California Independent System
Operator Corporation

September 26, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20246

**Re: California Independent System Operator Corporation
Docket Nos. ER11-4100-___ and ER11-3616-___**

**Response to the August 27, 2012 Letter Regarding
ISO Compliance Filing**

Dear Secretary Bose:

On March 14, 2012,[1] the California Independent System Operator Corporation ("ISO") submitted a compliance filing in this proceeding. On August 27, 2012, Commission Staff issued a letter requesting additional information in order to process the March 14 filing.[2] This filing responds to Commission Staff's August 27 request. The ISO respectfully requests that the Commission accept the March 14 filing with the support of the additional information included in this response, as compliant with Order No. 745.[3]

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[1] The ISO filed errata to the March 14 filing on March 15, 2012 to include tariff revisions referenced in the transmittal letter but inadvertently not included in the clean ISO tariff sheets and black-lines for the March 14 filing. In this ISO response, the filing, as corrected, is referred to as the March 14 filing.

[2] The ISO is referred to as the CAISO in the August 27 letter.

[3] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs ¶ 31,322 (Order No. 745), *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *order on reh'g*, Order No. 745-B, 138 FERC ¶ 61,148 (2012).

I. Responses to Requests for Additional Information

The ISO responds to each of the requests for additional information as follows:

1. Request No. (1):

In the March 14 Filing, CAISO states that the elimination of the default load adjustment for demand response resources that are dispatched when the locational marginal price (LMP) is at or above the threshold price satisfies the requirements of Order No. 745 and allocates the cost of demand response associated with the billing unit effect on a "market-wide basis." As described in Order No. 745, the cost of demand response associated with the billing unit effect is the difference between the amount owed by the Regional Transmission Operator and Independent System Operator (RTO/ISO) to resources, including demand response providers, and the revenue derived from load that occurs as a result of the dispatch of demand response resources. Accordingly, please describe which tariff provisions control the allocation of this cost and how they will allocate this cost market-wide.[4]

Response to Request No. (1):

To facilitate the Commission's review and inform the ISO's response to multiple information requests in the August 27 letter, the ISO describes the ISO settlement and cost allocation rules applicable to demand response resources in the ISO market. As part of this description, the ISO includes a description of the market-wide allocation of the costs of demand response associated with the "billing unit effect."

The ISO settles and allocates the cost of demand response pursuant to three sets of tariff provisions: (1) the costs paid to demand response providers for procured demand response that clears the day-ahead market, as set forth in tariff section 11.2.1.2; (2) the costs paid to demand response providers for demand response dispatched in the real-time market, as set forth in tariff section 11.5.1; and (3) the costs of the additional uninstructed imbalance energy payment to the load-serving entity that scheduled the day-ahead energy that was not consumed due to the demand response, as set forth in tariff section 11.5.2.

(i) *Settlement of day-ahead procured demand response costs*

The large majority of all energy supply costs in the ISO, including demand response costs, are incurred in the day-ahead and are reflected in day-ahead locational marginal prices (LMPs) paid by load as described below.

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[4] August 27 letter at 1-2 (citations omitted).

Pursuant to the net benefits test mandated by Order No. 745 (and implemented in section 30.6.3 of the ISO tariff), the ISO pays demand response providers the full LMP for actual energy provided by demand response resources in the integrated forward market (*i.e.*, the day-ahead).[5] Demand response resources, like generating units, are scheduled at their nodal locations and are paid the nodal LMP at their locations.

However, most of the demand in the ISO's balancing authority area is scheduled at default load aggregation points ("Default LAPs"), one for each of the three large investor-owned utilities. For each Default LAP, the ISO calculates an average zonal LMP based on the weighted average of the nodal LMPs within that Default LAP and the associated load is then settled at the LMP for that Default LAP.[6]

As explained in the attached declaration of Khaled Abdul-Rahman, Director, Power Systems Technology Development for the ISO, the LMP for energy at any given pricing node is comprised of three cost components: the energy component, the loss component, and the congestion component. The energy cost component or energy market clearing price of each LMP is always the same throughout the ISO. The differences in LMPs reflect the costs of losses and congestion. Resources within a Default LAP, including demand response resources, contribute to lowering the energy prices system-wide and can contribute to reducing the congestion and losses costs reflected in the LMP for the Default LAP.

