus business process mapping to resolve. SCE notes that while the number of Direct Access customers is relatively small, they represent a disproportionate share of SCE's DR participation, and participation rules need to allow a customer to be served by a non-utility LSE and a CSP.

1.6.3. Discussion

The ISO agrees with SCE's assessment that ultimately, addressing metering, meter data management, and telemetry will require significant stakeholder discussions, and that consensus business process mapping may be involved. The ultimate resolution of metering, meter data management, and telemetry issues most likely involves issues of CPUC jurisdiction as well as ISO market design, since the utilities' AMI programs are under CPUC oversight. However, the timing required for completing these processes extends well beyond the date when the ISO intends to provide enhancements to the MRTU Release 1 PL functionality.

The ISO has already established requirements for metering and telemetry for products that have been provided in the pre-MRTU market design and are provided under MRTU Release 1.[11] For these products, the ISO has not found differences in requirements that are created by adding the CSP to the types of market participants. These requirements are documented in the MRTU Release 1 Participating Load User Guide. In summary, interval metering is required for settlement of interval energy usage, but telemetry is required only for providers of ancillary services. If a PDR participates in the DA energy market and limits its RT market participation to energy in the Hour-Ahead Scheduling Process (as allowed in the PDR model), only hourly interval metering is required. If a PDR provides ancillary services, the ISO's operational requirements mandate the availability of telemetry, as described in the User Guide.[12] The ISO may consider alternatives to telemetry in the future, as it analyzes results of pilot programs using MRTU Release 1 PL functionality that the IOUs are implementing for summer 2009, but this is unrelated to the implementation of Direct Participation.

One significant difference in metering requirements may occur as Direct Participation is implemented. As discussed in section 1.7, settlement of energy, ancillary services, and RUC capacity all necessarily rely on a "baseline" calculation that estimates what the PDR's energy usage would have been if it had not been dispatched as DR. If an end-use customer were not part of a PL

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11 Meter data management for retail end-use customers is under CPUC jurisdiction. For purposes of the ISO markets, Scheduling Coordinators that represent loads must submit Settlement Quality Meter Data for financial settlements, but the ISO relies on Local Regulatory Authorities such as the CPUC to establish metering and meter data management requirements.

12 Regulation will have technical requirements for telemetry beyond a one-way information flow to the ISO, and spinning reserve may have technical requirements beyond those required for non-spinning reserve. The outcome of these issues depends largely on seeking WECC interpretation of the technical requirements for these services. Because actual participation in ISO markets appears likely to occur for energy storage systems before PL resources, and because the technical specifications for these services appears to be the same (i.e., requirements for non-generation resources regardless of technology), the development of these technical specifications will occur in a parallel stakeholder process for energy storage systems.

resource, the LSE would be responsible for metering energy use, but this might not be interval metering. By adding DR response, the CSP is likely to use telemetry for monitoring its PDR resources to establish its own knowledge of baseline energy usage, as well as for verifying their response to dispatches. Adding requirements for the CSP to maintain separate interval metering could add to the CSP's operating costs. It must be recognized that the baseline calculation is only an estimate of what would have occurred under different circumstances, and has some amount of error. The presence of this error in estimation is important in determining metering requirements, because metering itself has certain tolerances for error: revenue quality metering has an allowable 0.5% error, while telemetry has an allowable 2% error. When there inherently is error in the baseline calculation that is part of determining the amount of DR response that has actually been delivered, the difference between 0.5% and 2% error in metering is likely to not be significant. Therefore, the ISO suggests as a Straw Proposal for stakeholder discussion to allow the CSP to provide either telemetry-based data or revenue quality meter-based data to support settlements of DR response, and invites comments on the advantages and disadvantages of this concept.[13] Stakeholders had mixed responses in their March 20 comments to using telemetry based data in lieu of revenue quality meter data and this will require further discussion through the stakeholder process.

