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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking regarding policies and protocols for demand response load impact estimates, cost-effectiveness methodologies, megawatt goals and alignment with California Independent System Operator Market Design Protocols.	Rulemaking 07-01-041 (Filed January 25, 2007)

ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE FOR THE 2012-2014 DEMAND RESPONSE APPLICATIONS

1. Summary

In Decision (D.) 09-08-027, the California Public Utilities Commission (Commission) approved Demand Response activities and budgets for Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E). D.09-08-027 also required SCE, SDG&E, and PG&E (collectively, the utilities) to file demand response program applications (Applications) by January 30, 2011 for approval of demand response activities and budgets for 2012-2014.[1] This ruling provides guidance related to the scope and contents of the Applications, solicits proposals that are consistent with the Commission's current policies for demand response, and directs that the Applications contain sufficient information to support a thorough and comprehensive review of demand response activities and budgets.

[1] D.09-08-027, Ordering Paragraph (OP) 41.

2. Background and Overview

A ruling issued on February 27, 2008, in this proceeding provided guidance on the content and format of the 2009-2011 Demand Response program applications that were filed in June 2008.[2] As was the case in that prior ruling, the main purpose of today's ruling is to provide policy and design guidance related to demand response program development for the next three-year program period (2012-2014) and ensure that the Commission has sufficient information available to evaluate the utilities' demand response activity and budget proposals. This ruling incorporates and clarifies information from the following sources:

1. D.09-08-027, which set forth several tasks for the utilities to undertake in preparation for the 2012-2014 Applications,
2. D.10-06-034, which adopted a settlement concerning emergency-triggered demand response programs,
3. D.10-06-036, which adopted Resource Adequacy changes that are relevant to demand response,
4. D.10-06-002, which addresses preliminary issues related to direct participation of demand response in California electricity markets, and
5. various actions by the California Independent System Operator (CAISO) that affect demand response.

In particular, this ruling provides guidance on the scope and contents of the utilities' 2012-2014 demand response program Applications that are due on January 30, 2011, with a focus on the following issues:[3]

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[2] Application (A.) 08-06-001 was filed by SCE, A.08-06-002 was filed by SDG&E, and A.08-06-003 was filed by PG&E.

[3] This ruling does not preclude the Commission or other parties from raising additional issues in the Applications proceeding.

- The importance of price-responsive demand response.
- Alignment of demand response program designs with resource adequacy requirements.
- Integration of demand response with wholesale markets.
- Implementation of a cap on emergency-triggered programs.
- Funding for the Integrated Demand Side Management activities.
- Additional activities related to demand response included in previous applications, including automated demand response/technology incentives, permanent load shifting, and existing and potential new pilot programs.
- Inclusion of demand response load impact estimates.
- Inclusion of demand response cost effectiveness analyses.
- Inclusion of information on demand response activities authorized in other proceedings.
- The contents and format of the utilities' Applications.

In general, consistent with Commission policy, the utilities are expected to propose improvements to existing demand response activities in order to increase the cost effectiveness of those activities and enhance their integration with California electric markets and resource adequacy requirements.

3. Guidance for Application Scope and Contents

In general, the utilities' applications shall conform with the guidelines outlined in this ruling. To the extent that utilities depart from these guidelines, they must include in their testimony the benefits that are gained from deviations from the requirements described here. All requirements for the 2012-2014 applications made in previous Commission orders, including any not mentioned in this ruling, still apply; the discussion in this ruling merely summarizes or clarifies some of the issues raised in earlier orders, and is not intended to be comprehensive.

3.1. Importance of Price-Responsive Demand Response and Dynamic Rates

As stated in D.09-08-027, price-responsive demand response and dynamic rates remain key components of the Commission's demand response policy because such activities can lower overall wholesale electricity costs for all customers and help mitigate wholesale market power. Price responsive demand response includes activities in which the utility calls on participating customers to reduce demand in response to an external price signal, such as an increase in the wholesale price of electricity or a metric that can be considered a proxy for the price of electricity, but utility customers do not see a change to their basic retail electric rate.[4] Instead, participating customers receive some financial incentive or payment for their load reduction. The development of dynamic pricing retail rates, such as critical peak pricing, continues to be an important strategy to increase price responsive demand response from individual customers. As with price-responsive demand response activities run by utilities or other entities, dynamic prices cause participants to reduce demand in response to increases in wholesale prices or proxy metrics for such increases. Unlike price-responsive demand response, dynamic rates accomplish this reduction in demand by exposing customers to higher retail rates reflecting temporary increases in the wholesale cost of electricity.