(ii) *Settlement of demand response costs incurred in real-time and allocation of real-time imbalance energy offset*

The ISO pays demand response providers for demand response procured in the real-time market the instructed imbalance energy settlement price pursuant to section 11.5.1 (instructed imbalance energy settlements) of the ISO tariff. The instructed imbalance energy settlement rules apply to all instructed imbalance energy procured in real-time. First, the cost of instructed imbalance energy supplied by demand response resources in real-time is settled through charges to those market participants, including load-serving entities, that require the service, *i.e.*, those that deviate from their day-ahead schedules and therefore

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5 Payments for energy supplied in the integrated forward market are governed by ISO tariff section 11.2.1.1. A demand response provider is defined as an entity that is responsible for delivering demand response services from a proxy demand resource providing demand response services, which has contractually agreed to comply with all applicable provisions of the tariff. (Appendix A to ISO Tariff.) By comparison, a demand response resource is defined as a resource providing demand response services. (Appendix A to ISO Tariff.)

6 Charges for demand scheduled day-ahead at an individual LAP are governed by section 11.2.1.2 of the ISO tariff.

require backing by the ISO for additional energy supply. To the extent that the sum of the settlement amounts for instructed imbalance energy does not equal zero (which can occur as a result of inadvertent flow, forecast errors, or any time the amount the ISO is obligated to pay exceeds calculated energy revenues, or due to other system conditions), the ISO will include the remaining costs of the instructed imbalance energy in a real-time imbalance energy offset charge assessed to all load-serving entities based on a *pro rata* share of their measured demand for the relevant settlement interval.[7]

Due to the elimination of the default load adjustment as directed by the Commission,[8] the ISO also will make an uninstructed imbalance energy payment to the load-serving entity that represents the load reduced by a demand response provider for any energy procured in the day-ahead market but not consumed as a result of demand response. This uninstructed imbalance energy payment will be allocated pursuant to sections 11.5.2 (uninstructed imbalance energy). Again, the cost of uninstructed imbalance energy is settled first through charges to those market participants, including load-serving entities, that require the service, *i.e.*, those that deviate from their day-ahead schedules and therefore require backing by the ISO for additional energy supply. Any incremental uninstructed imbalance energy costs not settled to deviations is allocated to measured demand under the ISO's real-time imbalance energy offset charge. The real-time imbalance energy offset charge includes a number of components, including the settlement of all incremental uninstructed imbalance energy. The allocation of the real-time imbalance energy offset charge is a market-wide allocation to measured demand.

It is the cost associated with this uninstructed imbalance energy payment that is the cost associated with the "billing unit effect" as described in Order No. 745. The ISO pays the demand response provider and the load-serving entity for the same curtailment. The allocation of the costs paid to the load-serving entity accounts for the "reduction in load" associated with the billing unit effect and is the method needed "to ensure that RTOs and ISOs recover the costs of obtaining demand response."[9]

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[7] ISO tariff, Section 11.5. Measured demand is defined in Appendix A to the ISO tariff as the metered ISO demand plus real-time interchange export schedules.

[8] The proposed ISO tariff revisions contained in the March 14 filing include revisions to section 11.5.2.4 of the tariff to eliminate the default load adjustment for resources dispatched subject to Order No. 745.

[9] *See* Order No. 745 at P 99.

2. Request No. (2):

In the March 14 Filing, CAISO states that by eliminating the application of the default load adjustment to demand response resources paid an LMP at or above the threshold price, and by allocating the costs of demand response market-wide, it satisfies the cost allocation requirements of Order No. 745. CAISO also states in its April 19 Answer that "costs of demand response resources are allocated to the load that benefits from the cost-lowering effect of demand response resources, through both the system-wide energy price as well as any regional benefits from reduced losses or less congestion that would affect the Default [load aggregation point] price." However, CAISO's filing does not include a demonstration that its cost allocation methodology allocates costs to those that benefit from a decreased LMP, as required by Order No. 745, which is necessary for the Commission to evaluate the proposal. Accordingly, please include such a demonstration in response to this request for additional information.[10]

Response to Request No. (2):

The ISO's general cost allocation provisions for demand response resources are discussed in the response to Request No. (1), above. The following simplified example, which is summarized in Table 1 below, illustrates the application of these cost allocation provisions and demonstrates that these provisions allocate costs to those that benefit from a decreased LMP.

