UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER11-4100-001**

REQUEST FOR REHEARING OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to Section 313(a) of the Federal Power Act[1] and Rule 713 of the Commission's Rules of Practice and Procedure,[2] the California Independent System Operator Corporation[3] respectfully submits this request for rehearing of the Commission's December 15, 2011 order in this proceeding.[4] The issues raised in this request for rehearing concern the directives in the December 15 Order regarding the "default load adjustment" – the ISO's carefully crafted approach for handling the problem of "double payment" for demand reductions by demand response resources in the ISO's wholesale market. As explained below, the Commission should grant rehearing of the directives in the December 15 Order regarding the default load adjustment.

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1 16 U.S.C. § 825*l*(a).

2 18 C.F.R. § 385.713.

3 The ISO is sometimes referred to as the CAISO. Capitalized terms not otherwise defined herein have the meanings given in the Master Definitions Supplement, Appendix A to the ISO tariff.

4 *Cal. Indep. Sys. Operator Corp.*, 137 FERC ¶ 61,217 (2011) (December 15 Order). As discussed further below, the December 15 Order addressed a filing submitted by the ISO on July 22, 2011 to comply with the requirements regarding demand response compensation set forth in Commission Order No. 745 issued in Docket No. RM10-17-000 on March 15, 2011. *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 No. 745-A). The December 15 Order should not be confused with Order No. 745-A, which was also issued on December 15, 2011.

I. Executive Summary

The ISO fully supports the policy goal of encouraging demand response resources through the design of independent system operator and regional transmission organization markets. We agree with the Commission that active participation by customers in the form of demand response helps to increase competition in organized wholesale energy markets, and the ISO has been a strong proponent of efforts to facilitate the participation of demand response in the ISO's wholesale electricity markets. The ISO is seriously concerned, however, that one aspect of the December 15 Order undercuts the realization of this policy goal.

The ISO seeks rehearing of the directive in the December 15 Order requiring the ISO to eliminate the use of the default load adjustment mechanism set forth in the existing ISO tariff for transactions subject to the requirements of Order No. 745. The discussion in the December 15 Order suggests that the Commission fundamentally misunderstands the nature of the default load adjustment. The default load adjustment is not a means for allocating the costs of payments made to demand response providers. The ISO has separate rules for allocating those costs. Instead, the default load adjustment is a carefully crafted mechanism previously approved by the Commission to ensure that ISO market participants, and ultimately consumers, do not pay twice for the same reductions in demand. The ISO provides a hypothetical example in this filing to illustrate the true allocation of demand response costs under the ISO's proxy demand resource market rules.

The uncertainty associated with the Commission's treatment of the default load adjustment under Order No. 745 has already delayed meaningful implementation of demand response in the ISO's wholesale markets. If the Commission does not reverse the portions of the December 15 Order rejecting the default load adjustment for transactions subject to the requirements of Order No. 745, most of the load in California could be prevented from participating in the ISO's wholesale markets for the foreseeable future. The default load adjustment was developed with the input of key stakeholders in the state, most notably the California Public Utilities Commission (CPUC). If the CPUC concludes that it does not want consumers to pay twice for the same reductions in demand, the CPUC may not authorize participation in the ISO wholesale markets by load served by state investor-owned utilities. Thus, this aspect of the December 15 Order could undercut the primary policy goal of Order No. 745.

The rejection of the default load adjustment for transactions subject to Order No. 745 is not only inconsistent with the Commission's policy objectives; it also is the result of a number of legal errors. First, the order incorrectly characterizes the default load adjustment as violating the cost allocation requirements of Order No. 745. To the extent Order No. 745 could be read to implicitly affect the default load adjustment, the December 15 Order fails to address the ISO's explanation in its compliance filing that retention of the default load adjustment is consistent with or superior to the requirements of Order No. 745. This failure to address the ISO's explanation is impermissible, especially given that Order No. 745 expressly authorized public utilities such as the ISO to attempt to show how its proposed or existing practices are consistent with or superior to the order's requirements in whole or in part.

Further, the requirement in the December 15 Order to eliminate the default load adjustment is also arbitrary, capricious, and unsupported by substantial evidence. It would reverse express directives in the Commission's Order No. 719 rulemaking without full notice or an opportunity for comment. Moreover, the December 15 Order includes no finding that the default load adjustment is no longer just and reasonable and no evidence to support such a finding, and thus the elimination of the default load adjustment is beyond the Commission's authority. In addition, the default load adjustment is an essential feature of demand response design in California. Eliminating the default load adjustment would represent an intrusion on issues properly left to California state jurisdiction and would have an adverse impact on the development of demand response in California.

For all of these reasons, the Commission should grant rehearing of the December 15 Order and permit the ISO to retain the existing default load adjustment in its tariff for transactions subject to Order No. 745.

II. Background

A. Proxy Demand Resources

For over a decade, the ISO has provided the opportunity for demand response resources to participate in the ISO's markets through its participating load program.[5] The ISO has also spent years and substantial resources developing the rules under which aggregators of retail customers can participate in the ISO wholesale markets in a manner that is consistent with all Commission requirements established prior to Order No. 745.

In 2010, the ISO sought and obtained Commission approval of tariff provisions that allow a new category of demand response resources – proxy demand resources – to participate in the ISO markets. The ISO developed its proxy demand resource proposal with substantial input from all stakeholders, including demand response providers. The ISO designed the proxy demand resource to work in concert with the efforts of the CPUC, which has promoted the integration of retail demand response into the wholesale markets and which initially authorized state utilities to begin developing retail demand response programs that can bid into the ISO's markets.

The Commission, in orders issued in July 2010 and January 2011, accepted tariff revisions submitted by the ISO to allow certain demand response resources, including aggregators of retail customers, to participate in the ISO

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[5] The December 15 Order finds that the requirements of Order No. 745 do not apply to participating loads. December 15 Order at P 7 n.6, P 56. The ISO agrees with that finding.

wholesale market as proxy demand resources.[6] The ISO "pays LMP [locational marginal price] at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying resources to provide day-ahead and real-time energy,"[7] as well as ancillary services,[8] in the ISO market. With the Commission's approval, the ISO implemented the proxy demand resource tariff revisions on August 10, 2010.

A critical element of the proxy demand resource tariff provisions approved by the Commission is the default load adjustment set forth in Section 11.5.2.4 of the ISO tariff.[9] The purpose of the default load adjustment is to prevent a wholesale double payment resulting from a payment being made for the demand

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6 *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,045 (2010), *order on compliance and reh'g*, 134 FERC ¶ 61,004 (2011). A proxy demand resource is defined in Appendix A to the ISO tariff as "[a] Load or aggregation of Loads capable of measurably and verifiably providing Demand Response Services pursuant to a Proxy Demand Resource Agreement." Demand response services are defined in Appendix A as "Demand from a Proxy Demand Resource that can be bid into the Day-Ahead Market and Real-Time Market and dispatched at the direction of the CAISO." Each proxy demand resource is represented by a demand response provider, which is defined in Appendix A as "[a]n entity that is responsible for delivering Demand Response Services from a Proxy Demand Resource providing Demand Response Services, which has undertaken in writing by execution of the applicable agreement to comply with all applicable provisions of the CAISO Tariff."

7 Order No. 745 at P 14.

8 Specifically, proxy demand resources can provide non-spinning reserve in the ISO's ancillary services market. *See* ISO tariff, Section 30.5.2.6.

9 Section 11.5.2.4 of the ISO tariff reads as follows:

> For the purpose of settling Uninstructed Imbalance Energy of a Scheduling Coordinator representing a Load Serving Entity, the amount of PDR Energy Measurement delivered by a Proxy Demand Resource that is also served by that Load Serving Entity will be added to the metered load quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource is associated.

The term PDR Energy Measurement is defined in Appendix A to the ISO tariff as "[t]he Energy quantity calculated by comparing the Customer Baseline of a Proxy Demand Resource against its actual underlying Load for a Demand response event." The Customer Baseline is calculated as set forth in Section 4.13.4 of the ISO tariff.

response services provided by a proxy demand resource and a payment also being made to a load serving entity (LSE) for uninstructed imbalance energy resulting from the ISO's acceptance of a bid from a proxy demand resource (*i.e.*, energy scheduled day-ahead by the LSE but not consumed in real-time because of the demand response service provided by the proxy demand resource). The default load adjustment eliminates this wholesale double payment by adding back the energy measurement for a proxy demand resource to the LSE's meter quantity in the ISO's uninstructed energy settlement pre-calculation. This settlement mechanism results in an adjusted meter demand value for the LSE, thus eliminating the uninstructed energy payment that would otherwise result from the demand response service provided by the proxy demand resource.[10] The ISO included the default load adjustment in its tariff pursuant to the directives in the Commission's Order No. 719 rulemaking that independent system operators and regional transmission organizations (ISOs/RTOs) are authorized to address the wholesale double payment issue on a region-by-region basis.[11]

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[10] *See* 132 FERC ¶ 61,045, at P 25. The double payment is a settlement consequence that applies only to demand response resources operating in the wholesale market in the instance where the demand response provider and the LSE can be different entities, as is the case for proxy demand resources (and also for reliability demand response resources, discussed below). ISO Response to the April 16, 2010 Letter Requesting Additional Information Regarding Proxy Demand Resource Tariff Amendment, Docket No. ER10-765-000, at 3-4 (May 17, 2010).

[11] *See Wholesale Competition in Regions with Organized Electric Markets*, FERC Stats. & Regs. ¶ 31,281, at P 159 (2008) (Order No. 719), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 70 (Order No. 719-A), *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (Order No. 719-B).

The July 2010 order described the proposed default load adjustment in detail in the section of the order entitled "Costs and Settlement"[12] and went on to state that "[w]e accept the CAISO's cost and settlement provisions."[13] The acceptance of these cost and settlement provisions was conditioned only upon the requirement that the ISO undertake a study to determine if the effects of demand response apply more broadly than to the individual LSE in which the proxy demand resource is located.[14] The Commission accepted the ISO's proxy demand resource tariff provisions as compliant with Order No. 719.[15]

The default load adjustment was a significant feature cited by the CPUC in its June 4, 2010, decision affirming that the ISO's proxy demand resource design is consistent with the CPUC's own efforts to promote demand response in the State of California.[16] As explained in the ISO's 2010 Demand Response Report,[17] the June 4 CPUC Decision directed the California investor owned utilities (IOUs) subject to the CPUC's jurisdiction to prepare to bid demand

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[12] *See* 132 FERC ¶ 61,045, at PP 25-26.

[13] *Id.* at P 32.

[14] *Id.* at P 34. The order notes that "this study is for informational purposes only. The Commission will not notice the filing, nor accept comment on it, and the filing does not require Commission action." *Id.* at P 34 n.24. Such an informational study requirement does not in any way alter the Commission's finding that the default load adjustment is just and reasonable by accepting those provisions under Section 205 of the Federal Power Act (FPA).

[15] 132 FERC ¶ 61,045, at P 23; 134 FERC ¶ 61,004, at P 22.

[16] *See* CPUC Decision 10-06-002, issued in Proceeding R.07-01-041, at 15, 19-22 (June 4, 2010) (June 4 CPUC Decision). That CPUC decision is available on the CPUC's website at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm and is provided in Attachment A hereto. To ensure a complete and accurate record in the instant proceeding, the attachments to this request for rehearing include documents that the ISO also attached or cited in the Order No. 745 proceeding (Docket No. RM10-17).

[17] 2010 Demand Response Report in Docket No. ER06-615-000, at 2 (Jan. 14, 2011). The 2010 Demand Response Report is provided in Attachment B hereto.

response into the ISO market using proxy demand resource pilot programs.[18] While a positive first step, the June 4 CPUC Decision also expressly directed that bundled utility customers could participate only through IOU pilot programs. The decision did allow for direct access customers (*i.e.*, those retail customers that procure their electricity through a third-party electricity provider) to offer demand response in the ISO markets. The decision also identified several important issues that the CPUC stated had to be resolved and clarified before it would allow all customers to offer demand response into the ISO markets. Those issues include retail compensation and financial settlement concerns, consumer protection and information needs, CPUC jurisdiction and oversight over third-party (*i.e.*, non-IOU) demand response providers, and resource adequacy capacity credit for new or modified demand response products, as well as accounting for proxy demand resource bidding within the CPUC's long-term reliability and procurement planning processes.[19]

In addition, an ISO tariff amendment is pending before the Commission in Docket No. ER11-3616 that will apply the existing default load adjustment to the settlement of transactions regarding another category of demand response resources in the ISO wholesale market, emergency-triggered reliability demand response resources. The December 15 Order leaves all issues related to the reliability demand response proposal to that proceeding.[20] As such, the ISO will

[18] June 4 CPUC Decision at 24.

[19] *Id.* at 6-23.

[20] December 15 Order at P 7.

not address issues related to reliability demand response resources in this rehearing request.

B. Order No. 745 and 745-A

In Order No. 745, the Commission established new requirements regarding compensation to be provided for demand response in organized wholesale energy markets overseen by ISOs/RTOs.[21] Order No. 745 required ISOs/RTOs each to submit, by July 22, 2011, a compliance filing that addressed the following issues: (1) the net benefits test for demand response compensation described in Order No. 745; (2) the measurement and verification of demand response performance; and (3) the allocation of demand response costs.[22] The order also stated that "[i]n its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of [Order No. 745]."[23]

Order No. 745 did not directly address the default load adjustment mechanism. The discussion of cost allocation issues in Order No. 745 stated that "[s]ome commenters argue that costs should be assigned to the LSE associated with the demand response provider because it is this entity that receives the full benefit of demand response," and cites the ISO as one of the

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[21] Order No. 745 at P 1.

[22] *Id.* at PP 6, 81,102. Three ISOs/RTOs subsequently requested extensions of time to submit their compliance filings. The Commission granted those requests of the three ISOs/RTOs. *See* notices of extension of time issued in Docket No. RM10-17-000 on July 8, July 11, and July 22, 2011.

[23] Order No. 745 at P 4 n.7.

commenters making that argument.[24] On the page of the ISO comments that the Commission appeared to have in mind,[25] the ISO explained (among other things) that the default load adjustment resolves the potential for wholesale double payments.[26] Order No. 745 contained no directives that squarely addressed the default load adjustment or the wholesale double payment issue. However, Order No. 745 did "reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response."[27]

Due to the lack of clarity on the default load adjustment issue, on April 14, 2011, the ISO filed a motion for clarification or, in the alternative, request for rehearing, requesting confirmation that Order No. 745 does not require the elimination of the default load adjustment and thereby mandate wholesale double payments for demand response reductions, with respect to both proxy demand resources and reliability demand response resources.[28]

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24 *Id.* at P 98 & n.189.

25 Although footnote 189 in Order No. 745 cites page 6 of the ISO's May 13, 2010 comments on the notice of proposed rulemaking issued in Docket No. RM10-17, rather than page 6 of the ISO's October 13, 2010 comments on the supplemental notice of proposed rulemaking issued in that proceeding, it appears that the Commission intended to cite the latter. This is because only page 6 of the ISO's October 13 comments contains discussion of cost assignment to an LSE.

26 ISO comments on supplemental notice of proposed rulemaking, Docket No. RM10-17-000, at 6 (Oct. 13, 2010).

27 Order No. 745 at P 101.

28 Motion for Clarification or, in the Alternative, Request for Rehearing of the California Independent System Operator Corporation, Docket No. RM10-17-001, at 4-6, 9-16, 21-34 (Apr. 14, 2011). The ISO's April 14 filing also raised other issues not germane to this request for rehearing.

Following the issuance of Order No. 745, all three IOUs in California requested on April 8, 2011 that a CPUC Administrative Law Judge delay a proposed decision on the financial settlement issues germane to the CPUC's demand response rulemaking. These settlement issues are conditions precedent to the CPUC's issuance of a final decision on bidding demand response into the ISO market.[29] On May 9, 2011, the CPUC issued a ruling that extended by 18 months (*i.e.*, until November 2012) its schedule for completing its demand response rulemaking. The CPUC found that the extension was necessary in relevant part because "[s]ome market participants have interpreted [Order No. 745] as eliminating the possibility of the DLA [default load adjustment]," and therefore the CPUC must "await clarification from the FERC regarding whether PDR [proxy demand resource] may be implemented as already approved by the FERC."[30]

Timely issuance of these CPUC decisions is critical to the timely participation of proxy demand resources in California. As the Commission recognized in the proxy demand resource proceeding, "much of the potential new Proxy Demand Resource participation is contingent on an upcoming CPUC decision."[31] Until the CPUC proceeding resolves these outstanding issues, the CPUC's prohibition on bundled utility customers offering demand response other

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[29] *See* http://docs.cpuc.ca.gov/efile/MOTION/133321.pdf, which is provided in Attachment C hereto.

[30] Assigned Commission's Ruling Amending Scoping Memo, issued in Proceeding R.07-01-041, at 3 & n.3 (May 9, 2011). This CPUC ruling is available on the CPUC website at http://docs.cpuc.ca.gov/efile/RULINGS/134968.pdf and is provided in Attachment D hereto.

[31] 132 FERC ¶ 61,045 at P 34 n.23; 134 FERC ¶ 61,004 at P 14.

than through IOU pilot programs remains in effect.[32] While market participants have expressed interest to the ISO in participating in the ISO market as proxy demand resources, to date there has only been a single third-party participant piloting the proxy demand resource functionality with direct access customers, apparently because third-party demand response entities and direct access customers are holding off until stakeholders and the CPUC formally settle the retail rules relating to direct participation. At the time the 2010 Demand Response Report was issued, the expectation was that the retail rules would be decided in time for all customers to participate in the ISO market by the summer of 2011.[33] However, as explained above, that expectation has not been met, due in relevant part to the Commission's directives regarding the default load adjustment.

In Order No. 745-A, the Commission stated that it could not address the request for confirmation contained in the ISO's April 14 filing. Instead, the Commission stated that it would address the ISO's request for confirmation in the proceeding on the ISO's filing to comply with Order No. 745 (the instant proceeding) and in the proceeding on the ISO's tariff revisions to implement reliability demand response resources (Docket No. ER11-3616).[34]

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[32] Declaration of Peter Skala on Behalf of the California Public Utilities Commission at 9. Mr. Skala's declaration, which was originally attached to the ISO's April 14, 2011 motion for clarification or, in the alternative, request for rehearing of Order No. 745 in Docket No. RM10-17-001, is provided in Attachment E hereto.

[33] 2010 Demand Response Report at 3-4.

[34] Order No. 745-A at PP 140-41.

C. The December 15 Order

On July 22, 2011, the ISO submitted a filing in the above-referenced docket to comply with the directives in Order No. 745. The ISO's compliance filing explained that the ISO should be permitted to retain the Commission-approved default load adjustment. In particular, the ISO stated that, for the reasons also provided in its April 14 filing, the Commission should grant clarification or rehearing that Order No. 745 does not require the default load adjustment to be eliminated.[35] The ISO also explained that if the Commission did not grant such clarification or rehearing, the Commission should find, in its order on the compliance filing, that the ISO's retention of the default load adjustment is "consistent with or superior to the requirements of [Order No. 745]."[36] Further, the ISO explained that the provisions of the existing ISO tariff allocate the costs of proxy demand resources to those that benefit from demand response reductions. Therefore, the provisions of the existing ISO tariff satisfy the requirements of Order No. 745 regarding the allocation of demand response costs.[37]

The December 15 Order accepts in part and rejects in part the ISO's July 22 compliance filing.[38] In particular, the December 15 Order finds that the compliance filing did not demonstrate that the ISO's current cost allocation methodology, including the default load adjustment, appropriately allocates costs

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35 July 22, 2011 compliance filing at 11-12.

36 *Id.* at 12-13 (quoting Order No. 745 at P 4 n.7).

37 July 22, 2011 compliance filing at 15.

38 December 15 Order at Ordering Paragraph (A).

to those that benefit from the demand reduction as required by Order No. 745.[39] The December 15 Order states that, because the default load adjustment settlement process purportedly requires the load serving entity to pay for load that it does not ultimately serve, the default load adjustment "effectively allocates the cost of demand response to the host load serving entity even though the benefits of demand response may extend beyond the host load serving entity,"[40] and does not "allocate the cost of the demand response purchase proportionally to the entities that benefit."[41] As a result, the December 15 Order finds that the ISO has not demonstrated that its cost allocation methodology complies with the requirements of Order No. 745.[42] The December 15 Order directs the ISO to file a cost allocation methodology that complies with Order No. 745, within 90 days after issuance of the December 15 Order.[43] Although the December 15 Order mentions that the ISO argued in its compliance filing that the default load

[39] *Id.* at PP 43-46.

[40] *Id.* at PP 6 & n.4, 44.

[41] *Id.* at P 46.

[42] *Id.* at PP 45-46.

[43] *Id.* at P 46. Further, the December 15 Order rejects tariff revisions that the ISO proposed in the July 22, 2011 compliance filing to serve as the ISO's "mechanism for not paying demand response resources when the LMP is less than the threshold price" established pursuant to the Order No. 745 net benefits test. *Id.* at P 32. The December 15 Order also finds that the ISO "exceed[ed] the scope of Order No. 745 by attempting to include, on compliance, tariff provisions regarding the level of compensation a demand response resource can receive when market conditions do not satisfy the net benefits test, i.e., when the LMP does not equal or exceed the threshold price." *Id.* Based on these findings, the use of the default load adjustment and all other aspects of the ISO's cost allocation methodology when the LMP is less than the threshold price are beyond the scope of the directives in Order No. 745 and the directives in the December 15 Order. As a result, this request for rehearing cannot and does not address any issues regarding the use of the default load adjustment when the LMP is less than the threshold price.

adjustment is consistent with or superior to the requirements of Order No. 745,[44] that ISO argument is not addressed anywhere in the substantive discussion in the December 15 Order.

III. Specification of Errors

In accordance with Rule 713(c)(1) of the Commission's Rules of Practice and Procedure,[45] the ISO respectfully submits that the December 15 Order erred in the following respects:

1. In finding that the default load adjustment mechanism does not satisfy the requirements of Order No. 745, the Commission erred for the following reasons:

    a. the finding mischaracterizes the default load adjustment as a means for allocating the costs of demand response and fails to address the ISO's actual mechanism for allocating the costs paid to demand response providers;

    b. the finding fails to address the ISO's explanation that retention of the default load adjustment is consistent with or superior to the requirements of Order No. 745, contrary to the Commission's express authorization of such an approach to compliance in Order No. 745;

    c. the finding is an unexplained departure from precedent;

    d. the finding is an impermissible reversal of authorizations in a prior rulemaking without notice and an opportunity to comment;

    e. the finding is impermissible absent a finding, supported by the evidence, that the default load adjustment mechanism is unjust, unreasonable, or unduly discriminatory or preferential;

[44] *Id.* at PP 37, 42.

[45] 18 C.F.R. § 385.713(c)(1).

f. the finding adversely affects demand response development in California, contrary to the Commission's stated goals, and interferes with the ongoing participation of proxy demand resources in the ISO's wholesale markets; and

g. the finding intrudes upon the jurisdiction of state commissions.

IV. Statement of Issues for Rehearing Request

In accordance with Rule 713(c)(2) of the Commission's Rules of Practice and Procedure,[46] the ISO states that this request for rehearing raises the following issues:

1. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism mischaracterizes the default load adjustment as a means for allocating the costs of demand response and fails to address the ISO's actual mechanism for allocating the costs paid to demand response providers.

2. Whether the Commission's failure to address the ISO's argument that retention of the default load adjustment is consistent with or superior to the requirements of Order No. 745 is permissible. *See Fed. Power Comm'n v. Texaco, Inc.*, 417 U.S. 380, 397 (1974); *TNA Merchant Projects, Inc. v. FERC*, 616 F.3d 588, 593 (D.C. Cir. 2010); *Cleveland Constr. Co. v. NLRB*, 44 F.3d 1010, 1016 (D.C. Cir. 1995).

3. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism is an impermissible unexplained departure from precedent. *See Atchison, Topeka & Santa Fe Rwy. v. Wichita Bd. of Trade*, 412 U.S. 800, 816-17 (1973); *Hatch v. FERC*, 654 F.2d. 825, 834 (D.C. Cir. 1981); *Greater Boston Television Corp. v. FCC,* 444 F.2d 841, 852-53 (D.C. Cir. 1971).

4. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism is an impermissible reversal of authorizations made in a prior rulemaking without notice and an opportunity to comment. *See City of Idaho Falls v. FERC*, 629 F.3d 222, 227 (D.C. Cir. 2011); *Alaska Prof'l Hunters Ass'n, Inc. v. FAA*, 177 F.3d 1030, 1034 (D.C. Cir. 1999).

5. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism is an impermissible modification of existing

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46 18 C.F.R. § 385.713(c)(2).

tariffs because the Commission failed to make a finding, supported by substantial evidence, that the default load adjustment mechanism is unjust, unreasonable, or unduly discriminatory or preferential. *See* 5 U.S.C. § 706; 18 U.S.C. § 824(d); *Fed. Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348, 372 (1956); *Transcontinental Gas Pipe Line Corp. v. FERC*, 518 F.3d 916, 921 (D.C. Cir. 2008).

6. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism is unwise policy, in light of the adverse effects on demand response development in California and on the ongoing participation of proxy demand resources in the ISO's wholesale markets.

7. Whether the Commission's directive to the ISO to eliminate the default load adjustment mechanism improperly intrudes upon the jurisdiction of state commissions.

V. Request for Rehearing

A. The December 15 Order Mischaracterizes the Default Load Adjustment

The December 15 Order incorrectly describes the allocation of demand response costs under the default load adjustment mechanism. Specifically, Paragraph 6 of the December 15 Order describes that cost allocation in the following manner:

> For settlement purposes, under CAISO's Proxy Demand Resource program, the total amount of Proxy Demand Resource energy measurement (calculated by comparing the customer baseline of a Proxy Demand Resource against its actual underlying load for a demand response event) is added to the demand of the load serving entity in which the Proxy Demand Resource is located. This add-back is intended to prevent the load serving entity from being compensated for demanding less energy than scheduled in the day-ahead market because of the Proxy Demand Resource's load reduction. However, this add-back of the demand reduction results in the load serving entity paying for load it does not ultimately serve.[4] This add-back is referred to as the "default load adjustment."

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[4] CAISO indicated that this issue would be appropriately resolved by the California Public Utilities Commission (CPUC),

> potentially through bilateral agreements between the load serving entity and the Demand Response Providers. In its order on the Proxy Demand Resource proposal, the Commission declined to address the impact of these agreements[.]

December 15 Order at P 6 & n.4.

Based on this description of cost allocation under the default load adjustment, the December 15 Order finds that the ISO has not demonstrated that its current cost allocation methodology, including the default load adjustment, appropriately allocates costs to those that benefit from demand reductions.[47] Specifically, the December 15 Order finds that the "CAISO's proposed cost allocation methodology for demand response allocates to the host load serving entity *the entire cost* of the revenue shortfall caused by the demand response purchase" and does not "allocate the cost of the demand response purchase proportionally to the entities that benefit."[48] As a result, the December 15 Order finds that the ISO has not demonstrated that its cost allocation methodology complies with the requirements of Order No. 745.[49]

The December 15 Order mischaracterizes how costs of demand response purchases under the existing, Commission-approved ISO Tariff provisions are allocated. In fact, the ISO tariff allocates the cost of demand response purchases proportionally to the entities that benefit from demand response. The purpose of the default load adjustment, on the other hand, is to eliminate the wholesale double payment, so that the ISO does not pay twice for the same

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[47] December 15 Order at P 43.

[48] *Id.* at P 46 (emphasis added).

[49] *Id.* at PP 45-46.

curtailment.[50] The following hypothetical example illustrates the true operation of the ISO's proxy demand resource tariff provisions.[51]

This example is based on the following assumptions:

- Load Serving Entity A schedules 100 MW in the day-ahead market and has a perfect load forecast;
- Demand Response Provider B, which represents 15 MW of the load reduction of a proxy demand resource, clears 10 MW in the day-ahead market and clears an additional 5 MW in the real-time market;
- The day-ahead LMP price for load is $80;
- The day-ahead LMP for the proxy demand resource represented by Demand Response Provider B and for a separate resource, Generator C, is $80; and
- The real-time LMP and uninstructed energy price is $100.

Using these assumptions, the total net settlement for Load Serving Entity A, Demand Response Provider B, and Generator C are calculated as follows:

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50 To the extent the LSE has procured capacity and/or purchased energy that was not consumed, and to the extent the LSE and the demand response provider are different entities, any compensation issues are resolved by the demand response provider and the LSE between themselves.

51 The ISO also provided an example illustrating the operation of the default load adjustment in the Draft Final Proposal for the Design of Proxy Demand Resource at 39-40 (Aug. 28, 2009). The ISO issued that document in the stakeholder process for the proxy demand resource tariff amendment, and cited the document in the tariff amendment filing, including a specific reference to the example. *See* transmittal letter for proxy demand resource tariff amendment (Docket No. ER10-765-000), at 12 n.34, 14 n.36, 22 n.50, 24 n.56 (Feb. 16, 2010).

Market Activity	**Load Serving Entity A**	**Demand Response Provider B**	**Generator C**
Day-ahead			
– Cleared day-ahead bids **Load is balanced.**	-100 MW	10 MW	90 MW
– Day-ahead settlements **Costs are allocated appropriately and revenue neutrality is maintained in the day-ahead market.**	-$8,000	$800	$7,200
Real-time			
– Cleared real-time bids	N/A	5 MW	0 MW
– Meter readings	85 MW	5 MW	80 MW
– Uninstructed deviations before applying the default load adjustment	15 MW	0 MW	10 MW
– Effect of applying the default load adjustment	-15 MW	N/A	N/A
– Uninstructed deviations after applying the default load adjustment	0 MW	N/A	N/A
– Real-time settlements **Costs are allocated appropriately and revenue neutrality is maintained in the real-time market.**	N/A	$500	-$500
– Net of day-ahead and real-time settlements **Revenue neutrality is maintained.**	-$8,000	$1,300	$6,700

As shown in the example above, applying the default load adjustment ensures that load is balanced, revenue neutrality is maintained, and costs are allocated appropriately to those that require balancing services. Using the language of the December 15 Order, “the cost of the demand response purchase” in the day-ahead and real-time is not allocated solely to Load Serving Entity A in the example. In fact, if the ISO did not apply the default load adjustment, the ISO would have to allocate the additional cost of the “double payment” to load or other market participants as uplift. Application of the default load adjustment keeps the market settlement and load balance simple and eliminates uplift costs directly associated with the double payment that would otherwise have been allocated as uninstructed energy to the LSE.

In this example, the day-ahead dispatch cost for the proxy demand resource represented by Demand Response Resource B and for Generator C is allocated to the buyers of energy, *i.e.,* the scheduling coordinators for Load Serving Entity A. The real-time imbalance energy cost for the proxy demand resource ($500 in the above example) is allocated to Generator C, because it under-delivered on its supply schedule. In the ISO market, real-time imbalance energy cost is allocated in two tiers, just like for other imbalance energy. First, the real-time imbalance energy payment to the proxy demand resource is allocated in tier 1 to those that required the service, *i.e.*, those that deviated from their schedules and therefore required backing by the ISO for additional supply – in this example, Generator C. Since Load Serving Entity A has no deviations in this example, it is not allocated the real-time imbalance energy payment to the proxy demand resource in the first tier. Second, any excess real-time imbalance energy cost is allocated in tier 2 to the entire market (including Load Serving

Entity A) based on measured demand.[52] In short, payments of locational marginal prices made to proxy demand resources are allocated to the load that benefits from the demand response reduction, *i.e.*, to all load day-ahead and to deviations in real-time, entirely consistent with the requirements of Order No. 745.

Contrary to the statements in the December 15 Order, the default load adjustment does not allocate any “revenue shortfall.” Load Serving Entity A pays for day-ahead scheduled load at the day-ahead settlement price, and the adjustment to Load Serving Entity A’s day-ahead schedule using the default load adjustment is *solely* for purposes of calculating uninstructed deviations and avoiding the double payment, *i.e.*, a payment to Load Serving Entity A for uninstructed deviations based on the curtailed MW amount in addition to the payment to Demand Response Provider B for energy from the proxy demand resource.[53] Thus, no revenue shortfall is allocated using the default load adjustment.

