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Witness: David Barker

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

DAVID BARKER

CHAPTER VI

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

May 6, 2014

SDGE

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PREPARED DIRECT TESTIMONY OF

DAVID T. BARKER

CHAPTER VI

PHASE THREE ISSUES AND QUESTIONS

COMMENTS ON THE DEMAND RESPONSE AUCTION MECHANISM AND PHASE TWO ISSUE COST EFFECTIVENESS PROTOCOLS

The purpose of my testimony is to provide overall comments on the Demand Response Auction Mechanism (DRAM) and cost-effectiveness protocol issues. As indicated on page 6 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* (Joint Ruling), dated April 2, 2014, "parties' testimony should address the remaining issues in Phase Two" which included revisions to the cost effectiveness protocols. In developing the comments on the DRAM, I respond to questions posed in Attachment A of the Joint Ruling. I am employed by SDG&E as an economist in the Resource Planning group. My business address is 8330 Century Park Court, San Diego, CA 92123. My full statement of Witness Qualifications is set forth as part of my Prepared Direct Testimony.

I. OVERALL DRAM COMMENTS

Question 1: Please provide your overall comments on the Demand Response Auction Mechanism (DRAM) provided in Attachment B.

Response 1: SDG&E supports using auction mechanisms where auctions will bring together many potential sellers, many potential buyers, and where the product being offered is a homogeneous, or standard, product. The DRAM proposed in Attachment B fails on all three accounts and should be rejected as a DR capacity procurement mechanism for SDG&E. The

DRAM has a single buyer, the DRAM as one of many DR procurement mechanisms may not have many sellers, and the DRAM products are not single standard products.

The proposed DRAM capacity product is not a homogenous product since it mixes several very different capacity products, flexible, system and local DR capacity, and potentially may add more characteristics by specifying dispatch properties. In actual fact, the proposed DRAM is not an auction mechanism but a Request for Offer (RFO) of DR capacity products. Unlike an auction where price determines the winning bids, the DRAM also requires a ranking of the DR capacity characteristics, making it redundant with other utility RFOs for preferred resources.

It is unclear if there will be enough sellers in the SDG&E DRAM given DR aggregators will also have many other outlets to sell the capacity product beside the DRAM. For example, DR aggregators can sell in the bilateral Resource Adequacy (RA) market. And Load Serving Entities (LSEs) may be the DR aggregator and simply use its customers to self-supply DR RA capacity. Once implemented, another potential place to sell DR RA capacity will be in the California System Operator's proposed voluntary/ backstop capacity market. In addition to markets for RA capacity, SDG&E is issuing an RFO for 200 Megawatts (MW) of preferred resources in 2014. DR aggregators can sell their capacity product to the utility through this process. Finally, if a significant amount of sophistication is required to aggregate diverse customer loads to provide the prescribed capacity products, it may limit the number of sellers.

The proposed DRAM also fails to provide multiple buyers even though standard DR capacity products are proposed. These types of products would be of use to all LSEs in the SDG&E service area since the capacity products provide RA credit that all LSEs are required to have. Instead, the DRAM would be limited to the IOU as the sole buyer.

As a result of having a single buyer, the DRAM requires two price caps, one based on the average price and one based on a cost-effectiveness calculation. If the binding cap is the average price, some cost effective DR would be rejected since if bids are normally distributed around the average price, half of the bids would be rejected regardless of cost effectiveness. If the binding price cap is based on a cost effectiveness protocol, it would be no better than a preferred resource RFO since the cost effectiveness evaluation in both cases is based on avoided cost of providing the product with conventional resources.

While not part of the DR Auction Mechanism, the DRAM proposal would also place targets on the utility for supply-side DR. The targets are misplaced since as explained in the testimony of SDG&E policy witness James Avery, SDG&E believes customer response to accurate price signals is also price responsive DR that the State should pursue, not just supply-side DR that can bid into CAISO energy and ancillary service markets through the Proxy Demand Resource (PDR) protocol. Therefore, there should be no target for the amount of DR bid as a price responsive supply-side resource other than a target based on the market potential for cost effective supply-side price responsive DR.

Question 2: Understanding SDG&E's general position that there should be no DRAM for SDG&E, if the Commission decides to pursue a DRAM, what should the mechanism look like? How would you change the DRAM provided in Attachment B?

Response 2: Since the intent is to create capacity products that are fully fungible, I would recommend that there be separate auctions for each of the major types of capacity, one for each local capacity area, one for system capacity, and one for flexible capacity. For SDG&E, this can be collapsed into two auctions, one for local capacity and one for flexible capacity. Bidders should be allowed to bid into the auctions for local, system, and flexible capacity, using the same customers, with the recognition only one bid would be accepted. The local product would be a one year product, while the flexible capacity could be one year or a winter-only seasonal product.