Consider demand response provider A representing demand in the service territory of load-serving entity B. A separate load-serving entity C serves demand in another Default LAP. If demand response provider A bids into the day-ahead market and is cleared to provide 2 MW of demand response in the day-ahead market because the bid is economic and satisfies the net benefits test, demand response provider A will be paid for the 2 MW at the applicable day-ahead nodal LMP. The costs of the energy payment to demand response provider A will be reflected in the LMP for the Default LAP as well as the energy component in the LMPs system-wide. Thus, the nodal Default LAP settlement to load-serving entity B will reflect the impact of the 2 MW payment to demand response provider A.

Load-serving entity B will schedule 100 MW of demand in the day-ahead market. The scheduled 100 MW of demand reflects the 2 MW of demand associated with the demand response resource represented by demand response provider A. Separately, load-serving entity C will schedule 50 MW in the day-ahead market.

10 August 27 letter at 2 (citations omitted).

Default LAP LMPs paid by demand within an individual Default LAP will reflect the benefits of demand response in lowering the Default LAP LMP. Default LAP prices paid in all Default LAPs, such as the prices paid by load-serving entities B and C, will reflect the benefits of demand response in lowering the energy component of the LMP because the energy component is the same in all LMPs for the same interval. Costs of day-ahead procured demand response resources are allocated to the demand that benefits from the cost-lowering effect of demand response resources, through both the system-wide energy price as well as any regional benefits from reduced losses and/or congestion that affect the Default LAP price.

Continuing the same example, in real-time, demand response provider A bids additional demand reductions and is dispatched to provide a further 1 MW of demand response in real-time because the bid is economic and satisfies the net benefits test. Demand response provider A will be paid for the 1 MW of instructed imbalance energy at the applicable real-time nodal LMP.

Load-serving entity C, which had scheduled 50 MW in the day-ahead time frame, also has 3 MW of real-time deviations from its forward schedule and thus has a metered demand of 53 MW. Because load-serving entity C deviated from its forward schedule and required additional supply in the real-time market, load-serving entity C will pay the cost of the instructed imbalance energy. The 3 MW imbalance energy payment made by load-serving entity C will generate revenues to pay for instructed and uninstructed real-time supply that would include paying demand response provider A (even though the demand is located in a different Default LAP). In the real-time, the primary beneficiaries of decreased LMP are load-serving entities and participating resources that deviated from their schedules by consuming more energy (or delivering less energy) than scheduled in the day-ahead and therefore required backing by the ISO in the form of additional supply from imbalance energy. These market participants are allocated the instructed imbalance energy costs of real-time demand response.

Load-serving entity B, which had scheduled 100 MW in the day-ahead market, had metered demand of 97 MW, *i.e.*, the 100 MW scheduled by load-serving entity B in the day-ahead market minus the 2 MW demand reduction provided by demand response provider A in the day-ahead market and minus the 1 MW of demand response provided by demand response provider A in the real-time market. In this example, the entire deviation of load-serving entity B is the result of the demand response provided by demand response provider A (the 2 MW clearing the day-ahead market plus the additional 1 MW dispatched in the real-time market). The elimination of the default load adjustment results in load-serving entity B being paid for the 3 MW difference between its day-ahead schedule of 100 MW and its metered demand of 97 MW as uninstructed imbalance energy.

Load-serving entity C has a 3 MW deviation and is charged for both real-time instructed imbalance energy and uninstructed imbalance energy. In this example, only load-serving entity C is generating revenues to compensate incremental supply resources procured in the real-time market. Yet the ISO is obligated to pay load-serving entity B for the 3 MW of uninstructed imbalance energy associated with the 2 MW of day-ahead demand response and 1 MW of real-time demand response. The ISO must also pay demand response provider A for the 1 MW of instructed imbalance energy procured in the real-time. In other words, the ISO must pay for 4 MW of real-time imbalance energy (both instructed and uninstructed) but is only charging for 3 MW of real-time imbalance energy associated with the deviation of load serving entity C, creating the need for an uplift to allocate the costs of the additional 1 MW of real-time imbalance energy. This uplift cost is attributable to the need of the ISO to pay for more MW of imbalance energy than can be directly assessed to the market, *i.e.*, the billing unit effect.