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[4] Proxy metrics for an increase in the price of electricity include, but may not be limited to, high temperatures or the time of day.

This proceeding will focus on price responsive demand response, not dynamic rates.[5] However, in developing programs for their 2012-2014 applications, the utilities should keep in mind that the proposals should complement dynamic pricing and/or respond to wholesale price signals. The utilities are also encouraged to design new programs or modify existing programs so that enrollment and participation in price-responsive demand response is increased.

3.2. Alignment with Resource Adequacy Requirements

Through its Resource Adequacy framework, the Commission sets the Resource Adequacy requirements for each Load Serving Entity (LSE).[6] The load impact from event-based demand response programs is counted for Resource Adequacy as net Qualifying Capacity,[7] which reduces the utilities' short-term capacity procurement obligations. In the annual Resource Adequacy process, the Energy Division staff determines the total megawatts from event-based programs by local capacity area and month for each LSE. The load impacts from the non-event-based demand response programs are assumed to be included in the total load forecast, and so are not counted as qualifying capacity.

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[5] The authority to develop and recover costs associated with dynamic rates will be addressed in other proceedings.

[6] Load Serving Entities, or LSEs, consist of Investor-owned utilities, energy service providers (ESPs), and community choice aggregators (CCAs).

[7] Qualifying Capacity is defined in D.04-10-035 at 21-22, and refers to the actual MW for a specific resource that may be counted toward the amount that an LSE is obligated to have available in advance. D.04-10-035 adopts a series of formulas for computing qualifying capacity for various types of resources. These rules have been revised and amended, most recently for Demand Response in D.10-06-036.

Historically, demand response activities were not designed in close coordination with the Resource Adequacy requirements and rules. This may lead to an inadvertent undervaluing of demand response resources. For example, in the annual Resource Adequacy accounting process, a demand response program's capacity or load impact may be adjusted downwards in the calculation of Qualifying Capacity if the available hours of the demand response program are different from the hours used to measure Resource Adequacy availability. If resource adequacy qualifying capacity numbers are used in place of the program's undiscounted load impact numbers in the calculation of a program's cost effectiveness, prorating a demand response program's capacity in the Resource Adequacy process would reduce its actual cost effectiveness compared to the level calculated using the total load impact number.

To the extent feasible, the utilities shall propose demand response programs that are compatible with Commission rules established for Resource Adequacy, in order to improve the consistency and comparability between demand response resources and supply-side resources for Resource Adequacy accounting purposes. I anticipate that compatibility with resource adequacy rules will be considered, along with other relevant factors, in the review of demand response proposals in the forthcoming applications proceedings.[8] In order to inform Commission review of program design compatibility with Resource Adequacy requirements, the utilities' applications shall describe how

[8] A final determination of factors to be considered in the evaluation of the Applications will occur in the Applications proceeding itself; this ruling does not contain an exhaustive list of factors that will be considered, nor does it determine how those factors will be weighed in the future proceeding.

program design conforms with these requirements (particularly those discussed in Subsections 3.2.1 through 3.2.4 below), and maximizes the value of each program under existing Resource Adequacy rules. For proposals that depart from existing Resource Adequacy requirements, utilities shall provide the rationale and analytic support for non-conformance with these requirements.

3.2.1. Demand Response Event Hours

In D.10-06-036, the Commission adopted changes to the hours of measurement for demand response programs for Resource Adequacy purposes. Under current rules, Commission staff measure the capacity of demand response programs using the average estimated (ex-ante) load impacts from 2:00 p.m. - 6:00 p.m.[9] These Resource Adequacy measurement hours do not necessarily determine the hours that a demand response program can operate; a program may operate during different or for additional hours. However, a program that is able to operate during all of the measurement hours will receive the maximum Net Qualifying Capacity, increasing the cost effectiveness of programs compared to those that operate during different hours. D.10-06-036 determined that new measurement hours for demand response programs would go into effect in 2012, and provided that the proposed utility demand response programs for 2012-2014 should incorporate the new Resource Adequacy measurement hours as part of their design.[10] Consistent with this directive, the utilities shall align their

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[9] D.10-06-036, Appendix B at.19.