There should be no separation of capacity products based on the type of DR product bid into the CAISO market (Reliability Demand Response Resource (RDRR) or PDR); the capacity products should be agnostic on how the DR is bid into the CAISO markets. It is assumed that if the DR aggregator and the participating customers benefit directly from the sale of energy and ancillary service products, they will use DR in CAISO markets to maximize their economic benefit. To assure a competitive supply, a minimum of five sellers for any product would be required, but could include the utility. The structure of the auction would be different than the currently proposed DRAM in that the CPUC or other state agency would retain an auction administrator to qualify bidders, to establish the maximum amount of DR each buyer is willing to take, evaluate bids, make capacity awards and receive security deposits from winning bidders. A market monitor would also be retained to detect market manipulation, reject unreasonably high bids, and set the price cap. The capacity products would have all LSEs operating in the utility's service area as buyers since all have similar RA requirements. The buyers would have the option to only buy DR priced below the price cap or the LSE could buy all cost effective RA (if price cap is binding and the cost effectiveness price is higher than the price cap) or the LSE could buy no RA of the type auctioned if it can demonstrate to the auction administrator that it has no need for the particular type of RA based on resources owned or under contract at the time of the auction. Winning contracts would be allocated first to the LSE proposing to be the DR aggregator (i.e. if SDG&E was a bidder it would receive its DR supply bid) and then proportional to RA need as determined by the auction administrator. Finally, since DRAM is not the only mechanism for procuring price responsive DR, there would be no DR supply-side targets.

II. STANDARD CAPACITY PRODUCT DEFINITIONS

Question 3: Are the DR capacity products described in the DRAM sufficient to be homogenous products?

Response 3: Making the DR procurement a standard capacity product can create the standardization necessary for the product to be the same across DR providers. Because DR can potentially supply many different energy products in day-ahead and real-time energy markets based on bidding parameters and a number of ancillary services depending on response time, auctioning the entire DR product could not be a standard product and would have too many distinct different characteristics for an auction to be an efficient mechanism. But a DRAM capacity product acceptable for RA compliance for system, local, or flexible capacity would be more or less a standard product.

There are a number of characteristics that have not yet been determined that need to be determined before there can be a standard capacity product as explained in the testimony of Victor Kruger.

Question 4: Should system, flexible and local capacity be separate products?

Response 4: Yes, but for SDG&E it can be collapsed to local and flexible to minimize the number of products offered. First, some LSEs may have a need for flexible capacity, but none for local. Others such as SDG&E have more need for local capacity and less need for flexible capacity in the near term. Unless separated, an LSE may be forced to take more of a capacity product than it needs and reject a product that it does need.

If the DRAM is constructed with SDG&E as the sole buyer, it could identify how much of each product it needed, but then would have to include "adders" to the price of the less desirable product or somehow adjust the ranking to take the "least cost bids." While SDG&E recognizes that the RAM process uses "adders" to equate the different values for products with lower valued characteristics, the use of an adder or other ranking system converts the auction to an RFO and the lowest prices are transformed to a least-cost best-fit evaluation. Since SDG&E is currently developing an RFO process for preferred resources, the DRAM is redundant. On the other hand, if the two products are separated into local and flexible capacity, it could be a true auction where price alone determines the winning bids.

SDG&E would eliminate a separate auction for the emergency-based DR product in its service area. Currently SDG&E has less than 2 MW of customer load on the Base Interruptible Program, the customers likely to transfer to an emergency-based supply-side resource. Further, it is a type of supply-side DR the CPUC has indicated previously it does not want to encourage, so why have a separate auction for this product? If dispatch is considered an important characteristic of the DR capacity product, again the DRAM devolves into a redundant RFO.

Restricting the DRAM to two auctions in its service area, SDG&E would capture most potential DR since all local capacity and flexible capacity will also be system capacity. So DR excluded from the DRAM for SDG&E would be limited to a few customers in the eastern part of its service area that are not in its Local Capacity Area and some temperature sensitive DR that could not find aggregation partners to provide winter local DR. Since the CAISO requires the same amount of local capacity for the entire year and all generation resources provide annual local RA, it would be up to the aggregator of temperature-sensitive DR to find the partner entities willing to provide local DR for the winter season. The limited amount of DR that would not fall into local and flexible categories could find buyers in bilateral RA markets or could remain as load modifying DR.

Question 5: Should different contract lengths (1, 2, 3 years) be considered different products?

Response 5: No, different contract lengths are not considered different products in the DRAM proposal. There does not appear to be any different characteristics of contracts providing local and flexible capacity separating them in the DRAM. The bids for years 2 and 3 can be evaluated on the same dollar per kW-year basis since inflation is relatively minor. In RAM, bidders may bid contract lengths of 10, 15, and 20 years, and the contract length has no bearing on its product designation.

Question 6: Are the proposed contract durations of one, two or three years sufficient? Should contracts of a longer duration be included? Why or why not? If yes, what duration(s) is/are recommended?

Response 6: Contracts of one, two or three years should be allowed since that will mirror the length of multi-year RA obligations the CPUC is considering in the RA proceeding and the structure of the multi-year forward voluntary/backstop market the CAISO is considering. In addition, existing DR programs operate on a three year cycle with one year commitments, so the range of one to three years will match customer expectations. Longer duration projects based on technology-based DR would be more cost competitive if the fixed costs could be spread over more years of a contract. However, this type of DR is better evaluated in an RFO process for preferred resources if it is supply-side DR where all the attributes of the technology are considered or as part of load-modifying DR through utility programs.

Question 7: Emergency demand response resources are included in the DRAM, which means that these resources must receive their capacity payments via a competitive mechanism. Provide specific recommendations on this approach.

Response 7: SDG&E opposes the use of DRAM competitive procurement mechanism for emergency demand response for the SDG&E service area. First, the CPUC decided it wanted to phase out emergency programs like the Base Interruptible Program (BIP) in favor of price responsive supply-side DR programs. No resources should be expended designing a product and encouraging enrollment in a DR product that the CPUC desires to reduce. Second, for SDG&E the emergency-based programs have been very small, forecasted to be less than 2 MW in 2014. It would be a waste of resources to develop all the overhead costs of an auction mechanism and standard contract for a product likely to attract a couple of MW. Third, the capacity products have no consideration of dispatch other than differences between local and flexible capacity, so having a separate product based on dispatch limitations is incompatible with the standard capacity products being sold.