If there were no default load adjustment, there would be a second and additional payment to Load Serving Entity A of $1,500 (15 MW * $100 real-time uninstructed energy price) for its load deviation. This load deviation would represent the “over-procurement” by the Load Serving Entity A for energy procured but not consumed because of demand response by Demand Response

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52 *See* ISO tariff, Sections 11.5, 11.8.

53 This example shows that the default load adjustment is not a true mechanism for allocating demand response costs – the payments made to demand response providers. Even if the Commission continues to characterize the default load adjustment as a form of cost allocation, however, the Commission must consider the ISO’s demand response cost allocation provisions in the aggregate.

Provider B. This would be a second bucket of costs to be uplifted to California customers for the same service, essentially compelling customers to pay $2,800 (*i.e.*, $1,500 plus $1,300) in total for this 15 MW of energy. Because there is no comparable "double payment" for the supply of energy from generation resources, the same 15 MW of energy would only cost $1,300 if provided by Generator C ($800 for 10 MW in the day-ahead and $500 MW for 5 MW in real-time). The ISO respectfully submits that compelling such a $2,800 double payment over the objections of the utility providing the jurisdictional service (the ISO) and the applicable state regulator (the CPUC) is inconsistent with the Commission's obligations to consumers under the Federal Power Act.

The December 15 Order also is mistaken in asserting that the ISO indicated that any issues regarding the default load adjustment would be resolved by the CPUC, potentially through bilateral agreements.[54] It appears that the December 15 Order erroneously relies upon the following discussion in the July 2010 order regarding the proxy demand resource tariff amendment:

> [A] Proxy Demand Resource is paid as though it is generation, therefore, according to the CAISO, compensation issues between the Proxy Demand Resource and the load serving entity may develop. The CAISO states that the compensation issues would be handled through bilateral arrangements, between the Demand Response Provider and the load serving entity, which would occur outside of the CAISO's settlement process. Alternatively, the CAISO states the compensation issues could be addressed directly by the local regulatory authority. The CAISO states that its tariff will not indicate if and how revenues will be shared between the load serving entity and the Demand Response Provider.[55]

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[54] *See* December 15 Order at P 6 n.4.

[55] 132 FERC ¶ 61,045, at P 28 (footnotes omitted).

Any compensation or revenue-sharing issues between a load serving entity and a demand response provider on the retail level are entirely independent of the cost allocation set forth in the ISO tariff. As explained above, the settlement provisions included in the ISO tariff applicable to proxy demand resources allocate costs proportionally to all entities that benefit from demand response. Therefore, the December 15 Order errs in finding that the ISO's cost allocation provisions do not satisfy the requirements of Order No. 745.

B. The December 15 Order Fails to Address the ISO's Explanation that Retention of the Default Load Adjustment Is Consistent With or Superior to the Requirements of Order No. 745

The December 15 Order fails to address an important assertion regarding the default load adjustment that the ISO made in its July 22 compliance filing. In this regard, the ISO noted in its compliance filing the statement in Order No. 745 that, "[i]n its compliance filing an RTO or ISO may attempt to show, *in whole or in part*, how its proposed or existing practices are consistent with or superior to the requirements of [Order No. 745]."[56] The ISO went on to explain at length that, if the Commission found that Order No. 745 otherwise would require the default load adjustment to be eliminated, the Commission should find that the ISO's retention of the default load adjustment as part of the ISO's demand response compensation rules is consistent with or superior to the requirements of Order No. 745 due to the critical importance of the default load adjustment to the provision of demand response in California.[57]

[56] Order No. 745 at P 4 n.7 (emphasis added).

[57] Transmittal letter for July 22, 2011 compliance filing at 12-13.

The background discussion in the December 15 Order notes that the ISO "contends that the default load adjustment is consistent with or superior to the requirements of Order No. 745 because it is important to demand response in California."[58] However, the substantive portions of the December 15 Order fail to address the ISO's arguments. This failure by the Commission is impermissible. A Commission order may be upheld on appeal only "on the same basis articulated in the order by the agency itself."[59] If the Commission fails to address an argument in its order, the court cannot evaluate whether there is any reasonable basis for upholding the order.[60] Therefore, the December 15 Order errs in failing to address the ISO's argument that retention of the default load adjustment is consistent with or superior to the requirements of Order No. 745.

As explained in the background discussion above and further explained in Section V.C below, because demand response efforts in California have been premised on the assumption that the double payments avoided by the default load adjustment will not occur, elimination of the default load adjustment is having a devastating practical consequence for the ability of the ISO to implement proxy demand resource functionality in the ISO's markets, and for the ability of the CPUC to approve related retail demand response programs and

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[58] December 15 Order at P 37. The December 15 Order also notes that the comments submitted by the Electric Power Supply Association (EPSA) in the instant proceeding included the argument that, to the extent the Commission did not grant clarification or rehearing as requested by the ISO, the Commission should find that ISO's default load adjustment is consistent with or superior to the requirements of Order No. 745. *Id.* at P 42.

[59] *TNA Merchant Projects, Inc. v. FERC*, 616 F.3d 588, 593 (D.C. Cir. 2010) (quoting *Fed. Power Comm'n v. Texaco, Inc.*, 417 U.S. 380, 397 (1974) (internal quotation marks omitted)).

[60] *TNA Merchant Projects*, 616 F.3d at 593; *Cleveland Constr. Co. v. NLRB*, 44 F.3d 1010, 1016 (D.C. Cir. 1995) (stating that the court "cannot uphold silence" in an agency order).

financial settlement mechanisms. Retention of the default load adjustment is therefore a superior means for achieving meaningful demand response in California wholesale electricity markets.

C. The December 15 Order Errs in Requiring Elimination of the ISO's Approved Default Load Adjustment[61]

The Commission should reverse the requirement in the December 15 Order for the ISO to eliminate the default load adjustment in circumstances where the directives in Order No. 745 apply. Such a requirement is not only unwise policy, but it is also arbitrary, capricious, and unsupported by substantial evidence. Requiring elimination of the default load adjustment or mandating the wholesale double payments that the adjustment is intended to prevent would be legally impermissible and would have devastating practical consequences. Such a requirement would reverse express directives in Order No. 719 without full notice or an opportunity for comment. The December 15 Order also includes no finding that the default load adjustment is no longer just and reasonable and no evidence to support such a finding, and thus it is beyond the Commission's authority. In addition, such a requirement would represent an intrusion on issues properly left to California state jurisdiction.

From a practical standpoint, requiring a change to the default load adjustment would overturn an essential feature of demand response design in

[61] In this Section V.C, the ISO provides an explanation of legal flaws in eliminating the default load adjustment that is similar to explanations provided in the ISO's April 14, 2011, request for clarification or rehearing of Order No. 745. This is because Order No. 745-A directed that issues regarding the default load adjustment would be addressed in the instant proceeding, not in the Order No. 745 proceeding. *See* Order No. 745-A at PP 140-41. In order for the Commission to consider the ISO's explanations in the instant proceeding, the ISO is making them here.

California and would introduce substantial obstacles to the CPUC's ability to authorize participation of demand response as proxy demand resources.

1. Impermissible Reversal of Order No. 719

In Order No. 719, the Commission specifically declined to mandate a solution to the wholesale double payment issue and instead found that each region should propose its own solution for Commission acceptance. It stated that "in response to those who ask us to require . . . 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."[62] Pursuant to the Commission's express authorization in Order No. 719, the ISO proposed the default load adjustment tariff provisions in its proxy demand resource tariff amendment in order to address the wholesale double payment issue, and the Commission accepted those tariff provisions in July 2010 as just and reasonable.[63]

Because the Commission has already set forth in Order No. 719 its policy of granting ISOs/RTOs the flexibility to deal with the wholesale double payment issue pursuant to Commission-approved tariff provisions, it cannot modify that Order No. 719 policy directive, either explicitly or implicitly, without full notice and

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62 Order No. 719 at P 159. *See also* Order No. 719-A at P 70 ("Therefore, as stated in [Order No. 719], we require each RTO or ISO to work with its stakeholders, including load-serving entities and ARCs [aggregators of retail customers], to develop and implement protocols that will address those issues and allow [aggregators of retail customers] to operate within the organized market. Those protocols should address those issues raised by petitioners, including double-counting . . . .").

63 *See* 132 FERC ¶ 61,045 at PP 25-26, 32.

an opportunity for comment.[64] The December 15 Order, which was not issued in a rulemaking proceeding, provided no such notice or opportunity for comment. Indeed, the December 15 Order does not even mention the Commission's prior directives on this issue in Order No. 719. Therefore, the statements in the December 15 Order provide no basis for modifying the policy directive in Order No. 719.

Moreover, although the Commission is free to revise its policies established in a prior rulemaking, as set forth in rules and precedent, it must acknowledge it is doing so and provide a reasoned explanation.[65] Because the Commission does not acknowledge it is reversing portions of Order No. 719, it has not met the prerequisites for doing so.

2. Failure to Meet the Requirements of Section 206 of the Federal Power Act

Eliminating the default load adjustment would require the ISO to make substantial changes to its tariff and to its software configuration. The December 15 Order includes no finding that the default load adjustment market feature is no longer just and reasonable for certain transactions, as required by Section 206 of the Federal Power Act. Even if such a finding were implicit, the December 15

[64] *See, e.g.*, *City of Idaho Falls v. FERC*, 629 F.3d 222, 227 (D.C. Cir. 2011) ("Having established through public rulemaking in Regulation 11.2 a legally-binding methodology for setting future rates for licensees, FERC may modify that methodology only after notice and comment."); *Alaska Prof'l Hunters Ass'n, Inc. v. FAA*, 177 F.3d 1030, 1034 (D.C. Cir. 1999) ("Rule making, as defined in the APA [Administrative Procedure Act], includes not only the agency's process of formulating a rule, but also the agency's process of modifying a rule.") (internal citations omitted).

[65] *See Atchison, Topeka & Santa Fe Rwy. v. Wichita Bd. of Trade*, 412 U.S. 800, 816-17 (1973); *Hatch v. FERC*, 654 F.2d. 825, 834 (D.C. Cir. 1981); *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852-53 (D.C. Cir. 1971).

Order would still lack any reasoned explanation of such a finding and any evidence supporting such a finding.

Section 206(a) gives FERC authority to "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force" only *if* it first finds that any existing arrangement "is unjust, unreasonable, unduly discriminatory or preferential."[66] The Commission is required to "demonstrate by substantial evidence that the existing rate or tariff has become unjust or unreasonable, and that the proposed rate is both just and reasonable."[67] Absent a finding supported by substantial evidence that existing rates, charges, *etc.*, are no longer just and unreasonable, however, the Commission is not permitted to require modifications to them.[68] Courts have admonished the Commission for seeking to impose new rates without first determining that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential.[69]

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[66] *See, e.g., Panhandle Eastern Pipe Line Co. v. FERC*, 907 F.2d 185, 188 (D.C. Cir. 1990) (explaining that the court has "approved the Commission's use of a rulemaking to modify already-filed tariffs on the grounds that their inclusion of certain costs in a minimum bill rendered them unjust and unreasonable.").

[67] *Transcontinental Gas Pipe Line Corp. v. FERC*, 518 F.3d 916, 921 (D.C. Cir. 2008). Although the court in the *Transcontinental* case was addressing the requirements of Section 5 of the Natural Gas Act (NGA), Courts have repeatedly held that Section 5 of the NGA parallels Section 206 of the FPA and that the two statutes should be interpreted consistently. *See, e.g.*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000). Therefore, the same substantive evidence standard applies under Section 206 of the FPA.

[68] *See, e.g.*, *Fed. Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348, 372 (1956) ("The condition precedent to the Commission's exercise of its power under § 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential.'"); *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) ("In order to make any change in an existing rate or practice, FERC must first *prove* that the existing rates or practices are 'unjust, unreasonable, unduly discriminatory or preferential.'") (emphasis added).

[69] In *Western Resources, Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993), the court noted, "As we complained four years ago, '[o]n four occasions in the last three years this court has

A finding that the default load adjustment is unjust and unreasonable must be supported by a rational explanation and substantial evidence.[70] The December 15 Order contains no explicit finding that the default load adjustment is unjust and unreasonable and, to the extent such a finding is implicit, provides neither an explanation of this finding nor any evidence of problems created by the default load adjustment. Merely implying that existing rates are no longer just or reasonable, without providing any evidence to support that implication, is not a legally sufficient basis under Section 206 of the Federal Power Act for the Commission to overturn the existing rates.[71]

In addition, under the December 15 Order, the elimination of the default load adjustment only applies to some demand response transactions in the ISO's wholesale markets, but not to others. In the December 15 Order, the Commission states that:

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reviewed Commission efforts to compromise § 5's limits on its power to revise rates. On each the court has repelled the Commission's gambit. This is number five.' . . . We now make it an even six." (Citation omitted.) *See also Tenn. Gas Pipeline Co. v. FERC,* 860 F.2d 446 (D.C. Cir. 1988); *Northern Natural Gas Co. v. FERC*, 827 F.2d 779 (D.C. Cir. 1987); *Sea Robin Pipeline Co. v FERC,* 795 F.2d 182 (D.C. Cir. 1986); *ANR Pipeline Co. v. FERC,* 771 F.2d 507 (D.C. Cir. 1985); *Panhandle Eastern Pipe Line Co. v. FERC,* 613 F.2d 1120 (D.C. Cir. 1979).

[70] In order that a finding not be arbitrary and capricious, the Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) (internal quotation marks omitted). "Professing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making." *Nat'l Fuel Supply Co. v. FERC*, 468 F.3d 831, 843-44 (2006), *citing* State Farm, 463 U.S. at 42-43. "[M]ere invocation of theory is an insufficient substitute for substantial evidence and reasoned explanations." *Elec. Consumers Resource Council v.* FERC, 747 F.2d 1511, 1517 (D.C. Cir. 1984).

[71] *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 958 (D.C. Cir. 1983) ("Whether or not the finding that a new rate is reasonable (or that a proposed new rate is unreasonable) amounts to a finding that the old one was unreasonable, it will ordinarily be an abuse of the Commission's discretion not to make the latter finding explicit . . . .").

> As we further explain in the concurrently-issued order on rehearing of Order No. 745, the Commission's action in Order No. 745, undertaken pursuant to section 206 of the FPA, was limited to situations where a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and where dispatch of the demand response resource is cost-effective as determined by a net benefits test. The Commission's section 206 action did not extend to situations where the LMP is not greater than or equal to the threshold price, and as a result, compensation of demand response resources in those situations is beyond the scope of this compliance proceeding.[72]

Because this proceeding only addresses situations where a demand response resource is paid an LMP greater than or equal to the net benefits test threshold price,[73] the elimination of the default load adjustment does not apply when a demand response resource is dispatched but the LMP is less than the threshold price. The Commission does not provide any reasoned explanation as to why the default load adjustment is no longer just and reasonable when the LMP is greater than or equal to the net benefits test threshold price but remains just and reasonable when the LMP is less than the net benefits test threshold price.

3. The Adverse Impact of Elimination of the Default Load Adjustment on Demand Response Development in California

The default load adjustment is an essential feature of the demand response design developed over several years in California through the collaboration of the ISO, stakeholders, and the CPUC, and approved by the Commission.[74] Indeed, the CPUC's demand response efforts are premised upon

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[72] December 15 Order at P 32, citing Order No. 745-A at P 131 (footnote omitted).

[73] See the discussion in footnote 43 above.

[74] This years-long development process is discussed at pages 2-7 of the February 16, 2010, transmittal letter for the proxy demand resource tariff amendment in Docket No. ER10-765-000, which is provided in Attachment F hereto.

the design of the tariff revisions for use of proxy demand resources, including the critical default load adjustment feature, as originally approved by the Commission. If the design of the tariff revisions regarding proxy demand resources must be modified pursuant to the December 15 Order, that will introduce substantial uncertainty regarding the CPUC's ongoing proceedings addressing the terms under which utilities regulated by the CPUC can bid demand response as proxy demand resources. This is not merely a hypothetical concern. Prior Commission action had a significant impact on the delay of demand response at the retail level in 2010.[75]

Similarly, at the time the 2010 Demand Response Report was issued on January 14, 2011, the expectation was that the CPUC's retail rules permitting entities to bid demand response into the ISO market would be decided in time for customers to participate as proxy demand resources in the ISO market by the summer of 2011. But the uncertainty created by a requirement to eliminate the default load adjustment has already substantially delayed the CPUC's ability to authorize entities subject to its jurisdiction to bid demand response into the ISO.

Events have confirmed the adverse consequences to CPUC demand response initiatives arising from the potential elimination of the default load

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[75] The ISO filed the proxy demand resource tariff amendment on February 16, 2010, with a requested effective date of April 19, 2010 for the ISO's proposed proxy demand resource agreement and a requested effective date of May 1, 2010 for the rest of the tariff revisions. On April 16, 2010, Commission staff sent the ISO a letter seeking further information regarding the tariff amendment, and the ISO timely responded to the letter. On July 15, 2010, the Commission conditionally accepted the tariff amendment, made the proxy demand resource agreement effective July 19, 2010, and made the rest of the tariff revisions effective August 10, 2010. 132 FERC ¶ 61,045, at P 1. The timing of the April 16, 2010 letter, and the consequent postponement of the issuance of the order on the ISO's proxy demand resource filing, resulted in the CPUC being unable to authorize the implementation of proxy demand resources at the retail level for the summer of 2010. *See* June 4 CPUC Decision, provided in Attachment A hereto, at 20-21.

adjustment. On May 9, 2011, the CPUC issued a ruling that extended by 18 months (*i.e.*, until November 2012) its schedule for completing its demand response rulemaking. The CPUC found that the extension was necessary in relevant part because "[s]ome market participants have interpreted [Order No. 745] as eliminating the possibility of the DLA [default load adjustment] and therefore the CPUC must "await clarification from the FERC regarding whether the PDR [proxy demand resource] may be implemented as already approved by the FERC."[76]

Moreover, as explained in the Declaration of Mr. Skala, the CPUC has informed the ISO that, to the extent Order No. 745 mandates wholesale double payments to LSEs that are also demand response providers, the CPUC reserves the right to revisit its determinations conditionally authorizing entities subject to the CPUC's jurisdiction to participate in the ISO market as proxy demand resources.[77] Because most of the load in California is served by entities subject to CPUC jurisdiction, such action by the CPUC would clearly have crippling effects on the provision of demand response in California for the foreseeable future.[78]

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76 Assigned Commission's Ruling Amending Scoping Memo, provided in Attachment D hereto, at 3 & n.3.

77 Declaration of Mr. Skala, Attachment E hereto, at 10.

78 Pages 14-15 of the California Energy Commission's Revised Short-Term Peak Demand Forecast for 2011-2012 illustrates that the lion's share of load served by the ISO is IOU load. *See* http://www.energy.ca.gov/business_meetings/2011_packets/2011-03-09/2011-03-09_Item_11_Revised_Short-Term_Peak_Demand_Forecast_Committee_Report_2011-2012.pdf, which is provided in Attachment G hereto.

Unless and until the Commission grants the instant request for rehearing, the ability to participate in the ISO markets as a proxy demand resource may not be available for most of the load in California due to the directive in the December 15 Order to eliminate the default load adjustment.

4. Intrusion on the Jurisdiction of State Commissions

Because the December 15 Order requires elimination of the default load adjustment, it also intrudes on areas of state jurisdiction, thus violating the jurisdictional boundaries that the Commission committed to respect in the Order No. 719 proceeding and Order No. 745. In both Order No. 719-A and Order No. 745, the Commission recognized that "demand response is a complex matter that is subject to the confluence of state and federal jurisdiction."[79] In Order No. 745, the Commission stated that it was "not requiring actions that would violate state laws or regulations. The Commission also is not regulating retail rates or usurping or impeding state regulatory efforts concerning demand response."[80] But the consequences for the CPUC discussed above make it clear that requiring a change to the default load adjustment or the provision of wholesale double payments to LSEs that are also demand response providers *does* substantially impede California's state regulatory efforts on demand response. Thus, because the December 15 Order requires such changes, the order intrudes on state jurisdiction in the very manner that the Commission stated it would avoid.

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79 Order No. 719-A at P 54; Order No. 745 at P 114.

80 Order No. 745 at P 114. Similarly, in Order No. 719-A (at P 54), the Commission stated that the "intent and effect [of Order No. 719-A] are neither to encourage or require actions that would violate state laws or regulations."

VI. Conclusion

For the reasons discussed herein, the ISO respectfully requests that the Commission grant rehearing of the December 15 Order with regard to the issues addressed in this ISO filing.

Respectfully submitted,

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Counsel for the California Independent System Operator Corporation

Dated: January 17, 2012

Attachment A

Decision 10-06-002 June 3, 2010

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 (Filed January 25, 2007)

DECISION ON PHASE FOUR DIRECT PARTICIPATION ISSUES

1. Summary

Orders 719[1] and 719-A[2] of the Federal Energy Regulatory Commission (FERC) require Independent System Operators such as the California Independent System Operator (CAISO) to modify their tariffs to allow retail customers to bid Demand Response (DR) directly into their wholesale electric and ancillary services markets, either on their own behalf or through aggregators, if the relevant state or regional authorities do not prohibit such direct bidding. In today's decision, the California Public Utilities Commission

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[1] *Wholesale Competition in Regions with Organized Electric Markets* (FERC Order 719), issued on October 17, 2008, in Docket Nos. RM07-19 and AD07-7, available at http://elibrary.ferc.gov/idmws/file_list.asp?document_id=13656106.

[2] *Wholesale Competition in Regions with Organized Electric Markets* (Order 719-A), issued on July 16, 2009 in Docket No. RM07-19, available at http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-1.pdf.

(Commission or CPUC) directs the Investor Owned Utilities (IOUs) to prepare to bid DR from existing Participating Load Pilot (PLP) programs into the CAISO's wholesale market as soon as is feasible if the FERC approves tariff language that is acceptable to the CPUC, but prohibits further participation by IOU retail customers until the CPUC develops ratepayer protections and other relevant rules and protocols pursuant to the Commission's existing jurisdiction. This decision does not prohibit electric service providers ("ESPs") from engaging in direct bidding of retail DR on behalf of their own customers, either on their own or through third party Demand Response Providers (DRPs), but bars DRP representation of bundled IOU customers for the time being. DRPs, however, may provide direct bidding services if they contract with an ESP to provide such services for ESP customers.

Thus, this decision establishes the initial conditions under which the Commission will oversee retail direct demand response bidding participation, including the CPUC's duties to oversee the relationships between DRPs, ESPs, IOUs and retail customers. This decision also outlines the issues that must be resolved as the Commission considers allowing direct bidding of retail DR in the CAISO markets, including Commission oversight of programs and policies that apply generally to load-serving entities. The Commission will separately consider additional proposals[3] for direct bidding beyond the conversion of the existing PLP programs. This decision puts load-serving entities that choose to engage in direct bidding on notice that they may be subject to CPUC oversight related to the short and long-term reliability of directly bid resources for

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[3] SDG&E advice letter 2152-E and PG&E advice letter 3635-E.

long-term procurement analysis, counting conventions of directly bid resources for Resource Adequacy (RA) credit, compliance with environment related procurement statutes and policies, and consumer protection issues.

2. Background

Federal Energy Regulatory Commission (FERC) Orders 719 and 719-A require Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) to amend their market rules to permit retail customers to bid demand response[4] services directly into the RTO's or ISO's organized wholesale markets. Specifically, these orders require that end use customers, either on their own or through a Demand Response Provider (DRP)[5] be allowed to bid directly into these wholesale markets to the extent that the laws or regulations of the relevant electric retail regulatory authority do not prohibit a retail customer's participation. FERC recognized the significant role of state and local retail regulatory authorities in the design and implementation of such proposed direct bidding tools.[6] The California Public Utilities Commission (Commission or CPUC) is such a retail electric regulatory authority. In the absence of intervening regulations from the Commission, the FERC orders allow for direct participation

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[4] "Demand response can be defined as changes to electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, to incentive payments, or to reliability conditions." *Assigned Commissioner and Administrative Law Judges' Ruling Amending Scoping Memo*, issued in Rulemaking (R.) 07-01-041 on November 9, 2009.

[5] FERC Order 719 and 719A use the term Aggregator of Retail Customers, or ARC. For the purposes of this decision, DRP is synonymous with ARC.

[6] Order No. 719-A at ¶ 54.

of Demand Response (DR) in California's wholesale markets without any additional requirements or rules.

California's electric grid is operated by the California Independent System Operator (CAISO). The CAISO's primary efforts to implement direct participation of DR currently come in the form of the development of tariff language for its proposed Proxy Demand Resource (PDR) product.[7] The CAISO's PDR product would allow DRPs to aggregate the demand response of retail end-use customers, which would then be bid into the CAISO markets through a Scheduling Coordinator. As proposed in the CAISO's tariff filing, the load of these end-use customers would continue to be served by their respective Load Serving Entity (LSE). Because of the similar treatment afforded a PDR resource and a generator, the CAISO refers to PDR as a pseudo-generating resource. Since PDR would rely on an aggregation of retail end-use customers served by Commission-jurisdictional IOUs and non-jurisdictional ESPs, and may affect the composition of California LSE's long-term energy supply procurement plans, this new product creates many questions that the Commission must address.

On November 9, 2009, the scoping memo in R.07-01-041 was amended to initiate the Direct Participation Phase of this proceeding.[8] The Amended Scoping Memo directed that a workshop be held to address certain issues and established

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[7] CAISO *Tariff Amendment To Implement Proxy Demand Resource Product*, filed in Docket No. ER10-765 on February 16, 2010.

[8] *Assigned Commissioner And Administrative Law Judges' Ruling Amending Scoping Memo, Establishing A Direct Participation Phase Of This Proceeding, And Requesting Comment On Direct Participation Of Retail Demand Response In CAISO Electricity Markets* (Amended Scoping Memo), available at http://docs.cpuc.ca.gov/efile/RULINGS/109611.pdf.

a schedule to complete this phase of the proceeding by March 2010. The CAISO subsequently delayed its proposed PDR implementation date until May 1, 2010, prompting the Commission's Energy Division to propose a new schedule that allowed for the filing of legal briefs and two sets of reply comments so as to develop a more complete record. On April 16, 2010, FERC issued a notice of deficiency regarding the CAISO's PDR tariff proposal, including three discrete areas of concern.[9] Thus, it is unclear when or in what form the CAISO's PDR product may be approved by the FERC.

Participants in the workshop included the Alliance for Retail Energy Markets (AReM), CAISO, California Energy Storage Alliance (CESA), California Large Energy Consumers Association (CLECA), the Direct Access Customer Coalition (DACC), the Division of Ratepayer Advocates (DRA), Energy Curtailment Specialist (ECS), the Environmental Defense Fund (EDF), Joint Parties (EnerNoc Inc., CPower Inc., and Energy Connect Inc.), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). Parties' participation focused on four key questions:

1. What is the Commission's jurisdictional authority with respect to the retail customer's direct participation as DR bidders in the CAISO markets?
2. What rules should be established to properly address dual participation in Commission-authorized DR programs and the CAISO's PDR product?

[9] Letter from the FERC Office of Energy Market Regulation to the CAISO, filed in Docket No. ER10-765.

3. What communications protocols are needed to ensure that retail customers are properly and transparently paid and billed for DR, and that double-procurement is avoided?
4. Is there a need for an additional financial settlement between the LSE and DRP to ensure that the LSE is not paying for excess power that is not needed?

The following discussion addresses these four issues.

3. Discussion

3.1. Jurisdiction

The November 9, 2009 Amended Scoping Memo states that part of the purpose of Phase Four of this rulemaking is to "begin the [Commission's] effort to determine whether existing state procurement laws, decisions, rules or practices may directly or indirectly conflict with potential direct bidding by retail Demand Response into CAISO wholesale markets."[10] This question prompted an in-depth briefing and discussion at the workshops of whether and what jurisdiction the Commission may have over direct bidding activities.[11]

In their opening briefs, PG&E and DRA argue that the Commission may reasonably conclude that DRPs qualify as public utilities because their activities are closely connected, intertwined, and integrated with retail electricity services; and because DRPs will have dedicated their property to public use as a public utility. DRA argues that even if DRPs do not qualify as public utilities, they may

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[10] Amended Scoping Memo at 5.

[11] On January 22, 2010, the following parties submitted opening briefs regarding Commission jurisdiction over direct bidding of DR resources by retail customers into the wholesale energy markets run by the CAISO: SCE, PG&E, DRA, Joint Parties, and AReM. On January 29, 2010 PG&E, Joint Parties, AReM, SDG&E, and DRA submitted reply briefs on this same subject.

alternatively fit within the definition of ESPs. PG&E argues that even if the Commission were to determine that DRPs are not public utilities, the Commission has the authority over the relationship between DRPs and retail end-use customers.

AReM argues that DRPs cannot be defined as public utilities under California Public Utilities Code Section 216 because bidding retail DR resources into the CAISO's markets does not entail the use of "electric plant" as defined in Section 217.[12] AReM further argues that engaging in direct biding will not cause a DRP to fall within the statutory definition of an ESP because the direct bidding of retail DR resources into the CAISO's markets does not entail the provision of "electrical service" as that term is used in Section 218.3. Finally, AReM argues that third-party DR aggregators are not "aggregators" as defined in Section 331, and are therefore not ESPs under Section 365.1 because bidding retail customers DR resources into CAISO markets does not involve the aggregation of customer loads, and such activities do not entail "direct transactions" as that term is used in CPUC Section 365.1.

In its post-workshop comments and reply comments, AReM states that the Commission has no jurisdiction over contracts signed between an ESP and its direct access customer (or a DRP) and no authority over the rates, terms or conditions of service offered by ESPs. AReM reasons that direct access customers procure no energy from IOUs and are therefore free to participate directly in CAISO markets through any avenue they desire without Commission

[12] Unless otherwise stated, all statutory references herein are to the California Public Utilities Code.

oversight. AReM further argues that because ESPs are free to develop their own DR programs, these programs would not be subject to Commission jurisdiction. Finally, AReM sees no legal or policy basis to restrict the participation of direct access customers in CAISO markets, provided such customers are not enrolled in any IOU DR programs.

In its opening brief the Joint Parties state that the Commission does not have jurisdiction over DRPs because DRPs are not "public utilities" or ESPs. The Joint Parties note that the Legislature has never prescribed that DRPs are an "additional class" of public utility subject to Commission regulation. Finally, the Joint Parties argue that there is no rational basis to impose consumer protection rules for the CAISO's markets beyond the consumer protection laws applicable to businesses operating in California, including DRPs.

In its reply brief, the Joint Parties argue that according to the plain language of the relevant statutes, the legislature has never included DRPs within the legal definitions of "public utilities" or ESP. The Joint Parties conclude that any consumer protection rules deemed by the Commission or the CAISO to be required for DRPs beyond the current law applicable to California businesses should be addressed through rules governing participation in jurisdictional utility programs.

In its opening brief, SCE asserts that DR aggregators do not meet the statutory definition of public utilities. SCE urges, however, that DRPs qualify as ESPs. SCE argues that, even if the Commission were to determine that third-party DR aggregators are not ESPs, it can and should assure consumer protection by regulating the terms and conditions under which IOUs can approve its customer's participation in a direct bidding program.

In its reply brief, SDG&E asserts that DR service providers are within the definition of an ESP and as such are subject to the Commission's jurisdiction over ESPs for consumer protection purposes as indicated in Sections 394.2 and 394.25(e).

In sum, the parties take markedly different positions regarding whether DRPs should be treated as public utilities or ESPs, and whether such a determination conclusively establishes Commission jurisdiction. The Commission need not provide a comprehensive analysis of the Commission's jurisdiction over direct bidding in California at this juncture.[13] We agree with SCE, PG&E, DRA, and SDG&E that this Commission can impose reasonable terms and conditions on the IOUs' approval of its end-use customer's participation in a direct bidding program. As SCE points out, and contrary to the claims of AReM, participation in a direct bidding program can impact the reliability, cost, safety and maintenance of utility service. Similarly, DRA argues that the IOUs Resource Adequacy and Long Term Procurement Plans may also be compromised if CPUC oversight over direct bidding is not effective. Moreover, while ESPs are not subject to the same Commission jurisdiction as IOUs, ESPs are subject to significant CPUC regulation related to reliability, RA, and long-term procurement, as well as programs related to environmental issues such as the Renewables Portfolio Standards.[14]

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[13] Commission jurisdiction in this area shall be further examined in subsequent phases of this or other proceedings as particular regulations and protocols are developed for this nascent type of product.

