BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	)	R.09-10-032

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REPLY COMMENTS ON PROPOSED DECISION REGARDING DEMAND RESPONSE RESOURCES

In accordance with Article 14 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission"), the California Independent System Operator Corporation ("ISO") respectfully submits reply comments on the Proposed Decision Further Refining the Resource Adequacy Program Regarding Demand Response Resources ("Proposed Decision"), issued August 9, 2011.

I. DR RESOURCES SHOULD BE DISPATCHABLE BY LOCAL AREA

The Proposed Decision adopts the ISO's proposal that only those demand response ("DR") resources capable of being dispatched in the local area in which the reliability need occurs should count as local resource adequacy ("RA") capacity. The ISO's comments urged the Commission to retain this recommendation, for reasons that: (i) the recommendation is consistent with the key principle of the CPUC's RA program that RA resources must be available when and where needed; and (ii) curtailing load across a service territory when curtailments are only needed in a particular area is inefficient, costly and impacts reliability.

In its comments regarding congestion caused by DR program calls outside the local area where needed, Pacific Gas & Electric Company ("PG&E") states that: "[i]ndeed, the CAISO has not identified a realistic scenario that would create congestion costs by reducing load. … It is counter intuitive to claim, as the CAISO has, that dropping load will increase congestion or require the CAISO to have more reserves."[1]

PG&E's understanding of grid operations is mistaken, and its claim that curtailing large amounts of load across the system has no reliability or cost impact is unfounded. The ISO is a balancing authority responsible for system reliability and balancing supply and demand on a minute-by-minute basis. To perform its duties, the ISO runs a nodal market to ensure system stability and resolve congestion across thousands of nodes that make up the grid. The system must always be balanced within a tight frequency tolerance. If the ISO has no need for energy or load reduction in a particular area to address congestion, and yet large amounts of load are curtailed, then the system must be rebalanced through resource redispatch, based on economic bids, which does have a cost consequence. PG&E's statements inferring the lack of harm and cost are unfounded and unsubstantiated. The ISO suggests that the Commission place the burden on PG&E to demonstrate and provide analysis as to how and why there is no cost consequence of its dynamic rate program and the nature of its dispatch.

The ISO does not agree with the suggestion of EnerNOC, Inc. ("EnerNOC") to tie integration and bidding to a local dispatchability requirement in the specific manner presented. EnerNOC's proposed language could be incorrectly construed to mean that DR that is not locally dispatchable will still count for local RA until such time that it is integrated into ISO markets. The ISO maintains that resources must be locally dispatchable in order to count as local RA.

The ISO does support the recommendation of NRG Energy, Inc., that, instead of deferring the local dispatch requirement until 2013, the Commission should impose this requirement on reliability DR resources in order for those resources to count towards meeting local RA capacity requirements for the 2012 compliance year.

II. BACK-UP GENERATION

A. Back-up Generation Should Not Be Paid As Demand Response

Minimal use of back-up generation may be necessary to enable demand response to

[1] PG&E Comments, p. 5.

occur. As the California Large Energy Consumers Association ("CLECA") comments indicate: "[m]any, if not most, customers on BIP use back-up generation in a very limited manner to serve only a fraction of their load, generally for safety or environmental reasons."[2] If this is correct, then the Commission should consider a policy that allows for the minimal use of back-up generation to support primary demand response. This said, the Commission should not make a DR incentive payment for the portion of load served by back-up generation since paying back-up generation as DR is economically inefficient.[3] Without setting up rules to ensure economic equivalency between supply and DR resources, incentives can alter consumer behavior resulting in market distortions and inefficiencies.

If Commission policy allows back-up generation to be included as part of a customer DR strategy, then the kilowatt-hour output of the back-up generation should be subtracted from the total amount of "demand response" that a customer provides.[4] The DR quantity *net of electricity generated on-site* should be the quantity paid as demand response, regardless of the type of back-up generation used. This will maintain the efficacy of DR and not provide a perverse incentive to run back-up generation when, without an incentive, it could be uneconomic to do so. Further, eliminating demand response payments associated with back-up generation is unlikely to have a significant impact on the overall customer incentive payment or result in a mass exodus from the program, since as CLECA points out "… the vast majority of the customer facility's demand is dropped and only a small fraction is met through the use of back-up generation."[5]

B. Back-up Generation Under a Default Dynamic Rate Does Not Create Economic Inefficiency

PG&E argues that the Commission should not prohibit[6] the use of DR resources

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2 CLECA Comments, p. 4.

