BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking To Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	FILED PUBLIC UTILITIES COMMISSION SEPTEMBER 19, 2013 SAN FRANCISCO OFFICE RULEMAKING 13-09-011

ORDER INSTITUTING RULEMAKING TO ENHANCE THE ROLE OF DEMAND RESPONSE IN MEETING THE STATE'S RESOURCE PLANNING NEEDS AND OPERATIONAL REQUIREMENTS

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1. Summary

The Commission initiates this Rulemaking to determine whether and how to bifurcate current utility-administered, ratepayer-funded Demand Response programs into demand-side and supply-side resources, with the intent of prioritizing demand response as a utility-procured resource, competitively bid into the California Independent System Operator wholesale electricity market. The ultimate goal is to enhance the role of demand response programs in meeting the state's long-term clean energy goals while maintaining system and local reliability.

Thus, the purpose of this proceeding is to: (1) review and analyze current demand response programs to determine whether and how we should bifurcate them into demand-side (customer-focused programs and rates) and supply-side resources (reliable and flexible demand response that meets system resource planning and operational requirements); (2) create an appropriate competitive procurement mechanism for supply-side demand response resources; (3) determine the program approval and funding cycle; (4) provide guidance for transition years; and (5) develop and adopt a roadmap with the intent to collaborate and coordinate with other Commission proceedings and state agencies in order to strategize the future of demand response in California.

2. Background

Demand response is defined as changes in electricity use by customers from their normal consumption pattern in response to changes in the price of electricity, financial incentives to reduce consumption, changes in wholesale market prices, or changes in grid conditions.

Demand response programs are an increasingly important element of California's resource strategy. California's Energy Action Plans I and II list demand response and energy efficiency as a first-choice resource. According to the 2012 California Independent System Operator (CAISO) Annual Report, demand response programs operated by the investor-owned utilities (Utilities) meet almost 5 percent of total CAISO system resource adequacy capacity requirements.[1] These programs also provide reductions in peak electricity consumption, ratepayer savings through the avoidance of new generation construction, and greenhouse gas emissions reductions.

The Commission has undertaken major efforts to make demand response programs more effective in previous Rulemakings (R.) and Applications (A.), specifically R.02-06-001, R.07-01-041, and A.08-06-001. Since the issuance of R.02-06-001, the Commission has significantly improved the role of demand response programs in meeting California's energy needs. Decisions issued in previous proceedings covered a range of policy and technical issues. Decision (D.) 03-06-032 adopted price-responsive demand response programs for large customers and set annual participation goals for Utility demand response

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[1] CAISO 2012 Annual Report on Market Issues and Performance at 30. Available at http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

programs. R.02-06-001 initiated the Commission's exploration of advanced metering, real-time pricing, and default critical peak pricing tariffs.

D.05-01-056 approved demand response programs that focused on providing peak demand reduction driven by day-ahead high temperature, price, or demand level forecasts. It also approved reliability-triggered programs, to provide quick response load reduction capability, technology and technical assistance programs to automate customer response to demand reduction signals, and programs to educate customers about their ability to reduce their bills by rescheduling their usage to off-peak times.

When D.05-11-009 closed R.02-06-001, it cited the need for further attention to the cost-effectiveness evaluation of demand response programs, the role of Advanced Metering Infrastructure, real time pricing tariff development, and demand response goal setting. Subsequently, R.07-01-041 identified load impact estimation, cost-effectiveness methods, demand response participation goals, emergency-triggered programs, and integration with wholesale electricity markets as scoping issues. The rulemaking produced major decisions on load impact protocols (D.08-04-050), cost-effectiveness protocols (D.10-12-024), emergency-triggered program settlement (D.10-06-034), and direct participation rules (D.12-11-025).

The Commission has collaborated with stakeholders to make demand response programs more effective, yet its work is not complete. As demand response programs have evolved, so have the needs of our electric grid. In previous decisions, the Commission stated its intent to consider further and deeper changes to demand response programs. In D.12-04-045, the Commission stated its intent to address competitive procurement of demand response:

> The next major policy question we must address is the extent to which we will embrace competitive procurement of [demand response] and the timeline in which this transition will occur. Historically, California has employed a utility-centric model of [demand response] procurement that allows only a limited role for third party aggregators. However, this model is changing. … We think that third party aggregators can provide additional innovation and services to the market, yielding additional uncaptured potential benefits to [demand response] in California. We intend to take up this question in a new [demand response] policy guidance rulemaking to be opened later this year.[2]

The Commission recognized the potential benefits of non-utility provision of demand response resources in a changing environment:

> [The] changing nature of the electrical grid … call[s] into question whether a utility-centric model for [demand response] programs and services can meet current and future needs.[3]

The Commission also expressed its desire for a careful and thoughtful deliberation on the subject:

> Dismantling of the utility-centric model, as suggested by some parties in this proceeding, requires thought and deliberation beyond the time provided in the current proceeding. Furthermore, the issues go beyond the three-year cycle of a [demand response] application and are more appropriately addressed in the [demand response] rulemaking. The Commission must determine the future goals and policy objectives for demand response before addressing these issues. At this time, however, the most prudent path forward is to continue to gather information to develop a better record before making lasting changes to the current structure. We will address

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[2] D.12-04-045 at 16.

[3] D.12-04-045 at 190.

> these issues in the [demand response] rulemaking proceeding, R.07-01-041 or its successor.[4]

The time is ripe for the aforementioned deliberation. The following challenges and developments related to our electric grid call for the Commission's immediate attention to the matter.

3. Current Demand Response Framework and Challenges

The Commission has a long history of employing demand response programs in California. The number of milestones the Commission reached in recent years reflects the diligence of state agencies and other stakeholders. The Commission's and the stakeholders' work covers a range of topics from smart meter deployment to developing load impact and cost-effectiveness protocols, from approval of aggregator contracts to implementation of default Critical Peak Pricing and Time of Use rates for non-residential customers. Yet, as demand response programs evolved, so have the needs of the grid and the State's vision for future energy policy including the vision for the future of demand response.

3.1. Commission Staff Report on 2012 Demand Response

On May 1, 2013, the Commission staff issued a report[5] on lessons learned from Southern California Edison Company's (SCE) and San Diego Gas & Electric Company's (SDG&E) demand response programs during the Summer of 2012. Staff raised issues regarding the utilities' demand response program operations, designs, forecast, and performance. On average, the ex post results for all

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[4] D.12-04-045 at 191.

[5] The Commission Staff Report (Staff Report): http://www.cpuc.ca.gov/PUC/energy/Demand+Response/.

program events diverge from the daily forecast by a considerable degree. The Staff Report indicates that, historically, SCE and SDG&E underutilized demand response programs and dispatched their power plants to meet peak demand far more frequently in comparison to demand response programs. The demand response programs were not utilized to their full Resource Adequacy capacity even during extremely hot weather conditions. Staff found that SCE also deployed a dispatch strategy for its residential air conditioning cycling program that was intended to minimize customer fatigue but resulted in the program delivering less demand response capacity. Staff also found that SCE's and SDG&E's Peak Time Rebate (PTR) programs have a potentially large 'free-ridership' problem. Over $35 million of their PTR program incentives were paid to customers without providing significant load reduction (about 85%-94% of total paid incentives).

D.13-07-003 adopted many of the findings listed in the Staff Report and directed SCE and SDG&E to implement changes to improve their demand response programs.