[14] In Reply Comments on the Proposed Decision, Joint Parties point out that RA and LTPP only apply to load-serving entities.

No party disputes that the Commission has authority over the potential impacts of direct bidding on consumer protection, long-term procurement, resource adequacy requirements, or Loading Order[15] related issues. As FERC aptly explains:

> We recognize that demand response is a complex matter that is subject to the confluence of state and federal jurisdiction. The Final Rule's intent and effect are neither to encourage or require actions that would violate state laws or regulations nor to classify retail customers and their representatives as wholesale customers. The Final Rule also does not make findings about retail customers' eligibility, under state or local laws, to bid demand response into the organized markets, either independently or through an ARC [Aggregator of Retail Customers]. The Commission also does not intend to make findings as to whether ARCs may do business under state or local laws, or whether ARCs' contracts with their retail customers are subject to state and local law. Nothing in the Final Rule authorizes a retail customer to violate existing state laws or regulations or contract rights. In that regard, we leave it to the appropriate state or local authorities to set and enforce their own requirements.[16]

The CAISO agrees with FERC's assessment,[17] as does this Commission. The Commission will develop rules as appropriate to establish the terms and conditions by which the IOUs may authorize their bundled customers' participation in a DRPs direct bidding program and account for direct bidding

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[15] See *Energy Action Plan II[:] Implementation Roadmap For Energy Policies*, issued October 2005 by the Commission and the California Energy Commission (CEC), available at http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.doc.

[16] Order No. 719-A at paragraph 54.

[17] *Reply Brief Of The California Independent System Operator Corporation On Jurisdictional Issues*, submitted in the instant proceeding on January 29, 2010 at 3-4.

within the Commission's long-term procurement[18] and Resource Adequacy[19] duties. In particular, the Commission may, among other things, resolve customer complaints related to DRPs, establish financial responsibility standards for DRPs, and require DRPs to inform customers that enrolling with the DRP will mean that they will be unenrolled from DR programs offered by an IOU.

3.2. Dual Participation

Dual participation can be said to occur where a customer that is already enrolled in an IOU DR program also bids as a DR resource directly in CAISO markets, either individually or through a DRP. While the CAISO makes clear that its "Demand Response System will only allow one service account per demand response provider,"[20] the CAISO also acknowledges that multiple arrangements can be made against the performance of a particular resource. Dual participation arrangements can be quite complex. In reality, allowing dual participation at the start of a new direct participation program may be more burdensome than beneficial. This reality was not lost on the parties.

SCE argues that there are substantial complexities around dual participation in the context of direct participation in the CAISO markets, and asserts that dual participation should be considered only after the DRPs have

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[18] See e.g., California Pub. Util. Code, § 454.5, subd. (b)(1) (electrical procurement plans must account for utility owned generation, power purchase agreements, demand response contracts, electricity-related products and open positions to be served by spot market transactions).

[19] See California Pub. Util. Code, § 380 (requiring the Commission to design and implement a Resource Adequacy program).

[20] CAISO Comments at 4.

experience with bidding resources into PDR.[21] PG&E identifies several forms that dual participation could take and identifies potential costs and inequities that could arise in each instance. PG&E then concludes that "until the CAISO's program is well established, the Commission should not allow [Customer Service Accounts] that participate in a program run by an IOU to also be a part of a PDR for a non-IOU DRP."[22]

In spite of these complexities, most parties support, albeit conditionally, eventual integration of dual participation. In reply comments, PG&E argues that, rather than burden all parties with attempting to resolve the issues of dual or multiple participation at this time, the Commission should consider the issue after sufficient experience is gained with PDR.[23] EDF supports third party participation on claims that allowing DRPs access to accounts that are also managed by LSEs will maximize the amount of DR available to the grid. EDF cautions that dual participation should be allowed in a way that maximizes grid reliability by, among other things, avoiding double counting and allowing LSEs to rely on their contracted resources. DRA strongly agrees with principles that go to: 1) ensuring that only DR that actually performs is paid, and 2) ensuring that DR that does perform does not receive duplicative payments for the same load reductions from one or more source. DRA goes on to propose various rules for the Commission to adopt that would establish DRP registration requirements

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[21] SCE Comments at 7.

[22] PG&E Comments at 15.

[23] PG&E Reply Comments at 4.

and general guidelines for DRP service.[24] Energy Connect Inc. supports dual participation provided that the rules are "simple enough to be easily administered, reasonably immune to gaming, and easily understood by customers."[25]

The Commission finds these arguments to be persuasive. We determine that dual participation in IOU and DRP programs shall be implemented only after California has had reasonable and successful experience with single PDR program participation. Until this Commission orders otherwise, customers engaged in an IOU DR program will not be permitted to also participate in direct bidding of their DR resource into CAISO markets. Furthermore, ESP customers that are enrolled in IOU DR programs may not participate in the IOU program and bid directly into the CAISO market place. If an ESP customer wishes to bid into the CAISO market on their own or through a DRP, they must first exit the IOU DR program. Upon exiting the IOU program, an ESP customer may participate directly in the CAISO market to the extent that their contract with the ESP allows. However, because the Commission does not currently have a counting convention for direct participating load, the ESP will continue to be required to meet all RA and resource portfolio standards.

3.3. Communications and Settlement Issues

Communications issues concern what information flow is necessary between the LSE, the DRP (if any), and the customer providing the load drop to

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[24] DRA is concerned that utility ratepayers could be saddled with making duplicative payments due to the lack of oversight during daily market operations.

[25] Energy Connect Inc., Supplemental Comments on the Workshop Report at 6. Energy Connect Inc. is one of the Joint Parties.

identify the roles, interactions and responsibilities of all parties, and the need for consumer protections. Settlement issues generally address ensuring just compensation, appropriate mechanisms for transfers, minimum credit assurances, and whether pro forma contracts that address many of these concerns are necessary and/or appropriate. The interaction of these various issues and interests creates substantial complexity and warrants a cautious approach to implementing direct bidding.

With regard to settlements, as noted by the CAISO, "[m]ost parties, if not all, agreed in workshop discussions that a standard contract, versus multiple bilateral negotiations, should be developed to govern pertinent terms of the relationship between the Commission jurisdictional load-serving entities and the third-party demand response providers."[26] This agreement was reflected in the parties' comments on the workshop: most parties agreed that facilitating direct participation of DR in the CAISO markets requires addressing the operational and communication needs of the various stakeholders. SCE identifies various process and system concerns that need to be resolved prior to direct bidding of retail DR.[27] PG&E urges the Commission to adopt a pro-forma contract that sets the default amount, terms and conditions for the transfer of this amount, settlement mechanism for transfers, minimum credit and performance assurances, and other terms.[28] DRA argues that general communication and settlement concerns should be overseen by the Commission because the CAISO

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[26] CAISO Comments at 5.

[27] SCE Comments at 2-3.

[28] PG&E opposes the direct billing approach which it attributes to SCE.

would only track PDR performance results at the aggregated level, and would not analyze the performance of underlying customers that make up a PDR.[29]

DRA identifies under-collection, which it refers to as the "missing money" problem, as one of several issues that warrant additional discussion and some actual experience.[30] This was the communications issue most discussed by the parties. EDF explains that "the way the CAISO has structured its PDR settlement process has led to the LSEs asking that they be compensated by third-party DRPs for the energy they purchased for their customers that was not consumed because of demand response."[31] As explained by PG&E, this problem would arise under the following circumstances:

> …a DRP may bid DR into the CAISO's markets using PDRs comprised of portions of the LSE's load. If a DRP's bid for a PDR is accepted, then the DRP is compensated for its accepted load reduction bid just as though the PDR had a scheduled delivery of that amount of energy into the CAISO system.
>
> As a consequence, the LSE pays for load it does not place on the CAISO grid, and the DRP receives payment for energy it does not deliver into the CAISO grid.[32]

DRA, therefore, recommends identifying different types of participation frameworks and that the Commission allow only those frameworks that have been properly tested and refined in a PDR pilot.

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[29] DRA Comments at 3.

[30] DRA at 4-5.

[31] EDF Comments at 4.

[32] PG&E Comments at 6.

Since the complexities identified by parties in this proceeding cannot be resolved at this time, we will defer the development of the necessary customer protections until a subsequent phase of this proceeding. This action has the added benefit of allowing parties and the Commission to learn from the participation of the pilot programs before coming to conclusions which will impact the DR community at-large.

3.4. Implementation Timing

The Commission has regulatory oversight over IOU DR programs and contracts, and authority over long-term resource portfolio planning and retail sales of electricity. In existing retail DR programs, the IOU acts as the intermediary between the CAISO's markets and the customer or aggregator that is providing the DR resource. While these DR programs have not provided for a customer or aggregator to directly bid DR resources into the CAISO wholesale markets,[33] the Commission has directed the IOUs to better integrate their existing DR resources into the CAISO's energy and ancillary services markets.[34] Acting expeditiously to allow end use customers or aggregators to bid DR resources directly in these markets (to the extent that the laws or regulations applicable to the relevant electric retail regulatory authority do not prohibit a retail customer's participation) is consistent with our identification of DR as one of the state's preferred means of meeting growing energy needs.[35]

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[33] The Commission has authorized three Participating Load Pilot (PLP) programs in which the IOUs bid DR load reductions into the CAISO ancillary service markets.

[34] See Decision (D.) 09-08-027.

[35] See *Energy Action Plan II[:] Implementation Roadmap For Energy Policies*, issued October 2005 by the Commission and the California Energy Commission (CEC), available at http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.doc.

Footnote continued on next page

The CAISO has urged the Commission to identify what must be done to achieve some level of direct participation during the summer of 2010 and what must be resolved over the long term. The CAISO states that priorities should include modifying rules and tariffs to enable direct participation.[36] PG&E identifies various issues that must be addressed prior to the implementation of PDR, and argues that PDR should not be fully implemented until several months after the decision in this phase of the proceeding so that parties have adequate time to prepare to implement Commission directives.[37] While DRA agrees with PG&E that a schedule for full implementation of PDR, including dual participation, by the summer of 2010 is too compressed, AReM is skeptical of the claim that full-scale PDR cannot be implemented by the summer of 2010 and asserts that direct access customers who are not enrolled in IOU DR programs can participate in PDR during the summer of 2010.[38] AReM is opposed to PG&E's proposal that the Commission develop conditions for participation by retail customers.

Various parties suggest enacting a pilot or partial program as an initial step toward PDR rather than the full PDR program. For example, SCE states that it could modify its existing Participating Load Pilot (PLP) program to allow some PDR participants in 2010.[39] After having completed the initial work on its PLP, SCE states that the PDR product is better suited to small and medium

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[36] CAISO Comments at 1-2.

[37] PG&E Comments at 16.

[38] AReM Comments at 7.

aggregated DR resources. SCE further asserts that modifying its PLP to fit into the new PDR product framework would allow it to work with the CAISO on operation of the new PDR wholesale market product, while allowing additional development of rules and requirements for full implementation in 2011. Toward this end, SCE recommends that the Commission direct it to file an advice letter seeking authorization to modify its PLP for a PDR pilot in the summer of 2010, and that additional processes be ordered to resolve the outstanding issues in time for full implementation of PDR by the summer of 2011.

Various parties appear to embrace this approach. In Reply Comments PG&E states that it is prepared to implement the CAISO's PDR program on a limited basis. DRA also voices its agreement that PDR should be implemented in 2010 only as a pilot.[40] SDG&E also supports the use of pilot programs and proposes to leverage the existing PLP to implement PDR for the summer of 2010. SDG&E suggests that IOUs should solicit and incorporate third-party DRPs into their 2010 PDR pilots as a way to gain experience through real-time DRP/LSE interaction.[41] Similarly, EDF asserts that allowing DR providers to have access to the CAISO market in the same timeframe as IOUs will ensure that customers have access to both LSE programs and third party DRP programs, and will avoid giving the LSEs a competitive advantage.[42]

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[39] SCE's PLP has a three-year pilot program cycle (2009–2011), funded in D.08-12-038 and D.09-08-027.

[40] DRA Reply Comments at 3.

[41] SDG&E Reply Comments at 2.

[42] EDF Reply Comments at 3.

Taking the record of the proceeding as a whole, we conclude that the Commission should not allow DRPs to participate directly in CAISO markets on behalf of IOU retail customers until the CPUC develops adequate customer protections. Since the complexities identified by the parties in this proceeding cannot be resolved at this time, we will defer the development of the necessary customer protections until a subsequent phase of this proceeding.

As an initial step toward direct participation, DRPs can bid on behalf of ESP customers (provided the ESP customer is not in an IOU DR program), and we do not prohibit an ESP customer from bidding on its own behalf or for other ESP customers. However, those load-serving entities that choose to engage in the initial phases of participation may be subject to CPUC oversight related to the short and long-term reliability of directly bid resources for long-term procurement analysis, counting conventions of directly bid resources for RA credit, and consumer protection issues. We will also require PG&E, SCE, and SDG&E to file advice letters amending their PLP pilots and preparing them for direct participation as soon as FERC approves a PDR tariff that the CPUC deems appropriate. These party's PLP programs are in different states of development and have varying levels of funding remaining. Where there are insufficient funds to support a new pilot program, it may be necessary to engage in fund shifting as provided for in D.09-08-027. Some IOUs are proposing additional pilot programs outside of this proceeding.[43] We will not address the merits of those proposals here but will consider them separately.[44]

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[43] SDG&E advice letter 2152-E proposes to modify a portion of its day-ahead Capacity Bidding Program by 2010. PG&E advice letter 3635-E proposes to modify its PeakChoice program by summer/fall 2010. SCE filed a Petition for Modification of

Footnote continued on next page

Until the issues discussed in this decision are resolved, direct participation by DRPs is limited to the scenarios identified in this section. However, given the value of effectively regulated direct participation of PDR in the CAISO markets and our desire to secure these benefits for ratepayers, we intend to resolve the outstanding issues identified in this decision as expeditiously as possible.

On April 16, 2010, FERC issued a notice of deficiency regarding the CAISO's PDR tariff proposal, including three discrete areas of concern.[45] Neither the CPUC nor the parties have had the opportunity to review any final PDR provisions. We cannot at this time determine if or how the proposed PDR pilot programs might need to be modified. At this time the Commission remains hopeful that FERC will issue an order on the CAISO's PDR tariff filing in time for the pilot programs to be integrated into the CAISO's wholesale markets for the latter part of the summer of 2010.[46] We will leave Phase Four of this proceeding open for the limited purpose of addressing PDR implementation issues, such as whether and to what extent the Commission will approve the IOU pilot programs based upon the version of PDR eventually approved by the FERC. We

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D.09-08-027 on March 18, 2010 requesting to pilot an agricultural pumping interruptible program for ancillary services to bid into PDR, in addition to converting its existing PLP pilot to a PDR pilot.

44 In its comments on the Proposed Decision, SCE states that as part of its advice letter filing in compliance with this decision, it will include an agricultural pumping interruptible pilot for ancillary services to bid into PDR. As the other utilities have additional proposals before the Commission in other venues, SCE may propose the agricultural pumping pilot but should do so in a separate advice letter filing.

45 Letter from the FERC Office of Energy Market Regulation to the CAISO, filed in Docket No. ER10-765.

46 The Commission may have in an expedited proceeding to determine if the tariff language is appropriate.

clarify that while we defer action on approving IOU bidding of PDR products into the CAISO markets (depending on the outcome of the FERC's proceeding), the IOUs should continue to develop pilot programs as directed herein. Parties should closely monitor FERC Docket No. ER10-765 and be prepared to expeditiously evaluate the FERC's decisions on the proposed PDR product and comment on whether the CPUC should order the IOUs to participate in the CAISO's PDR bidding process after such tariff language is finally approved by the FERC.

We recognize that there may necessarily be an interval between a FERC decision on the CAISO's PDR tariff and the date for IOU participation in PDR bidding in order for the IOUs to modify their PDR programs to reflect FERC and/or CPUC orders approving use of a PDR product design. We will not assume the outcome of the FERC's process and, in effect, begin implementing a program that is still in development. In the event it is not possible to conclude the process by summer 2010, the PDR implementation issues will be addressed in future DR proceedings so that PDR may be implemented as expeditiously as possible.

4. Comments on Proposed Decision

The proposed decision in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 12, 2010 by AreM, DACC, EDF, Edison, EnerNOC, PG&E, and SDG&E. AReM, CAISO, DACC, DRA, EnerNOC, PG&E, and SDG&E filed reply comments on April 19, 2010. All comments and replies were filed timely.

5. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner in this proceeding and Darwin E. Farrar is the assigned Administrative Law Judge in Phase Four of this proceeding.

Findings of Fact

1. There are substantial complexities associated with dual participation in the context of direct participation of retail DR in the CAISO markets.

2. The Commission should consider issues related to dual participation after sufficient experience is gained with PDR.

3. IOUs may solicit and incorporate third-party DRPs into their 2010 PDR pilots as a way to gain experience with real-time DRP/LSE interaction.

4. The CAISO only tracks PDR performance at an aggregate level and does not see usage of the retail customer.

5. The Commission will consider what customer protection policies should be developed for DRPs in a subsequent phase of this proceeding.

6. The Commission shall revisit the question of whether it will allow more than one DRP per customer account in a subsequent proceeding.

7. The Commission shall revisit the question of whether dual participation should be restricted at the retail level in a subsequent proceeding.

8. The details related to settlement, information sharing, and communication shall be resolved in a subsequent proceeding.

9. The IOU PLP programs should be leveraged to design PDR pilot programs that may be ready to be implemented during the summer of 2010.

10. IOU proposals for additional participation in PDR will be considered separately.

Conclusions of Law

1. Consistent with FERC Orders 719 and 719-A, direct bidding by retail consumers of DR resources in wholesale markets cannot go forward in California except as allowed by the Commission and consistent with the terms and conditions established by the Commission.

2. The Commission has jurisdictional authority to restrict IOU customers from directly participating in the CAISO energy markets.

3. Energy Service Providers (ESPs) may engage in direct participation of retail DR on behalf of their own customers and other ESP customers, and an ESP customer can bid on behalf of itself.

4. Load-serving entities that choose to engage in the initial phases of participation may be subject to Commission oversight related to the short and long-term reliability of directly bid resources for Long-term Procurement analysis, counting conventions of directly bid resources for RA credit, environmentally-related procurement statutes and policies, and consumer protection issues.

5. The Commission has a role in consumer protection and may, among other things, resolve customer complaints related to DRPs, establish financial responsibility standards for DRPs, and require DRPs to inform potential customers that enrolling with the DRP will mean that they will be unenrolled from DR programs offered by another carrier.

6. To the extent that existing funds for the PLP programs are insufficient for Proxy Demand Response pilot programs, PG&E, SCE, and SDG&E may seek to shift funds pursuant to D.09-08-027.

O R D E R

IT IS ORDERED that:

1. There shall be only one Demand Response Provider per retail customer account.

2. There shall be no dual or multi-party direct bidding of Demand Response at the retail level.

3. The demand response of utility bundled customers shall not be bid directly into the California Independent System Operator's wholesale electric and ancillary services markets by Demand Response Providers until the Commission establishes consumer protection policies.

4. Any Direct Access customers enrolled in an Investor-Owned Utility demand response program must withdraw from the Investor-Owned Utility demand response program before engaging in direct bidding through a third-party. It is the third-party's responsibility to communicate this requirement to effected Direct Access customers.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 advice letter within 10 days of the effective date of this decision to modify its Participating Load Pilot program to Proxy Demand Resource pilot programs for summer 2010.

This order is effective today.

Dated June 3, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

Attachment B

California Independent
System Operator Corporation

January 14, 2011

VIA HAND DELIVERY

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **California Independent System Operator Corporation**
Docket No. ER06-615-___

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") hereby submits two versions of a report, entitled "2010 ANNUAL REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR EVALUATING DEMAND RESPONSE PARTICIPATION IN THE ISO; Reporting Period: Calendar Year 2010" (hereinafter, "Fourth Annual Report"). The two versions are:

- A Confidential Version (marked as such) containing confidential information; and
- A Public Version (marked as such) in which the confidential information has been redacted.

Because the documents are two versions of the same report, the ISO has marked each version as Attachment A to this transmittal letter. The Commission has directed the ISO file annual report on demand response participation in the Commission's June 25, 2007 Order on Compliance (California Independent System Operator Corp. 119 FERC ¶ 61,313 (2007) at P 226.

Though this letter, the ISO requests confidential treatment of the Fourth Annual Report, which is included as Attachment A to this filing, pursuant to Section 388.112 of the Commission's Regulations. Confidential treatment of this Fourth Annual Report is appropriate because the report contains commercially-sensitive data regarding the participation of one entity in the ISO's market. .

During calendar year 2010, there was only one demand response participant in the ISO market, the California Department of Water Resources, State Water Project ("CDWR-SWP"). Accordingly, the ISO will provide a copy of the Confidential Version of the Fourth Annual Report to CDWR-SWP. Last year, the ISO did not do so, because there were multiple demand response participants, and the ISO determined that it would not disaggregate the reporting information and prepare a custom report for each customer because it was unduly burdensome, beyond the scope of the reporting requirement, and because the information was already available to the market participants through the ISO settlement process.

COMMUNICATIONS

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CONTENTS OF FILING

The following documents are included in this filing:

(1) This Transmittal Letter;

(2) Attachment A Report, entitled "2010 ANNUAL REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR EVALUATING DEMAND RESPONSE PARTICIPATION IN THE ISO; Reporting Period: Calendar Year 2010"

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Respectfully submitted,

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ATTACHMENT A

ATTACHMENT A
PUBLIC VERSION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System	)	Docket Nos. ER06-615-___
Operator Corporation	)	

2010 ANNUAL REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR EVALUATING DEMAND RESPONSE PARTICIPATION IN THE ISO

Reporting Period: Calendar Year 2010

Date: January 14, 2011

Baldassaro "Bill" Di Capo
Senior Counsel for the California
Independent System Operator
Corporation

INTRODUCTION

Obligation to Submit an Annual Report

The California Independent System Operator Corporation ("ISO") submits this "2010 ANNUAL REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR EVALUATING DEMAND RESPONSE PARTICIPATION IN THE ISO; (hereinafter, "2010 Annual Report")[1]

The reporting requirement emanates from the Commission's June 25, 2007 Order on Compliance in proceeding commonly known as the "MRTU Docket", which provided that:

> Finally, we direct the CAISO to file annual reports evaluating its demand response programs, including the amount of demand response it has elicited. The CAISO should file the first report January 15, 2008. At a minimum, the CAISO's report must include: (a) information on customer enrollment for each demand response program in terms of the number of customers and total potential in load reduction in MWs; and (b) information on total load reductions achieved per program per event during the prior year, including the CAISO's system load at time of curtailments, total MWs reduced, total payments for reductions and effects of the demand response programs on wholesale prices.[*FN See, e.g. ISO New England, Inc., 102 FERC [Paragraph] 61,202 (2003)*] [2]

The CPUC is in the Process of Establishing the Rules for Retail Customers to Directly Bid Demand Response into the California ISO Market

The ISO launched its proxy demand resource product on August 10, 2010. Earlier that year, on June 3, 2010, the California Public Utilities Commission (CPUC) had issued a decision directing investor owned utilities to prepare to bid demand response into the ISO markets using proxy demand resource pilot programs.[3] While a positive first step, the CPUC decision also expressly limited the participation by bundled utility customers to participate through an Investor Owned Utility ("IOU") pilot program. The decision did allow for direct access customers, those that procure their electricity through a third-party electricity provider, to offer demand response in the ISO market. The decision also identified several important issues that the CPUC stated had to be resolved and clarified before it would allow all customers to offer demand response into the ISO market. Those issues include retail compensation concerns, information needs, and CPUC jurisdiction and oversight over third-party (i.e. non-IOU) demand response providers.

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[1] The ISO is sometimes referred to as the CAISO.
[2] *California Independent System Operator Corp.* 119 FERC ¶ 61,313 (2007) "June 25, 2007 Order on Compliance Filings" (hereinafter "June 25, 2007 Order") at P. 226.
[3] CPUC Decision 10-06-002, issued in Proceeding R.07-01-041. The decision can be accessed on the CPUC's website at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm.

Until the CPUC proceeding resolves these outstanding issues, the CPUC's prohibition on utility bundled customers offering demand response other than through IOU pilot programs remains in effect. While market participants have expressed interest to the ISO in the proxy demand resource product, to date, there has been no participation even from direct access customers, apparently because third party demand response entities and direct access customers are holding off until stakeholders and the CPUC formally settle the retail rules around direct participation. The ISO is concerned that the relatively slow pace of the state-level proceeding is slowing the pace of retail participation in the wholesale market.

To Date, the Situation in California Remains that There is No Avenue for Non-IOU Demand Response Providers to Access Resource Capacity Revenue Streams Under the CPUC's Resource Adequacy Program

Another factor constricting the robust participation of demand response in the wholesale market is the inability for third-party demand response providers to have access to resource adequacy ("RA") capacity payments, like other resource adequacy resource types, under the CPUC resource adequacy program. Currently, the CPUC has not established rules that allow a load serving entity to procure demand response resources to satisfy its resource adequacy capacity requirement. Instead, resource adequacy treatment is only given to demand response that is enrolled in a utility retail demand response program, and this demand response comes "off the top" of a load serving entity's resource adequacy requirement (by reducing the level of demand for which the IOU must procure RA resources). Without access to resource adequacy capacity payments, the ISO believes it will be very difficult for a competitive demand response delivery paradigm to develop in California. The ISO continues to petition the CPUC to eliminate this barrier and pursue a path for the competitive procurement of all demand response.

While the ISO is concerned about the pace of wholesale demand response development, the ISO is reasonably confident that, with time, these issues will be adequately and satisfactorily addressed. Encouragingly, the CPUC currently has two open phases in its demand response and resource adequacy proceedings (R.07-01-041 and R.09-10-032, respectively) to formally address demand response direct participation and resource adequacy concerns, and the CPUC has established a schedule for further treatment of each issue in each proceeding.[4] In alignment with the ISO, the CPUC's stated goal is "...to better integrate Investor Owned Utility (IOU) Demand Response programs into the California Independent System Operator's (CAISO) price-based

[4] See, e.g., Administrative Law Judge's Ruling Rescheduling Workshops on Remaining Direct Participation Issues (Phase Iv, Part 2), issued December 23, 2010 in R07-01-041 (accessible on the CPUC's website at http://docs.cpuc.ca.gov/efile/RULINGS/128779.pdf) and Phase 2 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge Determining the Scope, Schedule, and Need for Hearing in this Proceeding, issued October 29, 2010 in R09-10-1032 (accessible at http://docs.cpuc.ca.gov/efile/RULC/126035.pdf).

markets."[5] The expectation is that rules and regulations will be decided in time for all customers to participate in the ISO market by summer 2011, enabling the ISO to report results for proxy demand resources in the 2011 Annual Report.[6]

EXECUTIVE SUMMARY AND REQUEST FOR CONFIDENTIAL TREATMENT

Types of Demand Response Participation in the ISO

Participating Load: The Participating Load product is a dispatchable demand resource offered to the ISO through a demand response provider who also acts as the load serving entity for the underlying load. The Participating Load Agreement establishes the relationship between the demand response provider and the ISO and provides that the relationship is governed by the ISO Tariff.

Proxy Demand Resource: Conditionally accepted by the FERC on July 15, 2010, the ISO launched its proxy demand resource product in August 2010.[7] The proxy demand resource product was developed with extensive stakeholder input in response to the FERC Order 719, which required that the ISO amend its market rules to permit an Aggregator of Retail Customers (aka demand response provider) to bid demand response on behalf of retail customers directly into the ISO organized market.[8] The Proxy Demand Resource Agreement establishes the relationship between the demand response provider and the ISO and provides that the relationship is governed by the ISO Tariff.

Demand Response Participation

The situation continues that, as of the date of this report, the ISO Participating Load product has one active participant; the California Department of Water Resources State Water Project ("CDWR-SWP"). This participant schedules, bids, and settles under [redacted]

[5] *Administrative Law Judge's Ruling Soliciting Responses on Remaining Direct Participation Issues (Phase IV, Part 2)*, November 8, 2011, p. 2 (issued in DR proceeding R07-01-041 and accessible at http://docs.cpuc.ca.gov/efile/RULINGS/126178.pdf).

[6] The ISO notes that the Commission has directed the ISO to issue a study report on proxy demand resource participation that should not be confused with the ISO reporting on proxy demand response pilot activity that will be contained in next year's annual report. The Commission's order relating to the ISO's proxy demand response product requires the ISO to submit a study report containing twelve months of actual market data after the CPUC has developed the rules for direct response in CPUC Proceeding R07-010-41 and permitted full participation (i.e. not during the period in which the current pilot program is in place). The Commission recently recapped this reporting requirement in its *Order on Compliance and Rehearing*, 134 FERC ¶ 61,004 (issued January 4, 2011) at P 14, in Dockets ER10-765-001 and ER10-2621-000. This order is accessible on the ISO's website at http://www.caiso.com/2afc/2afcd85357fb0.pdf.

[7] *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC ¶ 61,045 (issued July 15, 2010), accessible on the ISO's website at http://www.caiso.com/27d9/27d9cbb6770.pdf.

[8] *Wholesale Competition in Regions with Organized Electric Markets, Order No. 719*, FERC Stats. & Regs. ¶ 31,281 (2008) at P 154, *order on reh'g,* Order No. 719-A, 74 Fed. Reg. 37,776 (Jul. 29, 2009), FERC Stats. & Regs. ¶ 31,292, *order on reh'g and clarification,* Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[redacted] unique Participating Load resource IDs, which can represent multiple underlying aggregated pump loads.

- **Scope of this Report** This report follows the ISO's previous annual reports of not including data for Pumped Hydro Storage Facilities. As the ISO originally explained in its First Annual Report, the reason for this approach is that these facilities operate differently than traditional demand response resources, in that pumped hydro storage facilities affirmatively schedule and increase load as well as provide load curtailment. The ISO believes that this report's focus on traditional demand response resources results in more meaningful content, because the reported information can be more meaningfully compared against other regions and organized markets, which was a primary purpose for imposing the reporting obligation.

Request for Confidential Treatment

Because the information in this Report focuses upon only one participant, the ISO is submitting this report with an accompanying request for Confidentiality and the ISO is concurrently submitting a Confidential Version/Public Version (in which the Confidential Information has been redacted).

Contribution of Demand Response to Non Spinning Reserves Needs for 2010

On average, over the January 1st to November 30th period covered in this report, the ISO system needed approximately 883 MW of Non-spinning Reserve capacity per hour to operate. The Participating Load participants that are the subject of this report contributed, on average, [redacted] MW of Non-spinning Reserve, either through accepted bids or self provision. These [redacted] MW represents nearly [redacted]% of the ISO's hourly Non-spinning Reserve need for 2010.

In 2010, the Participating Load resources cleared (bid and self provided) an hourly maximum of [redacted] MW and a minimum of [redacted] MW of Non-spinning Reserve capacity to the ISO. On average, [redacted] MW per hour was bid or self-provided to the ISO.

SUMMARY THE ISO'S DEMAND RESPONSE PROGRAMS FOR THE 2010 TIME PERIOD

Participating Load

In 2010, there were [redacted] active Participating Load resources associated with large pumping resources.[9]

The active Participating Load resources in the reporting period can be broken down as follows:

Participant:	California Department of Water Resources State Water Project ("CDWR SWP")
No of Resource IDs:	Total of [redacted] These Participating Load Resources represent an aggregation of pumps; they have been aggregated into separate Participating Load "facilities," for scheduling and settlement purposes.

Reporting Period for this Report and the Time Constraints of the Data Set

The reporting for the 2010 Annual Report reflects the same time constraints as the previous annual reports with respect to the time frames for which the data can be captured and conveyed by the January 15th due date. In order to produce and present relevant data consistent with the June 25, 2007 Order, the ISO must largely cull, correlate, and set out information compiled from a larger pool of underlying data in the ISO's settlement system. Thus, the ISO's information gathering is constrained by the structure of the ISO's settlement system and to the extent data can be timely analyzed and presented for inclusion in the 2010 Annual Report. The data set for this report runs from January 1, 2010 through November 30, 2010 ("Reporting Period") since not all December 2010 settlement data elements are timely available to incorporate into this report; therefore, data through the end of the calendar year cannot be gathered and complied for the full year before the report due date of January 15.