The remaining costs of the real-time imbalance energy payments, which in this example include the cost associated with the billing unit effect, are allocated through the real-time imbalance energy offset charge and allocated to all measured demand, which includes the measured demand of load-serving entities B and C. Because the entire ISO market receives indirect benefits of decreased LMP in real-time, the costs of real-time uninstructed imbalance energy is allocated to the entire market.[11] These cost allocation principles are the same principles that apply to the allocation of costs of other supply resources.

This example illustrates how the cost of demand response is allocated to the ISO load that benefits from the cost-lowering effect (*i.e.*, decreased LMP) of demand response resources in both the day-ahead and real-time.

[11] It is appropriate and consistent with Order No. 745 for the ISO to allocate real-time energy payments to measured demand, *i.e.*, the entire market. As the Commission explained in Order No. 745, demand response bids that clear at or above the price threshold of the net benefits test are deemed to be cost-effective, and cost-effective demand response bids are deemed to have lowered the overall cost of energy more than the LMP payment made for the energy supplied by demand response resources. Order No. 745 at PP 47-53. By the same reasoning, demand response bids that clear at or above the price threshold of the net benefits test (*i.e.*, cost-effective bids) are also deemed to have lowered the overall cost of energy. As a result, the entire market benefits from the reduction in the overall cost of energy, and allocation of the uninstructed imbalance energy payments based on measured demand is appropriate and consistent with Order No. 745.

Table 1

Market Activity	Demand Response Provider A	Load-Serving Entity B	Load-Serving Entity C
Day-ahead			
– Cleared day-ahead bid that satisfies the net benefits test	2 MW payment to A at nodal LMP	Default LAP price in B incorporates the LMP payment to A	Energy component of Default LAP price in C incorporates the LMP payment to A
– Scheduling by load-serving entities	N/A	100 MW (reflects the 2 MW of demand associated with demand response provider A)	50 MW
Real-time			
– Cleared real-time bid that satisfies the net benefits test	1 MW payment to A at nodal LMP	N/A	N/A
– Metered demand	N/A	97 MW	53 MW
– Payment due to elimination of the default load adjustment (billing unit effect)	N/A	Payment to B for 3 MW of uninstructed imbalance energy	Charge to C for 3 MW of uninstructed imbalance energy
– Allocation of the costs of uninstructed imbalance energy pursuant to the real-time imbalance energy offset charge	N/A	Allocated a portion of the costs associated with revenue deficit based on B’s measured demand	Allocated a portion of the costs associated with revenue deficit based on C’s measured demand

3. Request No. (3):

In the March 14 Filing and April 19 Answer, CAISO cites to a Commission order accepting market-wide cost allocation for demand response in ISO New England as compliant with Order No. 745. ISO New England stated in its filing that the specific conditions of its system are such that market-wide cost allocation allocates costs to those that benefit from demand response. Specifically, ISO New England's filing argued that demand response in one location tends to lower LMPs in multiple locations because transmission constraints on its system are not severe at this time. ISO New England also argued that demand response resources are located throughout the New England region, making simultaneous demand reductions in multiple zones relatively common, so that LMPs from dispatched demand response [are] likely to affect LMPs across the region even where binding transmission constraints do arise.