[10] D.10-06-036 at 44. Starting in 2012, the typical measurement hours for demand response programs will no longer be 2:00 p.m.-6:00 p.m. The new hours will be 4:00 p.m.-9:00 p.m. in November through March, and 1:00 p.m.–6:00 p.m. in April through October.

2012-2014 demand response program hours with the new Resource Adequacy measurement hours adopted in D.10-06-036.

3.2.2. Program Event Lengths and Consecutive Event Days

The current Resource Adequacy Qualifying Capacity counting rules for demand response differ from the rules for all other resources. The rules for demand response activities divide demand response programs into two categories, one for programs with maximum event lengths of up to two hours per call and the other for programs with maximum event lengths of over two hours per call. Programs in the latter category are preferred under the resource adequacy counting system, and currently, nearly all utility-funded demand response programs are in this latter category.

All resources other than demand response must be available to be called for a block of at least four consecutive hours on three consecutive days. Though Demand Response activities are not currently required to meet these availability requirements, the utilities are encouraged to propose (or maintain existing) program terms that would make 2012-2014 demand response programs consistent with these Resource Adequacy availability requirements, to the extent that it is feasible to make demand response programs available for four hours per event on three consecutive days.

3.2.3. Test Event

During a demand response test event, a program is called in the absence of an immediate need to reduce system demand, in order to gather information on the participation, response rate, and load impacts under that program. Currently, some of the utilities' demand response programs do not require any test events, meaning that unless an actual event responding to an immediate system need is called in a particular year, no actual demand response load impact data will be collected for that program in that year. This creates a challenge in estimating load impacts, and can be especially problematic when estimating the megawatts of demand response available for that program for the purpose of counting Resource Adequacy Qualifying Capacity. CAISO now requires new generation resources to run at least one test after coming on-line to provide data for use in estimating the Qualifying Capacity of the new facility. Demand response resources, similarly, should hold at least one event annually in order to maintain consistency with the requirements on other sources of Qualifying Capacity. Starting with the 2012-2014 applications, utilities shall require that every program hold at least one event per year. The event may be either an actual event or a test event; I encourage utilities to propose program terms under which any program that does not have an actual event called by late summer will hold a test event during the peak months of August or September.

3.2.4. Locational Dispatch

Each local capacity area within a utility's service territory has its own Resource Adequacy Qualifying Capacity needs.[11] Each year, the utilities incur costs for transmission and distribution projects to address transmission and distribution overload issues within local capacity areas. These upgrades may be intended to prevent congestion at particular substations and involve particular transmission and distribution lines. Demand response programs that can be dispatched locally to mitigate local capacity constraints could mitigate the need to spend some additional money on transmission and distribution upgrades,

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[11] In the April load impact report, the utilities submit the ex ante load impact by these local areas for the following Resource Adeuqacy year. Currently, there are a total of ten local areas in the utilities' territories: six in PG&E's, three in SCE's, and one in SDG&E's.

giving such programs additional transmission and distribution value beyond the overall capacity value associated with the program.[12]

Because some transmission and distribution costs may be avoided if a demand response program can be dispatched in specific local areas that experience constraints, to the extent possible utilities shall design demand response programs with locational dispatching capabilities in order to capture more value from demand response activities. In addition, to the extent feasible, utilities shall estimate a value associated with these locational dispatch abilities, or qualitatively describe their potential impact in constrained areas in their Applications.

In addition, utilities are encouraged to create programs targeted towards specific transmission facilities and specific contingencies that can be mitigated. Matching demand response programs to specific transmission or distribution contingencies can augment their value, to the extent that the costs of demand response are lower than the costs of specific transmission or distribution projects that would otherwise be needed. To the extent possible, utilities should identify specific contingencies that can be mitigated via specific demand response activities, and inform the Commission as to whether it makes economic sense to develop programs designed to mitigate those contingencies.[13] This might lead to the development of programs dispatched on a very granular basis, such as by substation or distribution circuit.

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[12] This is not the case for SDG&E, because it consists of only one local capacity area.

[13] This concept may be similar to SCE's existing Circuit Saver programs.