The January 1, 2010 to November 30, 2010 Reporting Period comprises:

- Ninety-two percent (92%) of the 2010 calendar year period,
- 8,016 hours out of 8,760 total hours in the calendar year, or
- 334 out of 365 calendar days.

[9] These [redacted] Participating Load resources are unique, non-pumped hydro storage facilities.

For future reporting purposes, the ISO respectfully submits that future annual reports could convey better information if the filing deadline were shifted, so that the reporting period could capture an entire twelve (12) month, 365 day calendar year. Later in the year, the ISO will file a motion with the Commission, asking to change the reporting date, to present this issue to the Commission. The file date would be best adjusted to a period more than 90 days after the calendar-year end to ensure final settlement data can be analyzed and included in the report.

In addition, the ISO Department of Market Monitoring (DMM) produces an annual report on the performance of the markets administered by the ISO. This DMM annual report covers the period of January 1st through December 31st of the year that is the subject of the report, and is published in a late-March to April time frame. Information in the DMM annual report pertaining to subjects such as system resource adequacy, ancillary services quantities and market performance, and other subjects, would be useful to ISO personnel in producing this annual report on demand response participation within the ISO markets.

NON-SPIN CAPACITY AWARDS AND PAYMENT FROM PARTICIPATING LOAD RESOURCES

In the ISO's wholesale markets, market participants can chose to bid Ancillary Services (such as Non-Spinning Reserves), or to self-provide them. Market participants that choose to bid ancillary services receive the Ancillary Service Market Clearing Price. Accordingly, the ISO makes payment to them for the ancillary service capacity type that was offered and accepted. On the other hand, those market participants that fulfill their ancillary service obligation by self-providing effectively receive an offset of their ancillary service obligation. The offset reduces or eliminates the quantity of ancillary service capacity that they must procure from the market.

On average, for the Reporting Period, the ISO system needed approximately 883 MW of Non-spinning Reserve capacity per hour to operate. This procurement average of 883 MW per hour is based upon the total ISO system requirement for non-spinning reserve capacity divided by the total number of hours for the reporting period of Jan 1, 2010 to Nov 30, 2010, which equates to 8,016 hours.

The Participating Load participant covered in this report contributed, on average, [redacted] MW of non-spinning reserves either through accepted bids or through self-provision. This quantity of Participating Load contribution represented nearly [redacted]% of the ISO hourly Non-spinning Reserve need during the Reporting Period.

However, the range of Non-spinning Reserve capacity offered (or self provided) exhibited some variations during certain, limited hours in 2010. In this regard, Participating Load resources cleared (bid and/or self provided) an hourly maximum of [redacted] MW and a minimum of [redacted] MW of Non-spinning Reserve capacity on certain occasions. On average, however, [redacted] MW per hour was bid or self-provided to the ISO.

TABLE 1 - Non-spinning Reserve Capacity Awards and Payment			
Total Non-spin Capacity Bid (MW)	**Total Non-spin Capacity Awarded (MW)**	**Total Non-spin Capacity Payments ($)**	**Total Non-spin Capacity Self-provided (MW)**
[redacted]	[redacted]	[redacted]	[redacted]

* *These values represent cumulative totals based on eight separate Participating Load Resources.*

<u>No-Pay for Unavailable Non-spin Capacity from Participating Load Resources</u>

No-Pay is a settlement mechanism to encourage resources, both generators and Participating Loads, to keep awarded Ancillary Services available for ISO dispatch (i.e., by following dispatch instructions and by avoiding uninstructed deviations). When triggered, the No-Pay mechanism results in the rescission of payment for the provision of Spinning Reserve and/or Non-spinning Reserve when, subsequent to: i) the ancillary service award for such ancillary services and ii) the ISO payment for the services, the ancillary service becomes either undispatchable capacity, unavailable capacity, undelivered capacity, or, in certain circumstances, unsynchronized capacity. In 2010, only a small percentage of the total Non-spinning capacity awarded to Participating Load resources (approximately [redacted]%) was rescinded through the No-Pay settlement mechanism during the reporting period.

TABLE 2 - Summary of Unavailable Non-Spin Capacity		
Total Non-spin Capacity Awarded and Self-provided (MW)	**Total Non-spin Capacity Unavailable Subject to the No Pay Provision (MW)**	**Total Non-spin Capacity Payment Rescinded Subject to the No-Pay Provision ($)**
[redacted]	[redacted]	[redacted]

<u>Real-time Energy and Payment from Participating Load Resources</u>

To meet its real-time reliability needs, the ISO dispatches real-time energy from dispatchable demand resources when it is economic to do so, based on the submitted bids that the Scheduling Coordinator has submitted to the ISO for Participating Load resources. A Participating Load resource can bid to curtail energy and to consume energy, in a fashion similar the way a generator can bid both incremental and decremental energy, by increasing or decreasing the generators energy output. Per ISO real-time dispatch instructions, a Participating Load resource is either paid for the amount of energy that the resource is instructed to curtail or pays for the amount of energy that the resource is instructed to consume. (This is analogous to the ISO paying a generator to increase output ("INC") and, correspondingly, the generator paying the ISO to decrease output ("DEC") relative to the resource's scheduled energy amount.) Any deviations associated with the ISO's real-time dispatches, i.e. under-deliveries or over-deliveries, will be settled with the Participating Load resource as uninstructed energy. The *Total Energy Settlement* values shown in Table 3 and Table 4 below are the net settlement of the ISO's instructed and uninstructed energy for dispatches to decrease consumption and for dispatches to increase consumption, respectively.

TABLE 3- Decrease Energy Dispatches- Real-time Energy & Settlement Summary				
Total Real-time Energy Offered (MW)	**Total No. of Dispatches (Events)***	**Total Real-time Instructed Energy (MW)**	**Total Real-time Energy Delivered (MW)**	**Total Energy Payments to DR Resources ($)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

**Where dispatches equal to or greater than 0.01 MW, in any interval, are aggregated by trade hour.*

TABLE 4- Increase Energy Dispatches- Real-time Energy & Settlement Summary				
Total Real-time Energy Offered (MW)	**Total No. of Dispatches (Events)***	**Total Real-time Instructed Energy (MW)**	**Total Real time Energy Delivered (MW)**	**Total Energy Charges to DR Resources ($)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

**Where dispatches less than -0.01 MW, in any interval, are aggregated by trade hour.*
+Megawatt quantity attributed to ISO issued Exceptional Dispatch instructions

Real-time Energy Dispatch Detail for Participating Load Resources

See Appendix A to the 2010 Annual Report for a detailed breakdown of Real-time energy dispatch, by hourly event.

SUMMARY OF ISO EVENTS BY MONTH AND HOUR

Given that the majority of dispatchable demand resource megawatts reported here are associated with large pumping resources used to move water around the state of California, these Participating Load resources do not exhibit the more traditional summer-peak demand response characteristic that one expects from demand response resources.

However, the fact that Participating Load resources, like large pumping resources, can participate in the ISO markets in all months and hours of the year means such resources can be of great benefit to the ISO as the system operator and helps further demonstrate the comparability that exists in the ISO wholesale market between supply-side and demand-side resources.

ISO Real-time Dispatches by Month

The data below demonstrates the broad availability of these Participating Load resources to provide real-time imbalance energy, both the ability to increase and decrease energy consumption based on ISO system needs. Table 5 below lists the days and hours by month that Participating Load resources were called to curtail load, i.e. decrease energy and Table 6 lists the days and hours by month that Participating Load resources were called on to consume energy, i.e. increase energy consumption. Table 7 lists the number of dispatch events by hour for the Reporting Period.

TABLE 5- Decrease Load ISO Dispatches by Month

Month	Days	Hours
July	[redacted]	[redacted]
August	[redacted]	[redacted]
September	[redacted]	[redacted]
October	[redacted]	[redacted]
November	[redacted]	[redacted]
Total:	[redacted]	[redacted]

TABLE 6- Increase Load ISO Dispatches by Month

Month	Days	Hours
July	[redacted]	[redacted]
August	[redacted]	[redacted]
September	[redacted]	[redacted]
November	[redacted]	[redacted]
Total:	[redacted]	[redacted]

TABLE 7 ISO Dispatches by Hour

Hour Intervals

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Count of Dispatches per Interval

SUMMARY ISO DEMAND RESPONSE RESULTS ACROSS COMPLIANCE YEARS

For 2010, the percentage of demand response contribution towards the ISO hourly average non-spinning reserve capacity requirement increased to [redacted]% from approximately [redacted]% in 2008 and 2009. The decline over 2008 and 2009 was due to the partial implementation of participating load functionality at the start of the new market (under the redesign known as "MRTU") which allows participating load to provide imbalance energy only for the purpose of providing non-spinning reserve. The [redacted]% figure over calendar year 2010 marks a return to the contribution level observed in calendar year 2007. For 2010, the amount of non-spin capacity bid into the market decreased 52.3%, while the amount of non-spin self-provided increased 57.2%, continuing the trend from 2009 for greater ancillary service participation through self provision from participating load. Real-time energy offers from demand response increased significantly in 2010 by 252% compared to 2009, even though the amount of energy the market required for economic dispatch from demand response declined 67.4%. For instance, in 2009, [redacted] real-time energy demand response dispatches were issued whereas in 2010, only [redacted] were issued.

Below are summary tables of comparative results across compliance years:

TABLE 8
Annual DR Contribution to Hourly Avg. Non-spin Capacity Requirement

Compliance Reporting Year	Hourly Avg. Non-spin Requirement (MW)	Hourly Avg. Awarded Non-spin Quantity (MW)	Percentage of Hourly Non-spin Requirement (%)
2007	812	[redacted]	[redacted]
2008	899	[redacted]	[redacted]
2009	906	[redacted]	[redacted]
2010	883	[redacted]	[redacted]

TABLE 9
Year-to-Year Comparison of Non-spin Capacity from Demand Resources*

Comparison Years	Compliance Reporting Year	Total Non-spin Capacity Bid (% Diff)	Total Non-spin Capacity Awarded (% Diff)	Total Non-spin Capacity Self-Provided (% Diff)
2007/2008	2008	15.7%	-31.9%	-17.9%
2008/2009	2009	-9.0%	-83.6%**	164.6%**
2009/2010	2010	-52.3%	-67.0%	57.2%

** (-) is a decrease and (+) is an increase in percentage difference between years*
*** Significant increase in the amount of Non-spin capacity self-provided in 2009 vs. 2008*

TABLE 10
Year-to-Year Comparison of Compliance from Demand Resources Providing Non-spin*

Comparison Years	Compliance Reporting Year	Total Non-spin Capacity Awarded and Self-Provided (% Diff)	Total Non-spin Capacity Unavailable Subject to No Pay (% Diff)	Total Non-spin Capacity Payment Rescinded Due to No Pay Provision (% Diff)
2007/2008	2008	-26.9%	-18.0%	-69.0%
2008/2009	2009	15.0%	-72.3%	-21.3%
2009/2010	2010	46.5%	365.9%	6.2%

** (-) is a decrease and (+) is an increase in percentage difference between years*

TABLE 11
Year-to-Year Comparison of Real-time Energy from Demand Resources (Load Curtailments)*

Comparison Years	Compliance Reporting Year	Total Real-time Energy Offered (% Diff)	Total No. of Dispatches	Total Real-time Energy Instructed (% Diff)	Total Real-time Energy Delivered (% Diff)
2007/2008	2008	-25.5%	55.4%	16.1%	1.2%
2008/2009	2009	-55.4%	320.8%	-22.1%	-0.4%
2009/2010	2010	252.2%	-67.1%	-67.4%	-63.2%

** (-) is a decrease and (+) is an increase in percentage difference between years*

RETAIL DEMAND RESPONSE PROGRAMS OPERATED BY INVESTOR-OWNED UTILITIES

As has been the case since the First Annual Report, the majority of demand response in California is developed through retail demand response programs that are authorized by the CPUC and funded, designed and operated by the three California IOUs (PG&E, SCE and SDG&E). Demand Response programs and budgets are approved by the CPUC on a rolling three-year program cycle. Program year 2010 was part of the 2009-2011 program cycle.

The IOU demand response programs can generally be classified as one of two types: price-responsive or reliability-based. Price-responsive programs are generally triggered Day Ahead or Day-of, based on non-emergency, price-related triggers. On the other hand, the reliability-based programs are only triggered during emergency conditions, be it a system emergency or a local transmission emergency.

Using August 2010 reported values, the aggregate number of megawatts expected based on CPUC ex-ante and ex-post load impact results in each demand response category (price-responsive and reliability-based), aggregated for the three large IOUs are shown in Table 12 below:

TABLE 12	**Summary of Utility Demand Response Programs for 2010**	
Program Type[10]	**Ex-Ante**	**Ex-Post**
Price-Responsive	589.7	745.4
Reliability-based[11]	1,544.7	750.5
Total:	2,134.4	1,495.9

[10] *Pacific Gas and Electric Company Monthly Report on Interruptible Load and Demand Response Programs for November 2010*, December 16, 2010, p3.

Ex Ante Estimated MW = The monthly ex ante average load impact per customer reported in the CPUC annual April 1st D.08-04-050 Compliance Filing multiplied by the number of currently enrolled service accounts for the reporting month, where the ex ante average load impact is the average hourly load impact for an event that would occur from 2 – 6 pm on the system peak day of the month.

Ex Post Estimated MW = the Annual ex post average load impact per customer reported in the CPUC annual April 1st D.08-04-050 Compliance Filing multiplied by the number of currently enrolled service accounts for the reporting month, where the ex post load impact per customer is the average load impact per customer for those customers that may have participated in an event(s) during all actual event hours in the preceding year when or if events occurred. New programs report "n/a" as there were no prior events.

[11] As described in footnote 10, under **Ex Post Estimated MW**, the significant difference between the ex-ante and ex-post value of 1,544.7 MW and 750.5 MW is attributed to new programs not having historical data, thus an "n/a" is reported for the megawatt value for new programs.

Triggering Events for IOU Demand Response Programs

In 2010, among the three IOUs, there were a total of eighty (80) event-days from June through October.

Event-days by Month for all Three IOUs

Table 13 reports on event-days by month based on aggregated data compiled from utility monthly reports submitted by the IOUs to the CPUC regarding the operation of their interruptible and demand response programs.[12]

TABLE 13 Event-days by Month for All Three IOUs

Month	Event-days*
June	2
July	16
August	32
September	28
October	2

**Includes event-days associated with testing certain utility demand response programs, including pilot programs*

For any particular IOU, an event-day may have been occasioned by both a reliability-based and price-responsive triggering event. Over the Reporting Period, sixty-one (61) price-responsive event-days and nineteen (19) reliability-based event-days were called, in total, by the three IOUs. A breakdown, correlating event days by IOU is shown in the tables below.

Demand Response Events, Broken Down by IOU

Multiple events and different demand response program types can be triggered on the same day, but only one event-day is counted in these circumstances. The following event-day data was provided by the utilities to the CPUC on the operation of interruptible and demands response programs:

[12] The information from the period June 2010 through October 2010 is derived from reports submitted to the CPUC by PG&E, SCE and SDG&E. Specifically, the information is taken from the following reports:

- Pacific Gas and Electric Company Monthly Report on Interruptible Load and Demand Response Programs for November 2010, dated December 16, 2010 Event Summary, p.8.
- A.08-06-001-Report of Southern California Edison Company (U338-E) on Interruptible Load Programs and Demand Response Programs, November 22, 2010, 2010 Event Summary pages.
- Report of San Diego Gas & Electric on Interruptible Load and Demand Response Programs for October 2010, dated November 19, 2010, 2010 Event Summary pages.

TABLE 14 Demand Response Events, by Program Type		
IOU	**Price-Responsive Event-days**	**Reliability-based Event-days**
PG&E	13	12
SCE	34	6
SDG&E	14	1

REAL TIME ENERGY DISPATCH BY HOURLY EVENT			
Dispatch Event		Data	Hour
Day	Hour		
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
		RT Energy Delivered; (MW)	[redacted]
		Energy Payment; ($)	[redacted]
		Hourly Avg. System Load; (MW)	[redacted]
	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]

[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
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[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]

2010 ANNUAL REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR
EVALUATING ISO DEMAND RESPONSE PARTICIPATION IN THE ISO
Docket No. ER06-615-___
PUBLIC VERSION

[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]

[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]	Real-time Energy Dispatched; (MW)	[redacted]
[redacted]	[redacted]	RT Energy Delivered; (MW)	[redacted]
[redacted]	[redacted]	Energy Payment; ($)	[redacted]
[redacted]	[redacted]	Hourly Avg. System Load; (MW)	[redacted]
[redacted]	[redacted]		[redacted]
Total Real-time Energy Dispatched; (MW)*			[redacted]
Total RT Energy Delivered; (MW)*			[redacted]
Total Energy Payment; ($)*			[redacted]

*See Table 3 and Table 4 in the body of the report for detailed information about real-time energy and payment from dispatchable demand resources. For example, as seen in this summary data, the net energy payment made by the ISO to Participating Load resources was $[redacted] which can be broken down from Tables 3 and 4 as $[redacted] payments to Participating Load resources and $[redacted] paid by the Participating Load resources to the ISO.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 14th day of January, 2011

/s/ Anna Pascuzzo

Anna Pascuzzo

Attachment C

FILED
04-08-11
04:59 PM

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 (Filed January 25, 2007)

JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), AND SAN DIEGO GAS AND ELECTRIC COMPANY (U 902 M), TO DELAY ISSUANCE OF PROPOSED DECISION ON PHASE IV, DIRECT PARTICIPATION

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Dated: **April 8, 2011**

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 (Filed January 25, 2007)

JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), AND SAN DIEGO GAS AND ELECTRIC COMPANY (U 902 M), TO DELAY ISSUANCE OF PROPOSED DECISION ON PHASE IV, DIRECT PARTICIPATION

Pursuant to Rule 11.1(a) of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, Southern California Edison Company, on behalf of itself, Pacific Gas and Electric Company, and San Diego Gas and Electric Company (jointly, the IOUs),[1] hereby requests a delay in the issuance of a Proposed Decision (PD) on the financial settlement issues germane to Phase IV of Rulemaking 07-01-041 (the DR OIR).

The IOUs believe that the March 15, 2011 decision by the Federal Energy Regulatory Commission (FERC) on DR compensation (Final Order 745) calls for the Commission to reassess its proposed timeline for issuing a PD in R.07-01-041, Phase IV. The February 17, 2011 *Administrative Law Judge's Ruling Providing Guidance For the Development of Direct Participation Rules, Forms, and Requirements* indicates that a PD on Phase IV may be issued on or before May 24, 2011.

---

[1] SCE has been authorized to file this motion on behalf of the IOUs.

The IOUs respectfully maintain that this timeline should be held in abeyance because the scope and import of FERC Order 745 are uncertain, and there is potential for the FERC decision to conflict directly with the CPUC's ongoing efforts to develop financial compensation rules between DRPs, LSEs and retail end-use customers in accordance with the Proxy Demand Resource (PDR) rules that FERC previously held to be just and reasonable.

Specifically, while FERC Order 745 does not, on its face, purport to disturb the California Independent System Operator's (CAISO's) PDR model, which FERC approved in the *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC paragraph 61,045 (2010), it may in fact do so.

As has been discussed extensively in this proceeding, the PDR framework requires LSEs to pay the CAISO for megawatt-hours of energy that their load does not consume. From an LSE's perspective, this creates a "missing money" problem. The parties to R.07-01-041 met for a three-day workshop last January to discuss, among other things, how to resolve this missing money problem caused by the PDR model. There are several potential approaches on the table—EnerNOC supports an "uplift" that would spread the under-collection amongst the IOU-LSEs' bundled customers; all other parties support some kind of financial settlement to make the LSEs whole, though there is disagreement about what the settlement price should be and who should pay whom.

FERC Order 745 proposes a model that could be interpreted to conflict with the PDR design. Under the model contemplated by Order 745, the LSEs simply pay the cost of the physical load that clears (in the example above, the LSE pays for 90 MWh), and the CAISO pays the DRP for 10 MWh of load reduction. The cost of paying for the load reduction (i.e., the 10 MWh that the CAISO paid the DRP) is then allocated amongst all market participants who theoretically benefited from lower energy prices resulting from demand response. Thus, FERC contemplates an "uplift" at the wholesale level to pay for the cost of the DR load reductions, which is potentially at odds with both scenarios that the Commission is considering in preparing a PD.

The IOUs believe that several parties—including the CAISO, the Edison Electric Institute, several generators, and perhaps even the Commission itself—are considering filing petitions for rehearing of FERC Order 745, which are due in mid-April. The FERC's ultimate decision on rehearing, if unchanged, may then be subject to challenge at the D.C. Circuit Court of Appeals. To make matters more complicated, the FERC has set a July 2011 deadline for ISO submittal of tariffs that conform to FERC Order 745. Should the CAISO submit a tariff that is consistent with the PDR model, it is difficult to know at this stage whether FERC will approve or reject the tariff.

In light of these uncertainties, the IOUs are concerned that the many moving parts in different jurisdictions will lead to procedural and logistical complications. Should the Administrative Law Judge issue a PD in late May as expected, the Parties could potentially be commenting on it (and perhaps on an Alternate PD, if one issues) even though the PD(s) may potentially stand at odds with a FERC decision on the CAISO's July compliance filing. This is to say nothing about whether the FERC decision will withstand scrutiny on a potential appeal at the D.C. Circuit Court of Appeals. Therefore, the IOUs request that the PD be deferred until more clarity obtains at FERC.

The IOUs suggest that the Rule 24 contract/tariff/registration workshop process continue as planned so that the DR OIR parties can make headway on the discrete issues that are not affected (or are only tangentially affected) by the tricky financial settlement issues that have only grown more complicated in recent weeks. This will permit the proceeding to avoid stagnation while, at the same time, obviating the risk of going down a path where the parties (and the Commission) waste valuable time and resources on issues that may ultimately be decided differently in another forum.

The IOUs do not suggest an indefinite delay. Rather, the IOUs propose that the Commission wait until the FERC rules on CAISO's compliance filing (due in July, but CAISO may submit it earlier) to see whether the PDR model—on which the parties' discussions have been based—remains in tact.

Respectfully submitted,

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On behalf of Joint Utilities :
Southern California Edison Company,
Pacific Gas and Electric Company, and
San Diego Gas & Electric Company

April 8, 2011

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), AND SAN DIEGO GAS AND ELECTRIC COMPANY (U 902 M), TO DELAY ISSUANCE OF PROPOSED DECISION ON PHASE IV, DIRECT PARTICIPATION** on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **8th day of April, 2011**, at Rosemead, California.

/s/ ALEJANDRA ARZOLA
By: Alejandra Arzola
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CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

PROCEEDING: R0701041 - CPUC-PG&E, SDG&E, ED
FILER: CPUC-PG&E, SDG&E, EDISON
LIST NAME: LIST
LAST CHANGED: APRIL 5, 2011

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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 (Filed January 25, 2007)

ASSIGNED COMMISSIONER'S RULING AMENDING SCOPING MEMO

Summary

The California Independent System Operator (CAISO) proxy demand response proposal was approved by the Federal Energy Regulatory Commission (FERC) in the *Order Conditionally Accepting Tariff Changes and Directing Compliance Filing*, 132 FERC paragraph 61,045 (2010). However, on March 15, 2011 the FERC amended its regulations in an attempt to further ensure the competitiveness of organized wholesale energy markets and remove barriers to the participation of demand response resources. The new FERC order calls into question whether the previously approved CAISO tariffs are permissible. This order amends the scope of the proceeding to allow consideration and clarification of FERC's new rule.

Discussion

In the Order Instituting Rulemaking that initiated this proceeding, the California Public Utilities Commission (CPUC or Commission) stated that it would consider modifications to demand response programs needed to support

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the California Independent System Operator's (CAISO) efforts to incorporate demand response into wholesale market design protocols.[1] On November 9, 2009, the original Scoping Memo in this proceeding was amended pursuant to Rule 7.3 of the Commission's Rules of Practice and Procedure. The amended Scoping Memo modified the scope of the proceeding to include certain issues related to the possibility of changes to the CAISO wholesale market design protocols to accommodate direct participation of retail demand response resources in CAISO wholesale markets, and set a schedule for consideration of these issues in a new Direct Participation Phase of this proceeding.[2]

The parties to this proceeding met for a three-day workshop to discuss issues related to the direct participation of retail demand response resources in CAISO wholesale markets including, among other things, how to resolve the missing money or double payment problem. The missing money problem occurs where, for example, a Load Serving Entity (LSE) procures 100 Megawatt-hours (MWh) of load and only 90 MWh is recorded on the LSE's customers' meters (the other 10 MWh are curtailed through a Demand Response Provider (DRP). Through a wholesale market settlement, the Independent System Operator (ISO) pays the LSE an energy payment for the 10 MWh that the LSE over-procured. However, the ISO also pays the DRP for the 10 MWh bid that cleared as energy supply. This creates what has been called a "missing money" problem for the LSE (that paid for more energy than its customers actually consumed).

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[1] Order Instituting Rulemaking 07-01-041 at 1.

[2] All references to rules are to the Commission's Rules of Practice and Procedure.

Workshop participants identified several ways to deal with the missing money problem. The CAISO noted that its proxy demand response (PDR) model is designed to address the problem through the deployment of a default load adjustment (DLA) mechanism. In contrast, EnerNOC supports an "uplift" that would spread the under-collection amongst the Investor-owned Utilities-LSEs' bundled customers. In general, while all parties to this proceeding support some kind of financial settlement to make the LSEs whole, there is disagreement about what the settlement price should be and who should pay whom.

While Federal Energy Regulatory Commission (FERC) Order 745 does not, on its face, purport to disturb the CAISO's PDR model it proposes a model that may conflict with the PDR design.[3] The FERC has set a July 2011 deadline for ISO submittal of tariffs that conform to FERC Order 745. Though staff has asked FERC for clarification of whether the CAISO's PDR model conforms to FERC Order 745, we do not now know if FERC will approve a tariff that is consistent with the CAISO PDR model. An extension of the statutory deadline set forth in California Public Utilities Code section 1701.5(a) and (b) is necessary to not only allow issuance of an order addressing the cost allocation, tariff language changes and settlement agreement issues at hand at the CPUC, but also to await clarification from the FERC regarding whether PDR may be implemented as already approved by the FERC.

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[3] Some market participants have interpreted the new FERC order as eliminating the possibility of the DLA.

IT IS RULED that:

1. The November 9, 2009 scoping memo is amended to accommodate consideration of the anticipated Federal Energy Regulatory Commission response to staff request.
2. It is necessary to extend the deadline for the proceeding beyond the May 9, 2010 deadline.
3. The proceeding will be completed within 18 months of the date of this ruling.

Dated May 9, 2011, at San Francisco, California.

/s/ MICHAEL R. PEEVEY
Michael R. Peevey
Assigned Commissioner

Attachment E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets) **Docket No. RM10-17-___**

DECLARATION OF PETER SKALA ON BEHALF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Peter Skala. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

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

A. I am employed by the California Public Utilities Commission (CPUC) as Manager, Demand-Side Analysis Branch, Energy Division.

Q. Please describe your professional and educational background.

A. My experience includes:

Supervisor, Climate Strategies, CPUC (2008-2010): Managed the California Public Utilities Commission team responsible for developing and implementing policies that achieve energy sector contributions to California's greenhouse gas reduction goals. Developed energy sector specific recommendations for the development of state, regional, and federal policies – most notably by the California Air Resources Board, the Western Climate Initiative, and California's federal legislative delegation – to ensure that the policies developed in these forums provide the correct incentives, signals, and resources to achieve energy sector emissions reductions. Provided subject matter expertise and assisted in the development of policies related to California's emissions performance standard, combined heat and power facilities, electric and alternatively fueled vehicles, carbon capture and sequestration projects, and a variety of other energy-sector greenhouse gas reduction technologies and initiatives.

Senior Analyst, Energy Division, CPUC (2007 – 2008): As the leader of the Energy Division's Long Term Procurement team, managed the development of electricity portfolios and procurement rules for California's three large Investor-Owned Utilities. Analyzed and developed revisions to all aspects of the Utilities' planning methodologies, policy recommendations, and residual net short assessments. Led workshops, evaluated input from stakeholder groups, identified and addressed data gaps, and briefed/developed recommendations for Commissioners on all aspects of utility procurement.

Regulatory Analyst; CPUC Office of Ratepayer Advocates (2001 – 2004): Performed economic analyses and developed recommendations in a variety of energy-related proceedings as a ratepayer advocate, working for an independent component of the CPUC.

Project Manager/Engineer; ERM, Inc. and GAIA Consulting (1990 – 2001) Walnut Creek, CA: Managed projects and performed a wide range of pollution prevention and soil and water remediation services for a full-service, international consulting firm.

Coordinated input from state and federal regulators, citizen groups, land owners, and other stakeholders to design and implement solutions to soil and water remediation projects.

Highlights of my education include:

San Francisco State University San Francisco: CA M.A., Economics (Graduate Achievement Award recipient)

University of Vermont Burlington, VT: B.S., Mechanical Engineering

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

A. In my declaration, I will discuss a number of demand response initiatives that the CPUC is undertaking at the retail level related to two demand response products that the California Independent System Operator Corporation (ISO) has developed or is developing at the wholesale level. These two wholesale demand response products are the Proxy Demand Resource (PDR) product and the Reliability Demand Response Resource (RDRR) product. As I will explain, the CPUC has worked closely with the ISO and interested stakeholders in California on both the design of these wholesale demand response products and on related initiatives where the CPUC, among other things, has determined whether to authorize California utilities and direct access customers to bid demand response into the ISO wholesale market. I will also explain that any directives of the Federal Energy Regulatory Commission (FERC) regarding the "default load adjustment" feature of the ISO's PDR and RDRR market design are critically important to the timing of the CPUC's future efforts to authorize California utilities and direct access customers to bid into the ISO market via the PDR and RDRR products and to resolve related retail compensation issues. The CPUC is concerned that the timing, development, and success of its initiatives related to the PDR and RDRR products will be adversely affected by recent directives potentially affecting the default load adjustment that are contained in FERC's March 15, 2011, rulemaking, *Demand Response Compensation in Organized Wholesale Electricity Markets*, Order No. 745, 134 FERC ¶ 61,187, 76 Fed. Reg. 16658 (March 15 Rule).

II. <u>The Proxy Demand Resource Product</u>

Q. What is the PDR product?

A. The PDR product is a demand response product developed by the ISO, in collaboration with the CPUC and a wide range of stakeholders, which is designed to allow demand response providers (DRPs) to aggregate the demand response of retail end-use customers, in order to permit that demand response to be bid into the wholesale markets operated by the ISO. The FERC authorized the ISO to implement the PDR product last year.

Q. What is the default load adjustment feature of the ISO's PDR product?

A. The default load adjustment is a critical element of the ISO's PDR product that was developed through the collaboration of the ISO, stakeholders, and the CPUC. The purpose of the default load adjustment is to prevent a wholesale double payment resulting from a payment being made for the demand response services provided by a PDR and a payment also being made to a load serving entity (LSE) for uninstructed imbalance energy resulting from the ISO's acceptance of a bid from a PDR (*i.e.*, energy scheduled but not consumed because the PDR provided the demand response services). The default load adjustment eliminates this wholesale double payment by adding the energy measurement for a PDR to the meter quantity of the LSE for that PDR in the ISO's uninstructed energy pre-calculation, resulting in an adjusted meter demand value.

Q. Please briefly describe the origins of the PDR product.

A. The PDR product was the result of years of related discussions among the ISO, the CPUC, and their respective stakeholders. During the summer of 2008, the ISO held a series of demand response technical design sessions with the goal of learning how to integrate retail demand response programs into the ISO's wholesale markets. In these sessions, the ISO proposed to develop the concept of the PDR product, which would be designed to allow participants in the retail demand response programs of the investor-owned utilities (IOUs) in California to participate in the ISO's markets through a market bid rather than through the manual process then applicable. The three IOUs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

Q. Was the CPUC taking actions regarding PDR in tandem with the ISO's development of its PDR product?

Yes. In August 2009, the CPUC issued a decision adopting the IOU demand response programs for the 2009 to 2011 demand response program cycle.[1] That August 2009 Decision included the requirement that the IOUs modify a portion of their demand response portfolios to participate as PDRs in the ISO markets.

