STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 28, 2004

Agenda ID #4197
Ratesetting

TO: PARTIES OF RECORD IN RULEMAKING 02-06-001

This is the draft decision of Administrative Law Judge (ALJ) Cooke. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the draft decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the draft decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages. Finally, comments must be served separately on the ALJ and the Assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:hl2

Attachment

186421

Decision **DRAFT DECISION OF COMMISSIONER PEEVEY AND ALJ COOKE (Mailed 12/28/2004)**

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)

OPINION APPROVING 2005 DEMAND RESPONSE GOALS, PROGRAMS AND BUDGETS

1. Summary

This decision approves Summer 2005 day-ahead notification demand response programs that focus on providing peak demand reduction driven by day ahead high temperature, price, or demand level forecasts. It also approves reliability-triggered programs that focus on providing 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 power to reduce their bills by driving their load off peak.

2. Procedural History

In Decision (D.) 03-06-032 the Commission adopted specific goals for utility price triggered demand response. That decision specified that the adopted goals were above and beyond any "demand response achieved through the emergency programs authorized in Rulemaking (R.) 00-10-002 (interruptible rulemaking)." (D.03-06-032, p. 8, fn 14.) The **adopted goals** were:

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Year	PG&E	Edison	SDG&E
2003	150 Megawatts (MW)	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

By ruling on June 2, 2004, the Assigned Administrative Law Judge (ALJ) modified the 2004 goals based on program performance as of April 1, 2004. The goals for subsequent years were not modified. The **2004 revised goals** were:

Year	PG&E	SCE	SDG&E
2004	333 MW	141 MW	47 MW

The **2004 enrolled price responsive load** as of July 2004 was:

Year	PG&E	SCE	SDG&E
2004	302 MW	205 MW	24 MW

On October 15, 2004 Pacific Gas and Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) filed proposed programs, budgets, MW goals, and cost recovery proposals for 2005 demand response programs. Some of the proposed programs were for price responsive demand programs, but other proposals were for reliability triggered demand response programs. On October 29, 2004, SDG&E filed additional proposed programs to specifically expand its reliability triggered demand response capability. PG&E, SDG&E, and SCE filed additional programs on

November 15, 2004 and December 1, 2004. All of these proposals will be addressed herein.

Consistent with the goal of meeting 3% of annual system peak load with price responsive demand response programs, D.04-12-048, the decision on utility long term procurement plans, adopted the following **2005 price responsive goals**:

Year	**PG&E**	**SCE**	**SDG&E**
2005	450 MW	628 MW	125 MW

These 2005 goals are subject to adjustment based on a review of whether the utilities utilized consistent annual system peak demand forecasts. In addition, the utilities were required to file additional price responsive programs for 2005 so that the adopted 2005 price responsive demand goals will be met. The incremental programs will be addressed in a subsequent decision, and should focus on day-ahead notification programs as described in today's decision.

3. What is Demand Response?

There are two general types of demand response programs that have been used to reduce demand when energy prices are high or when supplies are tight:

- "price-responsive" programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kilowatt (kW) or Kilowatt-hour (kWh) load reduction incentive), and

- "reliability-triggered" programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, often a commodity price discount).

Both types of programs motivate customers to reduce their loads in exchange for some type of benefit such as reduced energy rates, bill credits, or exemptions from rotating outages. Increasingly the line between these two types of programs has blurred. This blurring occurs because high market price forecasts often coincide with high temperatures and high system or local peak demands, which are two drivers of reliability concerns. When system demand is very high, reserve margins can be low, which puts the ability of the system to serve all the load online at risk in the event of an unexpected generation or transmission outage. When reserve margins fall below acceptable levels, reliability-triggered programs are called upon.

There is not currently a "day ahead market price" established by the California Independent System Operator (ISO), which has limited our ability to offer rates to customers tied to actual market prices or to test a customer's true "price responsiveness" to market prices. Several of the programs the utilities have characterized as price-responsive for 2005 use forecasted temperature or system demand levels to decide when to trigger program operation, rather than a forecasted market price. The "price response" from the customer comes as a result of the utility offering bill credits or other discounts to the customer as a result of reducing its load, rather than the customer responding to a market price or their tariffed electricity rate. Thus the price signal customers are responding to is indirect.

For purposes of this decision, any demand response program that is designed to be triggered the day ahead, whether for price, temperature, or system demand conditions, will be a day-ahead notification program and will count towards meeting the utilities goals for price responsive demand. In contrast, reliability-triggered programs are called on a shorter time frame, the day of, hour of, or as late as 15 minutes before, being needed. It is these programs, designed to truly respond to an emergency conditions, that will be considered "reliability-triggered" programs for today's decision. This delineation is somewhat different than how we, and the utilities, have characterized programs in the past, but helps to clarify the types of programs we are focusing on and why.