By citing to the ISO New England order, it is unclear if CAISO claims that conditions on its system are similar to those on the ISO New England system. Please clarify whether the justification provided by ISO New England also supports its cost allocation proposal or whether CAISO relies on other justifications. If so, please include such justifications in your response.[12]

Response to Request No. (3):

In citing the ISO New England order, the ISO was indeed stating that conditions on its system are similar to those on the ISO New England system in justifying the ISO's demand response cost allocation provisions. In that order, the Commission explained that ISO New England had provided the following four reasons why its cost allocation methodology is consistent with Order No. 745:

> (1) transmission constraints generally are not severe at this time, and therefore demand reductions in one location tend to lower LMPs in multiple locations; (2) demand response resources are located throughout the New England region, making simultaneous demand reductions in multiple zones relatively common, so that LMPs from dispatched demand response resources are likely to affect LMPs across the region even where binding transmission constraints do arise; (3) it would be extremely difficult to identify and allocate specific costs based on analysis of price impacts on a nodal or sub-regional basis; and (4) the analysis to discern how a demand reduction in one location affects (or does not affect) LMPs in other locations is extremely complex and, for the reasons stated above, appears to be unnecessary in the New England region.[13]

[12] August 27 letter at 3 (citing *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012)).

[13] *ISO New England Inc.*, 138 FERC ¶ 61,042, at P 37.

The Commission accepted ISO New England's cost allocation methodology as complying with Order No. 745.[14]

The four conditions cited by ISO New England are similar to the conditions that prevail in the ISO and justify the system-wide allocation of costs associated with the billing unit effect through the real-time imbalance energy offset charge. These conditions are discussed in the attached declaration of Dr. Abdul-Rahman.

First, as Dr. Abdul-Rahman explains, constraints on the transmission system operated by the ISO generally are not severe most of the time. Dr. Abdul-Rahman also explains that, in the ISO market, demand response resources participate in the load balance equation, which is formulated on a system-wide basis. The dispatch of demand response resources in any portion of the ISO system is reflected in the energy cost component or energy market clearing price of each LMP, which is always the same throughout the ISO. The energy market clearing price also impacts the loss component of each LMP throughout the ISO. Therefore, demand reductions in one location on the ISO system tend to lower LMPs in multiple locations on the ISO system.[15]

Second, Dr. Abdul-Rahman explains that retail demand response resources are located throughout California and will continue to be well dispersed as retail programs integrate into the wholesale market, making simultaneous demand reductions in multiple zones relatively common. Dr. Abdul-Rahman further explains that demand response resources participate in the load balance equality constraint just like generation resources, and impact the market clearing price, which impacts all locations throughout the ISO. In addition, demand response resources participate in the optimization of transmission constraints just like generation resources, and impact the flow on the transmission constraints just like generators do, including impacting shadow costs of binding transmission constraints. As a result of all these factors, LMPs from dispatched demand response resources are likely to affect LMPs across the California system region even where binding transmission constraints do arise between regions.[16]

Third, as Dr. Abdul-Rahman discusses, it would be very difficult to identify and allocate specific costs in the ISO based on analysis of price impacts on a nodal or sub-regional basis. In contrast to reactive power, which is often characterized as locally generated and consumed, the active power provided by generators or demand response reductions can travel to serve load located anywhere throughout the network. It would be very difficult to designate portions of

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[14] *Id.* at P 42.

[15] Declaration of Dr. Abdul-Rahman at 4-5.

[16] *Id.* at 5-7.

demand response reductions as physically serving certain load locations in certain portions of the network, just as it would be difficult to designate certain portions of generator output to only serve certain load.[17]

Fourth and finally, Dr. Abdul-Rahman explains that the analysis to discern how a demand reduction in one location affects (or does not affect) LMPs in other locations is extremely complex and, for the reasons stated above, appears to be unnecessary in the California region.[18]

Due to the existence in California of the four conditions discussed by Dr. Abdul-Rahman, the Commission should find that the ISO's cost allocation methodology, like that of ISO New England, complies with Order No. 745.

The ISO is not relying on other justifications besides those discussed above. For example, the ISO is not relying on justifications regarding the cost allocation methodologies of PJM or the Midwest ISO, which were the subject of Commission orders cited in a footnote to the August 27 letter.

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[17] *Id.* at 7-8.

[18] *Id.* at 8.

II. Communications

Communications regarding this filing should be addressed to the same individuals at the ISO who were designated to receive service in the March 14 compliance filing, namely:

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III. Service

The ISO has served copies of the instant filing upon all parties in the above-referenced proceedings. The ISO has also served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements. In addition, the ISO is posting the filing on its website.

