BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response, Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols	Rulemaking 07-01-041 (January 25, 2007)

INITIAL RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING REMAINING DIRECT PARTICIPATION ISSUES (PHASE IV, PART 2)

The California Independent System Operator Corporation (ISO) submits this initial response to the direct participation issues as requested by the Administrative Law Judge in this proceeding.[1] The ISO makes three key points as a general response to the issues to be addressed in this proceeding and provides specific responses, where appropriate, to the Commission's financial settlement questions.

The ISO believes this proceeding is the appropriate forum to address financial settlement issues and objects to any suggestion it would be appropriate to rely upon a wholesale financial settlement mechanism. In doing so, the ISO encourages the Commission to support the development of a competitive third-party delivered demand response paradigm to maximize the potential for flexibility and new demand response product and service innovations that will be essential to meeting California's environmental policy goals. In addition, any financial settlement mechanism developed to resolve retail compensatory issues between parties to a demand response transaction should be done in the most efficient manner to reduce the time and cost to deploy demand response services.

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[1] *Administrative Law Judge's Ruling Soliciting Responses on Remaining Direct Participation Issues (Phase IV, Part 2)*, Rulemaking 07-01-041, dated November 8, 2010.

The ISO also encourages the Commission to consider incorporating into this proceeding a limited opportunity for stakeholders to assemble as a working group to develop a compensation proposal or proposals for the Commission's consideration. The ISO is concerned that the calendared workshop will not provide a sufficient opportunity for further consideration and debate of the issues raised given their complexity. Proposals developed by the working group would likely aide the Commission's decision making process since stakeholders, versus Commission staff, would be responsible for deliberating and consolidating the ideas into specific proposals for the Commission's consideration. If supportive of this approach and to speed the process, the Commission should specify a limited timeframe and assign a utility responsible for coordinating the working group. As a final deliverable and with some additional time allotted, the workshop report could also incorporate the working group's compensation proposal. All parties would then have an opportunity to formally comment on the final report and proposal(s).

GENERAL RESPONSE

1. The ISO believes this proceeding is the appropriate forum to address financial settlement issues and objects to any suggestion it would be appropriate to rely upon a wholesale financial settlement mechanism.

Wholesale demand response participation in California has been structured around the ISO's proxy demand resource product (PDR), which was approved by the Federal Energy Regulatory Commission and implemented by the ISO with support from the CPUC and many of the stakeholders in this proceeding.[2] By itself PDR does not attempt to resolve the retail financial settlement concern that is the subject of this proceeding – the "missing money" or undercollection issue. Rather, the PDR design

[2] *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC ¶ 61,045 (2010).

addresses a wholesale market settlement issue, commonly referred to as "double payment," which it resolves through the ISO deployment of the "default load adjustment" mechanism. Certainly the ISO could have advocated for a wholesale market mechanism to account for the missing money as has been implemented by at least one eastern Regional Transmission Organization, but the long standing consensus view in California has been to leave this to the discretion of the local regulatory authority – to the point the ISO views this as settled policy subject only to the outcome of the recent FERC rulemaking that covers this same issue.[3] If the FERC final order mandates that wholesale markets address the missing money issue, then the CPUC, the ISO and stakeholders can engage further on how best to accomplish such a result.

The ISO and its stakeholders considered financial settlement issues in the development of PDR and adopted design features that addressed the double payment concern while recognizing that the CPUC is the proper entity to address the undercollection concern on the retail side. An example serves to illustrate the result.

Example: Double Payment and Undercollection

Assume that a demand response provider ("DRP") is submitting demand curtailment bids for the load of multiple retail customers of a load-serving entity ("LSE"). The DRP bids 10 MWh of demand curtailment from those retail customers. The LSE forecasts that, under normal circumstances without any demand curtailment, its load will be 100 MWh, so the LSE submits to purchase 100 MWh in that hour given the LSE has no knowledge of the demand curtailment bids submitted by the DRP. One hundred MWh of supply clears

[3] *Notice of Intervention, Comments and Request for Clarification of the Public Utilities Commission of the State of California Regarding the Proposed Rulemaking on Demand Response Compensation in Organized Wholesale Energy Markets*, FERC Docket No. RM10-17-000, May 13, 2010; and *Comments of the Public Utilities Commission of the State of California Regarding Technical Conference*, FERC Docket No. RM10-17, October 12, 2010.

the wholesale market, based on the LSE's offer – 90 MWh from generation resources and 10 MWh of demand curtailment from the DRP. The DRP receives the LMP for the 10 MWh that cleared the wholesale market. The LSE pays for the 100 MWh of load awarded in the day-ahead market.

