Rulemaking No: R.13-09-011
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Witness: Victor Kruger

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	R.13-09-011 (Filed September 19, 2013)

PREPARED DIRECT TESTIMONY OF

VICTOR KRUGER

CHAPTER III

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

May 6, 2014

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF

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CHAPTER III

PHASE THREE ISSUES AND QUESTIONS

RESOURCE ADEQUACY CONCERNS

AND

CAISO MARKET INTEGRATION COSTS

The purpose of my testimony is to respond to questions posed in Attachment A of the *Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings*, dated April 2, 2014. I am employed by SDG&E and hold the position of Market and Policy Analysis Manger. My business address is 8315 Century Park Court, San Diego, CA 92123. My full statement of Witness Qualifications is set forth as part of my Prepared Direct Testimony.

I. RESOURCE ADEQUACY CONCERNS

Question 1: Parties should provide a detailed explanation of their resource adequacy concerns, specific to the bifurcation framework adopted in D.14-03-026.

Response 1: Qualifying capacity from all DR programs is currently included in SDG&E's annual, year-ahead Local and System Resource Adequacy compliance filings. In this way, the DR resources currently "count" as supply-side RA resources. However, DR resources currently have none of the offer obligations or performance risks associated with other, traditional RA resources. While the bifurcation framework seeks to impose these offer and performance obligations on supply-side DR resources, it is unclear at this point the impact this change will have on existing programs, and how it will effect enrollment in DR supply-side offerings.

Moreover, while the expectation is that bifurcated supply-side DR will, similar to today, directly count towards meeting RA requirements, it is less clear how, and to what extent, load modifying DR will impact RA requirements.

FERC Order 764 was implemented by the CAISO on May 1, 2014 with a new financially binding 15 minute market and the elimination of the financially binding hour-ahead market. Coupled with this is the movement from a 90 minute ahead forecast for the real-time market to a more accurate 37.5 minute ahead forecast. The full impact of these new more timely and accurate needs on supply-side DR are not known exactly yet but it will increase the value of fast response DR. Changing the energy value of the supply-side DR products will alter bids to supply capacity to meet local or system net peaks and capacity to meet ramping needs.

II. MUST OFFER OBLIGATIONS, PERFORMANCE RISKS AND MARKET INTEGRATION COSTS FOR SUPPLY-SIDE DR

Today, conventional Local or System RA resources are required – through a Must-Offer Obligation (MOO) in the CAISO's tariff-- to economically bid or self-schedule their RA capacity into the CAISO every day. In addition, resources satisfying a Flexible RA requirement are prohibited from self-scheduling energy, and must economically bid into the CAISO market certain hours of each day. RA resources that fail to offer or schedule face unavailability charges and penalties, and RA resources that "underperform" relative to their award or schedule face imbalance energy charges.

Currently, none of these offer obligations or performance risks apply to DR resources. DR resources "count" towards satisfying an LSE's RA obligations, but are not required to actively participate in the CAISO's markets. Bifurcation would impose a new set of offer and performance obligations on supply-side DR. At the moment, supply-side DR faces uncertainty from not knowing what the final MOOs, counting rules and associated penalties will be, as offer obligations and performance risks specific to demand response are currently being determined at the CPUC and CAISO. While the specific obligations are not yet determined, it is clear that those obligations and risks will be elevated relative to the current framework, and may impact enrollment in supply-side offerings. At a minimum, SDG&E anticipates that some customers will migrate from supply-side programs (with increased obligations) to load modifying programs where direct participation in the CAISO's markets (and associated obligations) is not required.

In addition to must offer obligations and performance risks, supply-side DR will face new hurdles and costs to directly participate in the CAISO's markets – costs that are not present under the current framework. These include metering, reporting, interfacing (communicating) with the CAISO, as well as required interaction with a certified scheduling coordinator to facilitate bidding and settlements. A supply-side DR resource may commit only a portion of its expected capacity for RA to mitigate its exposure to penalties for non-performance and inaccurate measurement of the baseline for settlement, potentially lowering the overall value of DR from an RA perspective relative to the existing framework.