[1] CPUC Decision 09-08-027, issued with regard to Applications 08-06-001, 08-06-002, and 08-06-003 (Aug. 24, 2009), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/106008.DOC.

In June 2010, the CPUC issued a decision affirming that the ISO's PDR design is consistent with the CPUC's own efforts to promote demand response in the State of California.[2] The June 2010 Decision directed the California IOUs subject to the CPUC's jurisdiction to prepare to bid demand response into the ISO market using PDR pilot programs. The June 2010 Decision also expressly limited the initial participation by bundled utility customers to participate through an IOU pilot program. Given the importance of Demand Response in California's efforts to fulfill load through more environmentally sensitive resources,[3] the June 2010 Decision anticipated that the ability of CPUC jurisdictional retail customers to participate in the ISO's Proxy Demand Resource product could expand after some experience with the initial pilot programs.[4] The June 2010 Decision did allow for direct access customers (*i.e.*, those retail customers that procure their electricity through a third-party electricity provider) to offer demand response in the ISO market.

The decision also identified several important issues that the CPUC stated had to be resolved and clarified before it would allow all customers to offer demand response into the ISO market. Those issues include retail compensation and financial settlement concerns, consumer protection and information needs, and CPUC jurisdiction and

[2] CPUC Decision 10-06-002, issued in Proceeding R.07-01-041 (June 4, 2010) (June 2010 Decision), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/118962.DOC, as modified by Decision 10-12-060, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128488.DOC.

[3] See *Energy Action Plan[,] 2008 Update*, published in February, 2008, available at http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF.

[4] See June 2010 Decision at pp. 11-13.

oversight over third-party (*i.e.*, non-IOU) demand response providers, and Resource Adequacy capacity credit for new/modified demand response products, as well as accounting for PDR bidding within the CPUC's long-term reliability and procurement planning processes. The June 2010 Decision cited the default load adjustment as a significant feature of the ISO's PDR product.

Q. To what extent would you say that issues regarding PDR will affect the efforts of the CPUC to promote demand response in California?

A. A significant issue with the PDR product has the potential to require the CPUC to re-examine its related demand response initiatives and authorizations.

Q. Does the March 15 Rule create significant issues with the CPUC's demand response initiatives?

A. Yes. Certain statements in the March 15 Rule appear to have the potential to require the elimination of the default load adjustment feature of the ISO's PDR market design and have already caused the IOUs regulated by the CPUC to seek a delay in a CPUC proceeding related to the PDR product

Q. What statements in the March 15 Rule have created this uncertainty?

A. The example of the "net benefits test" in the March 15 Rule suggests that, when the ISO dispatches a reduction in demand by a demand response resource, the ISO will also reduce load attributed to a demand response resource by the quantity of the demand response resource dispatched. Under the ISO's default load adjustment, however, the

ISO adds the amount of energy delivered by a PDR to the metered load quantity of the associated load serving entity. But the March 15 Rule does not discuss the default load adjustment directly, and therefore it is currently uncertain whether the March 15 Rule does require the default load adjustment to be eliminated and double payments to be made. Accordingly, the CPUC will seek clarification and/or rehearing of the March 15 Rule.

Q. What are the potential implications for retail customers if the ISO is required to pay both a demand response provider and a load serving entity for the same reduction in demand?

A. Ultimately, retail customers would have to pay twice for the same demand reduction. Whether the PDR is also a load serving entity, the PDR will receive a market payment for the ISO's acceptance of its demand reduction bid. This market payment will be allocated to load and ultimately will be paid for by retail customers in California. Without the default load adjustment, a wholesale market payment will also be made to a load serving entity for uninstructed imbalance energy resulting from the reduction in demand. This imbalance energy payment will also be paid for by retail customers in California.

Q. Has the uncertainty caused by the March 15 Rule regarding the default load adjustment created any significant issues thus far?

A. Yes. On April 8, 2011, due to the issuance of the March 15 Rule, all three IOUs in California filed a joint motion in the proceeding in which the June 2010 Decision was issued. The three IOUs requested that a CPUC Administrative Law Judge delay issuance of a proposed decision on the financial settlement issues germane to the CPUC's demand response rulemaking until the uncertainty created by the March 15 Rule is resolved.[5] These financial settlement issues are conditions precedent to the CPUC's issuance of a final decision on bidding demand response into the ISO market.

Until the CPUC proceeding resolves these outstanding issues and the CPUC issues the proposed decision discussed above, the CPUC's prohibition on bundled utility customers offering demand response other than through IOU pilot programs remains in effect. As a result, the uncertainty regarding the ongoing validity of the FERC-approved PDR product created by the March 15 Rule has significant potential to delay the CPUC's ability to authorize entities subject to its jurisdiction to bid demand response into the ISO. While the CPUC remains committed to proceeding with development of a proposed decision to address the issues related to Proxy Demand Resources that are within the purview of the CPUC's authority; the CPUC requires significant market participant input on the development of the relevant retail tariff language, model service agreements, and consumer protection mechanisms. The regulatory uncertainty created by the March 15 Rule has already pulled significant CPUC and market participant resources away from resolving such issues, and threatens to undermine the quality and timeliness of participation in this important decision-making process. This possible delay is especially critical because the summer months are approaching, when PDR will be most needed to provide demand response in California.

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5 See http://docs.cpuc.ca.gov/efile/MOTION/133321.pdf.

Q. Does the uncertainty caused by the March 15 Rule regarding the default load adjustment create the potential for other significant issues?

A. It definitely does. At least one IOU has submitted a filing to the CPUC explaining that, once the ISO's PDR tariff language was finalized, it would take potentially nine to twelve months to design and implement their demand response bidding software and other internal processes consistent with the PDR requirements.[6] The threat that the critical default load adjustment feature may be eliminated creates the possibility that the IOUs will need to redesign their processes and software, thus jeopardizing their ability to take part in the PDR product in 2011 or even in 2012.

Moreover, the CPUC would also need to evaluate seriously whether it is in the interests of California consumers for the CPUC to authorize utilities and direct access customers to participate in any market product that could result in retail customers effectively paying twice for the same product. Therefore, to the extent the March 15 Rule mandates wholesale double payments for demand reductions, the CPUC reserves the right to revisit its determinations conditionally authorizing entities subject to the CPUC's jurisdiction to participate in the ISO market as PDRs.

III. The Reliability Demand Response Resource Product

Q. What is the RDRR product?

A. The RDRR product is a demand response product that will enable qualifying emergency-responsive resources to participate in the ISO market. The ISO is currently conducting a

[6] See pages 2-4 of the post-workshop comments filed by PG&E in Proceeding R.07-01-041 on February 11, 2011, available at http://docs.cpuc.ca.gov/efile/CM/130783.pdf.

stakeholder process to develop the tariff provisions, software changes, and business practice requirements to allow ISO market participation by RDRRs. The ISO has explained that the RDRR product is being built on the same platform as, and will have many similarities to, the PDR product. In particular, RDRRs will be subject to the same default load adjustment as PDRs.

Q. Please briefly describe the origins of the RDRR product.

A. The CPUC has approved a number of programs over the years that allow customer load to be made available for demand reductions in emergency circumstances. Such products effectively prevented the drop of firm load during California's "heat storm" of 2006, during which the state suffered 50-plus year-high temperatures (depending on statistical methodologies) for 24-hour-a-day periods over several weeks' time. After several years of discussions as to how such emergency-responsive demand response resources could be made available under the ISO's wholesale market design, the ISO, state utilities, and other interested parties entered into a settlement agreement in 2010 to develop RDRRs as a new category of demand response resources that can participate in the ISO market.

Q. What are the main features of that settlement agreement?

A. The settlement agreement, called the Reliability-Based Demand Response Settlement, was approved by the CPUC in 2010.[7] The express purpose of the settlement is to "address the operation of investor-owned utilities' emergency triggered DR [demand response] programs in the wholesale electricity market and the integration of emergency

[7] CPUC Decision 10-06-034, issued in Proceeding R.07-01-041 (June 25, 2010), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/119815.DOC.

triggered DR into wholesale market design." The settlement requires the ISO to develop "a wholesale reliability demand response product (RDRP) that is compatible with IOU reliability-based demand response programs." The settlement also states that information on the RDRP is intended to be incorporated into the IOUs' demand response portfolio applications for 2012-2014, which were filed in March 2011. The settlement can be modified only by written agreement of all the parties and approval of the CPUC.

Q. Would the elimination of the default load adjustment and the provision of double payments pursuant to the March 15 Rule create any significant issues for RDRRs?

A. Yes. As I stated above, the RDRR product is being built on the same platform as, and will have many similarities to, the PDR product – including the use of the default load adjustment. Therefore, to the extent the March 15 Rule applies to the RDRR product and requires the elimination of the default load adjustment and the provision of double payments, the March 15 Rule will adversely affect the RDRR demand response initiative in California.

Q. Please explain what those adverse effects are.

A. Requiring a change to the default load adjustment will substantially impede the implementation of the RDRR product pursuant to the CPUC-approved Reliability-Based Demand Response Settlement. That settlement is premised on the ISO's providing information regarding the RRDR product to the IOUs so they can include that information in their demand response portfolio applications for 2012-2014. If the ISO needs to radically modify that information in order to eliminate the default load adjustment and allow for double payments, the IOUs may be unable to implement their own demand response programs within the time contemplated in the Reliability-Based Demand Response Settlement. As a result, the terms of the settlement may be violated and the settlement may terminate unless the parties are able renegotiate a new settlement pursuant to the violation of those terms.

This settlement resolved years of discussion in various CPUC proceedings as to how emergency response demand response resources can participate in the ISO market. If the uncertainty created by the March 15 Rule results in termination of the settlement, the CPUC would most likely need to re-examine the terms under which emergency demand response can participate in the ISO market. At a minimum, such a re-evaluation could substantially delay emergency demand response resources from participating directly in the ISO market.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 12, 2011

Peter Skala

Attachment F

California ISO
Your Link to Power

California Independent
System Operator Corporation

February 16, 2010

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER10-____-000
Tariff Amendment to Implement
Proxy Demand Resource Product

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") submits this filing to modify the ISO tariff in order to reduce barriers to the participation of demand response in the ISO's market through the implementation of a new demand response product, the proxy demand resource ("PDR").[1] The ISO proposes the proxy demand resource product in order to increase demand response participation in the ISO market and respond to stakeholders' requests for a demand response product that will facilitate the participation of existing retail demand programs in the ISO market. The tariff provisions implementing the proxy demand resource product will satisfy the directives of the Commission's Order No. 719 that independent system operators should develop the capability to permit an aggregator of retail customers to bid demand response on behalf of retail customers directly into the ISO's organized markets to the extent permitted by applicable laws and regulations regarding retail customers.

The ISO respectfully requests that the proposed *pro forma* proxy demand resource agreement included in this filing be made effective on April 19, 2010, so that the ISO can begin entering into contracts with demand response providers that seek to take advantage of the new proxy demand resource product, and so

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[1] The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13. The ISO is also sometimes referred to as the CAISO. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the ISO tariff, and except where otherwise noted herein, references to section numbers are references to sections of the tariff.

that demand response providers can begin to seek approval from the load serving entities ("LSEs") for retail customers to participate in proxy demand resources and demand response providers can begin to register proxy demand resources at the ISO. The ISO requests that the rest of the tariff changes contained in this filing be made become effective on May 1, 2010, which is the date that the ISO's proxy demand resource market systems will become operational and can accept bids from scheduling coordinators for proxy demand resources in the ISO's market. Although it is requesting two different effective dates, the ISO requests that the Commission address all aspects of this tariff amendment filing in a single order.

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger.

I. Background

A. Development and Benefits of the Proxy Demand Resource Product

Wholesale demand response products, such as the ISO's proxy demand resource proposal, are designed to compensate market participants for responding to ISO price signals by reducing electricity use by end-use customers based on cleared day-ahead schedules and/or real-time energy dispatch instructions issued by the ISO. Under the ISO's proposal, a proxy demand resource is defined as a load or an aggregation of loads capable of measurably and verifiably reducing their electric demand in response to ISO dispatch instructions.

A proxy demand resource is controlled by a demand response provider but participates in the ISO market through an ISO-certified scheduling coordinator.[2] The scheduling coordinator representing a demand response provider submits schedules and bids for proxy demand resources to curtail load at a pricing node ("PNode") (or aggregated PNode) using a "proxy generator" as the modeled resource. The scheduling coordinator that represents the load serving entity will continue to schedule forecasted load at the default load aggregation point. The load serving entity and the demand response provider may be the same entity or different entities. Similarly, the load serving entity and demand response provider can be represented by the same scheduling coordinator or two different scheduling coordinators. The settlement for the curtailed portion of the load will be settled by the ISO directly with the demand response provider's scheduling coordinator at the proxy demand resource's specified PNode or aggregated PNode. Determination of actual delivery by the

[2] A demand response provider can also be an ISO-certified scheduling coordinator, which will allow the demand response provider to schedule and bid its own proxy demand resources in the ISO market.

proxy demand resource will be calculated as the difference between actual metered load for the proxy demand resource and a pre-determined baseline.[3] The load serving entity and the proxy demand response provider may enter into a bilateral agreement that addresses compensation for the energy procured by the load serving entity but not consumed as a result of load curtailment actions taken by the demand response provider. Alternatively, this compensation issue may be addressed by the local regulatory authority rules or regulation. For example, the compensation issue is currently being considered in the CPUC demand response proceeding discussed below in this transmittal letter. Accordingly, the ISO tariff will not indicate if and how revenues will be shared between the load serving entity and the demand response provider.

The proxy demand resource proposal is the result of efforts by the ISO to enhance stakeholder opportunities for demand response in the ISO's newly redesigned market structure. Culminating many years of work on the market redesign (also called the Market Redesign and Technology Upgrade or "MRTU"), the ISO implemented the ISO's new market and new tariff on March 31, 2009. The new tariff was initially filed in February 2006 and was further enhanced consistent with Commission directives in Docket No. ER06-615. In its September 21, 2006 order conditionally approving the MRTU tariff, the Commission discussed the benefits of demand response products and directed the ISO to work with market participants to develop additional opportunities for demand response resources to participate in the ISO market:

> MRTU provides loads with demand response capability – the opportunity to participate in the CAISO day-ahead, real-time, and ancillary services markets under comparable requirements as supply, and receive the corresponding market value. Price-responsive demand moderates price increases and price volatility for all customers . . . and it also helps to check potential market power because it provides a countervailing willingness to reduce demand in the face of high prices. Further, demand response contributes to reliability by shaving peak demand and providing reserves.
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> . . . .
>
> Recognizing the importance of demand response programs for the effective operation of electricity markets, we direct the CAISO to

3 *See* "Business Requirements Specification: Demand Response – Proxy Demand Resource (PDR), Version 1.8" (Dec. 23, 2009), at 17 ("Draft PDR Business Requirements Specification"). This ISO document is available on the ISO's website at http://www.caiso.com/2494/249473613ffe0.pdf.

> work with market participants to present additional opportunities for demand response resources to participate in the CAISO market.[4]

Since the issuance of the September 21, 2006 MRTU order, the ISO has worked extensively with stakeholders to achieve the goal of developing opportunities for market participation by demand response resources.[5] However, to date, the ISO's current market rules have not allowed the ISO to tap the full spectrum of potential demand response resources available in California in a fully effective and efficient manner.

The ISO currently provides for demand response resources to participate in wholesale markets primarily as "participating load,"[6] which enables resources to provide curtailable demand in the ISO market.[7] Over the summer of 2009, eight participating load resources actively participated in the ISO's new market.[8] The ISO is developing refinements to allow participating load to participate more fully in the ISO market in its upcoming "Markets and Performance" ("MAP") initiative.[9]

Although the ISO believes that the participating load tariff provisions provide an appropriate opportunity for certain demand response resources to participate in the ISO market, the ISO also believes that it is appropriate to

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4 *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at PP 10, 689 (2006). Subsequently, the Commission directed the ISO to file annual reports evaluating participation of demand response in the ISO market. *California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 226 (2007).

5 *See, e.g.*, *id.* at P 218 ("We fully support the CAISO and stakeholders' efforts to establish a collaborative process to address questions on how to develop and integrate demand response resources into MRTU"); *California Independent System Operator Corp.*, 126 FERC ¶ 61,148, at P 29 (2009) ("We note that the Commission has directed the CAISO to work with interested stakeholders to develop proposals for integrating demand response resources into the MRTU markets, and that the CAISO is complying with this directive").

6 *See* "Third Annual Report of the California Independent System Operator Evaluating Demand Response Participation in the ISO," Docket No. ER06-615-000 (Jan. 15, 2010), at 4 ("2009 Demand Response Report"). In 2009, the ISO implemented a number of small-scale demand response pilot programs to explore the feasibility of aggregating certain smaller demand response resources and bidding them into the ISO's day-ahead and real-time markets for ancillary services. *Id. See also California Independent System Operator Corp.*, 128 FERC ¶ 61,184 (2009) (accepting participating load pilot agreements filed by the ISO).

7 A participating load is defined in Appendix A to the ISO tariff as "[a]n entity, including an entity with Pumping Load or Aggregated Participating Load, providing Curtailable Demand, which has undertaken in writing by execution of a Participating Load Agreement to comply with all applicable provisions of the CAISO Tariff." Curtailable demand is defined in Appendix A as "Demand from a Participating Load or Aggregated Participating Load that can be curtailed at the direction of the CAISO in the Real-Time Dispatch of the CAISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the CAISO to meet Non-Spinning Reserve or Imbalance Energy."

8 2009 Demand Response Report at 6-7.

9 *See, e.g.*, *California Independent System Operator Corp.*, 129 FERC ¶ 61,157, at P 35 (2009).

develop an alternative mechanism for participation in the ISO market by demand response resources that do not satisfy the criteria to be participating load. Further, the ISO's current participating load model is not readily compatible with existing retail demand response programs managed by the three large investor-owned utilities ("IOUs") in California (Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company). Currently, existing IOU retail demand response programs can only be triggered based on a number of conditions such as price, ISO load forecast, and temperature forecast. In 2007, as an incremental step towards integrating the retail demand response programs into the ISO market, the ISO implemented a manual process for the IOUs to report to the ISO when their retail demand response programs were triggered.[10] Under the ISO's new market design, the ISO uses this information to adjust the procurement target for residual unit commitment ("RUC") in the day-ahead market and the forecast for real-time energy procurement to account for the expected demand response.[11]

During the summer of 2008, the ISO held a series of demand response technical design sessions with the goal of learning how to integrate retail demand response programs into the ISO's market.[12] The technical design sessions indicated that the existing participating load model did not provide the flexibility needed to integrate the IOUs' retail demand response programs into the ISO wholesale energy and ancillary services markets. In particular, the load serving entities expressed concern about the difficulty of forecasting the load of the underlying customers that make up a participating load resource separately and distinctly from their overall load. This load forecasting concern is exacerbated by the fact that retail demand response programs can experience customer migrations though changes in enrollment from month to month. Also, stakeholders expressed a concern that direct access customers whose load is not served by an IOU, actively participate in the IOU's demand response program, which further complicates load forecasting and raises other policy concerns.

In the technical design sessions, the ISO first proposed to develop the concept of a proxy demand resource in order to enhance its existing demand response capability and address the concerns raised by stakeholders.[13] The proxy demand resource proposal would be designed to allow participants in the

[10] The ISO implemented this process in compliance with the Commission's directive in *California Independent System Operator Corp.*, *supra*, 119 FERC ¶ 61,313, at P 221.

[11] *See* ISO tariff, Section 31.5.3.2.

[12] Materials related to the demand response technical design sessions are available on the ISO's website at http://www.caiso.com/1cbb/1cbbc8ec52810.html.

[13] *See, e.g.*, "Guidance Document on MRTU Release 1 Provisions to Support 'Demand Response' Programs" at 9-19 (concerning the ISO's proposed "Post-MRTU Release 1 Functionality: 'Proxy Demand Resource' – NEW"). This guidance document is among the materials posted on the ISO's website in connection with the demand response technical design session held on July 30, 2008.

IOUs' retail demand response programs to participate in the ISO market through a market bid rather than through a manual process, provide the flexibility to accommodate direct access customers that participate in IOU demand response programs and simplify forecasting and scheduling requirements for load serving entities to facilitate end-use customer participation.

In late 2008, the ISO established the proxy demand resource stakeholder process.[14] A list of the key dates in the stakeholder process is provided in Attachment E to this filing. This stakeholder process included over fifteen meetings and conference calls and eight opportunities for written stakeholder comments. The stakeholder process resulted in a final proposal for implementing the proxy demand resource product that was presented to and approved by the ISO Governing Board ("Board") at its meeting held on September 10, 2009.[15] An additional component of the proxy demand resource design, pertaining to the treatment of proxy demand resources in the local market power mitigation process, was presented to and approved by the Board at its February 11, 2010 meeting.[16]

In August 2009, the California Public Utilities Commission ("CPUC") issued a decision adopting the IOU demand response programs for the current 2009 to 2011 demand response program cycle.[17] This decision included the requirement that the IOUs modify a portion of their demand response portfolios to participate as proxy demand resources in the ISO market:

> Within 30 days of the filing of CAISO's Proxy Demand Resource tariff with the Federal Energy Regulatory Commission, the utilities shall propose modifications to one or more existing demand response programs that will make at least 10 percent of the megawatts enrolled in the demand response programs authorized in this decision comply with the requirements of CAISO's Proxy Demand Resource.
>
> Within 30 days of the approval of CAISO's Proxy Demand Resource tariff by the Federal Energy Regulatory Commission, each utility shall file a proposal with the Commission to make at least one new or existing demand response program or option within a program comply with the 10-minute dispatch notification

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[14] Materials related to the proxy demand resource stakeholder process are available on the ISO's website at http://www.caiso.com/23bc/23bc873456980.html.

[15] Materials related to the September 10, 2009 Board meeting are available on the ISO's website at http://www.caiso.com/241e/241ea8bb13ed0.html.

[16] Materials related to the February 11, 2010 Board meeting are available on the ISO's website at http://www.caiso.com/2732/2732dc1726d0.html.

[17] CPUC Decision 09-08-027, "Decision Adopting Demand Response Activities and Budgets For 2009 Through 2011" (Aug. 20, 2009). That CPUC decision is available on the CPUC website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/106008.pdf.

time requirements for participation in the CAISO's ancillary services market as either Proxy Demand Resource or Participating Load.[18]

By increasing the quantity of resources participating in the energy and ancillary services markets, the proxy demand resource product will provide greater market liquidity and help to mitigate potential market power concerns. In particular, the ISO believes that implementation of the proxy demand resource product may have the following benefits:

- Due to proxy demand resources participating in the ancillary services markets, the cost of procurement for ancillary services may be reduced. Additionally, given the greater liquidity and depth of these markets resulting from implementation of the proxy demand resource product, the chances of triggering scarcity reserve pricing pursuant to the ISO tariff[19] may also be reduced.

- Proxy demand resource performance could potentially reduce the cost of serving load at the applicable load aggregation point ("LAP") by reducing demand, and therefore reducing congestion costs, resulting in a lower locational marginal price ("LMP") at high-priced nodes.

- The cleared proxy demand resource schedule in the integrated forward market will be considered as a supply contribution towards the scheduled load in the integrated forward market, thereby reducing the RUC target, and thus reducing the amount of generator capacity procurement.

As noted above, the ISO proposes to implement the proxy demand resource product on May 1, 2010. The ISO also plans to explore enhancements to both the participating load product and the proxy demand response product and to consider further demand response products in the future as the ISO market evolves and additional needs and opportunities are identified.

B. Order No. 719

In addition to enhancing the ISO's demand response capabilities, the proxy demand resource proposal satisfies certain requirements of the Commission's Order No. 719.[20] Among other things, Order No. 719 established a number of requirements for independent system operators ("ISOs") and

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18 *Id* at pp. 240-41, Ordering Paragraphs 25-26.

19 *See* ISO tariff, Section 27.1.2.3.

20 *Wholesale Competition in Regions with Organized Electric Markets*, FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). Order Nos. 719, *et seq.* also added to the Commission's regulations 18 C.F.R. § 35.28(g), which includes demand response requirements applicable to ISOs and RTOs.

regional transmission organizations ("RTOs") related to demand response. Relevant to the instant filing, in Order No. 719, the Commission directed ISOs and RTOs to take actions that included amending their market rules as necessary to permit aggregators of retail customers ("ARCs") to bid demand response on behalf of retail customers into the organized electricity markets operated by the ISOs and RTOs (unless prohibited by the laws or regulations of the relevant electric retail regulatory authority).[21] The Commission also explained that it would permit each ISO or RTO to design ARC provisions that account for differences in each region's market design. Therefore, instead of developing *pro forma* language or requiring RTOs and ISOs to make detailed generic market rule amendments, the Commission "direct[ed] 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" a number of "criteria and flexibilities" specified in Order No. 719.[22]

The Commission directed each ISO and RTO to submit a filing demonstrating its compliance with Order No. 719, within six months after Order No. 719 was published in the Federal Register.[23] The Commission also explained, however, that "the compliance requirement is not meant to displace the timelines of any market improvements that RTOs or ISOs are currently undertaking."[24]

The ISO timely submitted a filing to comply with Order No. 719 within six months of its publication in the Federal Register. The ISO's Order No. 719 compliance filing included a discussion of the ISO's efforts to satisfy the directives in Order No. 719 regarding demand response, including the proxy demand response proposal that was being developed by the ISO and stakeholders.[25] In its November 2009 order on the ISO's Order No. 719 compliance filing, the Commission conditionally accepted the ISO's compliance filing and its plan to enhance the ISO's demand response market features as complying with the demand response requirements of Order No. 719.[26]

In the November 2009 order, the Commission also found that the ISO's roadmap to the development of the proxy demand resource proposal satisfied the ARC-related compliance obligation set forth in Order No. 719, and the

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[21] Order No. 719 at PP 3, 154. The Commission defined the relevant electric retail regulatory authority as "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." *Id.* at P 158.

[22] *Id.* As explained in Section III, below, the ISO's proxy demand resource proposal satisfies each of the criteria and flexibilities contained in Order No. 719.

[23] Order No. 719 at P 578.

[24] *Id.* at P 579.

[25] ISO Compliance Filing, Docket No. ER09-1048-000 (Apr. 28, 2009), at 16-23.

[26] *California Independent System Operator Corp.*, 129 FERC ¶ 61,157, at PP 35-43 (2009).

Commission noted that it would examine the ISO's proxy demand resource filing to ensure that it satisfies the requirements of Order No. 719:

> The CAISO states that the CAISO Tariff, market design, and software cannot currently accommodate the provision of demand response through an ARC. The CAISO claims that the implementation of such functionality requires resolution of complex scheduling, metering, and settlement issues. The CAISO expects to resolve these issues through the MAP initiative, specifically by implementation of the PDR product. . . . We find the CAISO in compliance with the directive of Order No. 719 regarding ARCs, insofar as the CAISO has provided us with an adequate roadmap to full compliance. Development and implementation of ARCs in the CAISO markets should be fully addressed by the CAISO in its MAP initiative filings providing for demand resource enhancements. However, we note that, once filed, the MAP initiative filings will be reviewed closely by the Commission to ensure that the CAISO's ARC proposal meets the Commission's objectives laid out in Order No. 719.[27]

In the course of the stakeholder process to develop the proxy demand resource product, the ISO and stakeholders agreed upon the use of the term *demand response providers* or "DRPs" to describe the entities in the ISO's market that Order No. 719 refers to as ARCs.[28] As explained below, the proxy demand response proposal submitted in the instant filing will allow demand response providers to aggregate retail customers for the purpose of bidding demand response directly into the ISO's market and will meet the objectives set forth in Order No. 719.

II. Components of the Proxy Demand Resource Product and Proposed Tariff Changes

A. Overview

Through the ISO's proxy demand resource product, demand response providers will each be authorized to take part in the ISO's day-ahead and real-time markets, including bidding to provide eligible ancillary services, once they have executed a *pro forma* proxy demand resource agreement with the ISO and

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27 *Id.* at PP 51, 56.

28 As reflected in some of the materials posted in the stakeholder process on proxy demand resources, demand response providers also were referred to as curtailment service providers or "CSPs".

satisfied of other applicable requirements to participate in the ISO market, including requirements of the local regulatory authority.[29]

The process for proxy demand resources to participate in the ISO's market will begin with the registration of such resources by the demand response provider that represents them. Information provided to the ISO and completion of the registration steps will be contained within an information system developed by the ISO that is known as the *demand response system*. Through the registration process, the demand response provider will identify the certified scheduling coordinator that will represent the discrete proxy demand resources to which the demand response provider wishes to assign a resource ID (as defined in the ISO tariff) and the load serving entity that serves the underlying load customer(s) which make up the resource ID. Each load serving entity is also represented by a certified scheduling coordinator (or acts as its own scheduling coordinator) in the ISO market.

The proxy demand resource product design separates the functions of these two scheduling coordinators (although a single scheduling coordinator could be utilized), in that the scheduling coordinator that represents the load serving entity will continue to schedule the demand for the end-use customers in the day-ahead market, while the scheduling coordinator representing the demand response provider will schedule and bid its proxy demand resources into the ISO market. This will allow the settlement for energy delivered (defined in the proposed tariff amendments as the *PDR energy measurement*) to be paid to the demand response provider's scheduling coordinator. Through identification of the scheduling coordinator representing the load serving entity, the quantity of the PDR energy measurement will be added to the demand of the scheduling coordinator representing the load serving entity to prevent that scheduling coordinator from being compensated for the imbalance energy provided by the proxy demand resource, which would result in a double payment to the load serving entity's scheduling coordinator.

The *pro forma* proxy demand resource agreement requires that the demand response provider certify to the ISO that its participation is authorized by the local regulatory authority and that it has satisfied all applicable rules and regulations established by the local regulatory authority. This extends to the execution of any bilateral agreements between the demand response provider and the load serving entities that the local regulatory authority may require. In this manner, the proxy demand resource amendments require that appropriate relationships be in place between the demand response provider and the load serving entity (whether this is established by bilateral agreement or rules and

[29] The local regulatory authority is defined in the ISO tariff as "[t]he or local governmental authority, or the board of directors of an electric cooperative responsible for the regulation or oversight of a utility." *Cf.* footnote 21, *supra* (setting forth Order No. 719 definition of relevant electric retail regulatory authority).

regulations governing the relationship). These relationships are established externally, and not within the ISO. The separate agreement entered into by these parties or the applicable local regulatory authority rules will provide the means for the demand response provider and the load serving entity to share the ISO revenues, in order to compensate the load serving entity for the energy that is purchased by the load serving entity but is not used due to the demand response service provided by the proxy demand resource.

After it is authorized to participate in the ISO market, the scheduling coordinator, on behalf of the demand response provider that represents one or more proxy demand resources, will be able to submit bids for proxy demand resources into the ISO market. Specific details of the ISO's proxy demand resource proposal, and the tariff changes needed to implement the proposal, are discussed below.

B. Definitions of Entities and Services

The ISO proposes to add the following interrelated defined terms to Appendix A to the ISO tariff in order to set forth in tariff language the types of entities and services to implement the proxy demand resource product:

- The term *demand response provider*, defined as an entity responsible for delivering demand response services from a proxy demand resource, which has undertaken in writing by execution of the proxy demand resource agreement to comply with all applicable provisions of the ISO tariff.

- The term *proxy demand resource agreement*, defined as an agreement between the ISO and a demand response provider, a *pro forma* version of which is set forth in Appendix B.14 to the ISO tariff.[30]

- The term *proxy demand resource*, defined as a load or aggregation of loads capable of measurably and verifiably providing demand response services pursuant to a proxy demand resource agreement.

- The term *demand response services*, defined as demand from a proxy demand resource that can be bid into the day-ahead market and real-time market and be dispatched at the direction of the ISO. While the current functionality for proxy demand resources is only demand *reduction*, the ISO has used the broader term *services* in contemplation of future demand response products with the ability to accept a dispatch to increase load (*i.e.*, increase consumption).

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[30] The proxy demand resource agreement is discussed further in Section II.C, below.