III. STANDARD CONTRACT TERMS

Question 8: In addition to the elements listed in this proposal, are there provisions that should be included in a standard contract? Explain the reason for each recommended provision.

Response 8: Yes, in order to be a standardized product, there should be additional provisions in the contract clearly specifying the product being sold including the baseline measurement process for settlement of capacity provided, windows of availability in terms of hours of the day, and use limitations (the number of calls on an annual or seasonal basis).

The contract should also memorialize all the bid criteria identified in the DRAM and in SDG&E Rule 32 including being subject to the must offer obligations, and that customers are not participating in other utility DR programs or providing the DR product to multiple LSEs with the same customers. The contract should also clearly specify prohibitions on actions such as artificially inflating the baseline or using other resources such as back-up generators to supply the capacity.

The contract should also provide for a security deposit upon signing of the contract, similar to the RAM contracts, in case of lack of performance by the DR aggregator or a violation of contract provisions (such as transferring obligation to another capacity type or not meeting the CAISO's must offer obligations).

Question 9: The proposal notes that penalties may apply if deliveries of the DR resource fall below 60% of contracted capacity. Comment on the appropriateness of penalties in addition to capacity de- rates, and the point at which penalties could or should apply.

Response 9: It is clear that baseline measurements are less than perfect, especially on high temperature peak days. This inaccuracy can lead to over or under delivery of load reductions. The penalty structure should be symmetric around 100 percent to encourage accurate forecasts of capacity. The proposed structure in the DRAM proposal seems centered on 85 percent of capacity – no payment for above 105 percent and penalties at 65 percent. Therefore the current penalty structure encourages bidding capacity above the expected amount to maximize the economic benefits. Any penalty structure in the DRAM should be somewhat symmetric around 100 percent delivery of the capacity product.

Because the product and baselines are new, the performance bands around 100 percent might be wide initially, but should eventually be narrowed. Also the penalty structure should be informed by the overall average performance. If, on average, 100 percent is delivered if the no-penalty bands are 75 percent and 125 percent, then maybe the range is sufficient to account for the inaccuracies of the baseline measurement. However, if there is a bias on one side, under delivery, then the penalty band should be narrowed in future contracts to decrease the probability of under-delivery.

IV. AUCTION DESIGN ISSUES

Question 10: This proposal currently envisions Commission-regulated utilities procuring DRAM capacity on behalf of their own load, and does not include a procurement obligation for other Load Sharing Entities. Comment on whether other Load sharing(sic) entities should also have a procurement obligation for DRAM capacity and, if so, how such procurement should be structured. Be as specific as possible.

Response 10: The auction should have multiple buyers of the product. The capacity product will qualify for RA, and Non-IOU Load Serving Entities have RA obligations just as IOUs do. There is no reason non-IOUs should not have access to this type cost effective DR capacity and should also have the same obligations as IOUs to acquire DR RA capacity. In fact, in SDG&E's case, a larger percentage of customer load of other LSEs in its service area is likely to participate in providing supply-side DR than the SDG&E bundled customer load. As an example, current participation in the Capacity Bidding Program (CBP), the SDG&E DR program most likely to be transitioned to supply-side DR, 65 percent of the MWs enrolled is from Direct Access (DA) customers and 35 percent is from SDG&E bundled customers.

If the DR capacity products are standardized and contracts minimize the risk of acquiring DR RA compared to other RA contracts, it should be no more difficult for a non-IOU LSE to acquire DR RA. However, SDG&E also believes that neither IOUs nor other LSEs should have to acquire DR RA for which they have no need.

The primary change in the auction mechanism with multiple LSEs is that there should be a CPUC or other regulatory agency-contracted auction administrator and market monitor. The auction administrator would conduct the auction including verifying eligibility of the bids so that any LSE including the IOU could also compete as a DR aggregator. Once the market monitor determined the auction was competitive, the auction administrator would divide the winning bids based first on self-supply (any winning bid by the LSE would be awarded to the LSE). The remaining contracts would be divided based on LSE RA need and trying to equalize the costs of RA contracts awarded to each LSE as much as possible.

Question 11: What other elements are needed to ensure the auction generates a competitive outcome?

Response 11: Depending on how many DR capacity products are defined and how difficult the aggregation requirements, there may be limited DR provider participation in the SDG&E service area, so there should be protections against market manipulation through market rules and the CPUC or other regulatory agency contracting for a market monitor. Given the uniqueness of the

SDG&E customer base that may not be attractive to DR providers (there are a limited number of large industrial customers) and the SDG&E preferred resource RFO, there should also be a requirement of a minimum of five unique sellers per product to avoid market power issues.

In addition, the CPUC should contract with a market monitor to assure the auction results are competitive. The market monitor would be responsible for determining if there was any evidence of market manipulation or non-competitive prices. The market monitor also would be the entity to eliminate bids determined to be "disproportionately high" and would determine the resulting price cap. In RAM, this "disproportionately high" criteria is demonstrated by comparing prices received in the auction to the IOU's other renewable procurement. Here, it could also be determined from SDG&E procurement of flexible and local RA in bilateral markets and the CAISO backstop/voluntary auction of RA or it could compared to the cost effectiveness threshold (the cost of new build capacity adjusted for DR use limitations). The market monitor would also have post-auction responsibilities to verify that winning bidders are providing the product contracted for – namely, that customers are part of only one DR program and that customers are not using back-up generation to provide any or all of the customer's load reduction.