In sum, supply-side DR will bear additional costs to directly bid into the CAISO markets, and will also be exposed to any non-availability charges and underperformance costs. Cumulatively, these impacts may affect enrollment in supply-side DR offerings and potentially decrease the amount of cost effective DR relative to the existing framework. In addition, a lower risk-adjusted RA value may be used by supply side DR programs to mitigate the exposure to penalties for non-performance, also impacting the amount of RA relative to the current counting framework.

III. REDUCING RA OBLIGATIONS WITH LOAD-MODIFYING DR

It is unclear at this point how the RA value of load modifying DR will be determined, but SDG&E expects it will take some time (perhaps years) to be fully reflected in the historical data. Therefore, it is expected that load modifying DR's impact on RA would be reduced from current levels since full credit for its capacity reduction will not be included in the early years of the load forecast used to determine RA requirements. The CEC should strive to accurately reflect the expected impacts of load modifying DR into their forecasts so the full RA value would be realized. Uncertainty of how load modifying DR will be reflected in the CEC forecast will likely result in an effective discount from today's RA value, but as indicated in the testimony of David Barker, SDG&E believes that any such reduction should not be included in the cost effectiveness protocols so as to avoid reducing the amount of cost effective load-modifying DR available.[1]

In addition to existing SDG&E load modifying DR programs, new DR programs are expected to be used to solve problems on the distribution system, like feeder or transformer overloads. This type of DR will be controlled by the utility for operational reasons, and initially will not be bid into the CAISO with a trigger price so they are considered load modifying DR. Many details remain on how to evaluate and use potential distribution reliability DR. It should still be available to reduce the annual system peak but may not be available for full use to meet ramping needs (flexible RA) because of its use for distribution reliability.

IV. CAISO MARKET INTEGRATION COSTS

Question 1: Parties should provide their understanding of the costs (in dollars) of the CAISO market participation either through their own direct participation or through the participation of other entities in other markets.

Response 1: The notion of participation by retail demand response, either by individual customers or through third-party aggregators, is both new and at the present time, very

[1] Barker Testimony, Response 22, page 21.

unpredictable. Because of that uncertainty and unpredictability, it is similarly uncertain and difficult to fully anticipate the full range and scope of costs that would be associated with CAISO market participation. Nonetheless, SDG&E has undertaken a study to determine as best as can be done what those costs are likely to entail. The cost break down is shown in two separate parts, the (1) administrative portion of implementation and (2) the information technology (IT) costs. The discussion below addresses the anticipated costs.

V. BUSINESS PROCESS COSTS

The business process cost is associated with process change implementation, on-going program management and support activities. These costs will be incurred regardless the level of participation. SDG&E needs to prepare and implement a business process in preparation for any third party market participation. SDG&E anticipates the need for 4 full-time equivalent employees (FTEs) to support these activities. These figures are anticipated and may change when the actual implementation is undertaken. The operational complexity involved in these processes could change these estimates. The roles at a high level can be broken down to:

- Project implementation (1 FTE)
- Enrollment/Disenrollment process (1 FTE)
- Program Management (1 FTE)
- Program Support (1 FTE)

We anticipate the cost for this portion to be in the range of $400k for implementation to $300k for annual operations.

VI. INFORMATION TECHNOLOGY COSTS

In order to implement a seamless, accurate process in CAISO market participation, SDG&E needs to modify existing systems and integrate with CAISO. Difficulty in estimating these costs is due to uncertainty in the potential level of participation. Managing a small number of customers with a manual process may be possible, but if the utilities are ordered to integrate the existing load modifying demand response into the market, full automation will be required. The full cost for IT implementation cost is estimated at $1.5 million. A fully automated process to allow third party participation will push the cost to $3.0 million.

Question 1: Parties should present a range of costs that they would consider to be reasonable. Explain why this range of costs is reasonable and costs outside the range are not reasonable.