3.2. Current Demand Response Framework

The Commission recognizes the deficiencies of the demand response programs in its attempt to value, design, plan, and operate demand response resources under a single framework despite the very different needs stemming from supply-side and demand-side of the energy balance equation and the different qualities demand response products can offer. The lessons learned from the demand response programs during the Summer of 2012 suggest that while demand response is valued as a preferred resource, it is not as reliable and useful as expected.

From a planning perspective, demand response programs allow a utility to avoid procurement of generation capacity. Currently, demand response resources dispatched by the utilities (i.e., event based) are counted towards fulfilling Resource Adequacy requirements as supply-side resources in Resource Adequacy filings. However, from an operational perspective, demand response is not held to the same requirements as other Resource Adequacy resources. For example, demand response resources are not bid into the CAISO market or subject to its Must Offer Obligations and penalties for non-performance. Demand response resources have very limited visibility and dispatchability to the CAISO's grid operator. California needs demand response to have supply-side operational characteristics and capabilities in order to meet the State's future system and market needs.

There are a variety of demand response resources. Non-dispatchable (i.e., non-event based) demand response resources reduce the Utilities' demand forecast, thereby reducing the Resource Adequacy requirement indirectly. Demand response also has potential value as a flexible capacity resource for renewable integration (through increasing or decreasing demand), a balancing energy and ancillary service resource; and as an alternative to transmission upgrades. While the grid may need reliable, flexible, and fast resources, many current programs are not yet capable of providing such qualities over a sustained period of time. For example, Ancillary Service maintains grid reliability and power quality. The use of demand response as an Ancillary Service would require reductions in notification time, increased speed, and accuracy of measurements; which may not be needed in traditional applications. Therefore, an understanding of the qualities that supply-side demand response resources can offer and the correct matching of these resources with the needs of the grid is essential for successful program design and implementation.

Current major challenges the Commission faces in its demand response programs can be categorized as follows:

1. **Program design and operation**: There is an ongoing tension between the supply-side and demand-side requirements for demand response. Demand response as Resource Adequacy resources should be held to the same requirements as generation resources for system reliability and economic efficiency. On the other hand, the needs and technical capabilities of customers and providers need to be considered in program design;
2. **Demand response delivery**: The current demand response delivery model is utility-centric, where all demand response programs are retail-oriented and marketed and operated by the Utilities. Other models deserve consideration;
3. **Regulatory challenges**: Short funding cycles and changes in demand response programs and funding amounts introduce uncertainty and may lead to barriers to the development of robust demand response resources;
4. **Planning challenges**: Limited regulatory oversight of the forecasting process and lack of geographical targeting in demand response programs create local and system resource planning challenges, especially in long-term planning where demand response and other short-term resources are difficult to forecast; and
5. **Customer participation**: With rapid changes in technology, regulations, and programs, customers need to be educated, motivated, and engaged.

3.3. San Onofre Nuclear Generating Station (SONGS) Outage

SONGS Units 2 and 3 were taken out of service in January 2012. Despite the loss of 2,200 Megawatts (MW) of capacity provided by SONGS, intensive interagency collaboration and relatively cool weather kept the grid reliable throughout that summer. However, as discussed in Section 3.1, demand response program performance during the Summer of 2012 in Southern California was less than satisfactory.

In June 2013, SCE announced that it will close SONGS permanently. This closure poses a major challenge to Southern California's electric system. The Commission committed to "work with critical state and regional government entities, particularly the CAISO, to ensure Southern California has an adequate supply of electricity this summer and into the future. This will require even greater emphasis on energy efficiency and demand response programs, as well as transmission upgrades and enhancements and some new generation resources."[6]

3.4. Flexible Capacity Needs

California's Renewable Portfolio Standard (RPS) requires Utilities, electric service providers, and community choice aggregators to increase procurement from eligible renewable energy resources to 33 percent of total procurement by 2020. Achieving this goal will require electricity generated by intermittent resources such as wind and solar. To maintain stability, grid operators will rely on load-following resources that are bid into the energy market and able to be dispatched on a minute-by-minute basis. Load-following resources typically

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[6] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M067/K039/67039193.PDF.

come from quick-start fossil-fueled generation plants; however, preferred resources, such as demand response, can also provide the needed reliability characteristics if designed properly.

Both the CAISO and the Commission have been active in this area. D.13-06-024 defined flexibility need as "the quantity of flexible capacity identified as needed by the ISO and the Commission to meet maximum three hour ramping and contingency reserves."[7] On August 2, 2013, the Resource Adequacy Phase 3 Scoping Memo was issued with the goal of resolving issues related to flexibility implementation for preferred resources, including demand response:

> [S]takeholders will develop counting rules, eligibility criteria, and must offer obligation for use-limited resources, preferred resources, combined cycle gas turbines, and energy storage resources for Commission consideration.[8]

Determination of a methodology for the Qualifying Capacity of wholesale demand response resources is also included in the scope of Phase 3 of the Resource Adequacy proceeding.

The CAISO is currently working on a Flexibility Resource Adequacy Criteria and Must Offer Obligation,[9] which is anticipated to be effective by the

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7 In addition to this requirement, a flexible resource must, to the extent possible, submit economic bids into the day-ahead and real-time markets. Flexible resources must be available for five minute dispatch between the hours of 5:00 a.m. to 10:00 p.m. These bidding requirements are not binding for 2014, however they are planned to be for 2015. *See* D.13-06-024 Appendix A.

8 R.11-10-023 Phase 3 Scoping Memo at 3.

9 http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

end of 2013. A specialized must offer obligation for demand response resources is included in this initiative.[10] The proposal allows demand response resources to provide flexible capacity to the CAISO based on the resources underlying load or during the time the CAISO is most likely to need the greatest quantity of flexible capacity.

3.5. Resource Adequacy Capacity Payment Mechanism for Demand Response

Resource Adequacy capacity payments present an economic opportunity for demand response resources. Under the current demand response framework, the Utilities' demand response programs provide incentive payments and are valued based on the avoided costs of building new generation capacity. They are not directly tied to the Resource Adequacy procurement mechanism. The load impact from event-based demand response programs is currently given local and system Resource Adequacy credits that count towards Resource Adequacy obligations alongside supply-side resources. However, at present there is not a Resource Adequacy price or value directly attached to the capacity credit that is given.

As described above, the Commission is in the process of determining a flexible capacity framework for preferred resources and the Qualifying Capacity rules for energy storage and wholesale demand response resources. In addition, CAISO and the Commission have been working on establishing a Joint

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[10] The initiative states that demand response resources have limited ability to reduce load during all hours between 5:00 a.m. and 10:00 p.m. The CAISO proposes that demand response resources must submit economic bids into both the day-ahead and the real-time markets from 6:00 a.m. to 11:00 a.m. or 4:00 p.m. to 9:00 p.m., and they must be able to provide at least three hours of load reduction.

Reliability Multi-Year Framework.[11] This framework aims to: 1) create two and three-year-ahead Resource Adequacy requirements, 2) develop a CAISO-run residual backstop auction, which will provide a platform for Load Serving Entities to procure capacity to fill Resource Adequacy obligations not met in the bilateral market, and 3) provide an annual long-term reliability planning assessment focusing on the four to ten-year forward period. The Joint Reliability Multi-Year Framework is expected to provide additional opportunities for preferred resources, including demand response, to compete to meet capacity requirements in the two and three year-ahead time frames.

The outcomes of the 2015 Resource Adequacy proceeding and the Joint Reliability Multi-Year Framework initiative will have significant impacts on the Resource Adequacy counting and capacity payment mechanism for supply-side demand response. We will coordinate closely with these two proceedings to determine the appropriate policy on the Resource Adequacy capacity payment mechanism for demand response.