Question 12: The proposal is to base the capacity cost cap for each auction on the average of bids received, per auction. Are there additional factors that should be considered in constructing a capacity cost cap? Is a different approach preferable? Please describe any recommendations in detail.

Response 12: Since there is no "market-clearing price," the proposed price cap is the best way to encourage sellers to bid a low cost since sellers know that only roughly half of the bids will be accepted. Such a cap is necessary to encourage low prices. However, the price cap, calculated as the average exclusive of disproportionately high bids, is totally determined by supplier bids and has no relationship to the cost of other RA products and no relationship to the DR cost effectiveness. So buyers should be allowed to take cost effective DR products above the price cap at their discretion. There is no need to reject DR products that are cost effective from the buyer's point of view in relationship to other RA products or other DR acquired through Requests for Offers or bilateral contracts. But it has to be at the buyer's discretion to avoid market gaming where all bidders bid slightly under the level determined to be cost effective and not to their best price. Also, since a price cap based on the average of seller's bids is subject to gaming, it is essential that a market monitor be able to exclude disproportionately high bids.

V. AUCTION IMPLEMENTATION ISSUES

Question 13: Are there benefits or drawbacks to holding one auction per year for seasonal products (May-Oct; Nov-Apr)? Describe these benefits and drawbacks. How should seasonal products be defined and structured, so as to maximize the potential of demand response in these seasons? If a different approach is preferable, describe in detail.

Response 13: There are benefits to determining seasonal products on a year ahead basis in that the overwhelming proportion of RA requirements are determined on a year ahead basis. Ninety percent of system and flexible RA and 100 percent of local RA are determined on a year ahead basis. However, the one year lag from contract signing and regulatory approval to implementation as proposed in the DRAM should be shortened to match the calendar year. If approved in September, delivery should start in January. There is no apparent reason to wait 12 months since unlike the RAM, for most DR nothing is being built and customers have to be in hand at the time of bid (or as proposed later in this testimony, at the time of contract signing or approval). Given the calculation of local capacity is on an annual basis, SDG&E has no use for 12 months of local capacity spanning two years since it would require the utility to find matching DR to fill in the remainder of each calendar year for it to any receive local RA credit.

With regard to structuring seasonal products, the DRAM assumes those are determined in the CPUC/CAISO process of defining DR products for RA and seems outside the scope of the DRAM.

Question 14: The proposed auction schedule is detailed in Attachment B. Provide any comments on the schedule, in recognition of the following desired parameters: a) maximum of six months from RFO issuance to Commission approval, b) up to 60 days for bid selection and contract signing, c) 60 days for Commission review and approval of contracts, and d) alignment with annual resource adequacy showings in October.

Response 14: The proposal of a maximum of 6 months from RFO issuance to Commission approval seems aggressive for DRAM as structured given the experience with RAM. In RAM, the CPUC is given 30 days to review and approve the contracts. Typically, it has taken 7 months from the solicitation to approval. Given the DRAM proposal provides for 60 days instead of 30 days for Commission review and approval, the proposed auction schedule is particularly aggressive compared to RAM. If the DRAM products are as proposed in Attachment B, with extensive ranking required, there should be 8 months from auction to approval.

The only way that review and awards can be speeded up is for the product to be more standardized. In ARB's cap-and-trade auction, awards are made in a week after the auction has been certified as competitive because the product is completely standardized. SDG&E would recommend that the flexible and local capacity products be separately auctioned in the SDG&E service area to create more homogeneous products not requiring "adders" or other ranking mechanisms to make the auction products comparable. Also, if the CPUC or other regulatory agency retained an auction administrator and market monitor, it would speed the process of checks on the integrity of the auction.

Question 15: Is it preferable to have additional minimum eligibility criteria for bids than those listed in this proposal? Please fully describe the recommended criteria and how it should be used to judge bid viability.

Response 15: The DRAM seems to adequately describe eligibility, though some of the criteria might be clarified. The requirement regarding having the customer in hand in order to be eligible to bid would seem to make it very expensive for a DR provider to provide an aggregated DR product as it would be risky to contract with customers without an RA contract in hand. The requirement should be to have the customers in hand by the time of contract signing or contract approval.

That the DR must be in the IOU service area is an implicit eligibility criterion that should be made explicit. It was stated as a criterion at the DRAM Q&A workshop, but it is not explicitly stated in the DRAM proposal in Attachment B. Another eligibility criteria clarification is that IOUs can aggregate customers bid in to provide local or flexible RA on an equal footing with other LSEs and DR aggregators if the CPUC or other regulatory agency contracts for a third party auction administrator and market monitor. Or if the IOU is required to run the DRAM, that it can self-supply DR RA capacity from its own DR programs.

Question 16: This proposal contains the option for the Commission to publish a weighted average of bids received at some point following each auction. Are there competitive, or any other, concerns with this action, should the Commission choose to adopt it? Describe in detail. If another approach or calculation is preferable, describe the recommendation in detail.

