BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and Practices for advanced metering, demand Response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

ASSIGNED COMMISSIONER'S RULING AND SCOPING MEMO (PHASE 2)

1. Summary

This ruling describes the issues to be considered during the remainder of this proceeding and the timetable for resolution of those issues. Specifically, Phase 2 will address the analysis framework for advanced metering infrastructure deployment. In addition, during the six to nine month period envisioned for Phase 2 (but not necessarily limited to that period), parties will continue to work on development of a Real Time Pricing tariff as well as the resolution of certain ongoing implementation issues carried forward from Phase 1 of this rulemaking.

2. Background

On September 19, 2003, the assigned administrative law judges (ALJs) and I solicited comments from the parties on the proposed scope of Phase 2 of this rulemaking.[1] Under our proposal, Phase 2 would focus on the development of an analysis framework for use in the respondents' business cases for possible widespread advanced metering infrastructure deployment (the so-called "AMI

Business Case"). Respondents would not file their actual business case applications until after this preliminary analytical work had been done. As part of this foundational effort, we proposed that parties also explore two additional matters: 1) revisions to the Standard Practice Manual (SPM) and 2) how air conditioner (AC) cycling can be presented as an alternative in the analysis framework. We also proposed to include within the scope of Phase 2 the continuing efforts to resolve a number of ongoing implementation issues, specifically, completion of a viable real time pricing (RTP) tariff proposal; questions about the scope of agricultural customer participation in demand response programs; whether to adopt the Office of Ratepayer Advocates' (ORA's) revenue shortfall recovery proposal; eliminating barriers to the availability of the Demand Reserves Partnership[2] to Investor-owned Utility (IOU) customers; and miscellaneous metering issues.[3]

On October 6, 2003, the following twelve parties filed responsive comments: the Building Owners and Managers Association (BOMA), the California Consumer Empowerment Alliance (CCEA), the California Farm Bureau Federation (CFBF), the California Large Energy Consumers Association (CLECA), the California Manufacturers & Technology Association (CMTA), the Coalition of California Utility Employees (CUE), ORA, Pacific Gas and

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[1] See *Assigned Commissioner and Administrative Law Judges' Ruling Setting Forth Scope of Phase 2,* issued September 19, 2003 (September 19 Ruling).

[2] The Demand Reserves Partnership program offered under the aegis of the California Consumer Power and Conservation Financing Authority (CPA) was one of four programs approved as demand response offerings for large customers in Decision (D.) 03-06-032.

[3] September 19, Ruling, pp. 3-11.

Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), San Francisco Community Power Cooperative (SF Co-op), Southern California Edison Company (SCE), and the Utility Reform Network (TURN).

3. Parties' Comments on the Issues Posed in the September 19 Ruling

a. AMI Business Case

In general terms, commenting parties supported[4] the idea of working on the analysis framework as a prelude to entertaining the utilities' actual business cases; however some disagreed with details included in the proposed evaluation framework attached to the September 19 ruling[5] and felt it was premature to endorse the Attachment[6] or that an existing PG&E model, if revised in a workshop setting, is a preferable approach.[7] Other parties proposed variations to the analysis framework. For example, ORA proposed that the business case analysis framework be expanded to include a customer-led roll out as an alternative.[8] CCEA suggested that Phase 2 develop the list of costs and benefits (categorized as "short term", "long term", and "out of scope") to be included by the utilities in their advanced metering business case applications, filed after this

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[4] See *San Diego Gas & Electric Company's Comments on Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2*, pp. 1-2.

[5] Establishing the Scope for The Business Case Structure to Evaluate Advanced Metering, Attachment A to the September 19 Ruling.

[6] *Southern California Edison Company's Comments on Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2*, pp. 2-3.

[7] *Comments of Pacific Gas and Electric Company on "Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2*, pp. 4-5.

[8] *Comments of the Office of Ratepayer Advocates on Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2*, p. 3.