C. Proxy Demand Resource Agreement and Demand Response System

The ISO proposes to add a new *pro forma* agreement – the proxy demand resource agreement – to Appendix B to the ISO tariff, in order to establish the terms and conditions pursuant to which the ISO and each demand response provider agree to discharge their respective duties and responsibilities under the ISO tariff.[31] The *pro forma* proxy demand resource agreement is largely modeled after the existing *pro forma* participating load agreement contained in Appendix B.4 to the ISO tariff, the provisions of which the Commission has accepted.[32]

The differences between the proxy demand resource agreement and the participating load agreement reflect the differences in entities and services involved under those two agreements. The proxy demand resource agreement includes provisions specific to proxy demand resources and demand response providers. For example, the proxy demand resource agreement contains several provisions regarding the inclusion of information on proxy demand resources in the ISO's new demand response system.[33] The ISO proposes to define the *demand response system* in Appendix A to the ISO tariff as a collective name for a set of functions of an ISO application used to collect, approve, and report on information and measurement data for proxy demand resources.[34]

Section 4.3 of the proxy demand resource agreement includes the requirement that the demand response provider must certify to the ISO that its participation is authorized by the local regulatory authority applicable to demand response providers, that the demand response provider has satisfied all applicable rules and regulations of the local regulatory authority, and that any agreements required by the local regulatory authority are fully executed. The inclusion of these provisions is consistent with Order No. 719, which explains that

> [t]he 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. The RTO or ISO should not be in

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31 *See pro forma* proxy demand resource agreement, Recital (D).

32 *See California Independent System Operator Corp.*, 88 FERC ¶ 61,182, at 61,590-91 (1999).

33 *See pro forma* proxy demand resource agreement, Sections 2.2, 3.2.2, 4.3, 6.1.

34 Further details regarding the collection of, approval of, and reporting on information and measurement data under the demand response system are provided on pages 18-23 of the "Draft Final Proposal for the Design of Proxy Demand Resource (PDR)" (Aug. 28, 2009) ("Draft Final PDR Proposal") and pages 21-26 of the Draft PDR Business Requirements Specification. The Draft Final PDR Proposal is available on the ISO's website at http://www.caiso.com/241d/241da56c5950.pdf. Details regarding the demand response system will be included in the Business Practice Manuals.

> the position of interpreting the laws or regulations of a relevant electric retail regulatory authority.[35]

Consistent with these same directives, although the ISO's demand response system will include a registration requirement for proxy demand resources, the ISO will not ensure the existence of or monitor the commercial arrangements associated with proxy demand resources, such as the exchange of settlements data and revenues between a demand response provider and the load serving entity for the proxy demand resource that the demand response provider represents. These commercial arrangements are to be addressed by the demand response provider and the load serving entity and appropriately take place outside of the ISO processes. Further, any retail rules applicable to the commercial arrangements should be established by the local regulatory authority rather than by the ISO.

D. Roles and Responsibilities of Demand Response Providers and Proxy Demand Resources

The ISO proposes to add new Section 4.13 to the ISO tariff to set forth the roles and responsibilities of demand response providers and proxy demand resources under the tariff.

Section 4.13.1 explains the relationship between the ISO and demand response providers. The section states that the ISO will only accept bids for energy or ancillary services, submissions to self-provide ancillary services, or submissions of energy self-schedules from scheduling coordinators representing proxy demand resources if such proxy demand resources are represented by a demand response provider that has entered into a proxy demand resource agreement with the ISO. Section 4.13.1 also provides that a demand response provider must accurately provide the information required in the demand response system, satisfy all proxy demand resource registration requirements, and meet standards adopted by the ISO and published on the ISO's website.

Section 4.13.2 requires that a single demand response provider must represent each proxy demand resource, although a demand response provider may represent more than one proxy demand resource. A demand response provider may be, but is not required to be, a load serving entity or a utility distribution company ("UDC"). This provision permits a demand response provider that is not a load serving entity or a utility distribution company to be an aggregator of other entities' loads.

Section 4.13.2 also requires that each demand response provider must satisfy registration requirements and must provide information that allows the

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[35] Order No. 719 at P 49 n.78.

ISO to establish customer baselines in accordance with the applicable Business Practice Manuals ("BPMs"). *Customer baseline* is a new term defined in Appendix A to mean a value or values determined by the ISO based on historical load meter data to measure the delivery of demand response services. The customer baseline represents an estimate of metered demand that normally would be expected for a particular proxy demand resource in the absence of a demand response bid, based on historical data.

The customer baseline methodology that the ISO will initially use when the proxy demand resource product goes into effect is described in the attached Declaration of Margaret Miller, Manager, Market Design and Regulatory Policy for the ISO.[36] As Ms. Miller explains, the ISO and stakeholders developed this initial methodology based on an evaluation of the design features appropriate to the ISO market and features of the customer baseline methodologies employed by other ISOs and RTOs that have demand response products, including PJM Interconnection, L.L.C. ("PJM"), the New York Independent System Operator, Inc. ("NYISO"), and ISO New England Inc. ("ISO-NE").[37]

As explained by Ms. Miller, several focused working group meetings with stakeholders were spent discussing baseline methodologies and reviewing related studies written by Christensen Associates Energy Consulting, LLC, Lawrence Berkeley National Laboratory, DTE Energy, and documents from ISO-NE and PJM. Discussions were also held with stakeholders concerning issues such as market manipulation by market participants of the baseline methodology used to settle proxy demand resources in the ISO market.[38] In addition, the ISO contracted with Utility Integration Solutions, Inc. to provide consulting services to help the ISO determine the appropriate baseline methodology to apply in order to settle proxy demand resources and to perform additional benchmarking and analysis regarding how other independent system operators and regional transmission organizations have implemented products similar to the proxy demand resource.

In the course of evaluating customer baseline methodologies, the ISO learned that no single customer baseline methodology meets every need and/or load type, and evidence shows that morning-adjusted and/or temperature-adjusted baselines tend to produce better results than unadjusted baselines. As

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[36] Ms. Miller's Declaration is provided in Attachment D to this filing. *See also* Draft Final PDR Proposal at 26-27 and 36-38 (containing discussion of the customer baseline methodology).

[37] Declaration of Margaret Miller at 9. *See also* "Customer Baseline Load Review and Recommendation" (May 26, 2009). This presentation is available on the ISO's website at http://www.caiso.com/23ca/23ca96e026e90.pdf.

[38] *See* "Overview of Findings from Baseline Studies" (May 26, 2009), available on the ISO's website at http://www.caiso.com/23ca/23ca94ed1a490.pdf;
"Baseline Analyses Using DBP (2006) and AMP (2008) Program Data" (May 26, 2009), available on the ISO's website at http://www.caiso.com/23ca/23ca93c0100e0.pdf;
"Customer Baseline Load Review and Recommendation", *supra*.

Ms, Miller explains, other ISOs and RTOs have had to make numerous refinements and enhancements to their own various customer baseline methodologies.[39] Consequently, the ISO has chosen to implement a simple core methodology for establishing customer baselines that it expects will be re-examined and refined based on the ISO's initial experience with the proxy demand response product.

In order to have sufficient flexibility to refine the customer baseline methodology or to tune the methodology for particular types of demand response providers based on its experience with the product, the ISO will publish the initial methodology and any modifications to it in the applicable Business Practice Manuals following the stakeholder process for changing BPMs in accordance with the requirements of the Business Practice Manual for BPM Change Management.[40] This approach is consistent with the practices of the NYISO and ISO-NE. In this regard, the NYISO includes its customer baseline calculation in its Day-Ahead Demand Response Manual.[41] ISO-NE also includes substantive details for calculation of demand response customer baselines in the ISO New England Manuals.[42]

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[39] Declaration of Margaret Miller at 6-7. In this regard, the Commission has explained that determining an appropriate customer baseline methodology requires the application of judgment based on the specific circumstances:

> We note that under the current DALRP [Day-Ahead Load Response Program] construct (where the Customer Baseline is only updated on days when offers in the DALRP are not accepted), there will always be a trade-off between baseline accuracy and participation in the DALRP – i.e., as the number of days in which DALRP offers are rejected increases, by default the Customer Baseline will be more accurate, at the expense of short term (and potentially long-term) DALRP participation. . . . *As such, a reasonable judgment has to be made concerning an acceptable baseline error rate so as not to discourage participation in programs like the DALRP*.

ISO New England Inc., 123 FERC ¶ 61,021 at P 27 (2008) (emphasis added).

[40] Declaration of Margaret Miller at 9-11.

[41] New York Independent System Operator, Inc. Manual 5, "Day-Ahead Demand Response Program Manual," Section 5.0. The manual can be accessed on the NYISO website at http://www.nyiso.com/public/webdocs/documents/manuals/planning/dadrp_mnl.pdf.

[42] See ISO New England Inc. FERC Electric Tariff No. 3,Section III, Market Rule 1, Appendix E, Load Response Program, which contains the following provisions:

> **III.E.6. Metering and Settlement**:
> Additional details concerning metering requirements and settlement procedures along with calculation of baseline quantities to be used to calculate the amount of interruption actually obtained are contained within the ISO New England Manuals.
>
> **III.E.8.3.3 Performance Measurement**. DR Resource performance will be determined in the same manner as in the existing Real-Time 30-Minute Demand Response Program as described in the ISO New England Load Response

Pursuant to new Section 4.13.2 of the ISO tariff, each proxy demand resource that is not within a metered subsystem ("MSS") is required to be associated with a single load serving entity and utility distribution company, and each proxy demand resource that is within an MSS is required to be associated with a single load serving entity. All underlying locations of a single proxy demand resource must be located within a single Sub-LAP. The ISO originally contemplated allowing the load of multiple load serving entities to be aggregated and to constitute a single proxy demand resource. However, upon further consideration of the issue, the ISO determined that allowing such an aggregation may have detrimental impacts on the registration and settlement of proxy demand resources. Therefore, the ISO modified its proposal so that, at least initially, a proxy demand resource must be associated with a single load serving entity and utility distribution company as discussed above. The ISO will consider allowing the load of multiple load serving entities to constitute a single proxy demand resource as a future enhancement to the proxy demand resource product.

Section 4.13.2 states that registration of a location for participation in the proxy demand resource product requires the approval of the underlying load's load serving entity and/or utility distribution company. Disputes regarding the rejection of a registration of a location will be undertaken with the applicable local regulatory authority and will not be arbitrated or in any way resolved through an ISO mechanism or process.[43] Further, Section 4.13.2 specifies that the meter data for each proxy demand resource will be metered load data.[44]

Section 4.13.3 requires each demand response provider to provide data, as described in the Business Practice Manual, identifying each of its proxy demand resources and such information regarding the capacity and operating characteristics of the proxy demand resource as the ISO may reasonably request from time to time. All information provided to the ISO regarding the operational and technical constraints in the Master File are required to be accurate and based on actual physical characteristics of the resources.

Section 4.13.4 addresses the authority of the ISO, which the ISO expects it will apply only in rare circumstances, to temporarily suspend the ability of a

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Program Manual, provided, however, that the customer baseline adjustment for the DRR Pilot program will be increased or decreased to reflect actual metered consumption during the two hours prior to the dispatch of the Demand Resources (i.e., adjusted symmetrically).

The ISO-NE tariff can be accessed on its website at http://www.iso-ne.com/rules_proceds/index.html. The ISO New England Load Response Program Manual (Revision 12, Effective Date: October 1, 2007) can be accessed on the ISO-NE website at http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[43] *See supra* footnote 35 and accompanying text.

[44] Metering of proxy demand resources is discussed further in Section II.F, below.

scheduling coordinator for a demand response provider to submit bids from one or more proxy demand resources. The suspension provision is discussed below in Section II.J of this transmittal letter.

E. Bidding and Scheduling of Proxy Demand Resources

The ISO proposes to add new Section 30.6 to the ISO tariff to set forth the requirements for bidding and scheduling proxy demand resources. Section 30.6 states that, unless otherwise specified in the ISO tariff and applicable Business Practice Manuals, the ISO will treat bids for energy and ancillary services on behalf of proxy demand resources like bids for energy and ancillary services on behalf of other types of supply resources. Pursuant to that provision, a scheduling coordinator submitting a bid for energy or ancillary services for a proxy demand resource will be subject to the same processes, bid validation, and market timelines as a scheduling coordinator that submits a bid for any other type of resource, unless otherwise specified in the tariff or a Business Practice Manual. For bidding and scheduling purposes, proxy demand resources will be modeled in the ISO's systems in the same manner as generators.

Section 30.6 specifies that a scheduling coordinator for a demand response provider representing a proxy demand resource may submit bids in the day-ahead and real-time markets for energy, in the RUC process, and in the ancillary services markets for which it is certified. A scheduling coordinator for a demand response provider representing a proxy demand resource may also self-provide ancillary services for which the proxy demand resource is certified. Demand response services will be bid separately from the underlying demand for the proxy demand resources.

During the stakeholder process that led to this tariff amendment, the ISO contemplated whether proxy demand resources should be permitted to participate in the hour-ahead scheduling process ("HASP"), the portion of the ISO's real-time market processes that addresses transactions over interties with neighboring balancing authority areas. After further analysis, the ISO determined that including proxy demand resources in HASP presents a significant implementation effort, considering that HASP currently is used primarily to pre-dispatch hourly intertie resources. Not all resources internal to the ISO balancing authority area, which include participating load and generation, are currently eligible to participate in HASP. Further, proxy demand resource participation in HASP would need to be based on hourly metering, which might create undesirable incentives for proxy demand resources to participate in the HASP market and would be inconsistent with the treatment given to other types of resources located within the ISO balancing authority area. Moreover, since MRTU start-up, the ISO has experienced some price volatility in the HASP market and it does not want to make any significant changes to HASP until those issues are resolved.

At the time the proxy demand resource product is first implemented, the non-spinning reserve market will be the only ancillary services market for which proxy demand resources will be certified. The ISO plans to augment the functionality in the future to permit the certification of proxy demand resources to provide additional types of ancillary services. In this regard, the ISO is undertaking a separate stakeholder initiative to modify ISO operating and technical requirements for ancillary services in order to facilitate further participation by non-generator resources in the ISO's ancillary services markets. The stakeholder initiative also includes recommended market enhancements that create an option for resources to allow the ISO to manage the energy output and usage of a resource providing regulation service. If adopted, these modifications would apply to both generation and non-generation resources, including proxy demand resources, that participate in the ISO's ancillary services markets.[45]

The ISO believes that the existing language in the ISO tariff is sufficient for purposes of providing notification of changes in enrollments and schedule changes for proxy demand resources that may occur between day-ahead and real-time dispatch of proxy demand resources. Both demand response providers and load serving entities need to be aware of proxy demand resource enrollments and scheduling changes. Demand response providers need to be aware because they are the entities responsible for forecasting and scheduling of all customer load. The ISO has existing mechanisms for communicating schedules in the day-ahead market and dispatches in the real-time market to market participants. The ISO has identified no need to modify the existing notification mechanisms other than a need to communicate megawatt quantities of dispatches to both demand response providers and load serving entities, which does not require a tariff change.[46]

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[45] The ISO commenced this stakeholder initiative in order to comply with a directive in Order No. 719 (at P 49) to RTOs and ISOs to allow demand response resources to participate in ancillary services markets assuming the demand response resources are technically capable of providing the ancillary service within feasible response times, and to comply with directives in the Commission's Order No. 890 requiring ISOs and RTOs to evaluate non-generation resources, such as demand response and storage, on a comparable basis to services provided by generation resources in meeting mandatory reliability standards, providing ancillary services, and planning the expansion of the transmission grid. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at PP 479, 888 (2007). Information regarding the ISO's non-generation initiative can be accessed on the ISO's website at http://www.caiso.com/2415/24157662689a0.html.

[46] For the proxy demand resource product, demand response providers and LSEs will have access to day-ahead generation market results, day-ahead expected energy information, and real-time dispatch information regarding their proxy demand resources. In cases where the demand response provider and the LSE are the same entity, that entity will have access to these types of information as to the proxy demand resources that the entity represents. In cases where the demand response provider and the LSE are separate entities, the LSE will be provided solely with read-only access to the information and only for the specific resource IDs of any proxy demand resources that are among the LSE's customers.

F. Metering and Telemetry of Proxy Demand Resources

The ISO proposes to require settlement quality meter data for proxy demand resources rather than using estimated meter data. This requirement is appropriate because, as discussed below, the ISO will settle transactions involving proxy demand resources by comparing the customer baseline of a proxy demand resource against its actual underlying load for a demand response event. The only means of accurately determining the actual underlying load in this calculation is to use settlement quality meter data.

To implement the requirement that proxy demand resources provide settlement quality meter data, the ISO proposes to modify Section 10.3.2.1, regarding the duty to provide settlement quality meter data, to state that each scheduling coordinator for a demand response provider is required to aggregate the settlement quality meter data of the underlying load to the level of the registration configuration of the proxy demand resource in the demand response system. Further, the ISO proposes to modify Sections 10.3.6.1 and 11.1.5, regarding the timing of the submission of settlement quality meter data, to state that scheduling coordinators cannot submit estimated settlement quality meter data for proxy demand resources and that the ISO will not estimate settlement quality meter data for proxy demand resources. For similar reasons, the ISO proposes to add new Section 4.9.12.2.6 to the ISO tariff to state that an MSS operator that owns or has an entitlement to a system unit is required to provide, through the scheduling coordinator representing the MSS operator, settlement quality meter data for the system unit's proxy demand resources.

Section 4.5.1.1.3 of the current ISO tariff states that, if two or more scheduling coordinators apply simultaneously to register with the ISO at a single meter or meter point for a CAISO metered entity or if a scheduling coordinator applies to register with the ISO for a meter or meter point for a CAISO metered entity for which a scheduling coordinator has already registered, the ISO will return the application with an explanation that only one scheduling coordinator may register with the ISO for the meter or meter point in question and that a scheduling coordinator has already registered or that more than one scheduling coordinator is attempting to register for that meter or meter point. The ISO proposes that proxy demand resources will be scheduling coordinator metered entities rather than CAISO metered entities. Therefore, the current tariff provisions in Section 4.5.1.1.3 are not applicable to proxy demand resources. Nonetheless, in order to clarify that the "one scheduling coordinator per meter" rule does not affect the ability of the ISO to implement the proxy demand resource product, the ISO proposes to modify Section 4.5.1.1.3 to state that nothing in the section will prohibit one scheduling coordinator from registering with the ISO to submit bids for demand response services from a proxy demand resource associated with a given meter or meter point where a different scheduling coordinator is registered for load associated with that meter or meter point.

The ISO proposes that proxy demand resources not be required to have telemetry under Section 31.5.7.1 (regarding rescission of payments for undispatchable RUC capacity) and has revised that section to reflect its proposal. Telemetry is required for all proxy demand resources that are providing ancillary services or are over 10 MW.[47]

G. Inclusion of Proxy Demand Resources in Resource Adequacy

The ISO proposes to allow proxy demand resources to satisfy the resource adequacy requirements of the ISO tariff. Therefore, the ISO makes modifications to Section 40.6.12 of the ISO tariff to establish that proxy demand resources, like participating loads, may be included in a resource adequacy plan and supply plan consistent with terms and conditions established by the CPUC or applicable local regulatory authority. The ISO also proposes to add new Section 40.8.1.3 to the ISO tariff to state that the default qualifying capacity[48] (*i.e.*, the maximum capacity of a resource adequacy resource) of a proxy demand resource, for each month, will be based on the resource's average monthly historic demand reduction performance during that same month during the availability assessment hours (as described in Section 40.9.3), using a three-year rolling average. For a proxy demand resource with fewer than three years of performance history, for all months for which there is no historic data, the ISO will utilize a monthly megawatt value as certified and reported to the ISO by the demand response provider; otherwise, where available, the ISO will use the average of historic demand reduction performance data available, by month, for a proxy demand resource. Proxy demand resources must be available at least four hours per month in which they are eligible to provide resource adequacy capacity and must be dispatchable for a minimum of thirty minutes per event within each of those months.

H. Exclusion of Proxy Demand Resources from Certain ISO Market Processes

The ISO proposes to modify Sections 31.2 and 33.4 of the ISO tariff to state that bids on behalf of proxy demand resources are not mitigated and are not considered in the ISO's market power mitigation-reliability requirement

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47 *See, e.g.*, Draft PDR Business Requirements Specification at 37-39 (indicating that proxy demand resources must meet certain specified telemetry requirements only if they are providing ancillary services or are over 10 MWs).

48 This provision applies only when the local regulatory authority has not established and provided to the ISO criteria to determine the types of resources that may be eligible to provide qualifying capacity and for calculating qualifying capacity for such eligible resource types, *e.g.*, proxy demand resources.

determination ("MPM-RRD") process for either the day-ahead market or the real-time market. The ISO originally intended to include proxy demand resources in the MPM-RRD process but not to subject proxy demand resource bids to market power mitigation due to the challenges of determining how to calculate cost-based default energy bids for these resources. After the ISO Board approved the proxy demand resource design in September 2009, however, the Department of Market Monitoring ("DMM") identified significant concerns with this approach. As the DMM explained in a memorandum it provided to the Board in February 2010,[49] including proxy demand resource bids in the MPM-RRD process without mitigating their bids could cause bids from generation resources with significantly lower costs (but higher-priced market bids) to be displaced by proxy demand resource bids in this mitigation process and the final market dispatch. Excluding proxy demand resource bids from this process avoids such economically inefficient outcomes and prevents the ISO's local market power mitigation provisions from being undermined. This is the same approach the ISO will use to handle convergence bids in the MPM-RRD process. In other words, the bids will be considered in the integrated forward market or real-time market without being mitigated and without being considered in the MPM-RRD. This change for proxy demand resources was approved by the ISO Board in February 2010.

The ISO also proposes to modify Section 36.8.4, regarding eligible sources for congestion revenue right ("CRR") allocation, to state that a proxy demand resource cannot be a nominated CRR source in a CRR allocation process. The ISO has made this change in response to a stakeholder comment that there could be potential gaming opportunities as a result of the interaction between the CRR allocation process and the dispatch of proxy demand resources.

I. Settlement of Demand Response Services

Settlement of demand response services provided by a proxy demand resource will be with the scheduling coordinator for the demand response provider that represents the proxy demand resource. The ISO proposes to add new Section 11.6.1 to the ISO tariff to state that settlements for energy provided by demand response providers from proxy demand resources will be based on the PDR energy measurement for the proxy demand resources. The ISO will provide payment under this tariff language for demand response services based on the verified performance of proxy demand resources (actual underlying load for a demand response event) as compared with historical metered demand customer baselines based on historical metered demand established for those proxy demand resources.

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49 The February 2010 DMM memorandum to the Board is available on the ISO's website at http://www.caiso.com/2733/2733950e66db2.pdf.

Consistent with the existing settlement provisions in Section 11 of the ISO tariff, the amount of energy provided by a proxy demand resource will be multiplied by the applicable LMPs (either day-ahead or real-time) at the Sub-LAPs for the proxy demand resources, and the schedules of resources serving load will be adjusted so as to avoid double payments, *i.e.*, payments for the demand response services provided in addition to payments to the resources serving the load for uninstructed deviations (*i.e.,* reductions of load) based on the demand response services provided.[50] In order to ensure the correct settlement amount, the ISO proposes to modify Section 11.5.2 to include proxy demand resources in the settlement of uninstructed imbalance energy, and to add new Section 11.5.2.4 to the ISO tariff to state that, for the purpose of settling uninstructed imbalance energy of a scheduling coordinator representing a load serving entity, the amount of PDR energy measurement delivered by a proxy demand resource will be added to the metered load quantity of the scheduling coordinator's load resource ID with which the proxy demand resource is associated.

J. Rescission of Payments for Demand Response Services Not Actually Provided and Temporary Suspension of Market Participation for Proxy Demand Resources

As Ms. Miller explains in her Declaration,[51] during the development of the proxy demand resource product, one significant concern was whether demand response providers could be paid for demand response services not actually provided to the market, *e.g.*, whether an end-user might not reduce its actual consumption of electricity any more than the end-user would have in the absence of a demand response market or whether the reduction in the use of electricity might be overstated, resulting in an overpayment to the demand response provider. Such overpayment could occur where there is intentional gaming or manipulation of customer baselines. For example, ISO-NE needed to obtain Commission approval of a tariff amendment to correct a flaw in the rules of its demand response program that allowed day-ahead load reduction program participants to exaggerate the load reductions from their demand response assets by overstating their assets' customer baseline.[52] As Ms. Miller explains, proxy demand resources, and demand response products in general, are uniquely susceptible to gaming.[53] Overpayments could also occur even if there is no overt intentional act by a market participant, but simply a flaw in the way an individual customer's baseline is determined.

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[50] The ISO provides an example of a settlement calculation for proxy demand resources in the Draft Final PDR Proposal at pages 39-40.

[51] Declaration of Margaret Miller at 12.

[52] *See ISO New England Inc*, 123 FERC ¶ 61,021 (2008).

[53] Declaration of Margaret Miller at 18-19.

In light of the challenges in establishing accurate customer baselines and measuring the actual services provided by proxy demand resources, as described above, the DMM made the following recommendation in its September 2009 memo to the ISO Board regarding the proxy demand resource product:[54]

> With respect to how potential gaming might be avoided or stopped once it is observed, we recommend that the ISO rely primarily on actions that could be directly implemented by the ISO such as modifying the details of baseline measurement rules and/or denying participation by PDR specific loads – rather than relying on any referrals of suspected gaming to FERC under federal rules prohibiting market manipulation. Absent clear evidence of fraudulent behavior, behavior that may be considered gaming may not be effectively mitigated by a referral under FERC anti-manipulation rules. Instead, we recommend the ISO establish its own authority to take mitigating actions if gaming is suspected.

As Ms. Miller further explains, in the ISO market, there is also the concern about the potential for load arbitrage between custom load aggregation points and default load aggregation points.[55] This concern exists because the load serving entity in the ISO market will continue to schedule its load at the default load aggregation point and the curtailable portion of the load which would be the proxy demand resource is bid and paid at a custom aggregation of nodes. LECG, LLC ("LEGC") raised this concern in its "Comments on the California ISO MRTU LMP Market Design", which were provided in Attachment C to the ISO's May 13, 2005 amendment to its conceptual market redesign submitted in Docket No. ER02-1256. LECG raised the following concern on page 62 of its Comments:

> Since demand response buys power at the zonal/LAP price in the DAM [day-ahead market] and sells power back at the nodal price, demand response at nodes within constrained regions have a money machine whenever their actual load is less than their allowed maximum demand response offer. The LSE providing demand response would merely buy power equal to its demonstrated dispatch capability at the LAP price in the DAM and bid demand response at a low enough price to ensure it is dispatched nodally down to its planned consumption in RT [real-time], earning the difference between the nodal price and the zonal price for doing nothing. This would be equivalent to the effect of virtual demand purchases at zonal prices in the DAM that are settled at nodal pricing in real-time.

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[54] The September 2009 DMM memorandum to the Board is available on the ISO's website at http://www.caiso.com/241e/241ec4e711e00.pdf.

[55] Declaration of Margaret Miller at 19.

In order to address concerns about gaming and the potential for inaccuracies in establishing customer baselines, the ISO has included in its proxy demand resource software requirements the ability to monitor certain metrics once the proxy demand resource product goes into effect. These metrics will include, but are not limited to, statistically high adjustment factors, statistically high revenues, statistically low bids, and statistically poor baseline model fits.[56] Should a proxy demand resource repeatedly fall outside of identified ranges, or fail multiple metrics, the ISO will perform a study to determine if there is a likelihood that the proxy demand resource has been compensated for demand response that was not really provided to the market.

The ISO proposes to add two related tariff provisions to address this possibility. First, in new Section 11.6.2, the ISO proposes language to make it clear that all bids for energy on behalf of proxy demand resources must represent actual adjustments of proxy demand resources taken in response to a dispatch instruction. If requested by the ISO, the demand response provider for a proxy demand resource dispatched by the ISO must provide to the ISO data to support proof of performance of the proxy demand resource. The ISO is including these requirements in order to ensure that payments for load adjustments pursuant to the proxy demand resource product are made only when such payments are justified. As stated in Section 11.6.2, in the event that the ISO determines through evaluation of the proof of performance or its own analysis that a bid for energy from a proxy demand resource: (i) does not represent an actual adjustment of the proxy demand resource taken in response to a dispatch instruction and (ii) has resulted or will result in a payment for demand response services not actually provided by the proxy demand resource, the ISO may rescind such payment. This provision implements the principle that the ISO only pays resources for services actually provided to the ISO's market. The ISO has comparable authority to rescind RUC Availability Payments for undispatchable or undelivered RUC capacity (Section 11.2.2.2 of the ISO tariff) and to rescind payments for ancillary services capacity that is undispatchable, unavailable, or undelivered (Section 11.10.9 of the ISO tariff).

Second, in new Section 4.13.4, the ISO proposes that, in the event that the ISO determines through evaluation of the proof of performance described in Section 11.6.2 or its own analysis that a bid for energy from a proxy demand resource: (i) does not represent an actual adjustment of the proxy demand resource taken in response to a dispatch instruction and (ii) has resulted or will result in a payment for demand response services not actually provided by the proxy demand resource, the ISO may immediately suspend the ability of the proxy demand resource to provide demand response services by sending written notification of the suspension to the scheduling coordinator for the demand response provider representing the proxy demand resource. Within two business

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[56] *See* Draft Final PDR Proposal at 16-18.

days of the notice of suspension, the ISO will provide the scheduling coordinator and the demand response provider with the information justifying the decision to suspend. The ISO and the affected scheduling coordinator and demand response provider will confer and exchange information in an effort to resolve any dispute as to whether suspension is warranted. The ISO will submit to the Commission supporting documentation, including any information provided by the affected scheduling coordinator and demand response provider, within ten business days after any suspension unless the ISO concludes that suspension is not warranted. The ISO will provide the affected scheduling coordinator and demand response provider with a copy of any documentation submitted to the Commission. The suspension will remain in effect for ninety days after the ISO submits its initial filing of supporting documentation, unless the Commission directs otherwise or the ISO determines that the suspension should continue for fewer than ninety days. After the ninety-day period expires, the suspension will remain in effect only if the Commission requires it to remain in effect.

The ISO's proposed tariff language provides a sufficient opportunity for the affected scheduling coordinator and demand response provider to confer with the ISO as to whether suspension is warranted, and the ISO will timely provide all documentation supporting any suspension with the Commission. As a result, the Commission will timely be made aware of each suspension and, if it so chooses, the Commission can take any action it deems appropriate regarding the suspension. Each suspension will be limited to a maximum of ninety days after the ISO submits its initial filing of supporting documentation unless the Commission finds that extending the suspension is appropriate. The time frames that the ISO proposes will also provide sufficient time to identify and correct any flaws in the customer baseline for the affected proxy demand resource, including any changes to the Business Practice Manuals to reflect the changes in the baseline methodology.

The ISO's proposal to suspend the provision of demand response services and rescind payment in the event that a bid from a proxy demand resource does not represent an actual adjustment of load is comparable to provisions in PJM's open access transmission tariff ("OATT"). Pursuant to its OATT, PJM disallows payments to so-called economic load response participants (which provide demand response in PJM) that are not the result of demand reductions executed in response to the locational marginal price in the day-ahead energy market and/or the real-time energy market, and PJM may suspend market activity by economic load response participants if they continue to submit settlements for such demand reductions.[57]

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[57] PJM OATT, Attachment K – Appendix, Section 3.3A.6.

K. Modifications of Existing Tariff Provisions to Accommodate the Implementation of the Proxy Demand Resource Product

The ISO proposes to modify a number of ISO tariff provisions in order to integrate the components of the proxy demand resource product into the existing structure of the tariff. Most of these tariff modifications consist of adding the term proxy demand resource and/or the term demand response provider to existing tariff language, or of making tariff changes regarding the proxy demand resource or demand resource provider that parallel existing tariff language. Due to the large number of these tariff revisions, the ISO has listed them in Attachment C to this tariff amendment instead of in this transmittal letter.