Assuming perfect performance by the curtailing customers, the DRP curtails 10 MWh of load, which is paid as energy supply by the wholesale market. The LSE procured 100 MWh of load, but, as measured by meter data, its customers only consumed 90 MWh. It appears that the LSE over-procured energy; therefore, the LSE would receive an uninstructed energy payment for the 10 MWh of over-procurement through the wholesale market settlement. Since both the LSE and DRP received compensation associated with the 10 MWh demand curtailment, there would be a double payment. While the demand response regimes adopted by some RTOs can result in such a double payment, PDR applies an adjustment (the "Default Load Adjustment") in the uninstructed energy settlement pre-calculation for the LSE to ensure that only the DRP is compensated for the real-time demand reduction of the curtailing customers (the proxy demand resource). This design mechanism eliminates the need for an uplift charge to be allocated through the ISO wholesale market settlement.

At the retail level, only 90 MWh of load is metered, and so the retail customers of the LSE (including those retail customers whose curtailment comprised the resource which the DRP bid into the wholesale market) only pay the LSE for 90 MWh at the full retail rate. However, the LSE, which procured 100 MWh of energy in the wholesale market to serve its expected load, only receives compensation from its retail customers at the retail rate for 90 MWh. The difference between the wholesale cost of procuring 100 MWh of energy and the compensation for 90 MWh of metered load at the retail level results in a potential loss of revenue to the LSE; this is the retail "missing money" or undercollection concern.

The second part of the example above illustrates the second of the two financial settlement issues involving demand response being debated across the country – whether and how much a load-serving entity should be compensated for energy that it procured in a wholesale market but that was subsequently sold back to the ISO or RTO by a third-party demand response provider. In essence, the demand response provider never paid for the energy it sold in the first instance. The analogy for generating resources is a generator that sells energy to the ISO yet never pays for its fuel supply. Compensating the demand response provider for the energy provided for demand response without appropriate compensation to the load-serving entity obfuscates the true cost of energy, which can lead to economic inefficiencies.

The key concern here is the principle of equivalent treatment between supply and demand resources. Without setting up the rules to ensure economic equivalency, incentives can alter consumer behavior resulting in market distortions. To illustrate this point, an example originally presented by Professor William W. Hogan is worth repeating here. This example demonstrates how locating a generator on the customer side of the meter to appear as demand response can result in a different economic outcome compared to offering that same generator directly in the wholesale market.[4]

> Another way to view demand response through the lens of equivalent treatment is to consider the impact on the behavior of consumers. … One way to test this proposition would be to consider the behavior of the consumer who is installing a new generator at its location. Presumably under our simplified assumptions, the behavior should be the same with respect to placing the generator on the consumer side of the meter versus on RTO [ISO] side of the meter. If the new

[4] William H. Hogan, "Demand Response Pricing in Organized Wholesale Markets," Prepared for ISO/RTO Council, 13 May 2010, pp.5-6. The paper can be found using here: http://www.hks.harvard.edu/fs/whogan/Hogan_IRC_DR_051310.pdf

> generator is on the consumer side of the meter, then running the generator would reduce net demand and would be accounted as and would be observationally equivalent to imputed demand response.[5] However, if the consumer installs the generator on the RTO [ISO] side of the meter then the sale of energy would be treated as a normal sale, and the purchase of energy to satisfy load would be treated as a normal purchase. The net physical flows would be the same in either case. Again, for simplicity, ignore non-energy charges. Would the consumer see the same economics?
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> Suppose the LMP is $50/MWh and the consumer has a load of 10 MWh. In addition, assume the putative generator would produce 6 MWh in the same hour at a cost of $50/MWh. Suppose the consumer installs the generator on the RTO [ISO] side of the meter. Then the consumer pays $500 for its 10 MWh of load, receives $300 for its 6 MWh of generation, and incurs a cost of $300 for generating the power. In effect, the consumer is paying $500 for 10 MWh of load and its generating subsidiary is breaking even in producing and selling the output of 6 MWh.
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> In the case of the installation on the consumer side of the meter, the consumer would reduce its measured load from 10 MWh to a net of 4 MWh. The consumer would incur the cost of $300 for 6 MWh of generation, and pay $200 to the RTO [ISO] for net load of 4 MWh. In addition . . . the consumer would be treated as having provided 6 MWh of imputed demand response, and would receive $300 payment for the imputed demand response. The net position of the consumer would now be a net payment of $200 rather than a net payment of $500 for the load. In other words, the consumer is getting 6 MWh for free. Apparently the location of the meter relative to the generator matters, although it should not.