3.6. Participation of Retail Demand Response in the CAISO Energy Market

The CAISO has been working to design market products where capacity provided by demand response programs can be bid into wholesale markets in order to increase competition, promote efficiency, and reduce costs. In R.07-01-041, the Commission stated it would consider modifications to demand response programs needed to incorporate demand response into wholesale markets. In 2009, the Commission ordered the Utilities to modify

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[11] http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-YearReliabilityFramework.aspx.

existing demand response programs such that at least 10 percent of their demand response programs comply with Proxy Demand Resource (PDR) requirements and in 2010 authorized pilot projects to participate in PDR.[12] In addition, the Commission is nearing implementation of direct participation rules (Rule 24) to allow the bidding of bundled customers' load into the CAISO wholesale markets.

Despite these promising developments, demand response capacity has not been integrated into the CAISO's wholesale markets yet. None of the 2,400 MW from the Utilities' retail demand response programs[13] participated in the CAISO markets in 2012 and the CAISO's ability to dispatch these demand response resources continues to be limited. As the CAISO states:

> …challenges include limited use of the ISO's proxy demand resource program, the timing and quality of demand response data, and limited integration of available demand response data into ISO operations. While the ISO implemented a proxy demand resource product in 2010, no bids from these resources were dispatched in 2012. Although proxy demand resource product participation in the ISO markets has been approved by [the Federal Energy Regulatory Commission], the [Commission] has limited bundled utility customer participation in this program to pilot programs. Thus, while the utilities' programs were triggered more by price than for reliability purposes, the integration of these programs with the market is still poor as

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12 In July 2010, the Federal Energy Regulatory Commission approved the CAISO PDR which enables demand response participation as a single resource or an aggregation of resources in the wholesale day-ahead and/or real-time energy markets and in the Ancillary Services market.

13 Reliability and price-responsive programs.

> commitment and dispatch decisions continue to occur outside the market optimization.[14]

The Commission is hopeful that the new vision for demand response resources in this rulemaking and the increasing collaboration among the state agencies will help California overcome these challenges.

4. A New Vision for Demand Response

Given the background and the issues previously discussed, the Commission sees an urgent need to initiate this rulemaking and continue to resolve several issues raised in prior rulemakings. California's procurement goals for renewable and low greenhouse gas emitting resources, as well as the CAISO's need for flexible capacity resources, necessitate the creation of a competitive procurement process where the Commission may need to bifurcate demand-side and supply-side demand response resources. As the Commission considers this new configuration, there is no intention to diminish the value of retail demand response, but rather to take advantage of the strengths of different demand response programs.

Another goal of this proceeding is to increase the penetration of demand response programs by doing a close examination of how we frame the programs, how they are offered, procured, and reduce barriers to entry for new customer participation.

With this initiative, the Commission intends to build upon the body of work completed to date and retool demand response to align with the grid's needs and enhance the role of demand response in our energy policy. Since the

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[14] CAISO 2012 Annual Report on Market Issues and Performance at 35. http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

grid's needs are no longer limited to shaving peak electricity load, the potential that demand response resources offers must be exploited to the fullest extent possible and desirable. These changes should contribute to the efficient use of resources, take advantage of competitive markets, and be simple to administer. This will require close coordination with existing demand forecast, procurement planning and transmissions planning processes.

As the Commission stated in D.12-04-045, this rulemaking will address the major policy question on demand response delivery. Historically, the Commission employed a utility-centric model of demand response procurement that allows only a limited role for third party aggregators. With the implementation of Rule 24, it should be possible for third party demand response providers to play a much larger role in the procurement of supply-side demand response. The Commission considers third party demand response providers to be able to provide additional innovation and services to the market, yielding greater demand response potential in California.[15]

We will also consider extending funding cycles for demand response portfolios. In considering longer-term funding horizons, this rulemaking will balance the need for regulatory certainty with the need for flexibility to terminate underperforming programs or desire to bring online new programs based on innovations in the market, with the need to ensure that the portfolios are cost-effective and based on the best-available data.

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[15] D.12-04-045 at 16.

5. Preliminary Scoping Memo

The issues that we consider to be within the scope of this proceeding at this time are discussed in the following sections.

5.1. Bifurcating Demand Response Programs

This Rulemaking will review and analyze current demand response programs to determine whether and how to bifurcate them as demand-side (customer-focused programs and rates) and supply side resources (reliable and flexible demand response that meets local and system resource planning and operational requirements).[16] Towards that end, this rulemaking will identify the criteria that should be used to distinguish demand-side and supply-side demand response resources and determine whether there is an optimal mix that should be maintained. The Rulemaking will also determine the specific roles for the utilities and demand response providers for the delivery of demand response starting in 2016.

Furthermore, this rulemaking will examine and seek stakeholder input on the following issues:

1. Are there any potential problems or concerns with bifurcating demand response programs into demand-side and supply-side resources?
2. Under a bifurcated framework, how should demand response programs or products be designed? How should existing programs evolve?

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[16] Demand-side programs are load-modifiers, e.g., dynamic rates and demand response supporting programs, whose impact is reflected in the California Energy Commission's (CEC) load forecast, because the programs modify the system load shape. Supply-side resources will be those that can qualify for Resource Adequacy credits.

3. How could the Commission adopt a competitive procurement mechanism for supply-side demand response similar to the procurement process utilized in other Commission programs (e.g. Renewable Portfolio Standard)? This includes identifying the planning steps and competitive procurement process that will determine the demand response products Utilities should procure to fulfill their demand response needs while balancing the needs of customers and those of stakeholders, including the CAISO. What are the strengths and weaknesses of the Commission's procurement mechanisms and lessons learned from other Commission programs that should inform the design of supply-side demand response procurement?
4. What mechanisms shall the Commission develop such that local and system reliability needs forecasted by resource planners drive the development and procurement of demand response programs?
5. What changes in programs (e.g. locational targeting, longer funding cycles, load-increasing) and evaluation methods will create greater certainty that a demand response program can supply capacity when and where the grid needs it?
6. How should the Commission determine the appropriate policy on Resource Adequacy capacity payments for demand response?
7. What should be the role of the Utilities in demand response programs going forward? Should special consideration be given to each sector (residential, commercial, industrial) or other customer attributes?
8. How should demand response programs be operated to be more competitive and lead to a robust demand response market?

9. Are there disincentives that limit the interest of potential demand response providers (including Utilities) in demand response programs? What can the Commission do to overcome those disincentives, if any?

10. How should cost-effectiveness be treated, if at all, under a competitive procurement framework for supply-side[17] demand response?

11. How does a proposed bifurcated framework with supply-side demand response enforce the loading order and ensure that demand response is procured and operated as a preferred resource before the utilities peaker power plants?

12. What are the standards, technologies, and architectures needed to enable greater participation by demand response providers in the residential and small- and medium-sized business customer base?

13. As contemplated in the existing energy efficiency portfolio, high upfront costs act as a significant barrier to deploy additional cost-effective savings. The Commission is piloting a series of on-bill financing activities, including providing ratepayer funded Credit Enhancements. Should ratepayers provide similar Credit Enhancements in Demand Response programs to take advantage of the emerging infrastructure? If so, at what level and for what types of programs?

14. What are additional ways to reduce the number of customer touchpoints between our retail Demand Response programs with other existing Demand Side programs (i.e. Energy Efficiency and Distributed Generation)?

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[17] Cost-effectiveness of demand-side demand response programs may be considered in a later phase of this rulemaking.

5.2. Program Approval and Funding Cycle

This Rulemaking will provide timely guidance to eliminate uncertainty and ensure stability in the demand response funding and procurement process so that all stakeholders can move forward accordingly.