1.7. Settlement Issues

1.7.1. Background

As illustrated by the discussion in the Issue Paper, perhaps the most difficult issues in implementing Direct Participation involve financial settlements, since two market participants are now involved in serving the same end-use customers and revenues must be divided between them. Also, as previously noted, the ISO's DR programs require the aggregation of end-use customers within local areas, so that the ISO can use these resources effectively in the MRTU market's congestion management. The proxy generators in the PDR model must represent Demand Response within Sub-LAPs, some of which are smaller than Local Capacity Areas. The LMPs will vary between the Default LAPs that apply to most loads, and settlement issues include which price applies to scheduling of demand and which price applies to DR to dispatch by the ISO, which are not necessarily the same price.

In the Draft Final proposal for PDR it is proposed that the settlement for the curtailed portion of the load be settled by the ISO directly with the CSP at the PDR's specified CLAP. The CSP would be paid the Day-Ahead LMP at the CLAP for Day-Ahead PDR and the Real-Time LMP at the CLAP for Real-Time PDR. Determination of actual PDR delivery would be derived from measurement of aggregate meter usage, calculated from a pre-determined baseline. Verified performance against the baseline would determine the energy settlement with the CSP at the CLAP. Any other settlements between the CSP and the LSE would be performed bi-laterally between the LSE and CSP outside of the ISO's settlement process.

In accordance with this process, bids to curtail load that clear the Day-Ahead and/or Real-Time Market will appear as a reduction to the LSE's Day-Ahead Load Schedule for the purpose of settlement of uninstructed deviation. The LSE will still pay for Day-Ahead scheduled load at the Day-

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13 In the event that the CSP provides settlement quality meter data from revenue quality energy metering rather than telemetry, the ISO does not propose to establish requirements either that (a) the CSP must install separate metering or (b) the LSE must provide its meter data to the CSP. This is an issue for which the LSE and CSP may negotiate a mutually acceptable solution, subject to requirements that may be adopted by the Local regulatory Authority (e.g., the CPUC). In the event that the CSP provides telemetry data for settlement, it must provide the ISO with access to real-time telemetry, which may be aggregated as described in the User Guide.

Ahead DLAP price and adjustments to the LSE's Day-Ahead schedule would be for purposes of calculating uninstructed deviation only.

In the next phase of the stakeholder process which will occur in April – August 2009 the ISO and stakeholders will engage in more detailed discussion on these topics and the ISO will provide some more detailed settlement examples for stakeholder discussion.

Some approaches to settlements involve comparisons of end-use customers' final metered demand to estimates of what their demand would have been if they were not participating in DR programs. If DR operations were only short-term events, verifying the response of the affected end-use customers could be simple. However, a review of the ISO's history of declared system emergencies shows that it is not unusual for these events to last from three to eight hours, and for declared transmission emergencies to last twelve or more hours. During this time, variations in most customers' normal demand can be expected, and even increases in demand during the time of a DR operation do not mean that the affected customers are not complying with the requested demand reductions below what their demand would otherwise have been. Thus, to determine compliance with DR schedules and dispatches as a basis for settlements, the ISO will establish methodologies for calculating baseline energy usage, through stakeholder and working group processes following the Order 719 compliance filing.

The considerations in establishing baseline methodologies were discussed in the Issue Paper and illustrated in the January 15 stakeholder meeting presentation, which is available at: http://www.caiso.com/2335/2335f3d540050.pdf.

1.7.2. Stakeholder Comments

Stakeholder comments on settlement issues commonly address the range of issues that are identified above (location for settlement of DR, allocation of revenues between CSP and LSE, and baseline calculations), among other issues.

A number of market participants support the ISO adding an additional settlement back to the LSE for Day-Ahead energy purchased but not consumed and other market participants believe any additional settlements between the CSP and LSE should be settled bi-laterally without ISO intervention.

Some Market participants also expressed in their comments that more detailed settlements examples are needed to understand the full impact of the settlement of PDR on all ISO settlements changes.

AReM is concerned that the use of CLAPs will discourage customer participation in high-cost areas, and is interested in developing an alternative.[14] However, AReM is concerned that alternative approaches to settlements would require the ESP to pay for its full energy schedule, even if a DR program operated and the actual load was reduced. AReM also commented that they support starting with the CPUC baselines for use in the CAISO DR program rules but they do not agree that the CPUC load impact protocols are appropriate for DR programs implemented by ESPs or CSPs.