In the above example, the net cost to the consumer for placing the generator behind the meter is only $200 for the same exact service level that would cost another consumer $500, but for the putative demand response provided by the behind-the-meter generator. In the wholesale market, the consumer with the behind-the-meter generator could offer 6 MW of demand response at a price much cheaper than what the generator could independently offer 6 MWh in the wholesale market. This is because the consumer paid $500 (4 MWh retail x $50/MWh + 6 MWh generator x $50/MWh) for serving 10 MWh of load, but was rewarded an additional $300 (6MWh x $50/MWh) for the putative

[5] Imputed demand response is when consumers have an estimated consumption baseline and the difference between actual consumption and the baseline is the imputed demand response.

demand response. Without addressing these fundamental economic principles, there cannot be economic equivalency between what are purportedly "comparable" resources.

Some have suggested that the wholesale markets should compensate demand response resources at the LMP less certain components of the retail rate, ensuring demand response is the economic equivalent of generation. This concept is often referred to as compensation at "LMP minus G" (where G stands for the generation component of the retail rate). As demonstrated in the example above, economic equivalency between resource types is an important principle. However, there is no mechanism in PDR for the ISO to attempt to derive and apply a "minus G" value in its settlement process. Instead, this fundamental compensatory issue, which is significantly intertwined with retail rates, is to be addressed outside of the wholesale market by arrangements between the demand response provider or participating customer and the load-serving entity, presumably under the auspices of the CPUC in a proceeding such as this.

The concern with the ISO deriving a "minus G" value and subtracting it from the payment to demand response resources is two-fold. First, the ISO and stakeholders well understood the cost compensation concerns associated with wholesale demand response resources. ISO stakeholders concluded that cost compensation mechanisms, such as subtracting a component of a "retail rate," was an important concern that was best resolved by the local regulatory authority. Managing and coordinating retail rates at the wholesale level would be costly, resource intensive, and error prone, especially considering that retail rate designs not only vary by load-serving entity and customer type, but that retail rates often change. Second, stakeholders concluded that any "minus G" value the ISO derived would simply be a rough approximation of the actual retail revenue impact to load-serving entities. The issue of what component of a retail rate should be subtracted, and how much, is especially complex if a demand response resource is made up of an aggregate of multiple end-use customer types, *e.g.*, small and large commercial customers that take service under different retail rate schedules. Because the mix of different retail customer classes included in a wholesale demand curtailment bid may vary from hour-to-hour, the ISO could never develop a "minus G" component that truly tracks the retail revenue impact to load-serving entities. In addition, because any "minus G" value applied by the ISO will not necessarily be sanctioned by the local regulatory authority, parties to a demand response transaction may need to develop a contract for differences around the ISO's LMP minus G value, regardless of the final "minus G" approach incorporated into the ISO wholesale market settlement. For all these reasons, the conclusion of the ISO stakeholder process was to allow the retail undercollection concerns to be addressed by the CPUC, enabling the ISO to avoid delving into retail rate issues and avoiding the need for continual coordination on retail rates with the CPUC and the investor owned utilities. Thus, the ISO urges the CPUC to ensure that the fundamental economic principles of demand response are upheld in this proceeding, but refrain from considering whether the ISO should subtract a retail rate component from the LMP paid to demand response resources.

2. **The ISO encourages the Commission to support the development of a competitive third-party delivered demand response paradigm to maximize the potential for flexibility and new demand response product and service innovations that will be essential to meeting California's environmental policy goals.**

While protecting system reliability, state policies require the ISO to integrate more renewable energy into California's wholesale electricity market, ultimately reaching for a 33% renewable portfolio standard and a reduction of green house gases to 1990 levels by 2020. The challenge is renewable resources operate with inherent variability, which complicates system operations and unit commitment. For instance, the ISO analysis of the generation fleet by 2020 makes clear the trend toward fewer dispatchable resources and less operational flexibility as the renewable resource integration requirements increase.[6] Some of the assumptions supporting this analysis are that:

- A significant number of flexible gas-fired units retire by 2020 due to once-thru-cooling regulations and other reasons that total 15,701 MW with only 9,404 MW of planned flexible resource additions; and

- Net qualifying capacity credit given to renewables in fulfilling the planning reserve margin substantially increases by 2020 to 11,654 MW in the 33% renewable portfolio reference case, meaning more variable energy resources count toward satisfying the planning reserve margin.