Towards that end, the Commission will investigate the most suitable program approval funding cycle for demand response programs and determine whether a long-term, e.g., 10-year, rolling portfolio cycle with shorter procurement cycles (three three-year or two five-year cycles) may better serve the needs of the grid and stakeholders.

5.3. Roadmap for Future of Demand Response

Coordination and collaboration among state agencies, the Commission, CEC, and CAISO, are necessary for making demand response as effective as possible. This Rulemaking will determine ways and means to continue to coordinate and integrate demand response efforts of this Commission with those of other agencies.

The CEC recognizes the value of demand response resources and is in the process of gathering input to increase the amount of demand response resources available. Their results will be presented in the Integrated Energy Policy Report.

On May 13, 2013, the CAISO hosted a Demand Response and Energy Efficiency Roadmap Workshop to discuss the challenges of incorporating demand response in the CAISO market as well as other activities necessary to increase demand response capabilities in California. The CAISO released its "Demand Response and EE Roadmap: Making the Most of Green Grid

Resources" on June 12, 2013. The Commission staff provided comments on this Roadmap and generally agreed with the CAISO.[18]

5.4. Potential Bridge Year Funding and Staff Proposal on Demand Response Pilots

D.12-04-045 requires the Utilities to file an application on January 31, 2014 requesting demand response programs and budgets for 2015-2017. Given that the scope of this rulemaking includes potentially radical changes in the structure and budget cycles of these programs, the Commission does not find it prudent for the Utilities to spend time and resources planning for programs that may not fit into a new structure. However, the Commission also recognizes that our review and analysis will not be complete in time for the 2015 budget cycle. Thus, the Commission will move forward with developing a proposed decision that provides for 2015 funding for the current demand response programs.

In addition to providing bridge funding, the Commission has the opportunity to utilize 2015 pilot funds to prepare for a new demand response program structure. Attached to this OIR is a staff proposal for three demand response pilots, one for each of the Utilities. Two of the pilots will test the participation of demand response in the CAISO wholesale energy market and the third pilot will test the effectiveness of strategies to improve customer response to time-of-use and critical peak pricing rate.

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[18] http://www.caiso.com/Documents/CPUC-Comments%E2%80%93DemandResponseEnergyEfficiencyRoadmapJun17_2013.pdf.

Parties are asked to review the staff proposal and respond to questions on bridge funding and the staff proposal. Responses to the following set of questions shall be filed and served to the parties of record in R.07-01-041, no later than October 21, 2013:

1. Do you find it reasonable for the Commission to authorize SCE, SDG&E, and Pacific Gas and Electric Company (PG&E) a one-year bridge funding to allow current demand response programs to continue, as is, through 2015 while the Commission contemplates changes to the structure of the overall demand response program?
2. Do you support the objectives of the staff proposed pilots? Please provide alternative suggestions for Utility pilots in 2015 if you do not.
3. In Section II.C.4 of the staff proposal, Energy Division staff recommends that SCE and SDG&E will both need budgets that are 75-80 percent of PG&E's current Intermittent Resource Management Phase 2 (IRM2) budget ($2.458 million) to be able to effectively replicate the IRM2 pilot in their territories. Do you agree with that assessment? If not, what would be an appropriate budget for SCE and SDG&E to replicate the IRM2 pilot in their territories? Are there ways to modify the allocation of specific costs of the pilot such that SDG&E and SCE will not need as much as 75-80 percent of PG&E's budget?
4. Do you agree with the proposed budgets for the other pilots in the attached staff proposal?
5. In D.13-04-017, the Commission authorized SCE to shift $8.7 million in unspent funds from its Air Conditioner (AC) Cycling Program to fund various improvements to its Demand Response portfolio. It is Energy Division's understanding that SCE has approximately $8 million in unspent funds in its AC Cycling Program. Do you support shifting remaining unspent funds from SCE's AC Cycling Program to support the pilots described in the staff proposal? The same decision authorized SDG&E to shift

$1.7 million from its 2012-2014 demand response portfolio to fund various improvements to its Demand Response programs. Do you support additional fund shifting from SDG&E's 2012-2014 demand response portfolio to fund the pilots described in the staff proposal?

6. In D.13-07-003, the Commission directed SCE and SDG&E to transition their Peak Time Rebate (PTR) programs to be an opt-in program (in order for participants to be paid a monetary incentive for load reductions) by May 2014. This transition will enable both utilities to save significant incentive funds for the program. Energy Division's May 1, 2013 DR Lessons Learned Report estimated that SDG&E paid $10.1 million in 2012 PTR incentives to its residential customers, yet 94 percent of the incentives paid yielded no significant load reductions. SCE paid $27 million in 2012 PTR incentives, and 95 percent of incentives were paid to customers who were not expected to or did not reduce load significantly. Do you support the Commission using the expected savings from the PTR program incentives to fund the pilot activities described in the staff proposal?

6. Schedule

This proceeding will initially address bridge funding for 2015 and the staff proposal, and then address the proposed restructuring of the demand response program, the integration with the CAISO markets, and future funding configurations. The preliminary schedule is as follows:

EVENT	DATE
Responses Due to the Questions on the Staff Proposal	October 21, 2013
Prehearing Conference (PHC)	October 24, 2013 at 10:00 a.m.
Bridge Funding Decision	2nd Quarter 2014

On the basis of the discussion at the PHC, the assigned Commissioner or Administrative Law Judge (ALJ) may provide a more detailed schedule, and may modify this schedule as necessary to assure the efficient and effective conduct of the rulemaking. The Commission anticipates that this proceeding will be complete within 24 months of the date of the assigned Commissioner's Scoping Memo. In using the authority granted in Section 1701.5(b) to set a time longer than 18 months, we consider the number and complexity of the tasks.

7. Category of Proceeding

Pursuant to Rule 7.1(d) of the Commission's Rules of Practice and Procedure (Rules), this rulemaking is preliminarily categorized as "ratesetting" as that term is defined in Rule 1.3(e). Our intention is to conduct this proceeding by written comments from the parties, workshops, and possibly limited evidentiary hearings on technical issues.

8. Parties and Service List

PG&E, SDG&E, and SCE are named as respondents to this rulemaking. The Commission will serve this order on parties to R.07-01-041, the prior rulemaking on demand response. The official service list will be established at the initial PHC. We invite broad participation in this proceeding. If you are not already on the service list for R.07-01-041 and want to participate in the Rulemaking or simply to monitor it, follow the procedures set forth below. To ensure you receive all documents, send your request prior to the PHC. The Commission's Process Office will publish the official service list at the Commission's website (www.cpuc.ca.gov), and will update the list as necessary.

8.1. Requesting Party Status Prior to the PHC

Prior to the initial PHC, any person may ask to be added to the official service list. Send your request to the Process Office. You may use e-mail (Process_Office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, CA 94102). Include the following information:

- Docket Number of this Rulemaking;
- Name (and party represented, if applicable);
- Postal Address;
- Telephone Number;
- E-mail Address; and
- Desired Status (Party, State Service, or Information Only).[19]

If the OIR names you as respondent, you are already a party, but you or your representative must still ask to be added to the official service list.

8.2. Requesting Party Status after the PHC

If you want to become a party after the PHC, you may do so by filing and serving timely comments in the Rulemaking (Rule 1.4(a)(2)), or by making an oral motion (Rule 1.4(a)(3)), or by filing a motion (Rule 1.4(a)(4)). If you file a motion, you must also comply with Rule 1.4(b). These rules are in the Commission's Rules of Practice and Procedure, which you can read at the Commission's website.