Blue Point Energy suggests that bids should be settled by (1) paying the aggregator the cleared local aggregated resource load reduction, times the difference of the nodal RT energy price less the utility DA average price, (2) reimbursing the utility at the DA average price for the total of local aggregated

[14] The ISO notes that use of CLAPs is part of the MRTU Release 1 Participating Load model, as the result of an extensive stakeholder process in 2005, the Board of Governors decision on refinements to the MRTU market design in October 2005, and FERC's September 2006 order approving the MRTU design. The DDR design does not create the use of CLAPs, and the PDR model and the "partial participation" option in the DDR model provide alternatives to scheduling Participating Loads using CLAPs.

resource load reductions, and (3) charging the utility for uninstructed deviations (the total RT load less DA load plus aggregated resource reductions). Thus, the utility would still pay for the energy to meet its load, and any DA over- or under-forecast of load, but would be reimbursed for total local aggregated resource reductions. Blue Point Energy states that there are several benefits to this method, including (1) allowing demand side resources to capture wholesale prices, and respond as a single resource through aggregation, with aggregator performance judged on the aggregated response, (2) allowing utilities to manage and forecast load much like they do today without more granular forecasting, and (3) enabling "smart grid" by making behind the meter demand side resources available for dispatch and ancillary services as directed in FERC Order 719. Blue Point Energy asserts that (1) there is no need for aggregator performance to be based on utility baseline calculations when metering is available, and (2) individual outage and performance measures will be less important than the more easily accessible performance measures for the aggregated resource, because aggregated resources will be combinations of many resources and thus more diverse.

CDWR-SWP is concerned that in an alternative that first schedules load at the Default LAP and then pays DR using a CLAP, the Baseline determination is a critical point of the design. Without an accurate and true Baseline, the amount of DR is difficult to determine, and this type of proposal would introduce "money machine" opportunities. A PL that is located where the LMP is higher than the Default LAP LMP could schedule "additional demand" to its Baseline Demand, and the corresponding DR could then offset the "additional demand" and receive a savings at the higher LMP. Without actually providing any DR, the PL could pay less or even earn revenue. On the other hand, a load at a location with a low LMP would be discouraged to provide any DR because its scheduled demand would be charged the higher DLAP LMP, and the DR would be paid the lower CLAP or nodal LMP. CDWR-SWP believes that the fundamental problem is the Demand settlement at DLAP LMP, which is a weighted average of nodal LMPs that hides price signals at individual locations for Demand to respond. CDWR-SWP proposes to replace the DLAP LMP design with settlement of both Demand and DR at nodal or CLAP LMPs. To eliminate the "money machine" opportunities, Demand and DR would be settled at the same location's LMP.[15]

EnerNOC identifies that settlement issues include how CSPs are paid for their performance, what protocols or criteria apply to measurement and verification of DR data, how often this information is provided to the ISO, and in what format.

NAPP states that if an end user who participates in DR programs "earns" the retail rate savings in its utility bill and is therefore compensated by the ISO only for the incremental benefit, the settlement arrangement does not address the fact that the market rate would have been higher if not for the availability of the DR resource. NAPP suggests that the DR resource should be paid the full market energy price, without deducting the retail rate from that payment. NAPP notes that M&V of DR