IV. Conclusion

The ISO respectfully requests that the Commission accept this response as fully providing the additional information requested in the Commission Staff's August 27, 2012 letter. The Commission should accept the ISO's March 14, 2012 compliance filing, as supplemented by this response, as compliant with Order No. 745.

If there are any further questions or comments, please contact the undersigned.

Respectfully submitted,

/s/ John C. Anders

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Attorneys for the California Independent System Operator Corporation

cc: Dennis Reardon, Commission Staff

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket Nos. ER11-4100-___ and ER11-3616-___**

DECLARATION OF KHALED ABDUL-RAHMAN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

Q. Please state your name and business address.

A. My name is Khaled Abdul-Rahman. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed as Director, Power Systems Technology Development for the California Independent System Operator Corporation (ISO).

Q. Please describe your professional and educational background.

A. I received my Ph.D. in Power Systems in 1993 from the Illinois Institute of Technology (IIT), Chicago, IL. Since then, I have worked in the electric power system industry in the U.S. focusing primarily on large scale optimization software development, and deployment to production systems. My career includes working for different Energy Management System, electricity market, and information technology software vendors, and various consulting companies. Between March 2006 and July 2009 I was employed as the Independent

Principal Consultant for Electricity Markets at Siemens Transmission & Distribution, where my responsibilities included testing and supporting Energy Market Management software and deploying into production the Security Constrained Unit Commitment and Security Constrained Economic Dispatch software used in the new ISO market. In July 2009 I began work as the Principal for Power Systems Technology Architecture and Development for the ISO, and in July 2010 I became the Director of the Power Systems Technology Development group at the ISO. My current responsibilities include design, implementation, testing, deployment, and analyzing results of all market applications for the ISO's day-ahead and real-time markets. I have worked on many projects requiring deep optimization knowledge and full understanding of market design rules.

Q. What is the purpose of your declaration in this proceeding?

A. In my declaration I will explain that conditions on the ISO system are similar to those on the system operated by ISO New England Inc. Specifically, the same general system conditions that ISO New England described in its filing to comply with Order No. 745 to support the system-wide allocation of real-time demand response costs also prevail on the ISO system.

II. Conditions on the ISO System

Q. In ISO New England's filing to comply with Order No. 745, what system conditions did ISO New England describe in support of its cost allocation provisions?

A. ISO New England stated that the following four conditions exist on its system:

(1) transmission constraints generally are not severe at this time, and therefore demand reductions in one location tend to lower locational marginal prices (LMPs) in multiple locations;

(2) demand response resources are located throughout the New England region, making simultaneous demand reductions in multiple zones relatively common, so that LMPs from dispatched demand response resources are likely to affect LMPs across the region even where binding transmission constraints do arise;

(3) it would be extremely difficult to identify and allocate specific costs based on analysis of price impacts on a nodal or sub-regional basis; and

(4) the analysis to discern how a demand reduction in one location affects (or does not affect) LMPs in other locations is extremely complex and, for the reasons stated above, appears to be unnecessary in the New England region.

Q. Do the four conditions described by ISO New England also exist on the system operated by the ISO?

A. Yes, the same general conditions exist on the system operated by the ISO.

Q. **Please describe how the first of those conditions also exist on the system operated by the ISO.**

A. Constraints on the transmission system operated by the ISO generally are not severe most of the time. Both California and New England have seen substantial upgrades to the transmission infrastructure in each region in recent years that have reduced the incidence of congestion on each system. As a result, demand reductions in one location on the ISO system would tend to lower LMPs in multiple locations on the ISO system.

Q. **Are there additional reasons why demand reductions in one location tend to lower LMPs in multiple locations on the ISO system?**