Response 16: The "weighted average of bids received" is interpreted to mean revealing the price cap. SDG&E has two main concerns about revealing the price cap. First, if not all LSEs are participating in the DRAM and the price cap is revealed prior to obtaining a security deposit from the seller, there is a concern that low priced sellers may back out of contracts and sell to other LSEs at a price closer to the price cap. Second, there is a concern with the impact on the bids in subsequent auctions if the price cap is binding and is revealed. Unlike renewable energy, the costs of DR are primarily inconvenience costs and are not declining over time. The inconvenience costs are very hard to measure, so publishing a weighted average of bids received, which can be the top price of the bids accepted will provide the ability of sellers with low inconvenience costs to target higher prices in future bids with little fear of not being accepted, raising the overall average price of bids and the price cap in the subsequent auctions.

If the purpose is to provide ratepayers with the cost of DR, only the overall average of DR costs from all mechanisms need be provided – an average of event-based load-modifying DR, DR acquired via preferred resource RFO, DR acquired via the CAISO's voluntary auction of capacity, DR RA acquired bilaterally, and DR acquired through the DRAM.

Question 17: Are there problems with the first auction being in 2015?

Response 17: Yes. The underlying assumption is that the CPUC and CAISO can define and approve the DR capacity products including the must offer obligation and completion of a standard contract in 2014 with enough time for enough DR aggregators to acquire and aggregate enough customers to make competitive bids by April, 2015 (or February 2015 if the current complex ranking is retained). The RAM standard contract alone took between nine months and a year to be finalized and accepted by all IOUs and approved by the Commission. The DRAM, if adopted, should not start until 2016 with 2017 delivery of the DR RA products.

VI. DRAM TARGETS

Question 18: In D.14-03-026, the Commission discusses its policy of increasing the amount of demand response integrated into the CAISO market. Provide your thoughts on how we can determine an appropriate annual goal for overall demand response integrated into the CAISO market. Are there terms that we need to identify and define? What should those terms and definitions be?

Response 18: As indicated in the SDG&E policy testimony, accurate price signals through rate programs has a much more important role in promoting DR for its customer base than supply-side DR. Innovations such as Critical Peak Pricing sets out a price signal and lets the customer choose whether to buy the product. Because pricing DR is an equally beneficial approach to reducing the use of electricity in peak times, there should not be targets for amounts of supply-side DR in general and targets for DRAM in particular.

In pursuing supply-side DR, any target should take into account the appropriate maximum set by the CAISO and the CPUC. Demand Response is a use-limited resource that can disappear if the perceived costs are too high as was experienced in the California Energy Crisis. The CAISO and CPUC are considering a 5 percent cap on use-limited DR used for flexible RA and a similar cap for local RA as described in the testimony of Victor Kruger. However, this maximum alone should not form the target since it would have no relationship to cost effectiveness. Instead, if a target is chosen for price responsive supply-side DR, it should be IOU-specific and the result of an analysis of the amount of cost effective supply-side DR potential available in the IOU service area. The DRAM proposal has not undertaken such an analysis and so the proposed targets should be rejected.

The DRAM proposal to set a target for supply-side DR based on a percentage of peak capacity is off-base. First, peak capacity is the wrong measure for flexible capacity, which has no relationship to peak capacity. Instead, any target should be based on a percentage of flexible RA requirements and local RA requirements for all LSEs in the SDG&E service area and an assessment of the cost effective supply-side DR that can potentially meet those criteria. SDG&E sees no empirical evidence presented in the DRAM proposal about the amount of cost effective DR that could potentially supply flexible capacity in its service area and no mention of the maximum likely to be allowed by the CAISO and CPUC. Similarly, DR qualifying for local RA should be measured as a percent of local RA requirements. The target should be related to the amount of cost effective DR that could be aggregated to supply annual local capacity RA requirements in the SDG&E service area and the maximum amount of local capacity supplied from DR allowed by the CAISO and CPUC.

It should also be recognized that the DRAM is one of many potential DR acquisition processes. There is no benefit in setting a target for one process. The DRAM should have no targets or goals other than encouraging cost effective DR.

If a target is based on the amount of supply-side flexible and local capacity that is cost effective in an IOU's service area, the quantity target should take account of the amount of aggregation necessary to meet specified requirements. If there is one percent of current DR that might be classified in this proceeding as supply-side DR, it may aggregate to only one-quarter to one-half of one percent depending on the aggregation necessary to provide the DR capacity product at an acceptable level of calls for the participating customers. Given the current lack of DR capacity product definition and the lack of any potential study, there should be no near term targets for DRAM. Instead, there should be a maximum take for the LSE based on needs for flexible and local RA as determined in the LTPP in addition to the requirement that the DRAM price not exceed a cost effectiveness threshold.

Question 19: Why do you think the DRAM proposed targets are particularly inappropriate for SDG&E?

Response 19: The DRAM proposal would set the initial supply-side price-responsive DR target for SDG&E at 2.5 percent of peak load, supposedly based on the existing amount of price responsive DR. For SDG&E, 2.5 percent would be an amount of roughly 117 MW. In contrast, SDG&E projects that of its current DR programs, the Capacity Bidding Program would provide the potential to be supply-side price –responsive DR. Without considering the aggregation required to qualify for local or flexible capacity, it would be less than 20 MW, or 0.4 percent of peak capacity. If the air conditioning customers were aggregated together with an equal amount of winter DR capacity to provide local capacity, there may be an added 16 MW of DR. SDG&E would not be starting at 2.5 percent, but somewhere between 0.4 percent and 0.7 percent of peak load. Any supply-side DR target must be based on a realistic starting point based on utility-specific data.