3.3. Demand Response Integration with CAISO Wholesale Markets

In D.09-08-027, the Commission required the utilities to report on issues related to demand response integration with the new wholesale electricity market. In particular, OP 24.b provides for an examination of efforts to transition demand response programs into CAISO's new electricity markets. This report is required to include lessons learned from the 2009 Participating Load pilots as well as any experience from Proxy Demand Resource activities in 2010.[14] The report is also required to include:

1) an evaluation of the costs and benefits of integrating all demand response programs into Proxy Demand Resource and/or Participating Load systems developed by CAISO, 2) an assessment of the effect of each demand response program on scarcity pricing, 3) the identification of any barriers to integration with Proxy Demand Response and Participating Load, and 4) suggested next steps on how to address those barriers. D.09-08-027 requires each utility to provide its report by January 31, 2011.[15]

On July 15, 2010, the Federal Energy Regulatory Commission conditionally approved CAISO's Proxy Demand Resource tariff. Because utility participation on this tariff has not yet received final Commission approval or been implemented, there may be little or no actual experience with Proxy Demand Resource activities before the Applications are filed. Phase 4 of Rulemaking (R.) 07-01-041 has been left open for the purpose of addressing some outstanding

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[14] Participating Load and Proxy Demand Resource are electricity products that may be bid in to CAISO's wholesale energy markets.

[15] See D.09-08-027, OP 24(b).

Proxy Demand Resource implementation issues, which are likely to be resolved in early 2011. Though Proxy Demand Resource experience will still be limited when these reports are prepared, the utilities' reports shall provide the transition assessment ordered in D.09-08-027 and will include as much detail in their assessments as possible based on the best information available when the reports are prepared.

3.4. Megawatt Cap on Emergency-Triggered Programs

The Commission initiated Phase 3 of R.07-01-041 to develop policy related to emergency-triggered demand response programs and in particular, on how better to integrate these programs into the wholesale electricity markets. One of the key issues in Phase 3 is whether and how the utilities' emergency-triggered demand response programs will be counted as Resource Adequacy Qualifying Capacity.

As part of the settlement adopted in D.10-06-034, CAISO agreed to initiate the design of a new market product, called the Reliability Demand Response Product, which will enable the utilities' emergency-triggered programs to be bid into the wholesale electricity market. The decision also caps the amount of megawatts from emergency-triggered programs that count toward Resource Adequacy. Specifically, D.10-06-034 adopts caps that are a percentage of total system peak load, and that ratchet downward annually during the 2012 through 2014 period (3% in 2012, 2.5% in 2013, and 2% in 2014). To the extent that emergency-triggered program capacity exceeds the cap, the Commission has discretion over how to treat the oversupply. D.10-06-034 also emphasizes that ratepayer funds should not subsidize emergency-triggered program oversupply.

D.10-06-034 instructs the utilities to address the following issues in their 2012-2014 demand response Applications: (1) how emergency-triggered demand response programs will be integrated with the CAISO's Reliability Demand Response Product (based on the best information available on that new product at the time the applications are prepared), (2) emergency-triggered program marketing efforts, (3) how the utility plans to limit enrollment in emergency-triggered demand response programs so that the cap is not exceeded, and (4) a regulatory mechanism that ensures that Resource Adequacy payments or other ratepayer funds will not subsidize the emergency-triggered programs if an oversupply is determined. In addition, I require the utilities to explore options for limiting enrollment in emergency-triggered programs through innovative methods, which could include a periodic (for example, triennial) auction for participation in BIP or similar programs.

Because ratepayer funds may not subsidize the administrative or incentive costs of excess capacity enrolled emergency triggered programs beyond the cap adopted in a particular year, I expect this proceeding to include the development of a mechanism to identify the potential for over-enrollment and prevent such inappropriate subsidies. As a part of their applications, the utilities may submit proposals for identifying and addressing excess enrollment in emergency-triggered programs and avoiding ratepayer subsidies. To the extent possible, such proposals shall provide a step-by-step narrative with a timeline of all activities needed to determine whether there is an oversupply of emergency-triggered demand response, and to ensure that any such oversupply does not receive ratepayer funding.