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[19] If you want to file comments or otherwise actively participate, choose "Party" status. If you do not want to actively participate but want to follow events and filings as they occur, choose "State Service" status if you are an employee of the State of California; otherwise, choose "Information Only" status.

If you want to be added to the official service list as a non-party (that is, as State Service or Information Only), follow the instructions in Section 8.1 above.

8.3. Updating Information

Once you are on the official service list, you must ensure that the information you have provided is up-to-date. To change your postal address, telephone number, e-mail address, or the name of your representative, send the change to the Process Office by letter or e-mail, and send a copy to everyone on the official service list.

8.4. Serving and Filing Documents

Until the initial PHC, use the service list for the prior Demand Response Rulemaking, R.07-01-041, for any filings. We anticipate that the Process Office will publish the official service list immediately following the initial PHC. Following the initial PHC, when you serve a document, use the official service list published at the Commission's website as of the date of service. You must comply with Rules 1.9 and 1.10 when you serve a document to be filed with the Commission's Docket Office. If you are a party to this Rulemaking, you must serve by e-mail any person (whether Party, State Service, or Information Only) on the official service list who has provided an e-mail address.

The Commission encourages electronic filing and e-mail service in this Rulemaking. You may find information about electronic filing at http://www.cpuc.ca.gov/PUC/efiling. E-mail service is governed by Rule 1.10. If you use e-mail service, you must also provide a paper copy to the assigned Commissioner and ALJ. The electronic copy should be in Microsoft Word or Excel formats to the extent possible. The paper copy should be double-sided. E-mail service of documents must occur no later than 5:00 p.m. on the date that service is scheduled to occur.

If you have questions about the Commission's filing and service procedures, contact the Docket Office.

9. *Ex Parte* Communications

Pursuant to Rule 8.4(b), *ex parte* communications are governed by Rules 8.2(c) and 8.3.

O R D E R

IT IS ORDERED that:

1. A rulemaking is instituted on the Commission's own motion to enhance the role of demand response in meeting the State's resource planning needs and operational requirements. The rulemaking will (a) review and analyze current demand response programs to determine whether and how we should bifurcate them into demand-side and supply-side resources; (b) create an appropriate competitive procurement mechanism for supply-side demand response resources; (c) determine the program approval and funding cycle; (d) provide guidance for transition years; and (e) develop and adopt a roadmap with the intent to collaborate and coordinate with other Commission proceedings and state agencies in order to strategize the future of demand response in California.

2. Responses to the set of six questions regarding demand response program bridge funding and the staff pilot proposal shall be filed and served no later than October 21, 2013. For the purposes of this filing only, parties should use the service list in Rulemaking 07-01-041.

3. A prehearing conference will be held on October 24, 2013 at 10:00 a.m. in the Commission hearing room.

4. The assigned Administrative Law Judge, in consultation with the assigned Commissioner, may make any necessary adjustments to the schedule for this proceeding.

5. The category of this rulemaking is preliminarily determined to be "ratesetting" as that term is defined in Rule 1.3(e) of the Commission's Rules of Practice and Procedure.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are named as respondents and are parties to this proceeding pursuant to Rule 1.4(d) of the Commission's Rules of Practice and Procedure.

7. The Executive Director will cause this Order Instituting Rulemaking to be served on all respondents and on the service lists for Commission proceeding, Rulemaking 07-01-041.

8. The Commission's Process Office will publish the official service list on the Commission's website (www.cpuc.ca.gov) following the initial Prehearing Conference. Parties may also obtain the official service list by contacting the Process Office at (415) 703-2021.

9. Interested persons must follow the directions in Section 8.1 of this Order Instituting Rulemaking to become a party or to be placed on the official service list as a non-party.

10. The assigned Administrative Law Judge will have on-going oversight of the service list and may institute changes to the list or the rules governing it, as needed.

11. Parties serving documents in this proceeding must comply with Rule 1.10 of the Commission's Rules of Practice and Procedure regarding electronic mail (e-mail) service. Parties providing e-mail service must also provide a paper copy to the assigned Commissioner and Administrative Law Judge.

This order is effective today.

Dated September 19, 2013, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

ATTACHMENT A

STAFF PROPOSAL

Staff Proposal for Demand Response Pilots in 2015

August 2013

• Summary

This is a staff proposal for demand response pilot projects to occur in 2015. The goals are to

1) Test the participation of demand response in the CAISO wholesale energy market through two pilot programs.
   a. Further the currently ongoing Intermittent Resource Management Phase 2 (IRM2) pilot in northern California.
   b. Implement the IRM2 pilot in southern California.

2) Test the effectiveness of the following strategies at improving customer response to time-of-use and critical peak pricing rates
   a. Increase customer awareness of peak hours;
   b. Use feedback and social norms to encourage behavior change; and
   c. Introduce automated technologies that shift or reduce load during peak hours.

• Participation of Demand Response in the Wholesale Energy Market

○ Background

This pilot project proposal for bidding demand response (DR) into the wholesale market is in response to the new demand response Order Instituting Rulemaking (OIR). This pilot would occur in the context of several ongoing activities that will materially affect what can actually be done in 2015, the effective date for this pilot. These activities are:

- IRM2 Pilot – PG&E
- Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO) - CAISO
- Resource Adequacy Flexible Capacity Framework - CPUC
- Rule 24 - CPUC

These outcomes of these activities will affect the means and the ability of DR to play a part in the evolution of the California electricity grid. DR's ability to be operated as a "flexible capacity resource" as well as an ancillary services resource can be of enormous value going forward.

Table 1

At present, there are only two CAISO mechanisms that enable DR to participate in the wholesale market: Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR).[1] There is another

CAISO Services	IRM2 – PDR	When?	Program window
Energy Service			
Day Ahead Energy	Yes	Phase 1*	24 hour availability – Mon-Sun – year round
Real Time Energy	Yes	Phase 2**	24 hour availability – Mon-Sun – year round
Ancillary Service			
Day Ahead Non-Spin	Yes	Phase 2**	24 hour availability – Mon-Sun – year round
Real Time Non-Spin	Yes	Phase 2**	24 hour availability – Mon-Sun – year round
Day Ahead Spin	N/A	N/A	N/A
Real Time Spin	N/A	N/A	N/A
Day Ahead Regulation Up	N/A	N/A	N/A
Real Time Regulation Up	N/A	N/A	N/A
Day Ahead Regulation Down	N/A	N/A	N/A
Real Time Regulation Down	N/A	N/A	N/A

mechanism called Participating Load, but this has largely been abandoned. There are no mechanisms for DR to provide ancillary services. PDR only provides for the "ramp up" characteristic in terms of flexible capacity. However, as shown in Table 1, the supporting market mechanisms are not currently in place to

[1] As of the publishing of this report, FERC has only approved CAISO's PDR tariff.

allow DR to provide these services. Areas shown in Table 1 in yellow are services that are not supported in the CAISO PDR mode.[2]

- ### Pilot Proposal for IRM2 Enhancement in Northern California

  - #### Problem Statement

A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs

Demand Response (DR) resources can potentially provide flexible resources and resource adequacy (RA) capacity to the CAISO, but a complete end-to-end demonstration of the use of DR resources must be conducted to validate processes, procedures, and systems of all parties. The Intermittent Resource Management Phase 2 (IRM 2) pilot[3] addresses this need by creating the infrastructure allowing third parties to bid DR into the wholesale energy market.