In theory, price-responsive programs are called on before reliability programs and serve to reduce system load and the need to call on reliability-triggered programs (historically, the interruptible tariffs). The availability of price-responsive load to reduce demand with a slightly longer lead time (generally the day ahead) is an important tool in meeting day-to-day demand requirements; because they have some lead time notice requirements, day-ahead notification programs are valuable for reducing predictable high peak loads. Reliability-triggered programs, like interruptible rates, have much shorter notice times, and serve as an important tool in mitigating unexpected shortages, local distribution problems, or transmission constraints that could result in system failures.

Every rate schedule provides a price signal that causes a customer to place load on the system consistent with that signal. Although all large customers are currently enrolled on time of use tariffs, the current volumetric Time of Use (TOU) rates for the largest customers do not send a strong signal to reduce load during the peak period because the price differentials between peak and mid-peak periods are low. In addition, the summer peak period is currently applied to a fixed afternoon period from May through September whereas the most critical peak loads are of much shorter duration. Without modifying our rate design, customers will not have strong ongoing price incentives to systematically move their load during critical peak demand periods off of the system. If we truly want to reduce our peak demand, we must modify our rate design to provide a stronger price signal to customers to shift load out of the critical peak. We have begun this process through the joint ALJ/Assigned Commissioner ruling issued on December 8, 2004.

As a result, the day-ahead notification programs that we will approve for 2005 will focus on providing incremental peak demand reduction driven by day ahead high temperature, price, or demand level forecasts. The reliability-triggered programs we will approve for 2005 will focus on providing quick response and targeted locational load reduction capability. We will also carefully review and approve technology and technical assistance programs to automate customer response to demand reduction signals, and education of customers about their power to reduce their bills by driving their load off peak.

4. Policy Issues for 2005 Programs

4.1 Counting MW from Reliability Programs Towards Price Responsive Demand Program Goals

As PG&E points out in its October 15, 2004 filing, "Reliability programs are generally called when "day-of" prices are very high, and price responsive programs are generally implemented in anticipation of these high prices, but on a "day-ahead" basis." (P. 50.) As explained above, we will categorize the MW from any program that provides a day-ahead demand reduction signal, whether it is based on a price, temperature, or reliability forecast, to count towards meeting the utilities' price responsive demand program goals adopted in D.03-06-032 and D.04-12-048. We characterize these programs as day-ahead notification programs. Programs that are triggered the day-of serve a different purpose, to support immediate system reliability, and do not count toward the program goals adopted in the Energy Action Plan, our procurement decision, or D.03-06-032.

4.2 Integrated Demand Side Management (IDSM) Marketing

All three utilities advocate a 'portfolio' approach to marketing and communicating demand response programs, especially to large customers. This involves analyzing a customer's operations to identify demand management opportunities that include conservation, energy efficiency, time of energy use management, demand response, and self-generation. Integrating demand management options can promote multiple gains through one customer investment. The utilities are in various stages of IDSM marketing development. Similarities among the utilities include the use of informational tools such as website where customers can view their usage data and information displays, such as the Energy Orb, that alerts customers of current rate periods and impending demand response events. Among other items, SCE requests funding for collateral material, PG&E would fund account executive training, and SDG&E's includes a building operator certification program to train building operators in energy efficient operation of buildings.

Conceptually, providing customers with an integrated presentation of their energy management options, that addresses demand reduction strategies, energy efficiency, and other options, makes complete sense and is to be encouraged. We approve the concept and encourage the utilities to pursue such an approach. However, the way that the utilities have addressed their efforts to accomplish this effort in their budget requests is not consistent. SDG&E, for example, identifies a category called Customer Awareness, Education, and Outreach ($1.7 million) that includes their integrated demand management efforts. PG&E, on the other hand, states that they are requesting funding to implement the integrated marketing, but no separate budget is requested, instead the costs appear to be incorporated into the budgets for each individual demand response program. SCE, on the other hand, asks for $801,000 for an Energy Efficiency / Demand Response Partnership Demonstration (see Attachment F, October 15, 2004) but that figure does not appear to track back to the discussion in the text of the filing regarding its integration efforts. In comments on the draft decision, the utilities should clarify what the budgets for their IDSM efforts are.