OIR has concluded.[9] SF Co-op urged us to be mindful that niche marketing of advanced metering infrastructure in transmission-constrained areas may be preferable to mass meter deployment.[10]

I am resolved that AMI will be the principal focus of our efforts in Phase 2. We will continue to use a working group format to examine AMI from a broad-based perspective,[11] as suggested by CCEA, rather than strictly from the utilities' business case perspective. Because PG&E presented an illustrative business case last year in Working Group (WG) 3, it would be logical to continue the AMI group process in that setting, though AMI efforts obviously affect customers of all sizes. I anticipate that WG 2 will be focused on RFP tariff development, and therefore see WG 3 as the best forum for this work.

Toward this end, I direct the WG 3 moderator to ensure that each interested party be allowed time to present its proposed list of costs and benefits to be included in the AMI analysis at a public workshop. This discussion should include a review of the costs and benefits from three different perspectives – utility (business case), customer, and societal, and must include the costs and benefits described in Appendix A of the September 19 Ruling, as well as a proposal detailing how to measure these costs and benefits. It will be useful to categorize these benefits as short term, long term or out-of-scope as noted above. Thereafter, agency staff will prepare a workshop report. Once the workshop

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9 *Comments of the California Consumer Empowerment Alliance on Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2,* pp. 2-6.

10 *Comments of the San Francisco Community Power Cooperative on Proposed Phase 2,* pp. 1-2.

11 Under this approach, costs and benefits would be categorized as "short term," long-term", and "out-of-scope." *Id.*, pp. 4-6. 5

report is published, interested parties will be asked to file comments on the report, including their recommended list of costs and benefits to be included in the AMI analysis, a brief summary of how they plan to gather or estimate either costs or benefits, and whether they agree with the proposal in Appendix A that each utility should examine three scenarios: expected costs under a business as usual case, a full scale rollout of AMI, and a partial roll out where only a selected fraction of each or some customer classes would receive a meter upgrade.

As noted below, this effort should also address how control technologies, including but not limited to residential A/C cycling, might be complementary to core AMI capabilities and allow various types of demand response programs to be implemented in addition to price responsive tariffs.

At the conclusion of the working group process, the Commission should be in a position to issue a template that will result in the respondent utilities filing applications for authority to implement AMI and recover its costs.[12]

b. SPM Revisions

Those commenting on the merits of revising the SPM as part of the preparation for the utilities' advanced metering business cases were generally cautious, suggesting that the issues are complex and may require hearings to resolve. For example, both PG&E and CLECA noted that the SPM is designed primarily for evaluating energy efficiency programs, and may not be entirely useful for evaluating the cost effectiveness of demand response programs. ORA

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[12] As the September 19 Ruling proposed, respondents will continue to record and track the administrative costs associated with Phase 2, to the extent consistent with the scope of the proceeding outlined in today's ruling, in their Advanced Metering and Demand Response Accounts previously established in Phase 1. The full commission must ratify the reasonableness of these expenses prior to authorizing actual cost recovery.

notes that revisions to the SPM are being considered in the current energy efficiency rulemaking (R.01-08-028) and that it would be wasteful to end up with two different standard practice manuals. Other parties, such as SDG&E and TURN conditionally support the suggestion in the September 19 Ruling that a consultant be retained to revise the SPM, with various caveats. For example, TURN believes that evidentiary hearings may be required to resolve revision-related disputes.