3.5. Funding for Integrated Demand Side Management Activities

An April 11, 2008, Joint Assigned Commissioner Ruling (ACR) in R.06-04-010 and R.07-01-041 directed the utilities to propose Integrated Demand

Side Management (IDSM) activities for 2009 through 2011 in a chapter to be included in both the energy efficiency and demand response portfolio Applications filed in summer 2008. The IDSM activities proposed in the integrated chapter received final approval through the energy efficiency proceeding (A.08-07-021 et al.), and received some funding through both the energy efficiency (D.09-09-047) and demand response (D.09-08-027) decisions. The demand response funds for integrated activities were approved through 2011, while the energy efficiency funds for integrated activities were approved through 2012. It makes sense to align the demand response and energy efficiency funding years for IDSM activities, and to consolidate the Commission's review of these integrated activities in one proceeding.

For the 2012-2014 demand response Applications, the utilities are directed to include a request for authority to continue existing integrated activities for one year (2012); funding for the demand response portion of these integrated activities for 2012 will be considered in the Applications. In effect, 2012 will serve as a bridge funding year for integrated activities that were approved in D.09-09-047, with future authority and funding for IDSM activities to be considered in future energy efficiency proceedings, starting with the energy efficiency applications for 2013-2015.

In addition to seeking funding for integrated activities for 2012, the utilities' 2012-2014 demand response Applications should identify the portion of local marketing, education, emerging technologies, and technology incentive audits that are specific to demand response separately from the portions that will be for integrated activities. Activities in these categories that are specific to demand response and are not conducted jointly with energy efficiency programs are not properly considered to be IDSM. For this reason, the utilities shall request funding in the demand response Applications for the full 2012-2014 period for any portions of marketing, education, emerging technologies, and technology incentive audits that only pertain to demand response.

3.6. Other Demand Response Program Considerations

3.6.1. Automated Demand Response and Technology Incentives

Automated demand response (Auto DR) refers to automated technologies that allow a customer's equipment or facilities to reduce electricity usage automatically in response to peak load conditions or high prices without the customer needing to take action. In D.09-08-027, the Commission authorized over $20 million in funding for Auto DR in 2009-2011, but also ordered the Demand Response Measurement and Evaluation Committee (DRMEC) to evaluate Auto DR's load impacts, cost-effectiveness, predictability of load reduction, potential for expansion, and integration with CAISO markets. A report is due to Energy Division by September 30, 2010, and a workshop will be held to solicit input from stakeholders on proposals for the next funding cycle. In addition, the utilities shall include proposals for funding and incorporating Auto DR into demand response programs for the 2012-2014 cycle.[16] The utilities' 2012-2014 Applications should contain Auto DR proposals that have been informed by the evaluation and by party input received at the anticipated workshop or through another means.

The Technology Incentives program is similar to the Auto DR program in that customers are provided a rebate or incentive for installing enabling technology to support demand response. The Technology Incentives budgets

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[16] D.09-08-027 at 93.

that were authorized for all three utilities for 2009-2011 are the largest line items within their respective demand response portfolios. The utilities are directed to identify the benefits of the Technology Incentives programs, including how these programs are enabling demand response, and provide estimates of the cost effectiveness of activities under the Technology Incentives programs.

3.6.2. Permanent Load Shifting

Permanent load shifting refers to shifting energy usage from one time period to another on a recurring basis. Permanent load shifting often involves storing electricity produced during off-peak hours and then using the stored energy to support load during peak periods.[17] Though permanent load shifting is unlike most demand response programs in operating on a regular basis, not just at peak times, it can reduce summer peak demand as much as or more than typical demand response programs can.

Previous Commission decisions approved utility Requests for Proposals (RFPs) to solicit multi-year commitments with third parties for permanent load shifting projects to reduce peak demand.[18] In D.09-08-027, the Commission ordered further study of possible strategies for increasing the availability of Permanent Load Shifting in the future.[19] The utilities' report is due on

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[17] Examples of permanent load shifting technologies include battery storage and thermal energy storage, and altering processes to shift the time of use or order of production activities.

[18] For example, D.09-08-027 authorized approximately $5 million to the utilities to maintain their existing contracts for permanent load shifting activities.

[19] D.09-08-027, OP 32.