3 For further discussion and an example of this point, please see *Initial Response of the CAISO Regarding Remaining Direct Participation Issues (Phase IV, Part 2),* Docket R.07-01-041 (December 8, 2010), posted on the ISO's website at: http://www.caiso.com/Documents/Dec8_2010Initial response-remainingdirectparticipatingissues_phaseIV_part2_docketR_07-01-041_OIRdemandresponse_.pdf

4 *Id.* at pp. 5 to 7.

5 CLECA Comments, p. 4.

6 The Proposed Decision does not 'prohibit' customers from using backup generation during DR events, as PG&E asserts. Rather it cannot be used for RA counting purposes.

supported by back-up generation as RA resources because that would impact its ability to roll-out dynamic rates since it cannot police all customers and how they choose to respond to a dynamic rate signal. The ISO understands this challenge; however, there is an important distinction between the economic inefficiency of making an explicit payment for back-up generation acting as DR and receiving an incentive payment versus taking service under a dynamic rate. Under a DR program, like the Base Interruptible Program, an explicit "capacity payment" is made to the customer for demand response. This explicit payment to a customer using a back-up generator introduces the economic inefficiency -- the customer is being paid not to consume and run its backup generation.

Under a dynamic rate, a customer chooses not to consume based on a price signal to avoid being charged to consume at a higher than normal rate. Unlike the Base Interruptible program, under a dynamic rate there is no additional payment on top of the rate savings from choosing not to consume. When a demand response program pays for demand response on top of the retail rate savings, it is this extra "incentive" payment that creates the market inefficiency. If a customer on a dynamic rate chooses to run a back-up generator, that decision is based on the cost of running the generator (and lost productivity or comfort) relative to the cost of the higher retail rate. However, for a DR program that makes an explicit payment, the decision to run a back-up generator is influenced by the amount of incentive received as "demand response" in addition to the rate savings. Dynamic rates and incentivized DR are not economically comparable on this point and running a back-up generator in a dynamic rate scenario does not create the market inefficiency as does an incentive payment.

C. No Substantiated Harm If Back-up Generation Is Eliminated

In its comments, PG&E claims that if its DR programs were redesigned, under the Proposed Decision's elimination of back-up generation, the consequences of the change have not been carefully evaluated. But PG&E then goes on to say that prohibiting customers from using back-up generation during DR events would risk grid reliability and load shedding. PG&E also admits that it is not in a position to police whether customers use back-up generation during DR events."[7] These statements raise the question -- how does PG&E substantiate the dire consequences of eliminating the use of fossil-fueled back-up generation if PG&E has no idea whether customers use back-up generation during a demand response event? The Commission should dismiss this unsubstantiated argument of undue harm unless PG&E and SCE can clearly demonstrate the reliability risk with facts and analysis.

III. DYNAMIC RATES REDUCE FORECAST LOAD AND DO NOT REQUIRE RA TREATMENT

The Commission should reject PG&E's argument that "[i]f the PD is not revised, PG&E will be required to seek an exemption for its dynamic rate programs or replace the RA provided by these programs."[8] Dynamic rates fundamentally alter the load shape and are more appropriate as an adjustment to the IOU forecast load rather than as a "resource." The ISO agrees with SCE that dynamic rate programs are more appropriately treated as a mechanism for forecast reduction instead of resource adequacy, which can lower the IOUs procurement needs on the day the program is called. [9]

Peak demand, which is the basis for calculating the 115% planning reserve margin under the RA program, should be reduced if customers are exposed to higher prices during peak periods. The reduced consumption will lower the amount of RA capacity required since the basis will be lower than what it would have been without the price signal provided under a dynamic rate tariff. Thus, the ISO finds PG&E's argument unsubstantiated and counter-intuitive to the fundamental design and intent of dynamic rates. No exemption is required. The programs will reduce forecast load, reducing the need for RA capacity on that reduced amount.

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7 PG&E Comments, pp. 1-2.

8 *Id.* at p. 6.

9 SCE makes this same argument which the ISO incorporated into its direct testimony on the IOUs 2012-214 demand response applications. Direct testimony of ISO, Docket A11-03-001, et al., (June 15, 2011), as posted on the ISO website at: http://www.caiso.com/Documents/June152011DirectTestimonyReIOUApps_Approval_DRProgramsEtc2012-2014DocketA11-03-001etal.pdf

IV. CONCLUSION

The ISO respectfully requests that the CPUC issue an order consistent with the ISO's reply comments.

Respectfully submitted,

/s/ Beth Ann Burns
Nancy Saracino
General Counsel
Beth Ann Burns
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom California 95630
Tel. (916) 351-4400
Fax. (916) 608-7222
Email: bburns@caiso.com

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