15 In additional comments, CDWR-SWP describes issues concerning clarify the obligations and limitations in use of Participating Load as a resource to the ISO, pursuant to filings in the ISO's FERC proceeding regarding parameters to guide the market optimization in making adjustments to certain Non-Priced Quantities (the "Parameter Filing"). CDWR proposes that operational procedures and dispatches should ensure that Participating Loads are firm load (as firm as non-Participating Loads which are scheduled at LAP level) when not voluntarily offering DR, clearly specify the circumstances under which the ISO is authorized to use Participating Load, ensure that Participating Loads are treated on a nondiscriminatory basis with other loads when not offering DR, ensure that RT dispatch of Participating Load for energy from Contingency Only Ancillary Services shall occur only in the event of a true contingency, identify circumstances in which Participating Load may or may not be used in providing the services that it offers to ISO, and require that Participating Load shall not be dispatched for economic purposes except pursuant to that Participating Load's bids. CDWR-SWP proposes that financial rates, settlement, and billing should ensure that Participating Load does not pay (through socialized cost allocation to loads) for the same services that it is providing, ensure that Participating Load is paid comparably to generators, ensure that Participating Load costs of providing service to ISO are covered, and hold Participating Load harmless from costs due to Parameter Tuning, nodal pricing, or any other adjustment or dispatch that has not been volunteered to the ISO. CDWR-SWP requests that legal tariff provisions and agreements should capture these principles in the Participating Load Agreement, limit ISO amendments to the Participating Load Agreement, allow loads to withdraw from Participating Load status, protect Participating Load from legal exposure for deviating from ISO dispatch or schedules, give Participating Load legal rights to decline dispatches or schedule adjustment, and commit that Participating Load will not be interrupted or adjusted except with consent.

resources is an evolving area of focus across all ISO regions, and suggests that current rules should be assessed and addressed through a working group to implement a selection of methodologies that address the differences between customer load profiles, the factors that impact their profiles and the DR participation.

PG&E states that M&V protocols should not afford opportunities for gaming, such as allowing a DR provider to inflate his baseline at a higher price location while lowering his baseline at a lower price location and thus get paid for doing nothing. PG&E suggests that the ISO should coordinate any efforts to develop M&V protocols closely with the CPUC's extensive work on estimating the load impacts of DR programs, especially for CPUC jurisdictional entities.

SCE agrees with the ISO Issue Paper's statements that it is necessary to avoid "double payments" for DR program participation and wholesale bidding, and that the issues of settlement will require significant discussion. SCE's comments suggest that the issues of scheduling and compensation for the newly proposed Direct Participation are very similar to the issues of scheduling and compensation for Direct Access customers that participate in the wholesale market through utility DR programs, which the utilities, ISO, and other stakeholders began to work through in late November 2008, and recommends that this effort should continue. SCE notes that previous ISO and CPUC workshops on metering, settlement and baseline issues have demonstrated that these issues are complex and potential solutions or approaches to resolution are wide and varied. SCE suggests that the California Load Impact Protocols being developed under the CPUC's DR OIR process should be used wherever possible to facilitate consistency among market participants for determining load impacts for retail participants. Of significant importance are the models used to develop baselines for resource performance, which will need consensus review by all market participants.

In addition, SCE and other parties have collaborated to understand the issues that they see in implementing DR programs for which the LSE is not the same entity as the developer of the DR programs, which is currently the IOUs under CPUC jurisdiction, and to develop a joint proposal to the ISO for resolving these issues, in the context of designing the PDR model. SCE has made presentations at the ISO's working group and stakeholder meetings to present the status of this work, and the most recent document detailing this work is available at http://www.caiso.com/2338/2338e5cc521b0.pdf. The ISO's review of this document is that it differs from the concepts for the PDR model that the ISO originally offered in summer 2008 in three ways:[16]

1. Settlement of the DR that is dispatched by the ISO using CLAP and Sub-LAP LMPs, instead of using the Default LAP LMP, to encourage CSPs to develop DR resources in locations with high LMPs,
2. Settlement of the dispatched DR through payments to the CSP (together with charges to the LSE for energy usage that would have occurred if DR bids were not dispatched), instead of through adjustments to LSE's demand schedule, and
3. Performance requirements that would need to be imposed for price-responsive energy, with additional data requirements, in order to support these settlement alternatives.

Since the January 15 stakeholder meeting on the ISO's Issue Paper, the ISO has met with SCE and other stakeholders to further develop all potential alternatives for settlements issues, and anticipates further developing these and other issues in working group meetings.

TURN supports an approach that unbundles the DR offered by a CSP for a DR aggregation from the load scheduled by the customers' LSE, for purposes of scheduling and settlement. This concept

16 The document provided by SCE also have several mischaracterizations of the ISO's proposals, which the ISO listed in slide 9 of its presentation at the January 15, 2009, stakeholder meeting, available at http://www.caiso.com/2335/2335f3d540050.pdf.

would continue to schedule and settle all LSE loads at the Default LAP level, while scheduling and settling the DR provided by CSPs at the local level, as a proxy generator.