A. Yes. It is should be noted that, in the ISO market, demand response resources participate in the load balance equation, which is formulated on a system-wide basis. The impact of the demand response reductions on the load balance equation is similar to the impact of an increase of supply or generation resources, *i.e.*, demand response resources participate in balancing total system supply and total system load. Since demand response resources participate in the load balance equality constraint, they (like generators) impact the shadow cost of this equality constraint. The shadow cost of this equality constraint is the energy market clearing price (MCP) of the ISO system. The MCP value is the same across all locations in the ISO network and it represents the first component (energy component) of the LMP at any location in the ISO network. Thus, the demand response reductions enable the market to clear energy at lower prices in multiple locations, which benefits all load in the ISO system. The second component of the LMP is the energy loss component, which is also dependent on the value of the MCP adjusted by the corresponding loss factor of the location. The third LMP component is the congestion component, which depends on the sum of shadow costs of binding network constraints multiplied by the corresponding shift factor of the location with respect to the binding transmission constraint. Therefore, the demand response reductions impact the energy MCP value which in turn impacts the first and second components of the LMPs at all locations in the ISO network. It should be noted that the first two components of the LMP account for the vast majority of the value of the corresponding LMPs. Absent congestion or with reduced incidences of congestion on the ISO network, the first two components account for almost the entire value of LMP. Therefore, every location in the network will benefit from the demand response reductions reflected as a lower energy MCP no matter where these reductions are located.

Q. **How do the second of the conditions described by ISO New England also exist on the system operated by the ISO?**

A. Currently, the vast majority of demand response in California is operated by the investor owned utilities and is not integrated into the wholesale market. Demand reductions from these programs occur throughout the three investor owned utility service territories, making simultaneous demand reductions in multiple zones relatively common. With the resolution of retail-wholesale demand response concerns in California, the investor owned utilities plan to convert certain of their retail programs to participate in the wholesale market, including air conditioning cycling programs and other price-responsive demand response programs that target the commercial market segment. Both of these types of demand response programs have underlying customers that are widely dispersed throughout the respective service territories of the utilities, with the expectation that future wholesale demand response participation will occur throughout the California region. Consequently, the price impacts of dispatched demand response resources are likely to affect LMPs across the California region even where binding transmission constraints do arise.

Q. Are there additional reasons why dispatched demand response resources are likely to affect LMPs across the ISO region even where binding transmission constraints do arise?

A. Mathematically speaking, demand response resources participate in the load balance equality constraint just like generation resources and impact the MCP, which impacts all locations throughout the ISO, as explained above. In addition, demand response resources participate in the optimization of transmission constraints just like generation resources and they impact the flow on the transmission constraints just like generators do, including impacting the shadow costs of binding transmission constraints. Both the load balance equality constraint and the transmission constraints are part of one market optimization problem, and due to the formulation of these constraints, there is interplay between the load balance and transmission constraints. In other words, the solution or the MW that is needed to satisfy load balance equality may introduce a flow on the transmission constraint based on the shift factor of this MW with regard to the corresponding transmission constraint. The opposite is also true, *i.e.*, the energy increase or decrease to mitigate an overload on a transmission constraint has an impact on which resources can be used to meet the system load balance constraint, thus impacting the shadow cost or the MCP of the load balance equality constraint.

Q. How do the third of the conditions described by ISO New England also exist in the ISO?

A. As noted above, the impacts of dispatching demand response are likely to affect MCPs and correspondingly the LMPs throughout the California region. In contrast to reactive power, which is often characterized as locally generated and consumed, the active power provided by generators or demand response reductions can travel to serve load located anywhere throughout the network. It is difficult to physically designate MW reductions or portions of demand response reductions to only serve certain load locations in certain portions of the network, just as it is difficult to physically designate certain portions of generator output to only serve certain load. There would be substantial uncertainty in attempting to isolate the price impact of discrete demand response resources separate from the impact of the numerous other resources on the ISO system as well as from the other factors that affect the calculation of LMPs under the ISO's market design. As such, it would be very difficult to identify and allocate specific demand response costs in the ISO based on analysis of price impacts on a nodal or sub-regional basis.

Q. Please describe how the fourth condition described by ISO New England also exists in the ISO.

A. The analysis to discern how a demand reduction in one location affects (or does not affect) LMPs in other locations is extremely complex and, for the reasons I explained earlier, appears to be unnecessary in the California region. Such analysis is not necessary for demand response resources to participate similar to generators in the load balance and transmission constraints because both types of resources have similar impacts on the system energy MCP and shadow prices of transmission constraints.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge.

Executed on September 26th, 2012.

K.H. Abdul Rahman

Khaled Abdul-Rahman