Given the above comments, and our need to keep Phase 2 relatively narrow, I believe that revision of the SPM should not be pursued as part of Phase 2. Instead, we may revisit this issue once the revisions underway in the energy efficiency rulemaking are complete.

c. AC Cycling

The parties' views are divided on the issue of comparing AC cycling with price responsive demand options in the AMI business case. PG&E argues that AC cycling and AMI are not comparable and thus AC cycling should not be evaluated at this point. SCE supports investigating the merits of direct load control alternatives within Phase 2, but is concerned that effort not jeopardize its proposal in the ongoing procurement docket to expand deployment of AC cycling. On the other hand, SDG&E notes the September 19 Ruling asks parties to compare AC cycling technologies that support emergency load shedding programs with AMI technology that supports both dynamic pricing and load shedding programs. SDG&E argues that the issues should not be framed as one of mutually exclusive choices. In SDG&E's view, AC Cycling should be considered as one part of a utility's demand reduction portfolio, and in the interests of program design flexibility, policymakers should ensure that over time AC cycling technologies are compatible with dynamic pricing programs;

thus, value should be placed on technologies that facilitate both policy choices, AC cycling and AMI. ORA also believes that the only viable AC programs are those that support dynamic pricing and load shedding. TURN supports establishing the framework for comparing AC cycling to price responsive demand response programs. CLECA generally supports the Commission's desire to take a direct look at AC load control as a step in the direction of addressing equity issues between those customers with large AC load and those who do not have such peaky load.

In recognition of the arguments of several parties that the technologies that implement these programs should be complements to AMI (rather than substitutes for it), I will include a review of AC cycling options as part of a parallel review of how control technologies interface with AMI.

Specific control technology proposals should not be approved without a clear understanding of how control technologies interface with core AMI capabilities. There are many unresolved issues about the nature and source of a price signal versus a curtailment signal, the protocols for transmitting such a signal, the devices that would receive, interpret and implement a decision rule to curtail a particular type of end-user equipment, etc. all of which should be examined before any further major IOU investments are authorized.

d. RTP Tariff

In general, parties support continuing RTP tariff development. ORA urges immediate development of a RTP tariff with or without a pilot, prior to Summer 2004. However, both ORA and CLECA note that existing rate designs do not support market-based prices, which are necessary for RTP tariffs. Underscoring the complexity of the issue, CMTA urges the Commission not to rush to complete the task of developing a full-scale RTP tariff by Summer 2004, but to take the time to resolve underlying fundamental issues (principally the fact that the actual rates to be contained in the RTP tariff must be linked to the utilities' cost of service) in order to develop a tariff that customers will actually use. In the meantime, CMTA urges consideration of a small scale pilot program roll-out next summer to test customer response to a particular baseline methodology, market price signals, and other design features.

After weighing these various views, I believe that parties in Phase 2 should proceed to develop a full production tariff, even though this may require more time than we have in Phase 2, and may require evidentiary hearings at some point. In other words, parties should view this task of "getting it right" as an ongoing one, not limited by the delineation of Phase 2.[13] Parties should use the WG 2 structure to complete this task, and should remain open to CMTA's idea that a small pilot might still be a worthwhile endeavor while the full tariff development is ongoing, as long as the development of a small pilot does not unduly complicate or hinder the group's progress in developing a full production tariff.

e. Revenue Shortfall Recovery

After reviewing ORA's revenue shortfall recovery proposal in Phase 1, the Commission required the utilities to make proposals for recovering net revenue losses from participation in the voluntary CPP tariff from within the class that caused the losses. Commenting parties are divided on how this should be handled going forward. CCEA urges us to adopt a method of recovering revenue shortfalls in Phase 2 based on these filings. Some parties believe we

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[13] If the matter is not resolved by the end of Phase 2, it can easily be rolled into the subsequent OIR planned to follow Phase 2.

must provide clarity as to where the issue will be resolved: here or in the utilities' general rate cases. ORA, SCE and TURN believe that evidentiary hearings may be needed to address some or all of the revenue shortfall issues associated with the ORA proposal or demand response programs in general. PG&E suggests that we resolve the issue separately from the AMI business case, in order to avoid delaying AMI. SDG&E wants a simpler approach, one that decouples revenue recovery from utility incentives, and is willing to work with all parties to develop a workable incentive program for utilities to recruit and retain customers on demand response programs and tariffs. ORA, the original proponent of the proposal, suggests that the dynamic shortfall discussion be deferred, but that the structural shortfall discussion be completed in Phase 2.