The IRM2 pilot is a very early stage training vehicle to give Demand Response Providers (DRP) experience in the wholesale market. There may be many potential DRPs who are not willing or able to take on all the required structural and functional requirements for CAISO participation. Currently, the IRM2 pilot is structured as a "one stop shopping" operation where all the services and infrastructure needed to bid DR into the wholesale market are provided by the Program Administrator and one particular consultant. For some IRM2 participants, this arrangement may be all that they would require for future participation.

However, during interviews with IRM2 participants, it became clear that there is also a compelling need to build expertise with direct CAISO engagement among certain participants, i.e., third party DR providers (DRPs or aggregators), large Direct Access Customers and Community Choice Aggregators. These participants ultimately don't want, or need, all the services provided for them in the context of IRM2.

Although the IRM2 learning can be applied by DRPs to build flexible DR capacity for bidding into the market, there is a gap in the learning for third parties that might want to build this capacity internally.

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2 The California Independent System Operator (CAISO) is currently engaged in a stakeholder initiative entitled, "Flexible Resource Adequacy Criteria Must Offer Obligation" (FRAC-MOO) that focuses on "how to operationally utilize flexible capabilities in the ISO market."

3 By PG&E Advice Letter (AL) 4077-E-A from Ordering Paragraph 80 of D.12-04-045. This AL was approved by Energy Division Disposition dated April 2, 2013.

The goal of this pilot would be to enable these parties to stand alone as direct participants in the CAISO market, independent of the utilities or other support structures provided by IRM2.

▪ How the pilot will address DR goal or strategy

Whether and how the pilot will address a DR goal or strategy

For PG&E, a potential productive focus would be to work with California's only CCA, Marin Energy Authority (MEA) to bring them into the IRM2 pilot initially, but in 2015 to migrate to the special emphasis noted below. To the extent that Direct Access customers and aggregators express interest in direct participation (without requiring the services provided by the IRM2 Program Administrator), they could be included in this pilot as well. However, due to budget limitations, it may be difficult to provide support for all interested parties.

- This pilot will focus on building the capability for direct involvement by the participant in setting up a PDR and conducting energy trades based on DR capacity in the wholesale day ahead market[4]. Participants must already have Scheduling Coordinator (SC) capabilities and have experience conducting trades in the day-ahead market.
- Participants, especially CCAs, should be able to access to adequate numbers of end-use customers or loads to be able to reliably meet ISO dispatch commitments.
- The focus of these participants' involvement will be to leverage learning and infrastructure from the IRM 2 pilot to be able to enable direct third party participation in the PDR, with the ultimate goal being direct participation of DR-based flexible capacity.

▪ Objectives and goals for the pilot

Specific objectives and goals for the pilot

- Engage one or more large DA customers and a CCA who currently have the capability to engage in energy trades in the CAISO day ahead market.
- Enable development of a DR portfolio that can provide flexible capacity to the CAISO
- Build third party capabilities to directly participate in CAISO PDR
- Produce a guidebook for direct participation of DR in the CAISO wholesale market
- Development of capabilities to enable DR to submit bids into CAISO ancillary services market

[4] To the extent that other vehicles are available for DR participation in CAISO markets, including the hour ahead and real time, these might be included as well.

▪ Budget and timeframe

A clear budget and timeframe to complete the pilot and obtain results within a portfolio cycle. Pilots that are continuations of pilots from previous portfolios should clearly state how the continuation differs from the previous phase

New **Pilot**

2015 (1 year only)		
$2,638,000		

Budget: PG&E $2,638,000

	PG&E
Program Administrator	$321,926
Customer Care Services (Metering billing EDS etc)	$160,961
Procurement (end to end - bidding scheduling etc...)	
Front (Scheduling - Bidding)	$321,926
Back (Settlements)	$321,926
Policy and Integrated Planning	$116,253
Marketing	
Internal	$80,480
Vendor	
Consultant + Research	$241,446
System (Hosted Solution)	
Platform	$160,961
Telemetry	$160,961
Forecasting	$107,307
Enabling Technologies (Equipment)	$107,307
Incentives	$536,541
Total	$2,638,000

▪ Standards and metrics

Information on relevant standards or metrics or a plan to develop a standard against which the pilot outcomes can be measured

This pilot will be measured by one standard only: whether the ability to initiate and conduct actual bidding in the wholesale market is achieved by the CCA and/or other third party participant. Other metrics include:

- the revenue achieved through the sale of DR "energy"
- the number of dispatches of the DR resource over the time when bids are submitted
- the ability of the DR resource to respond to ramping dispatch

- the ability of the DR resource to be bid in during the off season (winter months)
- the ability of the DR resource to qualify for RA credits

Methodologies to test the cost-effectiveness of the pilot

Where appropriate, propose methodologies to test the cost- effectiveness of the pilot

Staff believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. One of the main goals of the pilot is to determine the costs and benefits of having DR resources provide flexibility services to the CAISO. In particular, this pilot should develop a process for DR participants to follow to be able to participate in the wholesale market. The pilot will be developing the needed DRP infrastructure that will leverage the existing capacity developed and fine-tuned in IRM 2. Staff expects that the results will not be indicative of a full program, but that the investment will create infrastructure that will be fully scalable going forward.

A cost-effectiveness analysis, after the pilot is completed, on the expected costs and benefits of a full program that offers complete start-up procedures for large commercial customers and CCAs to participate in the wholesale market, would be a worthwhile exercise. To the extent that flexibility services implemented using DR under the PDR mechanism provides an economic benefit to participants, it would be meaningful to explore the necessary program attributes needed for future DR programs.

Evaluation, Measurement and Verification plan

A proposed EM&V plan

Participants will be evaluated on the following criteria:

- ability to use the PDR mechanism to submit bids in the wholesale market
- ability to characterize DR portfolio to provide flexible characteristics such as ramping, and the ability to be dispatched in off hours and off season
- ability to provide necessary technology to end customers to fulfill telemetry and/or metering requirements, and to be dispatchable by the CAISO as a flexible resource under the PDR mechanism

For the above evaluation criteria, certification by the CAISO will serve as the primary verification mechanism. Successful dispatch of DR resource and delivery of "energy" (required DR load reduction for specified period of time) along with financial settlement will constitute the verification that the PDR is functioning as designed and that the DRP is successfully completing the wholesale transaction.

▪ Strategy to identify and disseminate best practices and lessons learned

A concrete strategy to identify and disseminate best practices and lessons learned from the pilot to all California utilities and to transfer those practices to resource programs, as well as a schedule and plan to expand the pilot to utility and hopefully statewide usage.

Pilot results shall be reported at the public DRMEC spring or fall meeting on load impact or process evaluation results.

Participants, lead by the IOUs, will conduct quarterly meetings with the Energy Division throughout the pilot period. The meetings will include current work, budgets and foreseeable next steps to ensure parties are well informed.

At the conclusion of the field demonstration, IOUs with participants will provide the Energy Division with reports highlighting the lessons learned from this pilot. Any key lessons that can be extracted from this pilot will be used to enhance existing or new DR programs.

○ Pilot Proposal for IRM 2 Implementation in Southern California

▪ Problem Statement

A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs

This pilot proposal addresses a key problem of third party DR providers (and large end-use customers) lack of understanding and experience of bidding DR into the wholesale CAISO market.