Consistent with these results, more flexibility, not less, is what is needed to integrate greater amounts of renewable resources. Greater resource variability requires additional operational capabilities and flexibility, including additional ramping support, ancillary services and increased ability to manage over-generation conditions. With increasing variability and a corresponding decrease in supply-side predictability, the demand-side must compensate. System reliability depends on supply and demand balancing *exactly* second-by-second; failure to do so results in degraded system reliability, system instability, and potentially the unacceptable violation of applicable reliability standards.

With this background, and to satisfy the state's environmental policy goals, the Commission must eliminate barriers, establish clear polices and set-up a delivery paradigm that enables demand response to become a more elastic and responsive resource that can act as a "shock absorber" to attenuate supply-side variability through consumer load curtailment and consumption actions. In other words, demand response must add back some of the flexibility lost from the supply-side.

[6] Updated CAISO Presentation: Continued Assessment of Statistical Model (Step 1) and Selected Production Simulation (Step 2) Results, Slide #74 found at: http://www.cpuc.ca.gov/NR/rdonlyres/72E5B972-1842-4DA3-B09A-E009AB4FB878/0/UpdatedISO33PCTRPSStudyPresentationCPUCWorkshopfor113010.pdf

The Commission should make compensation decisions that are grounded in economic principles and that support the development of a competitive third-party demand response delivery paradigm in this important phase of the demand response proceeding. The ISO believes the existing regulatory paradigm of establishing retail demand response programs and budgets on multi-year cycles may be too rigid and not well suited to respond to the future resource needs described; the process limits flexibility and the ability to quickly respond to new circumstances, technologies and to provide tailored demand response product and service offerings to individual customers, where appropriate. The ISO believes a more competitive retail market for the development and delivery of demand response products and services is the way to spur the innovation and investment needed in this important area. Key decisions made in this phase of the proceeding, including the compensation concerns and the ease to which demand response transactions can be made, will fundamentally guide whether such a delivery paradigm will develop and thrive.

3. Any financial settlement mechanism developed to resolve retail compensatory issues between the parties to a demand response transaction should be done in an efficient manner to reduce the time and cost to deploy demand response services.

The transactional cost associated with enrolling, operating, and maintaining customers in demand response programs must be low given the resource size (often kilowatts) and potential for customer churn and migration. In previous ISO filings in rulemaking R.07-01-041, the ISO stated that a pro forma contract between the demand response provider and load-serving entity may be good approach.[7] The "pro forma" concept ensures that rates, terms and conditions are standardized, easing some of the "hassle factor" of the contracting process. However, another perhaps more efficient

[7] *Comments of the California Independent System Operator on Workshop Report for December 16-18 Workshops Re: Direct Participation of Retail Demand Response in ISO Electricity Markets*, January 22, 2010, at pp. 5-6.

approach may be a line item customer charge that is assessed directly by the load-serving entity to the participating customer, given it is the customer's choice to enroll in a demand response program or service offering in the first instance. This would perhaps be a more efficient approach and uphold the cost-causation principle since, under either a pro forma contract or a customer line item charge scenario, similar information exchanges and measurement and verification processes must be put into place for the load-serving entity to assess the proper charge to either the demand response provider or the customer. Under either a standard contract or line item billing approach, the back office systems of the load-serving entity likely will need reconfiguration to efficiently manage demand response service transactions along with the financial accounting. The ISO understands that significant changes to these systems can be costly, but views this investment as important to the overall flexibility and ultimate success of ushering in a new energy supply paradigm in California, where demand response is expected to play an important role in integrating renewable, variable energy resources.

SPECIFIC RESPONSES

The following specific responses follow the numbering included in the Administrative Law Judge's ruling and consider only the financial settlement issues calendared for December 8, 2010. The ISO intends to address these and other issues in further responses and during the upcoming workshop, as appropriate.

6. Will the design of the CAISO's PDR product cause LSEs to undercollect revenue from their end-use customers when part of their customers' expected energy use is curtailed by dispatch of a PDR?

The answer to this specific question is that it depends upon the cost of any undercollection relative to the market benefits gained from exercising demand response. But more fundamentally, the question becomes whether the total wholesale-retail compensation structure for demand response provide a societal benefit gained through an economic efficient outcome. Again, an example serves to illustrate the point:

Assume

- Customer A & B both consume 10 MWh.
- Customer A acts as its own LSE/DRP and is responsible for procuring its own energy.
- Customer B does not procure its own energy (performed by LSE) but acts as a DRP and sells demand response.
- All energy is valued at $50/MWh.