After weighing all of the comments, I conclude that ORA's revenue shortfall proposal should not be pursued in Phase 2. We have much to do in Phase 2 and this particular issue remains somewhat conceptual at this point, given current demand response participation rates; it can be addressed more efficiently in the future. While a future demand response forum effort is appropriate to establish broad policy decisions such as class versus system recovery, the specific mechanics needed to implement such a policy should then be developed in each IOU's general rate case (GRC).

f. CPA DRP

The September 19 ruling noted that there are ongoing implementation difficulties associated with the CPA DRP. Most parties who commented on this aspect of the ruling acknowledge that these issues must be resolved in order to ensure greater demand response participation. I see this as a serious ongoing implementation challenge. To that end, the assigned ALJs will shortly issue a ruling designed to ascertain the precise nature of the obstacles to implementation and thereafter will recommend to the Commission the appropriate actions needed to resolve any outstanding problems.

g. Agricultural Customer Participation

The September 19 ruling noted the need to expand opportunities for additional agricultural customer participation in demand response programs. Not all agricultural customers have interval meters. There is also a significant lag in the deployment of these meters for PG&E agricultural customers, as compared to SDG&E and SCE. There were various comments on these issues, but in general terms, the consensus is that they should be addressed separately, and not as a prime focus of Phase 2. I agree.

Consequently, I have asked the assigned ALJs to continue to develop these issues during Phase 2, independently from the AMI business case. One element of their inquiry will be to determine whether there are any tariffs or versions of CPP that would facilitate the demand response participation of agricultural customers. In addition, the ALJs will issue a ruling shortly that focuses on metering service issues[14]. As part of that effort, they will attempt to resolve outstanding concerns about agricultural customers who lack interval meters.

h. Miscellaneous Metering Issues

The September 19 ruling noted that among ongoing implementation matters, there are several meter "clean up" issues related to implementing the specific programs authorized in D.03-06-032, including:

- ♦ Uniformity in the provision of metering services for those customers with an Assembly Bill (AB) 29 X- equivalent metering system.

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[14] See Section 3.h of this ruling.

- ♦ Installation of AB 29 X equivalent metering systems for new IOU customers added since the AB 29 X conversions that took place between Fall 2001 and Summer 2002.
- ♦ Uniformity in the linkage between the existence of AB 29 X equivalent metering systems and automatic transfer of such bundled service customers to a Time of Use(TOU) rate.

In addressing these meter "clean up" issues in Phase 2, my intent is to make uniform the utility practices regarding who gets RTP metering systems, what costs are charged, and what services are provided to demand response program participants. This is consistent with the Commission's recent action in issuing Resolution E-3835. Resolution E-3835 identifies the demand response rulemaking as the appropriate proceeding to develop a cohesive statewide policy regarding meter installation, cost recovery and TOU rate schedules. Furthermore, I am interested in knowing how customers have responded since the AB 29X meters have been installed, and direct agency staff to begin working with the utilities in gathering and analyzing the appropriate data. Interagency staff will continue to work to obtain the necessary information from the respondent utilities, and following notice and comment procedures (as we have throughout this proceeding), the ALJs will draft the necessary decisional documents at the appropriate time during Phase 2 that will accomplish our goals in this meter "clean up" area.

i. Planning to Achieve 2007 Targets

In its comments CCEA proposes that we add to Phase 2 an element that would estimate 2004 planning and preparation activities needed to meet the interagency 2007 5% demand response goal. CCEA states that utilities should be given the option of proposing a planning and preparation scope for 2004, including budgets, for potential approval in the Phase 2 decision.[15] I believe this exercise could be quite fruitful, as a check on the feasibility of our 5% goal. To begin that effort, I will require each respondent to submit a plan containing its specific 2004 plans for meeting the 5% goal in year 2007; each respondent may also include its post-2004 plans to the extent then known. This plan will be due for filing on March 31, 2004, and should include the respondent's position on the need to modify the existing programs authorized in D.03-06-032 to achieve the 2004 goal, preliminary identification of new programs that may be needed to achieve the full 2007 goal, and any proposed changes in the goal based on initial deployment of programs.