December 1, 2010.[20] The utilities' 2012-2014 Applications shall contain proposals to expand the use of permanent load shifting that are informed by the December 2010 study, and should include discussion of the most effective ways to encourage an increase in cost effective permanent load shifting, for example through dynamic rates, future RFPs, or standard offer contracts.[21]

3.6.3. Existing and Possible Future Pilot Programs

D.08-12-038 and D.09-08-027 authorized over $16 million in funding for several pilot projects for the utilities to implement between 2009 and 2011. These pilot programs are a means to gather information, evaluate ideas, and test out new technologies or approaches. The Applications shall contain a discussion of what was learned from the pilots and, in particular, how information gathered in the pilots was used to improve existing or develop new demand response activities. This discussion may be drawn from evaluations or other reports on the pilots, and such evaluations and reports should be made available to the Commission.

As noted in the February 27, 2008, Administrative Law Judge Guidance Ruling, the use of demand response to better integrate intermittent renewable resources is important given the state's goals for its Renewable Portfolio Standard (RPS). The utilities are encouraged to develop ways that demand response can help integrate intermittent load from renewable sources, and to the

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[20] D.09-08-027, OP 32.

[21] For example, if the study determines that there is a large potential for permanent load shifting, the utility proposals should include appropriate efforts to capture that potential.

extent possible, utilities should include specific proposals in their Applications to facilitate integration of renewable energy sources into the California power grid.

To the extent that the utilities seek funding for additional pilots in their 2012-2014 demand response Applications, the utilities shall provide the rationale and objectives of the pilot as well as an information feedback plan to ensure that the pilot is properly evaluated and its results are disseminated and used to inform future program design.

3.7. Load Impact Estimates

In their 2012-2014 Applications, the utilities shall include demand response load impact estimates for each proposed demand response program. The utilities shall provide load impact estimates based on the Load Impact Protocols adopted in D.08-04-050 and modified by D.10-04-006. In addition, in order to allow comparisons with the load impact estimates used in the resource adequacy qualifying capacity calculations for existing demand response activities, the utilities shall also include the most recent Qualifying Capacity numbers made public by Energy Division staff for every program for which such numbers are available.[22]

The Applications should include a narrative summary describing the load impacts of all activities, along with a summary table consistent with D.10-04-006, Appendix 1, reflecting the estimated load impacts for each demand response activity requested. Ex post data for all existing programs should be reported for the most recent year available (2009 or 2010), and the ex ante data should be

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[22] Resource Adequacy Qualifying Capacity numbers for existing demand response programs estimates are available on the Commission's Web site at: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm.

reported for each monthly system peak load day under a 1-in-2 weather year and 50th percentile based on the new DR measurement hours adopted in D.10-06-036.[23]

The utilities' load impact estimates in the 2012-2014 demand response Applications will likely be based on their April 2010 load impact reports (which were based on 2009 ex post data), and because many changes were made to existing programs for summer 2010, the available load impact data may not take into account these recent changes. On April 1, 2011, the utilities will produce their annual demand response load impact report, which will be based on the 2010 ex post data. In order for the Commission to evaluate the demand response load impact and cost effectiveness before approving funding for the next budget cycle, the Commission may (depending on the proceeding schedule) require the utilities to submit revised testimony on load impact and cost effectiveness to reflect the load impact estimates in their April 1, 2011, filings. I encourage the utilities to make their best efforts to use the 2010 ex post data as much possible to avoid the need to submit revised testimony after April 1, 2011.

3.8. Cost-Effectiveness

Phase 1 of R.07-01-041 addresses the development of load impact protocols and cost-effectiveness protocols for demand response programs. As noted above, the Commission has adopted a demand response load impact protocol. The Commission may adopt a cost-effectiveness protocol for demand response resources before the end of 2010, and if a decision is issued before the Applications are filed, I anticipate that it will include instructions on the use of

[23] It is unnecessary to file ex ante for the 1-in-10 Weather Condition.

the new protocol in the 2012-2014 Applications. Until the Commission adopts a cost-effectiveness protocol for demand response resources, the utilities are directed to use the Consensus Framework proposed in this proceeding[24] to generate cost-effectiveness ratios for their 2012-2014 demand response program portfolios. If the Commission adopts a cost effectiveness protocol after the Applications are filed, the utilities may be directed to update their Applications with revised analyses after the Commission adopts a cost-effectiveness protocol.