Customer A

Customer A spends $500 in the day-ahead to procure 10 MWh (10 MWh x $50/MWh). Customer A sells back all 10 MWh in the real-time market as demand response at $50/MWh and earns $500 (10 MWh x $50/MWh). Customer A's net position is $0.

Customer B

LSE procures and schedules 10 MWh on behalf of Customer B. Customer B sells all 10 MWh in the real-time market as demand response at $50/MWh and earns $500 (10 MWh x $50/MWh). Customer B does not pay its LSE for 10 MWh since Customer B did not consume the 10 MWh. Customer B's net position is $500.

Conclusion:

One MW from Customer A or Customer B provides the same benefits to the system; however, Customer A can only sell demand response for ≥$50/MWh, otherwise it loses money, whereas Customer B can sell demand response for < $50/MWh and still make money. The wholesale market may appear to benefit from Customer B's lower energy bids, but the lower bid is only enabled because of the undercollection. If this undercollection is not recovered by the LSE from Customer B, an inefficient wholesale market outcome results. Thus, as a first priority the Commission should establish the long-term policies and principles for demand response cost compensation that will lead to economic efficiency and prevent the potential for such market distortions.

7. ***Can the LSE avoid the undercollection described above by either: (a) accurately forecasting its load, or (b) receiving sufficient communications from the DRP?***

Load serving entities are unable to avoid under-collection either through more accurate forecasting or improved communication. The ISO proxy demand resource product is structured so that load serving entities do not have to be particularly concerned about the actions of a demand response provider at the wholesale level. The intent of the proxy demand resource design was to enable load serving entities to go about their business of forecasting and scheduling load, remaining effectively financially unharmed in the wholesale market by the actions of demand response providers through the application of the "default load adjustment" mechanism described above under the ISO's general comments. Thus, any actions the load serving entity takes to alter its forward procurement in anticipation of load curtailments by a demand response provider merely translates into a form of arbitrage between a load serving entity's forward procurement cost and the ISO day-ahead or real-time market clearing price. The following three scenarios illustrate this point:

Scenario 1: LSE Ignores Demand Response Actions

A LSE forecasts and schedules its load without consideration of demand response at 10 MWh. Assume 2 MWh of demand response occurs, such that the aggregated meter data equates to 8 MWh. The ISO will resolve the "double payment" at the wholesale level by applying the default load adjustment. The

ISO will add the 2 MWh demand response back to the LSE's actual metered consumption to come up with an adjusted load quantity. In this scenario the adjusted load equates to 10 MWh (8 MWh meter data + 2 MWh default load adjustment). The 10 MWh will be compared to the LSE's day-ahead schedule of 10 MWh. In this scenario, the LSE had no load deviations (10 MWh adjusted load – 10 MWh schedule) and, therefore, no deviation charges were assessed. Assuming the procurement cost and retail rate are the same at $20/MWh, the LSE paid $200 (10 MWh x $20/MWh) for energy procured and was paid $160 (8 MWh x $20/MWh) by its customers. Thus, the LSE is missing $40 ($200 - $160); the equivalent to 2 MWh at the retail rate in this scenario.

Scenario 2: LSE Incorporates Demand Response in its Forward Schedule

A LSE forecasts its load without demand response at 10 MWh. However, the LSE anticipates 2 MWh of demand response and, therefore, schedules only 8 MWh in the day-ahead market. Assume 2 MWh of demand response actually occurs, such that the aggregated meter data equates to 8 MWh. The ISO will resolve the "double payment" at the wholesale level by applying the default load adjustment. The ISO will add the 2 MWh demand response back to the LSE's actual metered consumption to come up with an adjusted load quantity. In this scenario the adjusted load equates to 10 MWh (8 MWh meter data + 2 MWh default load adjustment). The 10 MWh will be compared to the LSE's day-ahead schedule of 8 MWh. In this scenario, it appears the LSE "under-procured or over-consumed" by 2 MWh, so the ISO will charge the LSE for the 2 MWh at the applicable real-time locational marginal price. Assuming the procurement cost and retail rate are the same, the undercollection equates to the cost of the 2 MWh multiplied by the applicable real-time locational marginal price.