Likewise, the long-term goal is limited for SDG&E by its customer base. Supply-side DR is likely to be primarily industrial load given the SDG&E approach to expanding pricing alternatives for residential and small commercial customers and the demanding requirements to be aggregated to be a supply-side resource outlined in the testimony of Victor Kruger. The industrial customer differences between SDG&E and the rest of the State is reflected in the current programs likely to provide supply-side DR. For the BIP program, SDG&E's percentage of statewide load drop was 0.1 percent in 2012.[1] For aggregator managed programs, like CBP, SDG&E's percentage of statewide load drop was 3.7 percent in 2012.[2] Both of these percentages are much less that an SDG&E proportionate share of total IOU load of 10.5 percent.

In addition, a large percentage of SDG&E's industrial load is served by other LSEs. SDG&E has the highest percentage of load served by LSEs of the three IOUs, 17percent compared to 14 percent for SCE and 12 percent for PG&E.[3] And while the percentage of DA load is 17 percent for SDG&E, the percentage of SDG&E's industrial load that are DA customers is over 50 percent. The long-term goals for DRAM need to recognize that other LSEs in SDG&E's service area may be DR aggregators and self-supply DR RA capacity products.

VII. COST EFFECTIVENESS PROTOCOL ISSUES

Question 20: What should be the scope of cost effectiveness analysis?

Response 20: The focus should be on the cost effectiveness of IOU feed-in tariffs for load-modifying event-based DR. Current load-modifying DR receives a payment for participation

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[1] Stephen S. George, Josh Schellenberg, , and Aimee Savage, 2012 Load Impact Evaluation of California's Statewide
Base Interruptible Program, April 1, 2013.

[2] Steven D. Braithwait, Daniel G. Hansen, and David A. Armstrong, 2012 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs, Volume 1: Ex post and Ex ante Load Impacts, April 1, 2013.

[3] California Energy Commission, California Energy Demand 2014 - 2024 Preliminary Forecast, Form 1.1c - Statewide - Mid Demand Scenario, Electricity Deliveries to End Users by Agency (GWh).

and/or a payment for each time it is called. The size of those payments to the customer or DR aggregator should be limited to levels that are cost effective, primarily through the Program Administrator Cost (PAC) test.[4]

Rates, including dynamic rates, should not be included in the IOU DR portfolio for purposes of calculating cost effectiveness. Rates do not lend themselves to cost effectiveness tests other than the non-participant test. Rates with demand response elements are part of a set of rates that are examined in the General Rate Case Phase 2 or Rate Design Window proceeding and have been approved using cost-based principles. Rates should not be subject to additional tests using a different, inappropriately applied methodology.

Supply-side resources may be evaluated using elements of the cost effectiveness protocols since the acquisition of capacity is separated from the energy market benefits for supply-side DR in the proposed DRAM. The cost effectiveness protocols should provide for a DRAM-based cost effectiveness limit. This supply-side DR cost effectiveness would use the capacity cost component of the cost effectiveness protocols adjusted for use limitations. It could provide a benchmark for local DR capacity if the reduction in value due to use limitations (A factor) is fixed as proposed in this testimony. A similar calculation could be made for flexible capacity, following the same method as for local capacity with a different use limitation adjustment factor (an A-prime factor) that has yet to be determined.

Question 21: How should the cost effectiveness protocols be applied?

Response 21: Individual load-modifying DR programs should be required to be cost effective <u>without</u> the burden of non-resource programs. Program costs should include all appropriate costs associated with that individual program plus any overheads that would normally be incurred by a

[4] Using the PAC test eliminates the issue with trying to value the inconvenience costs associated with customer DR participation that is necessary for the Total Resource Cost test.

third-party DR provider. However, because the overall portfolio is burdened with non-resource programs like "Flex Alerts" and other costs that would not normally be required except for the regulatory oversight of the Commission, the overall portfolio should not necessarily be required to be cost effective. This will be even more true in the future after bifurcation as the non-resource programs become a bigger share of the utility DR portfolio.

Question 22: Should the cost effectiveness calculation still include an avoided capacity cost for load-modifying DR?

Response 22: Yes. While load-modifying DR will not qualify for RA credit, it is still likely reducing the peak net of variable renewable generation if dispatched appropriately. As mentioned in the testimony of Victor Kruger, SDG&E has a concern whether that full impact will be reflected in the new calculation method for load-modifying DR. But even without a clear understanding of the new forecasting approach, the avoided costs of capacity should still be included for load-modifying DR even though it will not receive RA credit. However, to not bias DR toward load-modifying DR, there should be no multiplier for associated reductions in the planning reserve margin.

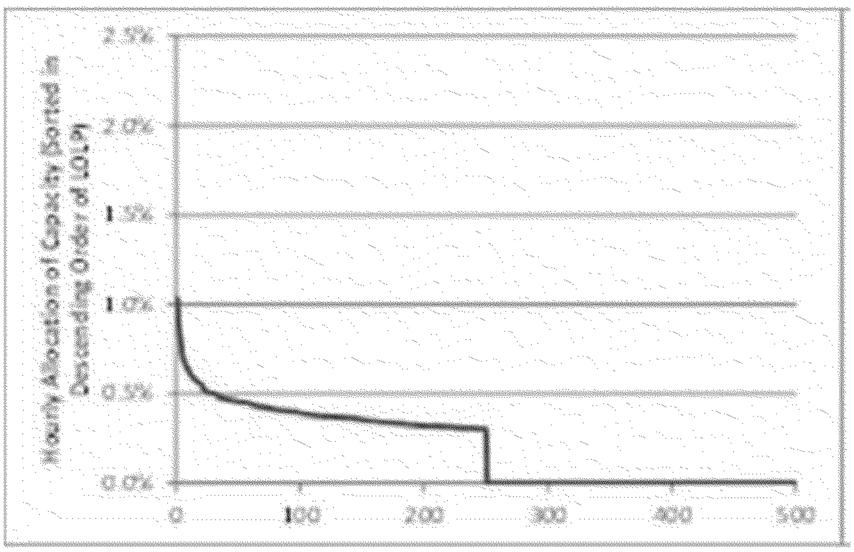
Question 23: What other changes should be incorporated into the calculation of avoided capacity and energy costs?