Response 1: The administrative portion of implementation and the information technology costs discussed in the above sections are reasonable considering the task and level of effort required for market integration.

- Costs have to be low enough to allow DR programs to be cost effective enough to be designed at a level that meets the CPUC's goals.
- Costs that are too high and prevent the CPUC's goals to be met are too high.

Question 2: For costs outside the range and therefore unreasonable, please provide examples of ways to decrease those costs.

Response 2: Examples of ways in which to decrease costs include delaying the establishment of DR goals until programs are more cost effective and changing program participation requirements (metering, communications, penalties etc.) result in more cost effective DR programs.

Question 3: PG&E provided a list of solutions for decreasing CAISO market integration costs in its December 13, 2013 filing at page 13. Provide comments on the list of solutions.

Response 3: The following provides the list of solutions referenced in PG&E's filing, dated December 13, 2013, and presents SDG&E's position regarding each:

- Have PDR be called in an "all or nothing" manner (discrete) like RDRR

SDG&E supports calling PDR in an "all or nothing" manner to simplify administration of this small program. SDG&E intends to bid in all of its current PDR as a single block. A different strategy will be required when future PDR products have significantly different dispatch characteristics.

- Create a DLAP-level PDR product

All of SDG&E's load is within a single DLAP and, consequently, already has a DLAP-level PDR product

- Simplify telemetry requirements

Telemetry requirements can be an obstacle for obtaining RA credit for a program. SDG&E supports simplifying and reducing the cost of telemetry as much as possible.

- Increase the minimum resource size for telemetry (now 10 MW)

Telemetry needed should reflect a least cost best fit objective. Telemetry could be justified for some programs less than 10MW in size and not for others that are greater than 10MW in size depending on the complexity telemetry needed and does the telemetry present an obstacle to meeting CPUC goals and CAISO needs.

- Simplify registration for mass market customers

SDG&E supports simplifying registration for mass market customers, with appropriate safeguards, to reduce costs and expand the possible participant base.

- Ease master file update requirements for supply-side DR resources

SDG&E supports easing master file update requirements for supply-side resources for efficiency but not at the loss of any information that is needed to optimize its value in the CAISO markets.

- Eliminate the requirement to separate PDR participants by LSE

This may not be necessary for most/all SDG&E programs. SDG&E supports elimination of this requirement in order to facilitate a more streamlined market integration process.

- Allow customers to be removed or added from a RDRR during a season (no "lockdown" of customers for a season)

SDG&E supports allowing customers to be removed or added from a RDRR during a season as long as the change is not administratively burdensome or adversely impacts the value in the CAISO markets.

- Reduce the number of subLAPs and have subLAPs rollup to LCAs

This does not apply to SDG&E with all SDG&E's service area being one subLAP and having a single Local RA area. Although SDG&E only has one LAP, we support simplification of the laps to accommodate a wider and more simplified process for market integration across California.

VII. WITNESS QUALIFICATIONS

My name is Victor J. Kruger. My business address is 8315 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric Company as the Market & Policy Analysis Manager in the Electric and Fuel Procurement Department for SDG&E. In my current position, I am responsible for working with the CPUC and CAISO in developing changes in policies to respond to new state goals, implement changes in current practices to meet these goals, manage SDG&E's RA and CRR positions and file compliance documents.

I attended the University of the Minnesota and graduated with a Bachelor of Science degree in Electrical Engineering in 1977. From 1977 to 2001 I worked for Wisconsin Electric Power Company and provided testimony for the State of Wisconsin, Michigan and FERC. From 2001 to 2003 I worked for Progress Energy as Risk Manager.

I was hired by SDG&E in 2004 in the Grid Operations Department, moved to the Transmission Planning Department in 2008 and to my current position in 2012. I have previously testified before this Commission in Applications for the Sunrise Power Link 05-12-014 and the Otay Mesa related transmission upgrades 04-03-008.