Scenario 3: LSE Attempts to Off-set Financial Impact of Demand Response

A LSE forecasts its load without demand response at 10 MWh. However, the LSE anticipates 2 MWh of demand response and, therefore, schedules 12 MWh in the day-ahead market to try an "offset" demand response costs in the real-time market as described in Scenario 1. Assume 2 MWh of demand response actually occurs, such that the aggregated meter data equates to 8 MWh. The ISO will resolve the "double payment" at the wholesale level by applying the default load adjustment. The ISO will add the 2 MWh demand response back to the LSE's actual metered consumption to come up with an adjusted load quantity. In this scenario the adjusted load equates to 10 MWh (8 MWh meter data + 2 MWh default load adjustment). The 10 MWh will be compared to the LSE's day-ahead schedule of 12 MWh. It appears the LSE "over-procured or under-consumed" by 2 MWh, so the ISO will pay the LSE for the 2 MWh at the applicable real-time locational marginal price. On the retail side, customers will pay the LSE for 8 MWh through the retail rate, and the ISO will pay the LSE for 2 MWh at the real-time price. So the total MWh amount collected is 10 MWh (8 MWh through retail rates + 2 MWh from the real-time market).

In this third scenario, the LSE purchased and scheduled 12 MWh but was paid for 10 MWh by customers and the ISO. The LSE undercollects on 2 MWh (12 MWh – 10 MWh). Assume the real-time energy price was higher than the LSE's procurement cost. If the cost of the 12 MWh was $240 (12 MWh x $20/MWh forward procurement cost) and the payment received was $320 (10 MWh x $20/MWh retail rates + 2 MWh x $60/MWh real-time price), then the "over-procurement" in the ISO market was beneficial to the LSE by $80 ($320-$240). Although, without demand response, the LSE would have benefited by $120 (2 MWh X $60/MWh real-time price) assuming 10 MWh was consumed and paid for by customers rather than only 8 MWh. Is the $40 ($120-$80) unrealized benefit considered an undercollection? Arguably, yes, given the principle of risk and reward, i.e. the LSE was under rewarded for the risk taken. Additionally, this scenario could have produced a different result had the real-time locational marginal price ended up lower than the LSE's procurement cost, resulting in a net loss to the LSE, re-emphasizing the principle of risk versus reward.

The point of this last scenario is to illustrate the basic market principle of arbitrage. This same scenario could be performed by the LSE, with similar results, with or without demand response. Whether there is, in principle, "missing money" is inarguable as long as the DRP and LSE are separate entities, but whether or not the LSE or ratepayers are financially harmed is a more complex issue that is intrinsically linked to a LSE's role in the market. More specifically, how positions taken by a LSE in the market, and the costs and revenues associated with specific transactions, impact the interaction between the revenue stream and regulatory structure. For instance, regardless of demand response, all wholesale-retail transactions have the potential for the over and under-collection of monies since wholesale prices are dynamic and retail rates are relatively fixed. Depending on the market positions a LSE takes, over or under-collections occur. Ultimately these over and under collections may be subject to balancing account treatment tied to a revenue requirement target that is to the benefit or detriment of ratepayers.

For the reasons outlined above, it is the view of the ISO that the LSE is unable to avoid undercollection by accurately forecasting its load. However, the financial impacts of the undercollection are different under different scenarios given that the undercollection may represent megawatts valued at the retail rate (Scenario 1), or at the ISO real-time locational marginal price (Scenario 2), or under arbitrage (Scenario 3). In addition, the financial impacts may be different based on how costs and benefits are dealt with under prevailing regulatory mechanisms.

8. ***In the case where the LSE is also the DRP, will the possible undercollection by the LSE be at least partially offset by the collection from the CAISO of the market price for the curtailed amount of energy by the LSE's affiliated DRP?***

Revenue collected by a load serving entity's affiliated demand response provider could be used to offset any under-collection, but it is unclear if it would be sufficient to cover any under-collection. However, the same undercollection concern does not exist when the LSE and DRP are the same entity. In this circumstance, the LSE pays for the forward procurement of energy to serve its load, and may, or may not, take into account demand response depending on the LSE's forward procurement position relative to its expected market outcomes and dispatch of proxy demand resources in real-time. Thus, the position the LSE takes in its forward procurement activity relative to actual load consumption in real-time equates to a form of arbitrage, to the benefit or detriment of the load serving entity. In other words, the LSE procures energy in the forward timeframe and then sells back what it does not consume. The entire transaction remains on one balance sheet, i.e. the LSE's. Thus, in the circumstance where the LSE and DRP are the same entity, the undercollection concern should not be a factor and the burden shifts to the LSE/DRP to properly account for monies internal to its organization.