1.7.3. Discussion

A factor that strongly influences the ISO's proposed resolution of settlement issues in this Straw Proposal is the current status of development of baseline methodologies for use in allocating financial payments among the ISO's market participants. Stakeholder comments indicate that market designs that depend strongly on baseline calculations take considerable time to develop and implement. This concern could lead to a conclusion that the initial implementation needs to use simplified requirements for use of baseline calculations. Depending on design of financial settlements, the baseline calculation can affect both the total revenue that is paid to DR (at the expense of market participants that are not involved in DR), and the allocation of revenues between the LSE and CSP. As discussed in section 1.7, the development of baseline methodologies is highly complex, which means that this task can be very time-consuming. Clear guidance cannot be obtained by examining the practices of other ISOs, because multiple methodologies are in use. The North American Energy Standards Board (NAESB) is working toward development of standards, but time is needed for completion of NAESB's work, and the NAESB work addresses what affected parties should include in their practices, but does not prescribe a methodology.

Nevertheless, the ISO needs to have some sense of direction for its conceptual design for implementation of Direct Participation, as part of its compliance with Order 719, and enhancing the existing DR functionality is also needed for compliance with other FERC orders. That is, FERC has directed the ISO to implement scarcity pricing within 12 months after MRTU Go-Live, and the ISO's stakeholder process on scarcity pricing has identified the enhancement of DR in the ISO's markets as a requirement for scarcity pricing. Vendor development of software enhancements, followed by implementation and testing by the ISO and market participants, limits the available time for developing a baseline methodology.

At this time, the ISO believes that the appropriate path through these complex implementation issues is to work cooperatively with the CPUC. The CPUC has developed load impact protocols for measuring the impact of DR programs as a whole, and the ISO understands that protocols for event-specific settlements among market participants are currently being developed. Therefore, as this Straw Proposal analyzes alternatives for the other major topics concerning financial settlements (which price applies to demand scheduling vs. DR, and how to allocate revenues between the LSE and CSP), the ISO sees considerable advantage in starting with the protocols that the CPUC is developing, exploring alternatives that could minimize the impact among market participants of any errors in baseline calculations, and thereby having opportunities to gain experience with baseline calculations. As the ISO and its market participants gain experience with baseline calculations, the ISO can re-examine its initial design of baseline methodologies and financial settlements, and work with the CPUC to develop consistent methodologies in wholesale and retail markets.

1.7.4. Other Issues

CDWR-SWP recognizes that there are tradeoffs among DR design options when DR is dispatched at its nodal location but most demand is scheduled and settled at the Default LAPs, and recommends resolving these issues by scheduling and settling all demand at nodal locations or CLAPs. FERC's September 21, 2006, decision conditionally accepting the MRTU tariff has ordered the ISO to develop Sub-LAPs to replace the existing Default LAPs within three years of MRTU operation, and the ISO has stated in several filings to FERC since that decision that it is committed to comply with FERC's order. However, the ISO is not required to replace the existing Default LAPs at this time, and will plan a separate stakeholder process to develop its compliance to this portion of FERC's September 21, 2006, order. FERC has addressed the concerns stated in CDWR-SWP's additional comments, in its February 19, 2009, decision in docket ER09-240-000 (uneconomic adjustment policy). This decision notes that PL receives nodal treatment as opposed to zonal treatment resulted from positions previously advocated by CDWR-SWP, finds that PL is not similarly situated to other market participants, and rejects CDWR-SWP's assertion of undue discrimination. The ISO's responses to CDWR-SWP's comments in docket ER09-240-000 explained that the ISO's market design and CDWR-SWP's existing transmission contracts provide adequate assurance that CDWR-SWP's load will be served, and FERC's decision finds that CDWR-SWP's arguments that its status as PL could result in denial of transmission service or involuntary curtailments are misplaced. The ISO's compliance process for FERC Order 719 includes an examination of barriers to DR, which is separate from the current process for developing Direct Participation, and the concerns to be examined can include CDWR's remaining requests.