L. Miscellaneous Minor Clarifications

The ISO proposes to make minor, non-substantive clarifications to the following tariff sections: Sections 4.9.13, 11.23(b), 31.5.4(c), 31.5.7, 34, and 34.5(1), and the definition of energy bid curve in Appendix A. The ISO also proposes to clarify that the term "Load" means "Participating Load" in certain language in the following tariff sections: Sections 6.3.1, 8.3.1, 8.3.4, 8.4.5, 8.4.6, 8.9, 8.9.3.2, 8.9.7.1, 8.9.11, 8.10, 8.10.3, and 8.10.6, and Sections C 15 and C 16 of Attachment K.

III. The Proxy Demand Resource Product Satisfies the Requirements of Order No. 719

As explained in Section I, above, in Order No. 719, the Commission directed 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 subject to a number of criteria and flexibilities specified in Order No. 719.[58] The revisions to the ISO tariff contained in the instant filing satisfy of the criteria and include each of the flexibilities required by the Commission. The criteria and flexibilities specified in Order No. 719 (underlined in the text below), and the means by which the instant tariff amendment satisfies each of them, are as follows:

- <u>The ARC's demand response bid must meet the same requirements as a demand response bid from any other entity, such as an LSE</u>.[59] Pursuant

[58] *See* Order No. 719 at P 158.

[59] In this regard, the Commission stated that, for example, (1) the ARC's demand response must be as verifiable as that of an eligible LSE or large industrial customer's demand response that is bid directly into the market, (2) 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, and (3) demand response bids from an ARC must not be treated differently than the demand response bids of an LSE or large industrial customer. *Id.*

to the instant tariff amendment, bids for demand response services from proxy demand resources represented by an ARC must meet the same requirements as bids from proxy demand resources represented by other types of entities. The proposed tariff provisions treat a demand response provider (the ISO's term for the ARC) the same, whether the demand response provider is a UDC, LSE,[60] end-use customer representing its own load, or aggregator of other entities' load.

- The bidder must have only an opportunity to bid demand response in the organized market and not have a guarantee that its bid will be selected. The ISO's tariff amendment gives bidders of demand response services the opportunity to bid demand response from proxy demand resources into the ISO market. Like other resources participating in the ISO's market, demand response providers have no guarantee that the ISO will accept their bids.

- An ARC must have the ability to bid demand response either on behalf of only one retail customer or multiple retail customers. Pursuant to the instant tariff amendment, a single demand response provider may submit bids on behalf of single retail customer under a proxy demand resource or multiple, aggregated retail customers under a proxy demand resource. A demand response provider may operate multiple proxy demand resources within its portfolio.

- Except for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate, there can be no prohibition on who may be an ARC. The ISO does not propose any prohibitions as to who may become a demand response provider. Any entity is eligible to become a demand response provider so long as it meets the requirements for all demand response providers established by the ISO. The ISO notes that the CPUC opened a "Direct Participation Phase" of its ongoing demand response proceeding 07-01-041 in November 2009, through issuance of an Assigned Commissioner's Ruling that stated in relevant part that:

  > Specifically, this Ruling identifies issues the Commission [*i.e.*, the CPUC] should address given a Federal Energy Regulatory Commission (FERC) order that requires CAISO to allow retail electric customers to bid Demand Response resources directly in the CAISO's wholesale electricity markets if state laws and rules do not prohibit such bidding,

[60] An LSE can be either a utility load serving entity or an electric service provider, which is defined in the California Public Utilities Code as an entity that provides electric service to retail or end-use customers but does not fall within the definition of an electrical corporation. *See* California Public Utilities Code, Sections 218, 218.3.

> and subsequent CAISO efforts to allow such direct participation. The comment process initiated in this Ruling aims to identify whether there are state laws and/or rules that either directly or indirectly prohibit retail customers from bidding into CAISO wholesale markets. This Ruling further seeks input on whether any such prohibitory laws and/or rules warrant modification in light of the potential benefits arising from additional Demand Response options in California, and if so, what modifications to state laws and/or rules are necessary to support the CAISO's efforts to allow direct participation. Finally, this Ruling requests comment on technical and/or policy issues or challenges that the Commission should address that may arise from CAISO's compliance with this FERC order, with specific proposals for how those challenges may be addressed.[61]

The Assigned Commissioner's Ruling sets forth a schedule that provides for a proposed decision in mid-February and a final decision in mid-March of 2010.[62] In addition to LSEs that are CPUC-jurisdictional entities, the ISO's proxy demand response will be available to demand response providers from other local jurisdictions.

- <u>An individual customer must be permitted to serve as an ARC on behalf of itself and others</u>. So long as it meets the ISO's requirements, an end-use customer may act as a demand response provider for its own load or on behalf of other retail customers.

- <u>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</u>. The ISO's tariff amendment requires registration of proxy demand resources with the ISO through its demand response system. Because the demand response providers will take part in the ISO's energy and ancillary services markets, they are considered market participants.[63]

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61 "Assigned Commissioner And Administrative Law Judges' Ruling Amending Scoping Memo, Establishing A Direct Participation Phase Of This Proceeding, And Requesting Comment On Direct Participation Of Retail Demand Response In CAISO Electricity Markets" (Nov. 9, 2009), at p. 2 ("Assigned Commissioner's Ruling"). This ruling can be accessed on the CPUC's website at http://docs.cpuc.ca.gov/efile/RULINGS/109611.pdf.

62 Assigned Commissioner's Ruling at p. 9.

63 *See* ISO tariff, Appendix A, definition of "Market Participant" (defining a market participant as "[a]n entity, including a Scheduling Coordinator, who either: (1) participates in the CAISO Markets through the buying, selling, transmission, or distribution of Energy, Capacity, or Ancillary Services into, out of, or through the CAISO Controlled Grid; or (2) is a CRR Holder or Candidate CRR Holder.").

Therefore, like other market participants, demand response providers are subject to the ISO's creditworthiness requirements.[64]

- The RTO or ISO may require the ARC to be an RTO or ISO member if its membership is a requirement for other bidders. As explained above, demand response providers are market participants and the proxy demand resources of demand response providers can only be bid into the ISO market by an ISO scheduling coordinator. The demand response provider must be an ISO-certified scheduling coordinator in order to schedule, bid, and settle its registered proxy demand resources with the ISO; otherwise, the demand response provider can hire the services of a scheduling coordinator.

- Single aggregated bids consisting of individual demand response from a single area, reasonably defined, may be required by RTOs and ISOs. Pursuant to the ISO's tariff amendment, each proxy demand resource is required to be associated with a single LSE and a single UDC (or with a single LSE in the case of a proxy demand resource within an MSS) as discussed in Section II, above, and all underlying locations of a single proxy demand resource must be located in a single Sub-LAP.

- 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. The ISO will ensure that the same customer locations (*i.e.*, customer service accounts) are not registered with the same proxy demand resource more than once or included in the portfolio of more than one demand response provider.

- The market rules must allow bids from an ARC unless this is not permitted under the laws or regulations of a relevant electric retail regulatory authority. The ISO's tariff amendment will allow bids from a demand response provider through its scheduling coordinator subject to any applicable requirements of the CPUC and local regulatory authorities. As noted above, the CPUC has opened a "Direct Participation Phase" of its demand response proceeding 07-01-041 in order to evaluate issues related to ISO's implementation of Order 719. The CPUC has indicated that will conduct its proceeding in parallel with the ISO stakeholder process and the CPUC has laid out a schedule that accommodates ISO's intended May 1, 2010 date for implementing the proxy demand response product.

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[64] *See* ISO tariff, Section 12.1 ("Each Market Participant shall have the responsibility to maintain an Aggregate Credit Limit that is at least equal to its Estimated Aggregate Liability").

IV. Effective Date

The ISO requests that proposed *pro forma* proxy demand resource agreement be made effective on April 19, 2010, and that the balance of the tariff changes contained in this filing be made become effective on May 1, 2010. The earlier effective date for the *pro forma* agreement will allow the ISO to begin entering into contracts with demand response providers that seek to take advantage of the new proxy demand resource product, will allow demand response providers to begin to seek approval from LSEs for retail customers to participate as proxy demand resources, and will allow demand response providers to begin the registration of such proxy demand resources at the ISO. As noted above, although the ISO requests one effective date for the *pro forma* agreement and a later effective date for the remaining tariff provisions, the ISO requests that the Commission address all aspects in this tariff amendment filing in a single order.

V. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be put on the official service list established by the Commission with respect to this submittal:

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VI. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VII. Attachments

The following attachments, in addition to this transmittal letter, support the instant filing:

Attachment A	Revised ISO tariff sheets that incorporate the proposed changes described above
Attachment B	The proposed changes to the ISO tariff shown in black-line format
Attachment C	Listing of modifications to existing ISO tariff provisions to accommodate the implementation of the proxy demand resource product
Attachment D	Declaration of Margaret Miller, Manager, Market Design and Regulatory Policy for the ISO
Attachment E	List of key dates in the proxy demand resource stakeholder process

VIII. Conclusion

For the foregoing reasons, the Commission should accept the proposed tariff changes contained in the instant filing without modification. Please contact the undersigned if you have any questions regarding this matter.

Respectfully submitted,

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Attachment G

COMMITTEE FINAL REPORT

REVISED SHORT-TERM PEAK DEMAND FORECAST (2011-2012)

MARCH 2011

CEC-200-2011-002-CTF

CALIFORNIA
ENERGY
COMMISSION

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DISCLAIMER

This report was prepared by the California Energy Commission Electricity and Natural Gas Committee as part of *2011 Integrated Energy Policy Report* proceedings – Docket # 11-IEP-1C. The report will be considered for adoption by the full Energy Commission at its Business Meeting on March 9, 2011. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

ABSTRACT

This report presents revised short-term peak demand forecasts for the California Independent System Operator control area. The forecasts are designed to be used by the California Independent System Operator in its upcoming analysis of local area capacity requirements. Staff concluded that peak electricity demand is likely to be significantly lower (3-5 percent) for 2011 and 2012 than in the adopted *2009 Integrated Energy Policy Report* forecast for all three investor-owned utility transmission access charge areas within the California Independent System Operator control area. Staff, therefore, recommends a reduced short-term forecast for the Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric transmission access charge areas.

Keywords: Forecast, peak demand, weather adjustment, transmission access charge, load-serving entity, regression analysis

Please use the following citation for this report:

Garcia-Cerrutti, Miguel. Tom Gorin. Chris Kavalec. Lynn Marshall. 2011. *Revised Short-Term (2011-2012) Peak Demand Forecast* Committee Final Report. California Energy Commission, Electricity Supply Analysis Division. CEC-200-2011-002-CTF.

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CHAPTER 1: Introduction, Summary, and Study Approach

Introduction and Summary

The electricity demand forecasts adopted by the California Energy Commission are key inputs into analysis necessary to determine resource adequacy requirements in the California Independent System Operator (California ISO) control area. The forecasts presented in this report are designed to be used by the California ISO in its analysis of local area generation capacity requirements. The local capacity requirements (LCR) study determines the minimum amount of capacity resources that must be available to the California ISO within each area identified as having local reliability problems. This determines the generation capacity required to address these problems, and that capacity is allocated to load-serving entities (LSEs) as part of their year-ahead local resource adequacy requirement.

The most recent demand forecast was prepared for the *2009 Integrated Energy Policy Report (2009 IEPR)*.[1] Since that work was completed, economic conditions have worsened in California, relative to the short-term assumptions underlying load forecasts for 2009 and 2010, resulting in lower than predicted load growth for these years. A new, preliminary forecast for the *2011 IEPR* will be complete in May 2011. The California ISO LCR study, however, requires an updated demand forecast before then. Staff, therefore, evaluated the *2009 IEPR* forecast against actual 2009 and 2010 loads and reviewed recent economic/demographic projections to assess whether the May preliminary forecast is likely to be significantly different from the previous forecast in the short-term (2011 and 2012).

Staff concluded that for all three investor-owned utility (IOU) transmission access charge (TAC) areas[2], the peak electricity demand forecast for 2011 and 2012 is likely to be significantly lower than the current, adopted *2009 IEPR* forecast. Staff recommends a lowered short-term forecast for the Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) TAC areas. The forecast recommended by this report for *1-in-10* (extreme) weather[3] is shown in **Table 1**, along with similar projections from the *2009 IEPR* forecast. Results for individual load pockets and LSEs within the IOU TAC areas are provided in Chapter 2. This revised forecast is intended

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1 *California Energy Demand 2010-2020 Adopted Forecast*, California Energy Commission, December 2009. Available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

2 The TAC areas include the IOUs and, for Pacific Gas and Electric and Southern California Edison, publicly owned utilities utilizing the IOU's transmission system.

3 Peak forecasts assuming *1-in-10* temperature conditions are of the most interest to the California ISO for planning purposes.

for near-term purposes only and does not imply any changes to the adopted longer-term forecast.

The estimated weather-normalized 2010 peak demand for the SCE TAC area as well as the 2011 and 2012 peak forecasts have been revised upward in this Committee report in comparison to the staff draft report for two reasons. First, staff discovered that the 2009 and 2010 data for one of the SCE TAC area weather stations (Burbank) was not consistent with the weather series used in developing the historical trend. Data was collected for the correct Burbank weather station and the regression for 2010 weather response was re-estimated for the SCE TAC area. Second, in response to public comments from SCE, staff decided to use 1960-2010 as the historical period to estimate average daily temperatures instead of 1950-2010. Staff determined that using a 50-year history provided more robust results. This change is discussed further later in this chapter. Each of these revisions had approximately equal impact on the increase in the 2011 and 2012 SCE peak estimates. This Committee report also provides an adjustment to the peak demand results designed to address California Department of Water Resources (DWR) water pumping operational concerns.

The rest of this chapter presents the staff approach to peak analysis. Chapter 2 provides results and caveats. Appendix A contains a discussion of peak demand coincidence analysis, and Appendix B gives the regression results driving the analysis.

Table 1: Comparison of Revised 1-in-10 and *2009 IEPR* Peak Demand Forecasts (Megawatts), 2011 and 2012

TAC Area	Year	Revised Forecast	2009 IEPR Forecast	Difference (Percent)
PG&E	2011	22,716	23,594	-878 (-3.7%)
	2012	23,033	23,959	-926 (-3.9%)
SCE	2011	25,107	25,878	-771 (-3.0%)
	2012	25,517	26,266	-749 (-2.9%)
SDG&E	2011	4,801	5,036	-235 (-4.7%)
	2012	4,882	5,124	-242 (-4.7%)

Source: California Energy Commission, 2011.

Study Approach

The two most significant factors in determining short-term peak demand forecasts are the level of current, weather-adjusted loads and near-term projections of the economic and demographic forecast drivers. To assess the reasonableness of using the *2009 IEPR* load forecast for the 2012 LCR study, staff examined hourly demand data through summer 2010 and the October 2010 economic projections by Economy.com for each of the three IOU TAC areas.

Weather-Adjusted Demand Assessment

Because summer peak demands are highly sensitive to temperature, any evaluation of peak demand trends must account for temperature effects. For this analysis, staff used hourly load data from the California ISO for the TAC areas and daily temperatures in 2010 to estimate the relationship between the summer weekday afternoon (1:00 p.m.-6:00 p.m.) [4] peak load and temperatures. Summer is defined as the period from June 15 to September 15. Since this analysis is intended to compare new estimates of weather-adjusted peak with the *2009 IEPR* long-term demand forecast, demand response impacts were added back into the actual peak loads.[5] The temperature variable for each TAC area is a weighted average of temperatures from a set of weather stations representative of the climate in that utility region. The weights are based on the estimated number of residential air conditioning units in each utility climate zone.

Staff used two weather variables: maximum and minimum daily temperatures. The maximum temperature, as applied in the analysis, was a weighted daily maximum, referred to as *max631*, consisting of 60 percent of the current day's maximum temperature, 30 percent of the maximum the day before, and 10 percent of the maximum two days previous. Weighting in this manner accounted for heat buildup over a three-day period. The minimum temperature was included to capture the effects of nighttime cooling (or lack of) and, combined with the maximum, serves as a proxy measure for daily humidity through the difference between the two temperatures. Daily afternoon maximum loads entered the regressions in absolute or logged form, depending on goodness of fit. Staff also tested for statistically significant differences, in terms of regression slope, among temperature increments.

The coefficients from the regressions were applied to historical temperature data for 1950-2010 for PG&E, 1960-2010 for SCE and 1979-2010 for SDG&E, resulting in an estimate of peak for each weather-year. The median of the annual peak estimates serves as a *1-in-2*, or average, weather adjustment for 2010. Extreme, or *1-in-10*, weather peaks were estimated by applying the adjustments used in the *2009 IEPR* forecast to the new *1-in-2* weather-adjusted peaks. These adjustments are based on historical relationships calculated between peak demand in extreme weather years and in average weather years assuming a normal distribution.[6]

Staff's typical practice in choosing a historical period to determine average temperatures is to use the maximum number of years for which daily temperatures are available for the

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4 Staff used 1 p.m. – 7 p.m. for PG&E, which often peaks later than the Southern California areas.

5 Maximum hourly demand response impacts in the summer of 2010 ranged from 80 MW for SDG&E to 325 MW for SCE. As of this draft, PG&E had not provided hourly demand response estimates for the summer of 2010.

6 The *1-in-10* multipliers were applied to *1-in-2* results as follows: 1.073 for PG&E, 1.088 for SCE and 1.10 for SDG&E. The multipliers are typically recalculated in each *IEPR* cycle.

required weather stations. For PG&E and SCE, this currently means 1950-2010. However, the 1950s were an unusually cool period in Southern California, with average temperatures increasing toward the end of the decade. This resulted in median peak estimates for SCE that varied considerably depending on the starting year used for weather history before 1960. After 1960, median peaks were not nearly as sensitive to the starting year—a starting year of 1965 or 1970 yielded almost identical results to 1960. Therefore, staff felt that the period 1960-2010 would provide more robust SCE results. Sensitivity to starting year was much lower for PG&E from 1950-2010. Full weather data for SDG&E is not available before 1979.[7]

Economic and Demographic Assumptions

In Energy Commission electricity demand forecasting models, one of the most fundamental drivers of the forecast is population growth. Staff uses the population forecast to project growth in the number of households and additions to commercial floor space in sectors such as schools, hospitals, and retail. The Department of Finance (DOF) population projections used by Energy Commission staff do not attempt to capture the short-term fluctuations in population associated with business cycles, so this driver is relatively stable over time and from forecast to forecast. DOF has not revised its demographic projections since the *2009 IEPR* forecast was prepared.

The near-term economic projections, however, are more pessimistic than those developed in 2009, reflecting a more severe economic downturn than had been anticipated. Economic forecast drivers, including personal income, employment, and industrial output, contribute to growth in the commercial and industrial sector demand forecasts and, to a lesser extent, to growth in the residential sector. Staff uses economic projections prepared by Economy.com and Global Insight to develop these economic forecast drivers. The *2009 IEPR* demand forecast base case relied on Economy.com's June 2009 "most likely" projections, while an "optimistic" case developed by Global Insight was used in the alternative economic scenarios for the 2009 forecast.

Figure 1 and **Figure 2** compare economic projections used in the *2009 IEPR* base forecast with the October 2010 Economy.com[8] "most likely" forecast of employment and state personal income, respectively.[9] The figures clearly indicate a more severe recession in 2009

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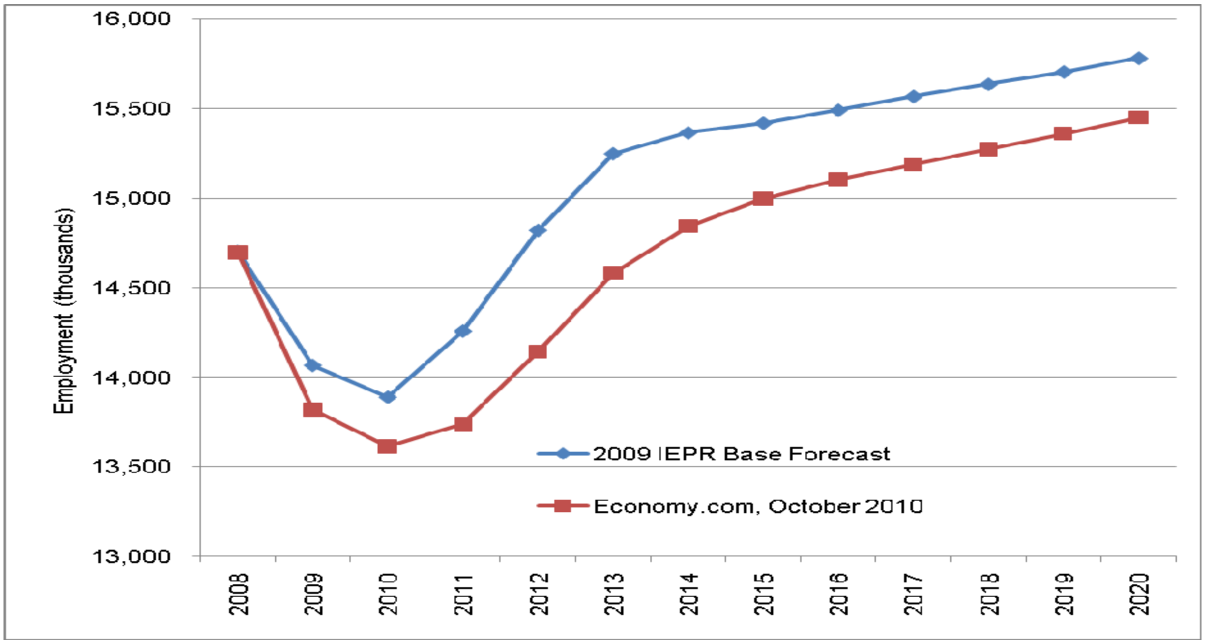
7 Daily weather data is not continuously available for El Cajon, one of the weather stations used for the SDG&E area, before 1979.

8 Since the *2009 IEPR* base forecast (as well as previous forecasts) relied on Economy.com projections, this analysis uses Economy.com as the reference economic forecast. Global Insight also projects significantly lower short-term economic growth compared to 2009 predictions.

9 Employment and personal income represent the two most important economic drivers for the *IEPR* forecasts. For some sectors, gross state product is used rather than personal income, but the two are highly correlated.

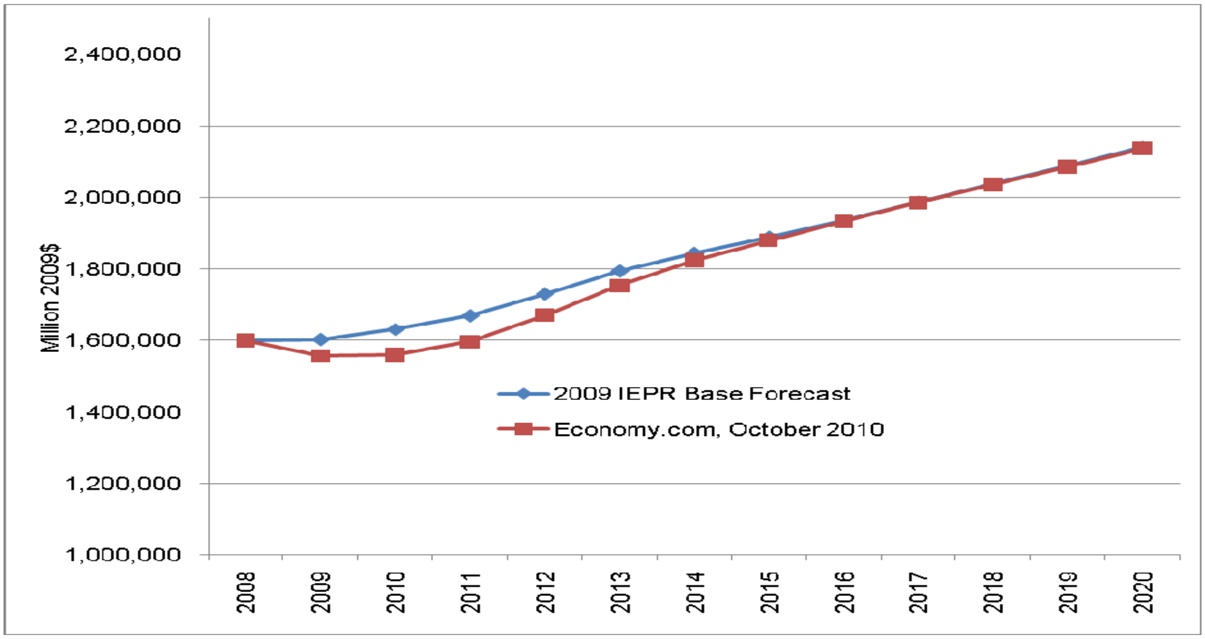
than was assumed in the *2009 IEPR* forecast and, in the case of employment, lower projected growth in the short-term (2010-2012). Economy.com (as well as Global Insight) updates its forecast monthly, so final economic projections used by staff in the *2011 IEPR* forecast will likely differ somewhat from this most recent forecast.

Figure 1: Comparison of Total State Employment Projections, *2009 IEPR* Base Forecast and Economy.com, October 2010



Source: Economy.com, October 2010.

Figure 2: Comparison Total State Personal Income Projections (2009$),
***2009 IEPR* Base Forecast and Economy.com, October 2010**



Source: Economy.com, October 2010.

Staff develops *IEPR* demand forecasts at the planning area level by aggregating county projections from Economy.com. Economic growth forecasts for the IOU planning areas serve as forecasts for the TAC areas.[10] To develop a peak forecast starting from the estimated weather-adjusted peaks for 2010, staff employed a peak demand econometric model estimated for the *2009 IEPR* forecast.[11] Rerunning the full end-use models with updated economic data was not feasible in the time frame available for this analysis. The peak econometric model provides output at the planning area level and includes per capita personal income and the unemployment rate as economic indicators. Staff compared forecast peak demand from this model for 2011 and 2012 using *2009 IEPR* economic assumptions with a forecast using October 2010 Economy.com projections and applied the percentage differences to *2009 IEPR* peak demand forecast growth.[12] Econometric model

10 IOU planning and TAC areas do not match exactly for PG&E and SCE but are close enough so that planning area economic growth rates are an excellent indicator for TAC area growth. In the case of SDG&E, the TAC area is identical to the planning area.

11 *California Energy Demand 2010-2020 Adopted Forecast*, *Appendix*, pp. A-4 – A-7. Regression results for this model are shown in Appendix B.

12 For example, if peak demand in the econometric model increased by 3 percent for a planning area from 2010 to 2011 using *2009 IEPR* economic assumptions and 2 percent using October 2010 projections, the peak demand growth rate for 2010-2011 would be the *2009 IEPR* growth rate times 2/3.

results were indexed to *2009 IEPR* growth rates since, unlike the *IEPR* forecast, the model does not explicitly incorporate efficiency or self-generation impacts, which are expected to grow significantly (and therefore reduce peak demand) in the 2010-2012 period. **Table 2** compares per-capita income and the unemployment rate assumed in the *2009 IEPR* forecast with the October 2010 Economy.com projections for the three IOU planning areas for 2011 and 2012.

Table 2: Comparison of *2009 IEPR* and October 2010 Economy.com Employment Growth Projections, 2010-2012

Planning Area	Year	Per-Capita Income (2007$), 2009 IEPR Forecast	Per-Capita Income (2007$), Economy.com, October 2010	Unemployment Rate, 2009 IEPR Forecast	Unemployment Rate, Economy.com, October 2010
PG&E	2010	43,805	42,460	13.72%	13.01%
	2011	44,241	42,882	12.33%	13.02%
	2012	45,215	44,274	9.69%	11.38%
SCE	2010	35,832	35,789	13.32%	12.55%
	2011	36,161	36,173	11.99%	12.46%
	2012	36,970	37,400	9.42%	10.89%
SDG&E	2010	43,350	41,865	10.99%	10.68%
	2011	43,900	42,386	10.05%	10.65%
	2012	44,797	43,874	8.20%	9.62%

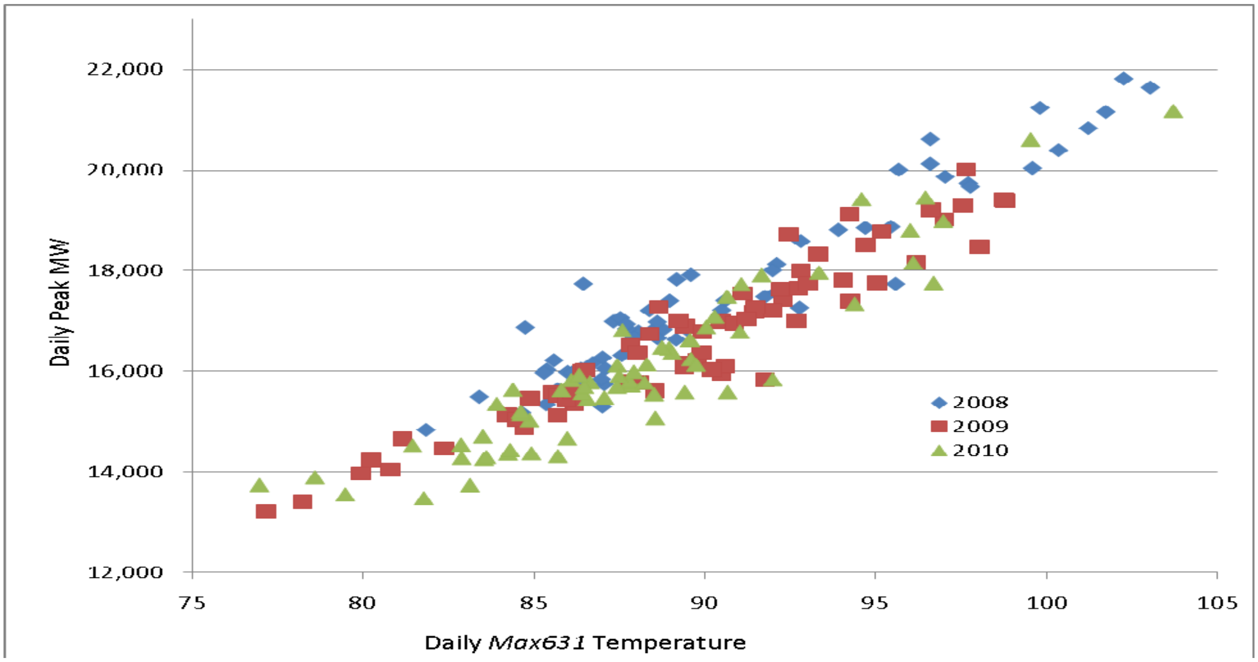
Source: Economy.com, 2009 and 2010.

The increased severity of the recession is most clearly seen in reduced projected personal income for 2010. As discussed in the next chapter, these indicators yield significantly reduced percentage growth in peak demand from 2010 to 2011 compared to the *2009 IEPR* forecast. Peak growth picks up from 2011 to 2012, although remaining slightly below *2009 IEPR* rates for all three planning areas.

CHAPTER 2: Results and Caveats

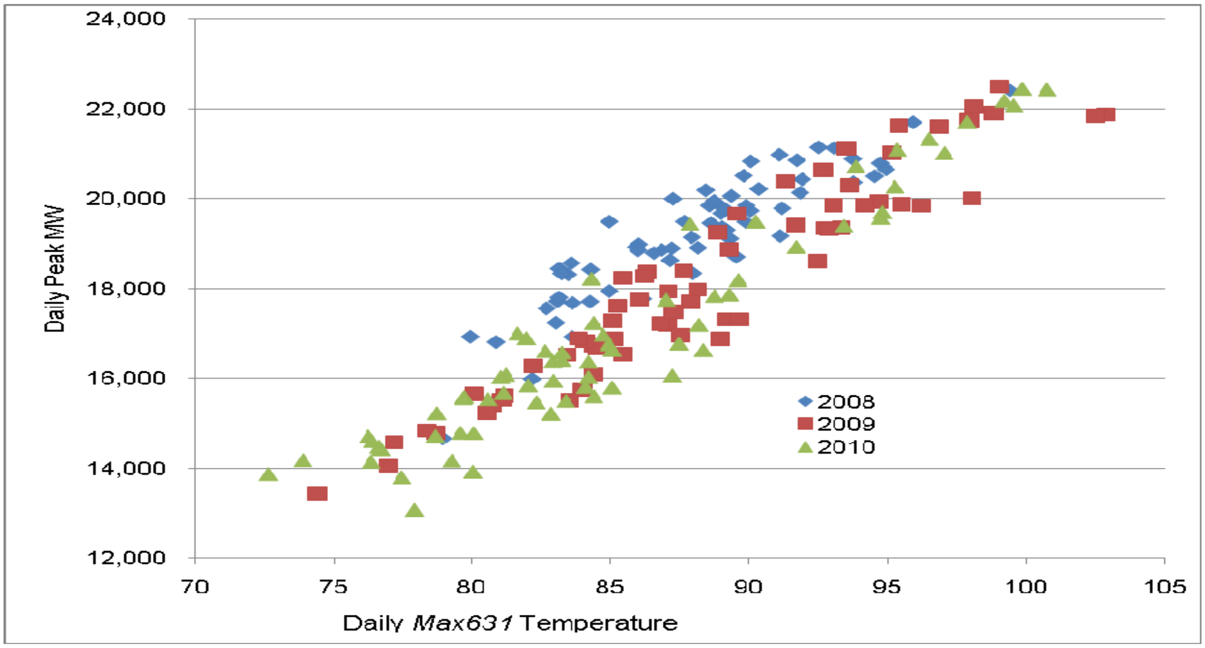
Figure 3, Figure 4, and **Figure 5** provide a glimpse of the data driving the 2010 weather-adjusted peak results presented in this chapter for PG&E, SCE, and SDG&E, respectively. Clearly, daily afternoon peak demand has fallen on average in 2009 and 2010 as a function of *max631* temperature compared to 2008. The figures show no apparent growth in peak demand from 2009 to 2010; indeed, demand appears to have dropped for SDG&E.