9. ***Traditionally, when an IOU calls one of its DR programs, participating customers reduce their energy purchases during some peak demand hours, but the Demand Response is not dispatched into CAISO markets. Does this reduction of energy purchases cause the IOU to experience an undercollection analogous to that discussed in items 6 and 7 above? If so, is the undercollection when an IOU calls one of its own programs comparable in size (on a $/MWh basis) to that brought about by dispatch of a PDR?***

When demand response is called outside the ISO market, undercollection can still occur, but the potential undercollection is of a different nature. Consider the following two simplified examples to illustrate the settlement of traditional demand response:

Scenario 1: The LSE and DRP are the Same Entity

Assume all energy is valued at $50/MWh. A bundled customer's load is served by the investor-owned utility. The customer is enrolled in the utility's demand response program and can provide 2 MWh of demand response. The customer responds with 2 MWh to a utility called event. The customer is paid $100 ($50/MWh x 2 MWh) by the utility for the demand response. The utility procured and scheduled 10 MWh through the ISO paying $500 ($50/MWh x 10 MWh). The customer meter data shows 8 MWh of energy consumption due to the 2 MWh of demand response provided. Therefore, the ISO would pay the utility $100 for 2 MWh [$50/MWh x (10 MWh scheduled – 8 MWh consumed)] of uninstructed energy. As the DRP, the utility had a $100 dollar expenditure. As the LSE, the utility's net position is $0 ($400 retail rate + $100 ISO payment - $500 procurement).

Scenario 2: The LSE and DRP are Separate Entities

Assume all energy is valued at $50/MWh. A direct access customer served by an electric service provider (ESP) has a load of 10 MWh. The customer enrolled in a utility demand response program can provide 2 MWh of demand response. The customer responds with 2 MWh to a utility called event. Assume the customer is paid $100 ($50/MWh x 2 MWh) by the utility acting as the DRP. The ESP procured and scheduled 10 MWh through the ISO paying $500 ($50/MWh x 10 MWh). The customer meter data shows 8 MWh of energy consumption due to the 2 MWh of demand response provided. Therefore, the ISO would pay the ESP $100 for 2 MWh [$50/MWh x (10 MWh scheduled – 8 MWh consumed)] of uninstructed energy, effectively addressing the undercollection concern in this scenario. The ESP's net position is $0 ($500 customer plus ISO payment - $500 procurement). As the DRP, the utility had a $100 expenditure for the demand response.

In both scenarios, the LSE- both the utility (scenario 1) and ESP (scenario 2) are left whole, i.e. there is technically no undercollection due to monies received through the wholesale uninstructed energy settlement. In reality, however, the ESP and utility could be either harmed by or benefited from the demand response actions of the customer based on what the ESP's or utility's expected retail rate recovery would have been but for demand response and their respective forward procurement costs relative to the uninstructed energy payment they received from the ISO. The challenge for the ESP in scenario 2 is that it cannot control the uninstructed energy price risk if it is unaware demand response actions are taking place, which may be different than for the utility depending upon the utility's internal procurement decisions relative to its demand response activities.

The ISO and stakeholders specifically addressed this risk in the proxy demand resource design. As previously described, the ISO implemented the default load adjustment, which expressly removes the uninstructed energy price risk from the LSE and leaves the missing money concern to be appropriately addressed at the retail level. The missing money is a component of the retail rate since it is the retail rate the LSE would have been paid in the first instance for these 2 MWh, but for demand response. Thus, the ISO does not believe the characterization of undercollection in the context of this question relates exactly to the same undercollection concerns discussed elsewhere in these comments, but instead show that other unique financial challenges exist for traditional demand response programs that are exercised outside the ISO market.

13. How do the benefits provided by direct bidding of PDR reach the LSE and its ratepayers? How do they offset the undercollection by the LSE?

Other parties to this proceeding are in a better position to assess the distribution of benefits; however, like traditional demand response programs, direct bid demand resources such as PDR must be recognized as resource adequacy qualifying resources and be incorporated formally into the IOUs long-term procurement plans so that future load growth and generation needs can be offset by dispatchable demand resources, where appropriate. The more formal integration of dispatchable demand resources into the procurement process, as generation comparable resources, is in accordance with the loading order specified in California's Energy Action Plan II and represents a tangible, albeit longer-term benefit to ratepayers. Short term ratepayer benefits are likely more obtuse based on the nature of IOU procurement portfolios and the IOUs exposure to the wholesale market on any given day and hour.

15. Given that the CAISO has chosen not to spread the costs of the undercollection brought about by operation of PDR by using market uplift charges, are there ways that the CPUC could bring about a similar outcome within the existing PDR structure adopted by the CAISO? In other words, are there other feasible methods by which the LSE/DRP could be made whole? Describe any such methods.