Response 23: Avoided system and local capacity costs allocation to hours and months should reflect the incidence of the future peak net of variable renewable resources and not be based on old data on past load peaks. The allocation of the expected lost load across hours for local capacity purposes should be changed and not be based on the top historical hours of use, but should be based on a loss of load expectation model specific to SDG&E's service area. This would provide much more probability of DR calls to September and October, months where SDG&E experiences more high usage days compared to the rest of the State.

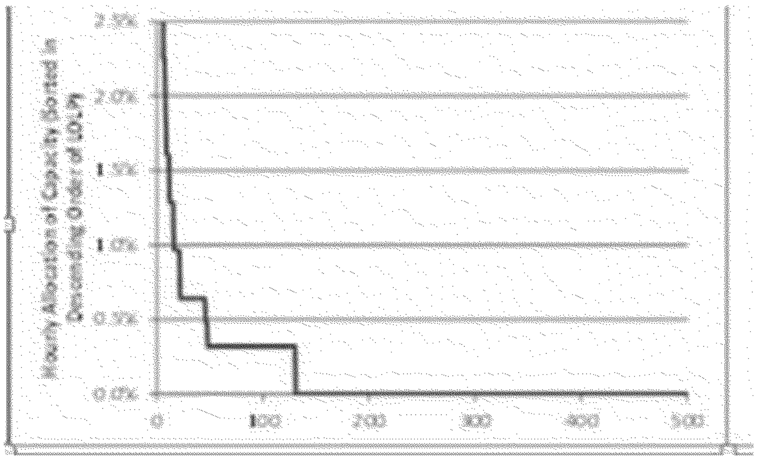
Avoided energy costs should also reflect future conditions and not be based on old information. Hourly price profiles should be modified to reflect the future hours of high prices with an extensive penetration of renewables. Production cost modeling could be used in parallel with market information to reflect the expected times of high prices similar to my testimony in SDG&E's most recent Rate Design Window. The shift in marginal energy costs due to variable renewable generation should be factored into hourly price forecasts to appropriately value the energy provided by DR.

Question 24: What other changes should be incorporated into the calculation of avoided capacity costs?

Response 24: The factor related to DR use limitations, the "A" factor developed by E3 and used in the current model, is flawed and should be modified. In the current method, generation capacity costs are allocated among 250 hours in the year, in inverse proportion to the amount of generation "headroom" in each hour. The generation capacity cost is allocated to hours to reflect the likelihood that load reduction or generation addition is needed in that hour. The graph below shows the E3 allocation of Loss of Load Probability (LOLP) to the top hours.



However, there was not a good match with the LOLP analysis of the number of hours a program is likely to be called based on stochastic analysis. SDG&E LOLP model, as well as those of the other IOUs show a much different story, with a significantly lower probability of needing DR programs more than 100 hours per year. The graph below shows the analysis from the PG&E LOLP analysis.



The current model for calculating the A factor should be changed to provide a more accurate assessment of the capacity value of DR. In comments submitted by the utilities on October 1, 2012 in R.09-11-014 regarding the broader, demand-side management cost-effectiveness framework, the utilities proposed a substitute for the current approach to allocation to capacity to number of hours of availability. E3's proposal at the workshop for a two-step A factor that accounts for both availability and dispatchability would be an appropriate modification to improve the A factor, and would be consistent with the approach SDG&E took in determining the A factor in the 2012-2014 cost effectiveness analysis before the Energy Division guidance required the use of the inferior assumptions that produced misleading DR cost effectiveness results.