Figure 3: Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature PG&E 2008-2010



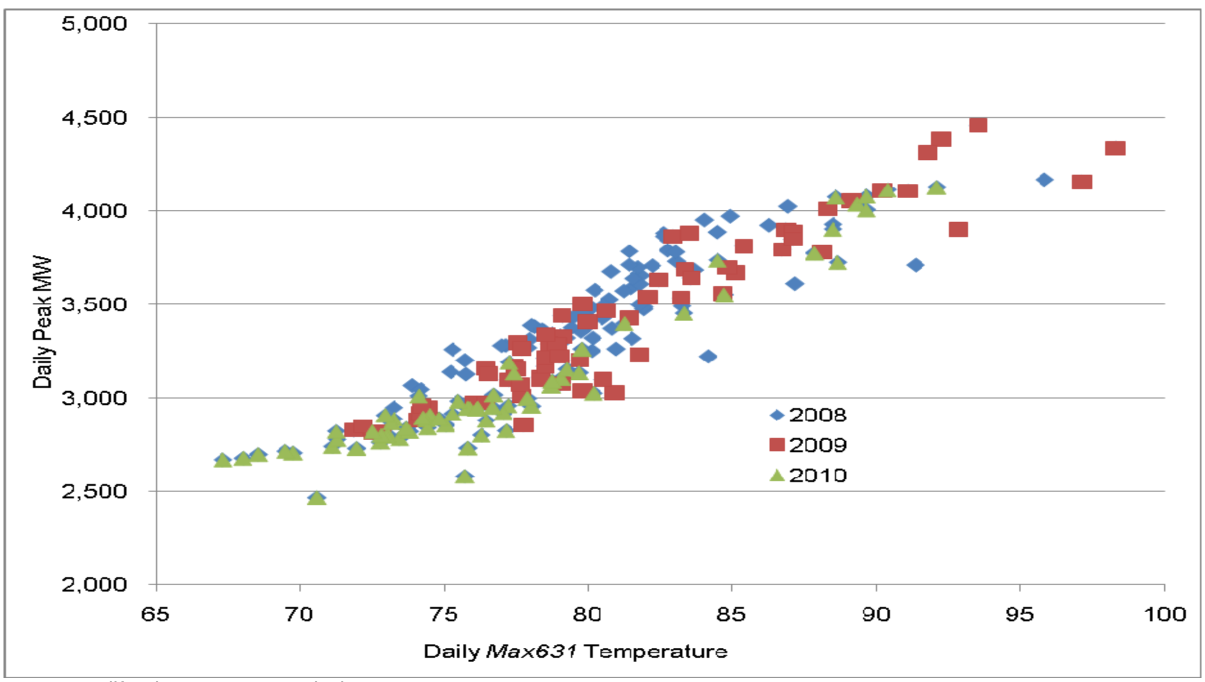
Source: California Energy Commission, 2011.

Figure 4: Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature SCE 2008-2010



Source: California Energy Commission, 2011.

Figure 5 Summer Weekday Afternoon Peak (MW) Versus Daily Max631 Temperature SDG&E 2008-2010



Source: California Energy Commission, 2011.

Weather-Adjusted 2010 Peak Estimates

Table 3 shows the estimated revised 2010 weather-adjusted *1-in-2* and *1-in-10* peaks for each TAC area that resulted from the regression analysis and compares these results to the *2009 IEPR* forecast. In addition to TAC areas, hourly load data was available for the Greater Bay and non-Bay Area portions of PG&E; peak demand (coincident) results are also shown for these two load pockets. Additionally, the table includes coincident totals for the California ISO, calculated by adding the TAC area estimates and multiplying by a coincidence factor.[13]

Table 3: Revised and *2009 IEPR* Weather-Adjusted Peak Demand (MW) by TAC/Load Pocket, 2010

TAC Area/Load Pocket	Revised 1-in- 2 Peak Demand	2009 IEPR 1-in-2 Peak Demand	1-in-2 Difference	Revised 1-in-10 Peak Demand	2009 IEPR 1-in-10 Peak Demand	1-in-10 Difference
PG&E	20,753	21,694	-941	22,268	23,278	-1,010
PG&E Bay Area	8,531	8,675	-144	8,884	9,034	-150
PG&E non-Bay	12,222	13,019	-797	13,384	14,244	-860
SCE	22,720	23,479	-759	24,719	25,545	-826
SDG&E	4,324	4,516	-192	4,756	4,967	-211
California ISO Total Coincident	46,650	48,496	-1,846	50,501	52,499	-1,998

Source: California Energy Commission, 2011.

2011 and 2012 Peak Forecast

For this analysis, staff revised the projected *2009 IEPR* peak growth rates for the IOU planning areas by comparing the output from a peak econometric model with *2009 IEPR* and October 2010 Economy.com economic indicators. **Table 4** shows the results of this adjustment for 2011 and 2012, along with peak growth rates from the *2009 IEPR* and the two econometric model runs. As discussed in Chapter 1, the growth rates from the econometric model runs are higher than for the *2009 IEPR* forecast since the econometric model does not incorporate incremental efficiency and self-generation impacts from 2009 onward.

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13 A region's coincident peak is the actual peak for the region while the non-coincident peak is the sum of actual peaks for subregions, which may occur at different times. The coincidence factor is 0.976, an estimate based on staff's review of historical differences between coincident and non-coincident peaks in the California ISO control area. See Appendix A for a discussion of coincidence factors.

Table 4: Adjusted *2009 IEPR* Peak Demand Growth Rates for 2011 and 2012 by Planning Area

Planning Area	Year	2009 IEPR Peak Demand Growth Rate	Econometric Model Growth Rates, 2009 IEPR Economic Data	Econometric Model Growth Rates, October 2010 Economic Data	Adjusted 2009 IEPR Peak Growth Rates
PG&E	2011	1.41%	2.45%	1.53%	0.88%
	2012	1.61%	3.66%	3.31%	1.45%
SCE	2011	1.33%	2.24%	1.48%	0.88%
	2012	1.53%	3.47%	3.12%	1.38%
SDG&E	2011	1.37%	2.00%	1.39%	0.95%
	2012	1.75%	2.80%	2.69%	1.69%

Source: California Energy Commission, 2011.

These growth rates, applied to the 2010 estimates shown in **Table 3**, yield the *1-in-2* and *1 in 10* peak projections, with two additional adjustments. First, water pumping energy use in the SCE and PG&E TAC areas is expected to increase due to a change in regulations.[14] Second, operational constraints on the Banks and South Bay water pumping plants in Northern California may require these facilities to operate at full capacity during peak hours.[15] Therefore, staff increased the *1-in-2* and *1-in-10* forecasts for the California Department of Water Resources in the Bay Area by the difference between estimated peak loads derived from observed data (after incorporating the increase discussed above) and the capacity of the Banks and South Bay plants.[16] **Table 5** shows the results for the TAC areas and major load pockets and compares these projections to *2009 IEPR* forecast totals.

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14 Restrictions on water pumping to California were lifted as of July 2010, based on a federal court decision: http://www.endangeredspecieslawandpolicy.com/uploads/file/09cv407%20Smelt%20(PI%20FOFCOL%20FINAL).pdf The load data for PG&E and SCE show an immediate increase in pumping contribution to peak demand in July 2010. Staff estimated the increase to be 140 MW for PG&E and 157 MW for SCE. These estimated increases were added to the 2011 and 2012 peak forecasts for these two areas.

15 Beginning in July 2007, a series of rulings have been issued that affect the operations of the State Water Project as it relates to exports from the Delta. These rulings specifically limit the ability of DWR to operate the Banks and South Bay pumping plants. The rulings are intended to protect endangered species and over the last few years, the operational criteria have evolved, with the rulings now addressing several fish species. As a result, DWR has fewer windows of time to export water from the Delta and the ability to move stored water through the Delta has shifted from spring into the summer months, when energy demands are the highest. As a result, DWR needs the ability to pump at Banks and South Bay Plants up to full capacity at any time when these constraints are not in effect, including hours of peak electricity demand.

16 This adjustment increased the DWR Bay Area (and therefore the PG&E Bay Area and PG&E total TAC) *1-in-2* and *1-in-10* peak forecasts by 98 MW for 2011 and 2012.

Table 5: Revised and *2009 IEPR* Weather-Adjusted Peak Demand (MW) Forecast by TAC/Load Pocket, 2011 and 2012

TAC Area/Load Pocket	Year	Revised 1-in-2 Peak Demand	2009 IEPR 1-in-2 Peak Demand	1-in-2 Difference	Revised 1-in-10 Peak Demand	2009 IEPR 1-in-10 Peak Demand	1-in-10 Difference
PG&E	2011	21,174	21,988	-814	22,716	23,594	-878
	2012	21,478	22,329	-851	23,033	23,959	-926
PG&E Bay Area	2011	8,870	8,768	102	9,226	9,131	95
	2012	8,995	8,880	115	9,355	9,247	108
PG&E non-Bay	2011	12,304	13,220	-916	13,490	14,463	-973
	2012	12,483	13,449	-966	13,678	14,711	-1,033
SCE	2011	23,077	23,785	-708	25,107	25,878	-771
	2012	23,453	24,142	-689	25,517	26,266	-749
SDG&E	2011	4,365	4,578	-213	4,801	5,036	-235
	2012	4,438	4,658	-220	4,882	5,124	-242
California ISO Total Coincident	2011	47,449	49,143	-1,694	51,361	53,200	-1,839
	2012	48,184	49,902	-1,718	52,150	54,021	-1,871

Source: California Energy Commission, 2011.

Finally, staff broke out individual load-serving entities (in addition to DWR) and load pockets for 2011 and 2012 using the same percentage distributions as in the *2009 IEPR* forecasts, adjusting the LSE entries so relevant sums matched totals for the TAC areas and the two PG&E load pockets. **Table 6** and **Table 7** show the results. North of Path 15 (NP 15), Zone Path 26 (ZP 26), and South of Path 15 (SP 15) are congestion zones as defined by the California ISO.[17] North of Path 26 (NP 26) is the sum of NP 15 and ZP 26 and is the same as the PG&E TAC area. DWR and Metropolitan Water District pumping loads are held constant for 2011 and 2012 across temperature scenarios. Water pumping loads tend not to be sensitive to temperature and economic conditions as is the case for other LSEs—staff therefore assumes no changes in forecast load unless new capacity is added.

17 The full network model map for the California ISO is available at http://www.caiso.com/2827/2827798d2ea50.xls

Table 6: Peak Demand Forecast (MW) by LSE/Load Pocket, Northern California

LSE/Load Pocket	1-in-2 Peak Forecast		1-in-10 Peak Forecast	
	2011	2012	2011	2012
PG&E Service Area - Greater Bay Area	7,730	7,842	8,050	8,166
Silicon Valley Power	488	495	508	515
NCPA - Greater Bay Area	274	278	285	289
Other NP 15 LSEs - Greater Bay Area	5	6	6	6
City/County of San Francisco	109	110	113	115
CA Department of Water Resources – North*	264	264	264	264
Greater Bay Area Subtotal	8,870	8,995	9,226	9,355
PG&E Service Area - Non Bay	9,200	9,337	10,110	10,254
NCPA - Non Bay	203	206	223	226
WAPA	173	176	190	193
Other NP 15 LSEs - Non Bay	146	148	160	163
Total NP 15	18,592	18,862	19,909	20,191
PG&E Service Area, ZP 26	2,267	2,301	2,492	2,527
CA Department of Water Resources, ZP 26	315	315	315	315
Total ZP 26	2,582	2,616	2,807	2,842
Total Non-Bay Area	12,304	12,483	13,490	13,678
Total NP 26 (PG&E TAC)	21,174	21,478	22,716	23,033

*Includes adjustment to address DWR operational concerns regarding the Banks and South Bay water pumping plants. This adjustment increases the DWR-North peak forecast (all entries in this row) by 98 MW.

Source: California Energy Commission, 2011.

Table 7: Peak Demand Forecast (MW) by LSE/Load Pocket, Southern California

LSE/Load Pocket	1-in 2-Peak Forecast		1-in-10 Peak Forecast	
	2011	2012	2011	2012
SCE Service Area - LA Basin	16,080	16,350	17,538	17,833
Anaheim	547	557	597	607
Riverside	580	590	633	644
Vernon	186	189	203	206
Metropolitan Water District	27	27	27	27
Other SP 15 LSEs - LA Basin	260	265	284	289
Pasadena	294	299	321	326
LA Basin Subtotal	17,975	18,276	19,603	19,931
SCE Service Area - Big Creek Ventura	3,897	3,962	4,250	4,322
CA Department of Water Resources-South	406	406	406	406
Big Creek/Ventura Subtotal	4,303	4,368	4,656	4,728
SCE Service Area - Out of Basin	533	542	582	591
Metropolitan Water District	259	259	259	259
Other SP 15 LSEs - Out of Basin	7	7	8	8
Total SCE TAC Area	23,077	23,453	25,107	25,517
SDG&E Service Area	4,365	4,438	4,801	4,882
Total SP 15	27,442	27,891	29,908	30,399

Source: California Energy Commission, 2011.

Caveats

The October 2010 Economy.com economic projections used in this analysis reflect recent information about the likely evolution of this recession, but forecast errors tend to be higher at times of turning points in the economy. Slackness in demand growth during times of recession can quickly be offset when the economy recovers.[18] Therefore, while electricity demand has been flat or declining in 2009 and 2010 as economic conditions deteriorated, a more significant "rebound" is certainly possible for 2011 and 2012 than is assumed in this analysis.

As discussed above, the forecast for 2011 and 2012 relies on an expectation that utility efficiency program and self-generation (particularly photovoltaic system) impacts will increase significantly in these two years, as assumed in the *2009 IEPR* forecast. Without these impacts, and using unadjusted output from the peak econometric model, the *1-in-2* peak forecast for PG&E and SCE would increase by around 500 MW by 2012. Projected 2012 SDG&E peak demand would increase by approximately 50 MW.

In the incremental uncommitted efficiency analysis[19] provided to the CPUC in early 2010 for long-term procurement purposes, staff estimated efficiency peak impacts additional to those estimated in the *2009 IEPR* forecast consistent with the requirement that IOUs make up 50 percent of savings that decay as efficiency measures wear out. The additional impacts are shown in Table 12 of the incremental uncommitted report. These impacts are not included in the results presented in this report—both Energy Commission and CPUC staff acknowledge that decay rates are highly uncertain and require further study. The additional efficiency as estimated would reduce the 2012 peak demand estimates by 117 MW for PG&E, 56 MW for SCE, and 4 MW for SDG&E.

As discussed previously, the forecast results depend to some degree on the historical period used to generate a distribution for peak demand. To account for climate change, a case can be made to use a period beginning more recently. For example, PG&E and SCE typically use a 30-year period for similar analyses. Using a 30-year time frame for this analysis would increase estimated 2010 weather-adjusted demand for SCE by around 90 MW and for PG&E by about 15 MW.

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18 Historically, in years immediately following a recession, annual growth in electricity usage has varied from less than 1 percent per year in the early 1990s to 7 percent in 1984.

19 *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, California Energy Commission, May 2010. Available at: http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

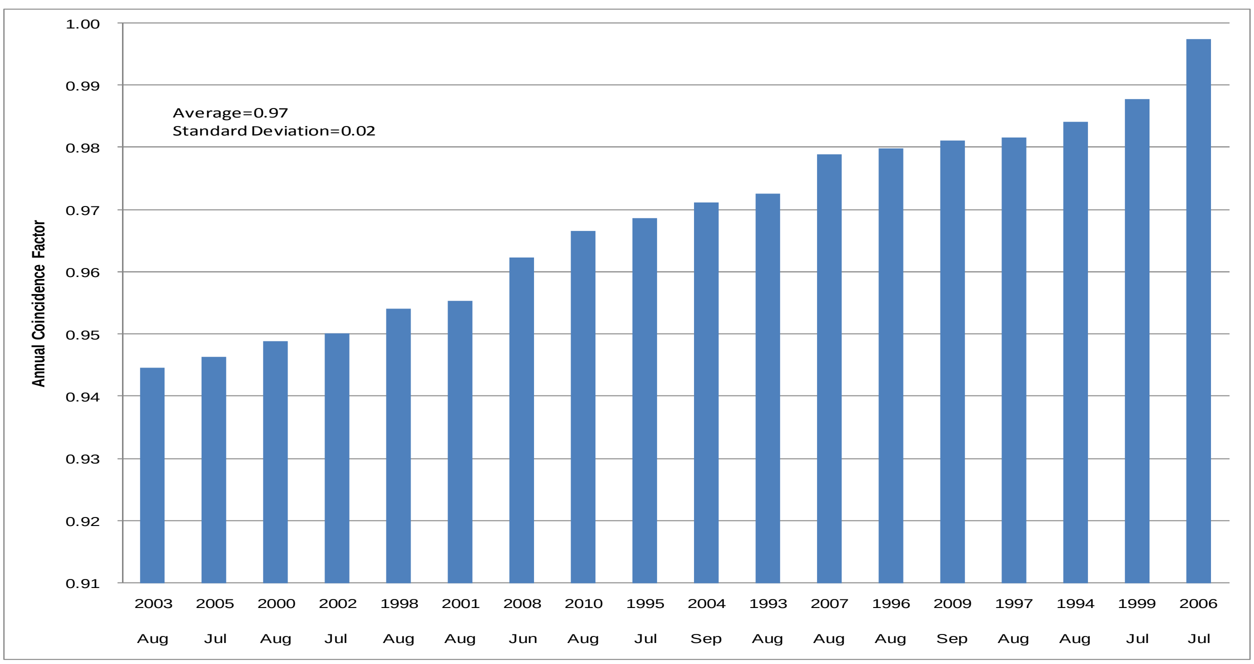
Glossary

2009 IEPR	*2009 Integrated Energy Policy Report*
California ISO	California Independent System Operator
DOF	Department of Finance
DWR	Department of Water Resources
IOU	Investor-Owned Utility
LCR	Local Area Capacity Requirement
LSE	Load-Serving Entity
MW	Megawatt
NP 15	North of Path 15
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SP 15	South of Path 15
TAC	Transmission Access Charge
ZP 26	Zone Path 26

APPENDIX A: California ISO Balancing Authority Area Coincidence

The peak demand for each TAC area in the California ISO is the non-coincident annual peak for that area. The peak demand forecast for the California ISO is the sum of the TAC areas (PG&E or NP26, SCE, and SDG&E), adjusted for the expected coincidence of the area peaks. Because each area may experience its peak demand on a different day or hour, the California ISO annual peak will be less than the sum of the individual area peak demands. The annual coincidence factor used in the forecast tables in this report and in the *2009 IEPR* forecast is 0.976, meaning the peak is assumed to be 2.4 percent less than the sum of the non-coincident peaks. This factor was estimated from the historic coincidence patterns between SDG&E, PG&E, and SCE utility areas. **Figure A-1** shows the historical variation in coincidence using Federal Energy Regulatory Commission Form 714 hourly loads for 2003 and California ISO hourly loads for 2004 to 2010.

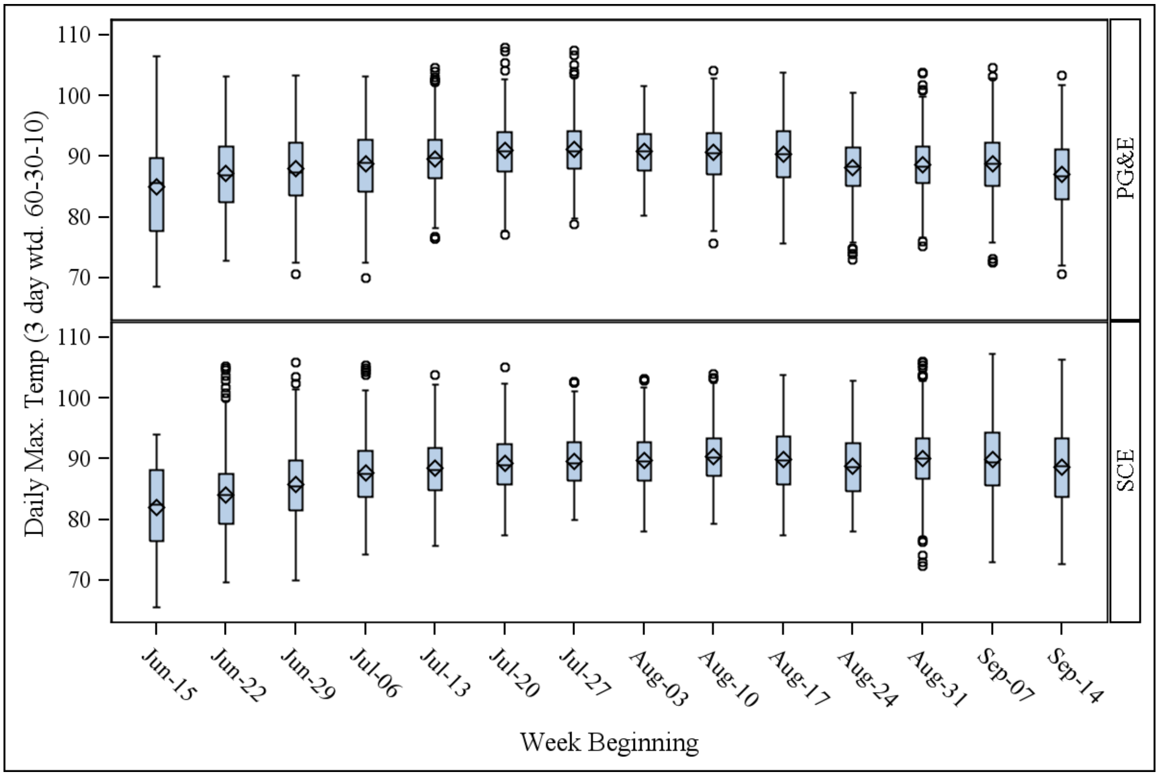
Figure A-1: Historical Coincidence of Annual Peak Loads in the California ISO



Source: California Energy Commission, 2010.

The different weather patterns between Northern and Southern California contribute greatly to this diversity. **Figure A-2** shows the average, 95th confidence interval and outliers of summer weekly temperatures over the last 60 years. Northern California is mostly likely to experience extreme temperatures in late July, when high temperature events in the SCE area are much less common. SCE's hottest days most frequently occur in late August and early September when PG&E experiences declining average temperatures along with some occasional high temperatures. This late summer pattern means the California ISO annual peak is most likely to occur in late summer. Two-thirds of the annual peaks in the last 17 years have occurred in August or September.

Figure A-2: Maximum Weekly Temperatures in Northern and Southern California (1950-2010)



Source: California Energy Commission, 2010.

Given this diversity, what is the expected coincident peak in each area at the time of the California ISO system peak? **Table A-1** shows each area's coincidence factor at the time of the system peak since 2001, where a coincidence factor of 1.0 means the TAC area had its annual peak at the time of the California ISO annual peak. The median coincidence factor for SCE is the highest of the three areas at 0.987, with a factor of 1.0 in five out of the last nine years. This indicates that most of the expected diversity at the time of the system peak is the result of lower loads in NP26, where the median coincidence factor is 0.961.

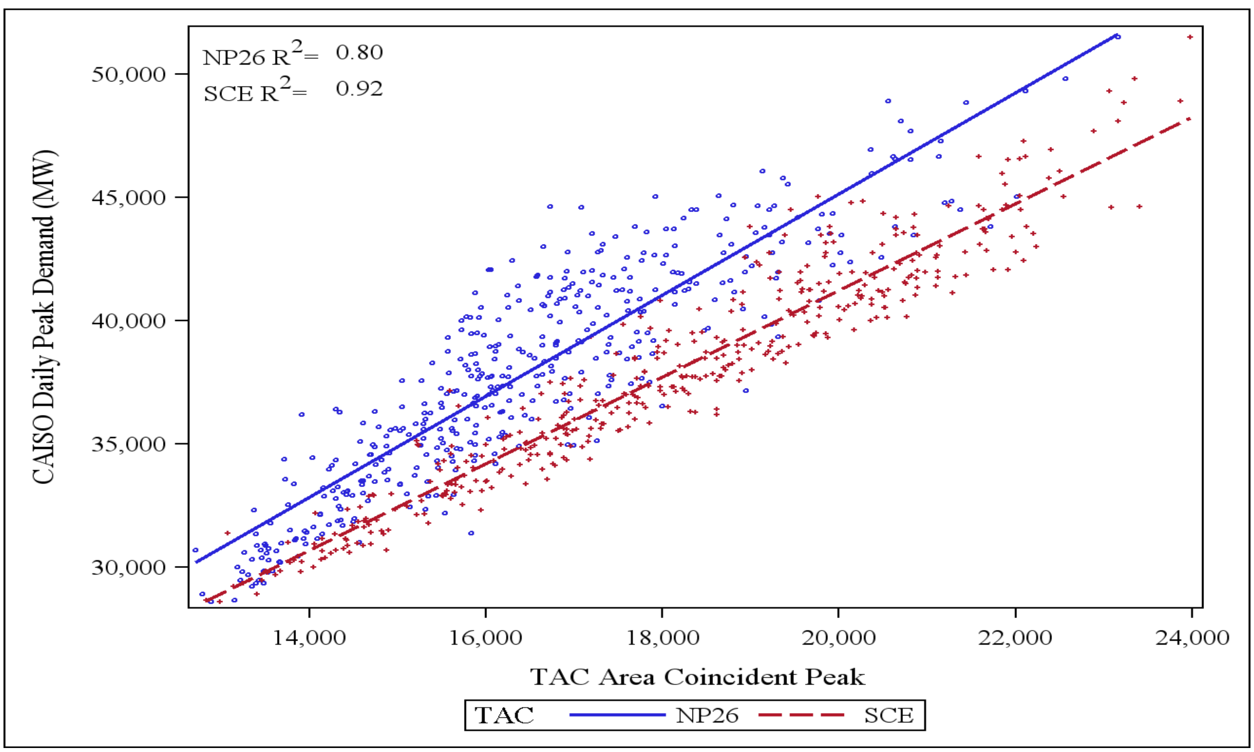
Table A-1: TAC Area Coincidence Factor at Time of California ISO Annual Peak Demand

Year	NP26	SCE	SDG&E
2001	0.922	1.000	0.915
2002	0.971	0.975	0.738
2003	0.966	0.922	0.836
2004	0.985	0.968	0.924
2005	0.954	0.951	0.883
2006	0.999	1.000	0.978
2007	0.956	1.000	0.977
2008	0.925	1.000	0.958
2009	0.956	1.000	1.000
2010	0.999	0.957	0.868
Average	0.963	0.977	0.908
Median	0.961	0.987	0.920

Source: California Energy Commission, 2010.

Figure A-3 illustrates the relatively stronger correlation between SCE loads and the California ISO peak, compared to NP 26 loads. This figure shows California ISO summer weekday daily peaks and SCE and NP 26 area coincident peaks since 2006. While SCE loads rise linearly with the California ISO peak, NP 26 loads show a correlation of about 10 percent less; the California ISO peak is most strongly driven by SCE area loads, and therefore the SCE peak is more coincident.

Figure A-3: California ISO Summer Daily Peaks and TAC Area Coincident Peaks (2006-2010)



Source: California Energy Commission, 2010.

APPENDIX B: Regression Results

Table B-1: Regression Results for Total PG&E TAC

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.01947	0.00141	13.84
Minimum Temperature	-0.00070	0.00201	-0.35
Dummy Constant: Weekend	-0.08128	0.00637	-12.76
Constant	8.00168	0.08396	95.30
Adjusted for autocorrelation: rho = 0.609, Durbin-Watson statistic = 1.565 R- Squared = 0.908 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-2: Regression Results for PG&E Greater Bay Area

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0134	0.0009	15.36
Minimum Temperature	0.0046	0.0017	2.70
Dummy Constant: Weekend	-0.1226	0.0064	-19.25
Constant	7.4706	0.0853	87.63
Adjusted for autocorrelation: rho = 0.581, Durbin-Watson statistic = 1.750 R- Squared = 0.904 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-3: Regression Results for PG&E Non-Bay Area, Includes Pumping

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0197	0.0018	10.80
Minimum Temperature	-0.0008	0.0022	-0.35
Dummy Constant: Weekend	-0.0624	0.0085	-7.33
Constant	7.3659	0.1023	71.98
Adjusted for autocorrelation: rho = 0.595, Durbin-Watson statistic = 1.482 R- Squared = 0.874 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-4: Regression Results for PG&E Non-Bay Area, Excludes Pumping

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	0.0204	0.0018	11.18
Minimum Temperature	0.0003	0.0022	0.14
Dummy Constant: Weekend	-0.0646	0.0087	-7.41
Constant	7.1869	0.1001	71.78
Adjusted for autocorrelation: rho = 0.542, Durbin-Watson statistic = 1.570 R- Squared = 0.896 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2010.

Table B-5: Regression Results for SCE

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631	276.43	15.24	18.13
Minimum Temperature	151.64	27.04	5.61
Dummy Constant: Weekend	-2017	100.60	-20.05
Constant	-15789	1273	-12.41
Adjusted for autocorrelation: rho = 0.513, Durbin-Watson statistic = 1.846 R- Squared = 0.937 Dependent variable = daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2011.

Table B-6: Regression Results for SDG&E

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631<=75 degrees	32.88	6.74	4.88
75<Max631<=80	40.06	7.50	5.34
80<Max631<=85	88.00	9.20	9.56
Max631>85	73.02	9.27	7.88
Minimum Temperature	12.65	3.93	3.22
Dummy Constant: Weekend	-374.45	17.33	-21.61
Constant	-321.54	581.32	-0.55
Adjusted for autocorrelation: rho = 0.402, Durbin-Watson statistic = 2.054 R- Squared = 0.958 Dependent variable = daily afternoon peak, June 15 - September 15, 2010			

Source: California Energy Commission, 2011.

Table B-7: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Natural Log (max631)	0.4710	0.0795	5.93
Per capita income (07$)	0.0070	0.0012	5.92
Unemployment rate	-0.0064	0.0014	-4.51
Avg. residential electricity rate (07$)	-0.0033	0.0017	-1.94
Avg. commercial electricity rate (07$)	-0.0026	0.0013	-1.97
Dummy: 2001	-0.0960	0.0177	-5.42
Dummy: 2002	-0.0625	0.0176	-3.55
Constant: Burbank/Glendale	-0.1113	0.0093	-11.99
Constant: IID	0.3591	0.0186	19.29
Constant: LADWP	-0.3426	0.0146	-23.51
Constant: PASD	-0.0594	0.0252	-2.36
Constant: PG&E	-0.2552	0.0137	-18.65
Constant: SCE	-0.2852	0.0132	-21.66
Constant: SDG&E	-0.5291	0.0272	-19.42
Overall constant	-1.5683	0.3693	-4.25
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 4,463 Dependent variable = natural log of annual peak per capita, 1980-2008			

Source: California Energy Commission, 2009.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C., this 17th day of January, 2012.

/s/ Bradley R. Miliauskas
Bradley R. Miliauskas