3.9. Other Demand Response-Related Proceedings

Several Commission proceedings other than these forthcoming Applications also address demand response-related issues.[25] Unless directed by the Commission, however, the utilities should not make proposals in their Applications that duplicate proposals that are under consideration in other proceedings. The Applications should identify and describe efforts to address demand response activities in other proceedings, including those focused on dynamic pricing proposals, in order to ensure that the programs proposed in the

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[24] *Joint Comments Of California Large Energy Consumers Association, Comverge, Inc., Division Of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) and The Utility Reform Network Recommending a Demand Response Cost Effectiveness Evaluation Framework*, filed September 19, 2007 (http://docs.cpuc.ca.gov/efile/CM/75556.pdf). The Consensus Framework was proposed by most parties in Phase 1 of R.07-01-041 and was used by the utilities to generate cost-effectiveness ratios for their 2009-2012 demand response program portfolios.

[25] For example, PG&E has an application seeking modifications to its AC cycling program (A.09-08-018) and SCE recently filed an application (A.10-06-017) seeking to modify its AC cycling program. There are also various dynamic pricing proceedings that are in various stages of review.

Applications can be reviewed and understood in the context of all demand response activities. The utilities' 2012 – 2014 Applications should also provide information on all existing demand-response related activities approved in other proceedings. This information should be comparable to the information provided on demand response activities under review in the Applications, as described in Section 3.10, below, and should include (but not be limited to) enrolled megawatts, expected megawatts for Qualifying Capacity purposes, costs, and funding information.

3.10. Required Program Information and Format

At a minimum, the Applications shall include the following information on each existing program that the utility proposes to continue during the 2012-2014 period, up to the most recent month for which data is available:

1. Budget and actual expenditures for 2009-2011 (annual and total for the three-year period)
2. Enrollment from 2009-2011 (annual and total for the three-year period), including:
   - number of participants,
   - type of participants, and
   - load impact, total and by type of participant.
3. Number of events called by month over the three-year period.

Proposed changes in the programs for 2012-2014 (if any) from existing activities, and reasons for those proposed changes. Consistent with Commission policy, the utilities are expected to propose improvements to existing demand response activities in order to increase the cost effectiveness of those activities and enhance their integration with California electric markets and resource adequacy requirements.

For all programs (existing or new) the Applications shall include the following information:

- Proposed budget,
- trigger mechanism,
- notification timing,
- baseline and other terms for settlement,
- incentive structure and funding,
- marketing and outreach funding,
- administration funding, and
- cost effectiveness and load impact information as described in Sections 3.9 and 3.10 above.

The proposed budgets for the entire portfolio shall be submitted in the format used in Tables 24-1, 24-2, and 24-3 in D.09-08-027. The proposed budgets should be organized according to the program categories that were adopted in the referenced tables, and should include four columns for each program line item: proposed annual funding for the three years (one column for each year) and a final column for the three year total. Additionally, the tables should include a sub-total for each program category for each year, and for the three-year period.

The utilities' Applications and work papers should be well organized in a format that is easy to follow. At minimum, the application should include an executive summary with a list of exhibits and summary tables. To extent feasible, the items in the summary tables should include references to the corresponding exhibits. Each exhibit should also include a table of contents. Utilities shall work with staff in the Commission's Energy Division to develop a reporting format that includes all required information.

IT IS RULED that:

1. The utilities' Applications shall conform with the guidelines outlined in this ruling.
2. To the extent that utilities depart from these guidelines, they must include in their testimony the benefits that are gained from deviations from the requirements described here.
3. All requirements for the 2012-2014 Applications made in previous Commission orders, including any not mentioned in this ruling, still apply.
4. The utilities' Applications shall, at a minimum, contain all program information required in Section 3 above.
5. The Commission's Process Office shall serve a copy of this ruling on the consolidated applications of Application (A.) 08-06-001 (consolidated with A.08-06-002 and A.08-06-003) as well as the service list of Rulemaking 07-01-041.

Dated August 27, 2010, at San Francisco, California.

/s/ JANET A. ECONOME for
Jessica T. Hecht
Administrative Law Judge

INFORMATION REGARDING SERVICE

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Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding and also on A.08-06-001 et al. by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated August 27, 2010, at San Francisco, California.

/s/ GLADYS M. DINGLASAN
Gladys M. Dinglasan

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074 or TDD# (415) 703-2032 five working days in advance of the event.