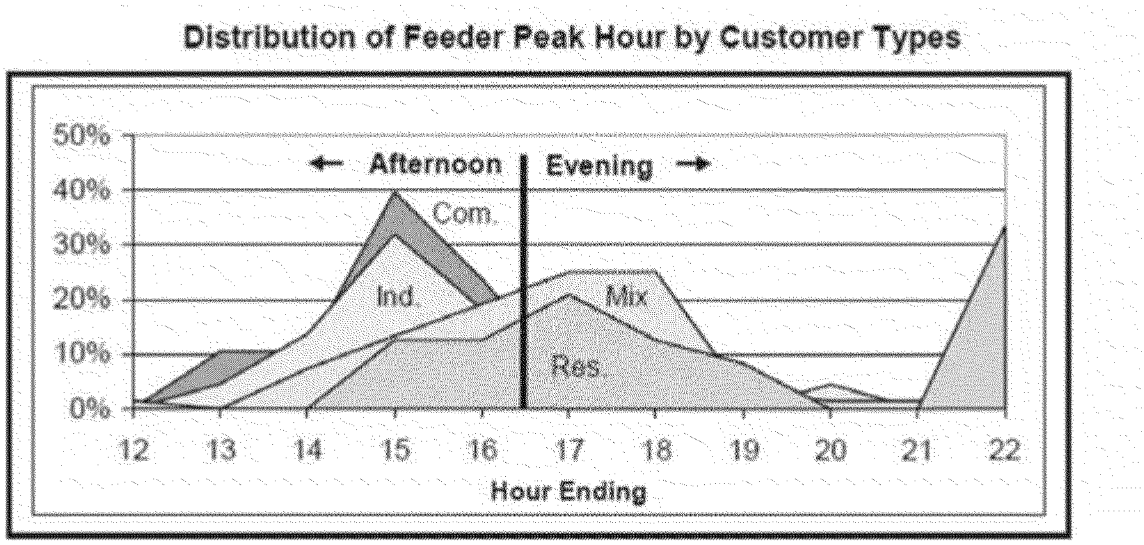
The B Factor adjusts the value of DR based on the length of the period of notification. A reduction occurs for DR programs that require day-ahead notification based on an analysis of forecast errors. Going forward notification longer than 30 minutes should have a reduction in value given the significant increase in forecast error with more variable renewable generation. Just as modifications to generation may be able to be made to make units more flexible, the cost effectiveness method should recognize the increased benefits associated with load-modifying DR that has greater flexibility. SDG&E recommends that the adjustment be tied to the amount of forecast error for different periods of notification. In addition, DR that is able to respond more quickly than 30 minutes should receive a premium, a B factor greater than one to reflect its increased value. While most of this DR with fast response is expected to be integrated into the CAISO markets and become supply-side DR, the B factor greater than one should be available for evaluation of utility supply-side programs or load-modifying DR that exhibits those characteristics. The specific calculation should be based on the added value the response time is providing. For example, second-by-second response could provide regulation and could be valued based on regulation costs, while 10 minute response could be valued based on provision of non-spin reserves.

The C Factor adjusts the value of DR for its degree of flexibility in calling the DR program. The determination of C Factor should remain unchanged. SDG&E provides 100 percent for the C factor if the program can be dispatched <u>both</u> locally and for statewide events. The C factor should remain so that DR load-modifying programs have incentive to provide maximum flexibility to meet both SDG&E and the State's needs.

Question 25: What changes should be incorporated into the calculation of avoided transmission and distribution costs?

Response 25: In SDG&E's view, deferral of transmission and distribution (T&D) investments requires there to be a long-term investment in DR technology. The technology increases the probability that the DR customer will continue to provide load reductions when needed, and not drop out if the number of calls is higher than the customer expected. The ability to defer T&D costs, the D factor, should remain unchanged from SDG&E's calculation of the percent of customers on each program that have automated technology. If a long-lasting technology is identified as a solution to defer distribution costs, the program should receive a D factor of 100 percent.

Allocation of T&D savings to hours of the day and day of each month also needs to be fixed. The deferred T&D costs in the current DR model are temperature driven. However, that is not accurate for well over 50 percent of SDG&E circuits. The circuits that are primarily residential and located near the coast peak in the evening or at night. The cost effectiveness method should fix the allocation of deferred T&D to hours for SDG&E based on the historical distribution of distribution circuit peaks, similar to E3's use of the top load hours for allocating capacity across hours and months.



Question 26: What changes should be made regarding dual participation?

Response 26: As indicated in the DRAM discussion, customers should not be allowed to provide supply-side DR capacity if enrolled in a utility load-modifying program. For ease of implementation, dual participation should be also prohibited for load-modifying DR as well.

If the Commission decides to allow dual participation in load-modifying DR programs, then the capacity benefits for dually enrolled customers should be calculated using the program with the highest capacity value after all adjustment factors are applied. Energy benefits should be calculated using an estimate of the number of events and energy prices dually enrolled customers are expected to experience (which may or may not be higher than for a customer only enrolled in the program that pays the energy incentive). The transmission benefits from the higher of the two programs should be used. All incentive costs from both programs should be included. In this way although the load reductions are used twice – once for the capacity benefit calculations and once for the energy benefit calculation there is no double counting of benefits.

Question 27: What should be done with participant costs in the TRC calculation?

Response 27: The Commission should continue to use a percentage of the incentives paid to customers as a proxy measurement for participant costs; 75 percent is a reasonable estimate. Trying to determine the distribution of customer costs is a monumental task with limited payoff. As the State moves toward supply-side DR, the application of cost effectiveness will be limited and resources should not be devoted trying to figure out customer costs. Studies based on unplanned outages will not provide a good proxy for participant cost for DR programs where outages are voluntary. Using the cost of an unplanned outage would greatly over estimate DR participant costs.

And as indicated earlier, increased reliance on the PAC test for DR will reduce the importance of the customer costs of participation in the DR program.

VIII. WITNESS QUALIFICATIONS

My name is David T. Barker. My business address is 8330 Century Park Court, San Diego, California, 92123. I have been employed as an economist in the Resource Planning group of SDG&E since 2007. Prior to that, I was employed as an economist in the Regulatory Affairs Department of Sempra Energy Utilities for five years from 2002 to 2007. Before 2002, I was employed at Southern California Gas Company in various staff positions including Economist (1991-1995 and 1998-2002), Market Consultant (1988-1989 and 1995-1998), Electric Energy Analyst (1990-1991), and Demand Forecasting Supervisor (1989-1990).

I received a B.S. in Mathematics from New York State University, a Masters of Economics degree from North Carolina State University, and a joint Ph.D. in Economics and Statistics from North Carolina State University. I taught undergraduate economics and statistics courses for four years on a full-time basis in Oregon, and then worked in the private sector for five years as an economist at Merrill Lynch prior to joining Southern California Gas Company.

I have previously testified before this Commission.