4. The Scope of the Remainder of this proceeding

Consistent with the preceding discussion, the following issues will be addressed in Phase 2:

- Analysis Framework for the AMI Business Case, Utilizing Utility, Customer and Societal Perspectives
- AC Cycling as a Control Technology that Interfaces with AMI Elements
- RTP Tariff Development
- Ongoing Implementation Issues, specifically, resolution of
  (1) CPA/DRP program disputes between DWR and the utilities;
  (2) delineated agricultural customer participation issues; and
  (3) delineated metering service "clean-up" issues.

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[15] *Comments of the California Consumer Empowerment Alliance on Assigned Commissioner and Administrative Law Judge's Ruling Setting Forth Scope of Phase 2*, p 3.

- ♦ A planning process for any near term adjustments in 2004 goals as part of achieving 2007 demand response targets.

5. Phase 2 Timeline and Scheduling Issues

The Commission is required by law to establish reasonable time periods for resolution of its proceedings, not to exceed eighteen months in this instance (Stats. 1996, ch. 856, § 1). In the first scoping memo issued in this proceeding on August 16, 2002, I established the schedule for what became Phase 1 of this rulemaking, culminating in two decisions.[16] We now approach the end of the eighteen-month time period, with much left to do in a multi-year effort to promote demand response. As noted in the September 19 Ruling, in this successor phase we will build on the foundation of Phase 1 and spend the remainder of this proceeding exploring a focused set of issues that are a necessary prelude to longer term demand response development.[17] I anticipate that the Phase 2 issues identified in this scoping memo will be resolved within a period of six to nine months. At the conclusion of Phase 2, the Commission will close this proceeding and issue and scope a new demand response rulemaking to continue its work.

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[16] D.03-03-036 and D.03-06-032.

[17] Consistent AB 1735 (Stats. 2003, ch. 452) effective January 1, 2004, the Commission must resolve the issues raised in a scoping memo within 18 months of the date the scoping memo is issued, except where a longer period is specifically justified and approved by the Assigned Commissioner (Pub. Util. Code § 1701.5 (a) and (b)). This scoping memo, which envisions a closure of R. 02-06-001 sometime in 2004, attempts to adhere to the spirit of applicable case management directives.

Procedural Schedule[18]

1. AMI Business Case Development

♦ Parties' File Proposals on AMI, including Lists Of Costs/Benefits Categorized as "Short Term", "Long Term", and "Out of Scope," and Proposals to Measure Costs/Benefits. Parties also Address AC Cycling as Interface with AMI Elements	December 22, 2003
♦ Workshops (WG 3) to Discuss AMI Proposals	January 2004 – February 2004
♦ Agency Staff Workshop Report	30-days after Workshops End
♦ Parties File Responses	21 Days after Report Released (Projected Submission Date)
♦ Draft Decision Issued	May/June 2004

2. Respondents file plans for achieving 2007 Targets	March 31, 2004
3. RTP Tariff Development (WG 2)	Throughout Phase 2
4. Ongoing Implementation Issues (ALJs)	Throughout Phase 2

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[18] This Procedural Schedule does not include timetables for resolution of ongoing implementation issues related to CPA DRP, agricultural customer participation, and meter service "clean up" issues which will be addressed by the assigned ALJs in individual rulings. Nor does it address the schedule for ongoing RTP tariff development, which will be developed by the WG 2 facilitator in consultation with the parties involved in that effort.