1.8. Performance & Compliance Evaluation

1.8.1. Background

There are two general aspects to monitoring and management of the performance of demand resources: general program monitoring to ensure that the ISO markets and market design are performing as intended, and response to non-performance by specific demand resources. The ISO as well as other entities will naturally be monitoring general program performance, and detail here is not necessary. The focus of this section is response to non-performance by specific demand resources.

1.8.2. Stakeholder Comments

EnerNOC identifies issues of performance management as including how underperformance is handled, whether there are penalties, whether credit provisions are triggered, and whether customers and CSPs performance would be de-rated due to non-performance.

1.8.3. Discussion

The PDR model that the ISO has described in its Draft Final Proposal PDR design include no-pay provisions for ancillary services and RUC capacity payments, and compliance requirements for resource adequacy, which are in place in MRTU Release 1 and apply to all suppliers of these services. The requirements that are applicable to other Supply resources have already been developed over the past several years through the ISO's operational experience, and there is no apparent reason why they should not continue to apply equally to DR programs.

Comments by SCE during stakeholder discussions suggest that PL resources should be subject to the same performance requirements for compliance with energy dispatches as generation. Although the ISO tariff defines Uninstructed Deviation Penalties (UDP) for energy from generation, these provisions are not currently active, and the ISO would need to file a tariff amendment and receive a FERC order before these provisions could be activated. In addition, the existing tariff provisions explicitly exempt all loads from these requirements, including PLs.

In searching for analogies to other types of performance requirements that currently exist, as part of considering whether any performance requirements beyond the existing AS and RUC no-pay provisions, and Resource Adequacy requirements, one can observe that LSEs are currently subject to minimum scheduling requirements in the DA market, as a percentage of total demand. The minimum scheduling requirements expire when Convergence Bidding is implemented, which FERC has ordered to be implemented 12 months after MRTU Go-Live. Convergence Bidding allows market participants to submit “virtual” bids for demand or supply into the DA market, which will automatically be reversed in RT. The purpose of Convergence Bidding is to encourage similar scheduling outcomes between the DA and RT markets, by allowing virtual bidders to replace the bids of actual demand or supply if the entities that actually serve demand or supply fail to schedule accurately in the DA market. There is no requirement for virtual bidders to accurately anticipate the RT market conditions, because the difference between DA and RT market prices provides the necessary financial enforcement mechanism.

Given the explicit UDP exemption to all loads that is already in the ISO tariff, and the FERC requirement to implement Convergence Bidding 12 months after MRTU Go-Live, the ISO does not see needs for additional non-compliance penalties for price-responsive energy dispatched from PDR, beyond the existing provisions that apply to AS, RUC, and RA capacity resources. However, the ISO will enforce the existing provisions for PDR just as it does for other market resources.

2. Next Steps

Based on the ISO’s review of stakeholder comments submitted to date, the following principles appear to be appropriate as a Straw Proposal intended for stakeholder discussion. The reader should understand that these are not final proposals, and that the ISO’s development of final proposals will occur only after stakeholder discussion and written comments.

The conceptual design for PDR will go the ISO Board for approval in May and is planned to be implemented by May 2009. The topics outlined in this Straw Proposal will undergo further discussion with stakeholders from April through August 2009. The ISO will host a stakeholder meeting to continue discussion with stakeholders on these issues on April 30. At that time the ISO will provide stakeholders with a detailed plan for stakeholder engagement for meetings and comments going forward through August.

This ISO will issue a final proposal in Direct Participation in September 2009 after stakeholder discussions are complete. The ISO also plans to issue a user guide for PDR in October 2009 that will describe the business processes in detail.