It would be more equitable for the CPUC to calculate and spread an uplift charge to all retail electricity customers, versus the ISO to all wholesale market participants. However, the Commission could consider a wait-and-see approach on the impacts of direct participation demand response by allowing all customers to participate without an explicit mechanism to address the undercollection. In so doing, the CPUC will, by default, employ a market uplift approach assuming undercollections are subject to balancing account treatment. This approach is not the theoretically pure economic demand response model and has risks, but it may be the most pragmatic short-term approach given the level of demand response anticipated over the next couple of years and, therefore, it likely would have a minimal overall impact on the market and ratepayers. For example, not considering any benefits from demand response, a conservative undercollection calculation associated with 500 MW of demand response operating for 50 hours per year valued at $150/MWh would equate to $3.75 million per year. This assumes the "generation" portion of the retail rate would be $0.15/KWh. This is likely a high cost figure relative to any actual undercollection that would occur over the next two years, especially considering no benefits are considered. Given the potential minor impact, the Commission could give the direct participation approach an opportunity to develop so that, with some experience, a more careful and informed assessment can be made as to the costs and benefits of different methods to address any undercollection concerns and ensure an efficient market outcome. If the Commission should elect to take a wait-and-see approach, the ISO would suggest it be time bound and have specific procedures in place to assure it is revisited in the future.

The risk associated with taking this approach is that customers and demand response providers grow accustomed to the more lucrative settlement structure, which may not be the best or most principled long-term approach. For instance, to introduce a "minus G" component into the settlement of demand response at a later date can cause significant negative reaction in the market as monies are being taken away, potentially resulting in certain transactions and contracts being uneconomic.

16. If the CPUC chose to spread any such undercollections to IOU ratepayers generally rather than getting a payment directly from the DRPs, would the outcome be more equitable than if the CAISO had chosen the approach used by eastern ISOs described above? Would this approach run counter to the CPUC's usual preferred approach of having rates and incentive payments reasonably reflect cost causation?

If the CPUC implements a method to address the undercollection, it could certainly be more equitable than any method the ISO could employ. For example, if a customer line item charge ultimately becomes the preferred option to assess undercollection, then any assessment could more easily represent the "generation" portion of a particular customer's retail rate. This is another reason why a line item charge on the customer bill may be the preferred method, although further discussion of the technicalities must be addressed. Conversely, if the ISO is required by FERC to apply the "generation" portion of retail rates to demand response resource made up of aggregated customers, it has to be done in a rough justice manner. It would be extremely difficult, and not desirable, for an ISO to track retail customers necessary to calculate and subtract a weighted average retail rate from a demand response resource made up diverse customers taking retail service under different rate structures and options. A CPUC initiated approach to address undercollection stands a far better chance of being more equitable and is under the appropriate jurisdiction relative to any approach the ISO could reasonably apply.

17. Does one approach or the other (spreading revenue undercollections among all ratepayers vs. recovering them only from DRPs and DR program participants) better incent increased DR participation? Does one approach or the other create undue advantage between IOUs, DRPs and their respective DR mechanisms?

As the ISO has demonstrated in the previous examples, the undercollection concern needs to be addressed longer-term to ensure economic efficiency and equivalency are achieved between supply and demand resources. Given market and revenue impacts are likely to be limited over the next couple of years, the short-term goal for the Commission should at a minimum be to establish the basic policies and principles that will guide the development of demand as a generation comparable resource that can directly participate in the ISO market. Policies and principles where dispatchable demand resources can:

- Enhance market efficiency;
- More effectively utilize grid infrastructure to enhance reliability;
- Reduce energy costs for all consumers;
- Help California achieve its environmental policy goals; and
- Support the integration of renewable, variable energy resources.

CONCLUSION

The ISO appreciates the opportunity to provide these comments on this important phase of this proceeding and looks forward to discussing the questions and its positions further at the upcoming workshop.

Respectfully submitted,
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Dated: December 8, 2010

CERTIFICATE OF SERVICE

I hereby certify that on December 8, 2010 I served, on the Service List for Proceeding R.07-01-041, by electronic mail, a copy of the foregoing Initial Comments of the California Independent System Operator Regarding Remaining Direct Participation Issues (Phase IV, Part 2).

Executed on December 8, 2010 at
Folsom, California

Anna Pascuzzo

Anna Pascuzzo,
An employee of the California
Independent System Operator