In the 2012-2014 DR application, PG&E requested and received funding to conduct a pilot called IRM 2 (Intermittent Resource Management Pilot 2). IRM 2 is in the early stages of its pilot implementation and is currently enrolling third party DR providers. The goal of IRM 2 is to demonstrate the capabilities of flexible DR resources which are required by the CAISO, furthering the testing of the capabilities of flexible DR resources that IRM (phase 1, earlier pilot by PG&E) attempted to accomplish.[5] This pilot

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[5] With active ongoing discussion on flexible resources through the FRACMOO proposal at the CAISO, the definition of flexibility continues to evolve. Flexible capacity is expected to submit economic bids into the day-ahead and real-time markets and be available for real-time dispatch. As outlined in the FRACMOO July Straw Proposal, a flexible capacity demand response resource would have the option of selecting a must-offer obligation and submit economic bids into the CAISO market. These bids would be submitted for all non-holiday weekdays in the morning hours (6am to 11am) or afternoon/evening hours (4pm to 9pm). The proposal further states the flexible demand response resource should be able to provide a minimum of three hours of load reduction. The PDR flexible capacity resource would provide the CAISO with the resource's use-limitations, similar to how generating resources report constraints. The supplier would also manage the use-limitations by bidding only that amount of demand response which is physically available to reduce load in each hour.

extends the IRM 2 model for SCE and SDG&E to enable third party DR providers and large end-use customers in Southern California to learn how to bid DR into the CAISO market.

Additionally, and only if the flexible DR products are defined by 2015, the pilot can attempt to bid flexible DR into the wholesale market.

- ### How the pilot will address DR goal or strategy

Whether and how the pilot will address a DR goal or strategy

The pilot extends the functionalities of PG&E's IRM 2 to Southern California utilities. It enables the third party DR providers in Southern California to learn how to bid DR into the wholesale market, and assist the CAISO in its efforts to balance the grid.[6] It also provides third party DR providers in Southern California with the necessary experience of offering *day-ahead* DR products in CAISO and the ability to understand how the proxy demand resource (PDR) mechanism works.

- ### Objectives and goals for the pilot

Specific objectives and goals for the pilot

Replication of IRM2 - The key objective of the pilot is to replicate PG&E's IRM 2 for the Southern Californian utilities.

Providing additional capacity to the SONGS affected areas - the pilot will provide additional capacity to the SONGS affected areas by giving DR providers, which serve the affected areas, priority enrollment in the pilot.

Creation of a pool of knowledgeable third party providers - The pilot will enable SCE and SDG&E to attract third parties DR providers and large end-use customers to bid demand response into the CAISO wholesale market, thereby gaining operational experience with the CAISO market and flexible capacity products. Additionally, the pilot *may* provide DR providers and large end-use customers with experience constructing their flexible capacity portfolio, while allowing the Southern California utilities to test the capability of their customers to deliver the needs of a flexible DR product.

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[6] D.12-11-045 provides an extensive discussion on the Commission's staged approach in involving utilities and their customers to wholesale DR competition. The Decision further outlines the next phase of the DR integration, which is direct participation in the CAISO wholesale electricity market. IRM2 and the pilot proposed here continues the progress towards those goals.

Testing day-ahead demand response - Distinct from the implementation of PG&E's IRM 2 which tests both day-ahead and real time demand response, the Southern California pilots will test the day-ahead flexible product only. Since the pilot runs only for one year, this seems to be the most reasonable product which can tested in a short time frame

Other goals - Similar to some of the goals of PG&E's IRM 2 pilot, this Southern California pilot will provide visibility to the CAISO of the operation of demand-side resources; evaluate and validate technology to enable DR to serve as a flexible resource; and assist the development of accurate customer load control strategies and forecast of load consumption or curtailment.

Development of a flexible demand resource – Similar to the goals of the PG&E IRM 2 pilot, this pilot will help develop processes, procedures and resources to provide flexible demand response to the CAISO. This goal is largely dependent on whether the CAISO is able to clearly define flexible demand resource by the time that the pilot is implemented.

- ### Budget and timeframe

New Pilot Budgets for 2015

Based on the available bridge funding, the budgets for SCE and SDG&E have been broken down into various expenditures required to replicate the IRM 2 pilot. The budgets for SCE and SDG&E are significantly smaller than the budget for PG&E (provided in the last column for comparison). The budgets of SCE and SDG&E should ideally be at least 75-80% of the budget of PG&E's IRM 2 to effectively replicate the pilot.

	SDG&E	SCE	PG&E (IRM 2 Budget)
Program Administrator	$63,409	$74,965	$300,000
Customer Care Services (Metering billing EDS etc)	$31,704	$37,483	$150,000
Procurement (end to end - bidding scheduling etc...)			
Front (Scheduling - Bidding)	$63,409	$74,965	$300,000
Back (Settlements)	$63,409	$74,965	$300,000
Policy and Integrated Planning	$22,898	$27,071	$108, 336
Marketing			
Internal	$15,852	$18,741	$75,000
Vendor			
Consultant + Research	$47,557	$56,224	$225,000
System (Hosted Solution)			
Platform	$31,704	$37,483	$150,000
Telemetry	$31,704	$37,483	$150,000
Forecasting	$21,136	$24,988	$100,000
Enabling Technologies (Equipment)	$21,136	$24,988	$100,000
Incentives	$105,681	$124,942	$500,000
Total	$519,600	$614,300	$2,458,336

Standards and metrics

Information on relevant standards or metrics or a plan to develop a standard against which the pilot outcomes can be measured

- Improved understanding of third party DR providers/large end-use customers of how to bid into the CAISO wholesale market.
- Increased visibility of DR in CAISO system.
- Enabling technologies evaluated and deployed.
- Large number and diversity of third party DR providers/large end-use customers as pilot participants.
- Third party/end-use customer feedback on the challenges of the flexible capacity DR product.
- Testing of customer capability to meets the needs of the flexible capacity DR product.

▪ Methodologies to test the cost-effectiveness of the pilot

Where appropriate, propose methodologies to test the cost- effectiveness of the pilot

IRM 2 is currently not testing the cost effectiveness of the pilot, but is exploring the cost-effectiveness of the full program which offers the flexible DR product. The Southern California utilities can be expected conduct the same cost-effectiveness for a full scale rollout of the program with the desirable flexible DR product attributes.

▪ Evaluation, Measurement and Verification plan

A proposed EM&V plan

Key elements of the EM&V plan to include:

- Evaluation and impact of the satisfaction of the customers participating in the pilot.
- Evaluation and impact of the satisfaction of the third parties participating in the pilot.
- Evaluation of the loads which can meet the needs of the flexible DR product.

▪ Strategy to identify and disseminate best practices and lessons learned

A concrete strategy to identify and disseminate best practices and lessons learned from the pilot to all California utilities and to transfer those practices to resource programs, as well as a schedule and plan to expand the pilot to utility and hopefully statewide usage.

PG&E has hired a Research Consultant for IRM 2 (Lawrence Berkeley National Lab). The budgets of the Southern California utilities will include funds to hire a Research Consultant who can study the results of the pilot and identify best practices. The reports should be publically available.

A quarterly meeting of the three IOUs, in various stages of IRM 2 implementation, can assist in disseminating best practices and lessons learned.

• Pilot to increase customer responsiveness to dynamic electricity rates

○ Background

This pilot proposal for testing behavior-based programs for non-residential customers on time-of-use (TOU) rates and critical peak pricing (CPP) rates is in response to the new demand response (DR) Order

Instituting Rulemaking (OIR). The OIR identifies five challenges in DR programs, one of which is the need to educate, motivate and engage customers so that they are able to successfully participate in DR programs and rates. In the next three years the number of small and medium commercial customers on TOU and CPP rates will increase significantly. This pilot creates an opportunity for utilities to engage with customers and understand the type of information and motivation they need to understand and respond to the dynamic rates.