6. Category of Proceeding

There is no change in the category disposition communicated to the parties in the initial Scoping Memo issued August 16, 2002.

7. Need for Evidentiary Hearings

Phase 2 will not require evidentiary hearings, unless they become necessary in the course of developing the RTP tariff. If that occurs, the WG 2 facilitator will advise the assigned ALJs that hearings are required.

8. Designation of Principal Hearing Officer

There is no change in the designated hearing officer determination communicated to the parties in the initial Scoping Memo issued August 16, 2002.

9. Parties and Service List Issues

The current service list for this proceeding is attached to this ruling, and any updates to the service list will be available on the Commission's website (www.cpuc.ca.gov). Those who are not already parties, but who wish to participate in this proceeding as full parties, with all the rights and obligations associated with party status, must make their request by written motion to intervene, or orally on the record during the proceeding. Those not already participating, but who wish to do so as nonparties, may request that their names be added to the service list (in the "information only" or "state service" category) by sending an e-mail note to ALJ Carew (ltc@cpuc.ca.gov).

In all other respects, the Commission will follow the electronic service protocols attached to the OIR as Appendix A.

10. Rules Governing Ex Parte Communications

This proceeding is subject to Pub. Util. Code§ 1701.3(c), which means that ex parte communications are prohibited unless certain statutory requirements are met (see also, Rule 7(c)). An ex parte communication is defined as "any oral or written communication between a decisionmaker and a person with an interest in a matter before the commission concerning substantive, but not procedural issues, that does not occur in a public hearing, workshop, or other public proceeding, or on the official record of the proceeding on the matter." (Pub. Util. Code § 1701.1(c))(4)). Commission rules further define the terms "decisionmaker" and "interested person" and only off-the-record communications between these two entities are "ex parte communications."[19]

By law, oral ex parte communications may be permitted by any commissioner if all interested parties are invited and given not less than three days' notice. If such a meeting is granted to any individual party, all other parties must be granted individual ex parte meetings of a substantially equal period of time and shall be sent a notice at the time the individual request is granted. Written ex parte communications may be permitted provided that copies of the communication are transmitted to all parties on the same day. (Pub. Util. Code § 1701.3(c); Rule 7(c)). In addition to complying with all of the above requirements, parties must report oral and written ex parte communications as specified in Rule 7.1.

IT IS RULED that:

1. The scope of Phase 2 of this proceeding is set forth in Sections 3 and 4 of this ruling.
2. The schedule of this proceeding, including its projected submission date, is set forth in Section 5 of this ruling. The ALJ may make any revisions to this schedule, as necessary to facilitate the efficient management of the proceeding.

[19] See Rules 5(e), 5(f) and 5(h).

3. The categorization and principal hearing officer determination made in the prior scoping memo dated August 16, 2002, remain unchanged.

4. This ratesetting proceeding is subject to Pub. Util. Code § 1701.3(c), meaning that ex parte communications are prohibited unless certain statutory requirements are met. Such communications are also governed by Rule 7(c) and must be reported, as provided in Rule 7.1.

5. The official service list is attached to this ruling, and parties shall follow the electronic service protocols appended to the OIR (Appendix A). Those who are not already parties, but who wish to participate in this proceeding as full parties, shall make their request by written motion to intervene, or orally on the record during the proceeding. Those not already participating, but who wish to do so as nonparties, may request that their names be added to the service list (in the "information only" or "state service" category) by sending an e-mail request to ALJ Carew at ltc@cpuc.ca.gov.

Dated November 24, 2003, at San Francisco, California.

/s/ MICHAEL R. PEEVEY
Michael R. Peevey
Assigned Commissioner

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day, served a true copy of the original attached Assigned Commissioner's Ruling and Scoping Memo (Phase 2) on all parties of record in this proceeding or their attorneys of record.

Dated November 24, 2003, at San Francisco, California.

/s/ KE HUANG
Ke Huang

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 insure 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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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, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.