3. Appendix A - Summary of Relevant Sections of Order 719 on Direct Participation

FERC Final Rule re Wholesale Competition in Regions with Organized Electric Markets (125 FERC ¶ 61,071) (issued in Docket Nos. RM07-19-000 and AD07-7-000 on October 17, 2008) (hereinafter "FERC Oct 17 Final Rule"). The FERC Oct 17 Final Rule states in pertinent part (numbers reflect Paragraphs numbering of the FERC Final Rule:

> 154. The Commission adopts in this Final Rule the proposed rule to require RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. We find that allowing an ARC to act as an intermediary for many small retail loads that cannot individually participate in the organized market would reduce a barrier to demand response. Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability. We also agree with commenter's that this proposal could encourage development of demand response ….
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> 155. … In the NOPR, the Commission sought to address the concerns of state and local retail regulatory entities by proposing to require that an ARC may bid retail load reduction into an RTO or ISO regional market unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate in this activity. The Commission's intent was not to interfere with the operation of successful demand response programs, place an undue burden on state and local retail regulatory entities, or to raise new concerns regarding federal and state jurisdiction, as some commenter's argue. As described above, we clarify that we will not require a retail electric regulatory authority to make any showing or take any action in compliance with this rule. Rather, this rule requires an RTO or ISO to accept a bid from an ARC, unless the laws or regulations of the relevant electric retail regulatory authority do not permit the customers aggregated in the bid to participate.
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> 157. With regard to LPPC's request that ARCs not bid on behalf of load served by ARCs that are not RTO or ISO members, SMUD's request for clarification that loads outside of an RTO's or ISO's control area would not participate in demand response programs, and TAPS's comment that the proposal should not require a change to an existing retail load reduction program, the continuing role of the relevant retail electric regulatory authority adequately addresses these concerns.
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> 158. Further, we agree with the comments that, because each region's market design is different, it is important to permit each RTO or ISO to design ARC provisions that account for these differences. Therefore, instead of developing pro forma language or requiring RTOs and ISOs to make detailed generic market rule amendments, we direct RTOs and ISOs to amend their tariffs and market rules as necessary to allow an ARC to bid demand response directly into the RTO's or ISO's organized market in accordance with the following criteria and flexibilities that remain largely unchanged from those advanced in the NOPR:
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> a. The ARC's demand response bid must meet the same requirements as a demand response bid from any other entity, such as an ARC. For example:

i. Its aggregate demand response must be as verifiable as that of an eligible ARC or large industrial customer's demand response that is bid directly into the market;

ii. The requirements for measurement and verification of aggregated demand response should be comparable to the requirements for other providers of demand response resources, regarding such matters as transparency, ability to be documented, and ensuring compliance;

iii. Demand response bids from an ARC must not be treated differently than the demand response bids of an ARC or large industrial customer.

b. The bidder has only an opportunity to bid demand response in the organized market and does not have a guarantee that its bid will be selected.

c. The term "relevant electric retail regulatory authority" means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission.

d. An ARC can bid demand response either on behalf of only one retail customer or multiple retail customers.

e. Except for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate, there is no prohibition on who may be an ARC.

f. An individual customer may serve as an ARC on behalf of itself and others.

g. The RTO or ISO may specify certain requirements, such as registration with the RTO or ISO, creditworthiness requirements, and certification that participation is not precluded by the relevant electric retail regulatory authority. [fn **212** The RTO or ISO should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority]

h. The RTO or ISO may require the ARC to be an RTO or ISO member if its membership is a requirement for other bidders.

i. Single aggregated bids consisting of individual demand response bids from a single area, reasonably defined, may be required by RTOs and ISOs.

j. An RTO or ISO may place appropriate restrictions on any customer's participation in an ARC-aggregated demand response bid to avoid counting the same demand response resource more than once.

k. The market rules shall allow bids from an ARC unless this is not permitted under the laws or regulations of relevant electric retail regulatory authority.

159. … Further, in response to those who ask us to require in this rule (1) that each RTO or ISO should be required to demonstrate net benefits of its program, (2) that bids should be aggregated on a local basis, and (3) that so called "double payment" should be either required or prohibited, we decline to do so here. Such issues are more appropriately addressed by each region in its compliance filing if it chooses to do so.

161. In accordance with NYISO's recommendation, the Commission will clarify that its regulatory reference in § 35.28 (g)(ii) to "organized market" has the same meaning as proposed under (g)(i) and that ARCs are to comply with any necessary technical requirements under the RTOs or ISO's tariff.