In separate decisions, the Commission has directed that PG&E, SDG&E and SCE transition all small and medium sized commercial customers (small commercial customers, or small businesses) to a new mandatory TOU rate. The Commission has also directed that after a period of adjustment on TOU that the utilities transition the same customers to a CPP rate, which the customer can choose to opt off of to return to the TOU rate. These rate transitions began in 2012 and will continue through 2016, and they will impact roughly 860,000 small and medium commercial accounts. The following table illustrates the timing and volume of customers that will transition to these rates by 2016.

Utility		**2012**	**2013**	**2014**	**2015**	**2016**
PG&E	*Customer Accounts (Rate)*	226,000 (TOU)	125,000 (TOU)	226,000 (CPP)	125,000 (CPP)	
SDG&E	*Customer Accounts (Rate)*			114,000 (TOU/CPP)		
SCE	*Customer Accounts (Rate)*			200,000 (TOU)	200,000 (TOU)	400,000 (CPP)

- **Pilot Proposal for behavior programs for customer on dynamic rates**

  - **Problem Statement**

A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs

Customer participation in and response to CPP rates have been monitored through demand response monthly reports and load impact statements. However, until 2012 the majority of customers on CPP have been large commercial, industrial or agricultural customers. Starting in 2014 load impact reports will include impacts from small commercial customers on TOU, and in 2015 reports will include impacts from small commercial customers on CPP. Even though individually these customers have a small amount of load to drop compared to large customers, the Commission recognized that as a customer segment they could contribute to peak load reductions if they are on a CPP rate.

Unlike many large customers that participate in demand response programs, small businesses do not have engineers, or energy managers on staff. In most cases they also do not have a utility sales or customer service representative assigned to them to offer solutions to reduce or shift load when an event is called. Few attempts have been made to include them in aggregator programs. The majority of small customers that will be placed on TOU and CPP rates will learn about them through marketing materials such as bill inserts, direct mail pieces, or digital ads. The marketing campaigns are designed to inform customers prior to the rate change that a rate change is coming, the purpose for the change, and the differences between the previous and new rates. The short-term marketing campaigns are not designed for stimulating long-term behavior change, such as repeatedly responding to a price signal.

The Commission recognized in D. 12-05-015, the Energy Efficiency Guidance Decision, that behavior-based programs should be included in the Energy Efficiency portfolio. Then in D. 12-11-015, the decision approving Energy Efficiency programs for 2013-2014, directed that utilities meet a target of reaching 5% of residential homes with a behavior-based pilot by the end of 2014. At the time the Commission approved a definition from stakeholders that behavior programs are required to include, comparative energy usage and disclosure, ex post measurement and experimental design. However, the Commission encouraged utilities to work with stakeholders to expand the definition and gave utilities the flexibility to increase program activities. In May of 2013 EnerNOC, in collaboration with the utilities, CPUC and many other stakeholders, issued a white paper on Residential Behavior Programs, that identified behavior intervention strategies that can be used to influence energy- related behaviors in demand side management programs. (ENERNOC, "Paving the Way for a Richer Mix of Residential Behavior Programs", May 31, 2013, p. i.)

The goal of pairing a behavior pilot with TOU and CPP rates is to identify the mix of strategies that enable small commercial customers to be successful on the rates so that a greater number of customers stay on CPP, save money by being on it, and reduce load when CPP events are called. The pilot will test which behavior- related strategies work for small business segments and identify whether and which behavior related strategies should be recommended to carry out on a larger scale in 2016.

- How the pilot will address DR goal or strategy

Whether and how the pilot will address a DR goal or strategy

Currently the Commission has not established a goal for the expected load reduction from small commercial customers on TOU or CPP. Monitoring customer understanding of the rates, actions customers take, and corresponding load reductions from each business segment in the first few years of implementation will enable the utilities to identify reasonable goals that CPP rates can contribute to retail DR. A 2015 pilot will also create an opportunity for the utilities, third parties and the Commission to understand what costs and activities are necessary to empower small commercial customers on CPP to achieve load reductions.

- Objectives and goals for the pilot

Specific objectives and goals for the pilot

- For Customers on TOU and CPP
- Goal 1: customers know when they are in a peak period, and know that they are paying (much) more for electricity than they would during off peak or partial peak hours
- Objective 1: Increasing customer awareness when peak hours are occurring. For example,
    - Test different methods of communication to remind customers when a higher price period starts and ends.
    - Commission decision should allow for flexibility so that pilots can be adapted to use the best communication channels to reach customers in 2015 (for example- maybe smart phone apps will be a great tool for communicating, but maybe there will be something else by 2015)
- For customers on TOU or CPP
- Goal 2: customer make adjustments to business practices during peak hours to use less energy
- Objective 2: Use feedback and social norms to encourage behavior change. For example,
    - Provide feedback loops for customers so they understand how they did during a CPP event and how they could do better
    - Identify discretionary load that customers can shift into off-peak

- Interview customers with the best load profile to understand how they achieve it and see if like business follow these best practices

▪ Consider a rewards program for customers doing well

- For customers on CPP

○ Goal 3: Identify types of businesses that could most utilize and benefit from automated technologies, or test methods to encourage adoption and installation of devices

○ Objective 3: Introduce automated technologies that shift or reduce load during peak hours, and identify how Objective 1 and Objective 2 work in concert with customers that have enabling technologies installed at their business

▪ There may be opportunities for utilities to pair Objective 1 & Objective 2 with technologies that will already be installed for some small businesses

- SDG&E- will deploy Programmable Communicating Thermostats in 2014

- PG&E will begin installing devices in 2014 through its emerging technologies program

Budget and timeframe

New Pilot Budgets for 2015

SDG&E	PG&E	SCE
$750,000	$750,000	$750,000

Minimum budget of $ 500,000 per utility, but that would exclude using any kind of technology or evaluation. $ 1 million would be more reasonable if pilots include automated devices.

Standards and metrics

Information on relevant standards or metrics or a plan to develop a standard against which the pilot outcomes can be measured

PG&E will have load impact data from 2014 that can be used as a baseline for TOU customers that participate in the pilot to help set target values for metrics. There will also be control groups to compare the effects of the strategies being tested. Possible metrics are:

- Customers know when peak hours are, and that they are paying more
- Customers reduce or shift load during CPP peak events
- Reductions from customers participating in the pilot are greater than customers not participating in the pilot

- ### Methodologies to test the cost-effectiveness of the pilot

Where appropriate, propose methodologies to test the cost- effectiveness of the pilot

The costs and impacts of each strategy should be tracked, as well as the impact of combining more than one strategy. Knowledge gained from identifying the cost-effectiveness of implementing Energy Efficiency behavior programs can be leveraged.

- ### Evaluation, Measurement and Verification plan

A proposed EM&V plan

Small business customers vary widely depending on the type of business. Therefore both pilots should examine the impacts to each business segment (restaurants, medical facilities etc.) The EM&V plan will also need to be designed so that it can disaggregate load impact attribution to each strategy. For example,

- What is the impact of Objective 1?
- What is the impact of Objective 2?
- What is the impact of Objective 3?
- What is the impact of Objective 1 or 2 combined with Objective 3?

- ### Strategy to identify and disseminate best practices and lessons learned

A concrete strategy to identify and disseminate best practices and lessons learned from the pilot to all California utilities and to transfer those practices to resource programs, as well as a schedule and plan to expand the pilot to utility and hopefully statewide usage.

Quarterly meetings with the utilities can assist in disseminating best practices. Quarterly meetings should be open to experts in behavior research to provide insight and learn from the pilots. There should be a final evaluation of the pilot and report with recommendations for best approaches to enable small commercial customers to achieve load reductions.

(END OF ATTACHMENT A)