It is not clear from the filings how the utilities plan to integrate the demand response budget into the existing energy efficiencies budgets. They should spell out in detail the incremental costs of adding the proposed demand response activities to existing energy efficiency activities. Two elements of the proposed integration stand out: expansion of customer services to include more in-depth audits that will provide both demand response and energy efficiency benefits and extension of these services to more customers. The utilities should clarify these plans in more detail prior to approval. The integration of demand response equipment incentives with existing energy efficiency incentives should be clarified as well.

4.3 Additional Meter Installations and Costs

In their October 15, 2004 filings, the utilities have pointed out that there is some inconsistency between utilities about installation of interval meters in response to AB1X 29 such that not all customers with loads greater than 200 kW have received meters. The utilities should install interval meters meeting the technical standards of the AB1X 29 meters for all customers with loads greater than 200 kW and place those customers on a time-of-use rate until such time that time of use rates for these customers are replaced with a new default tariff consistent with the December 8, 2004 ruling.

In its proposed budget, SCE requests $354,000 for on-going costs not covered by general rate case revenue requirements for meters installed in 2003 in excess of the 12,000 meters authorized by AB1X 29. Any new meters installed are expected to be recovered as part of SCE's authorized revenue requirement. PG&E does not specify their expected costs to install meters for all customers with demand of 200 kW or greater. D.01-05-032 authorized SDG&E to install interval meters for customers 100 kW and above, and therefore SDG&E does not appear to have this same issue.

D.01-05-032 authorized SDG&E to establish a memorandum account to record all capital and operating costs associated with installing the meters. The same decision allowed SDG&E, after Commission review, to recover in rates the recorded costs associated with the interval meters, less any funding provided by the California Energy Commission pursuant to Senate Bill 1X 5 and Assembly Bill (AB) 1X 29. Cost allocation methodology was to be subject to a subsequent application. This approach is reasonable for all three utilities for recording costs associated with meeting our goal of having interval meters in place for all customers with demand of 200 kW and above. Review of the costs recorded in the memorandum account should be limited to auditing that the amounts recorded were spent on the approved program. SCE should book the costs it identifies as Real Time Energy Meters into this memorandum account. PG&E should identify their expected budget necessary to install meters for all customers with demand 200 kW and greater in their comments on the draft decision.

SCE also proposes that customers over 200 kW, who are required to have a real-time or interval meter installed, be placed on a TOU rate. We agree with this requirement on an interim basis as it is consistent with our directive that the utilities install interval meters for all customers with demand of 200 kW and greater. Installation of interval meters would serve less purpose if customers were not taking service under a time-differentiated rate. When the Commission acts upon the January 20, 2005 rate design applications, customers should then be placed on the new default tariff, instead of the current TOU rate. SCE's current tariffs reference installation of the AB1X 29 meters as a precursor to being placed on TOU rates. SCE proposes to remove all references to AB1X 29 so that all customers over 200 kW are placed on TOU rates and outfitted with an interval meter (if they don't already have one). This change in the tariffs is reasonable, and if PG&E or SDG&E also have comparable language in their tariffs, they are authorized to make the same changes as proposed by SCE.

4.4 Authorized Budget Period

All three utilities recommend that we adopt programs and budgets for their demand response efforts through 2008. They argue that multi-year funding would provide program stability and align the budget cycles for demand response efforts with those of energy efficiency programs which would promote development and delivery of integrated programs and demonstrate stability of program design to potential customers. We agree that multi-year program authorization and funding is desirable, but given the newness of these programs, their lack of track record of demonstrated value to ratepayers, and the uncertainty of advanced metering infrastructure deployment (that will be considered in March 15, 2005 applications) that may affect future customer penetration and program plans, we find that the time is not ripe to adopt programs or associated budgets for 4 years. In this decision we will only adopt programs for 2005. Instead, we direct SCE, SDG&E, and PG&E to file applications for 2006 through 2008 demand response programs on June 1, 2005, the same date they will file 2006 through 2008 energy efficiency applications.

4.5 Budgets and Budget Flexibility

As a preliminary matter, both SDG&E and PG&E provided budgets for both ongoing and incremental costs to implement their current and proposed programs. SCE, on the other hand, only identified an incremental budget to implement the proposed changes to their current programs and fund new programs. In addition, in some cases, it appears that SCE did not reflect customer incentive costs in its budget estimates. For this reason, SCE's budget estimate does not reflect the true cost of the programs for 2005. In its comments on the proposed decision, SCE should present a budget for all programs, as modified herein, that reflect not only incremental costs to serve new customers or provide enhancements to programs, but also reflect the ongoing costs to serve existing customers. Expected customer incentive payments should also be reflected for all programs that include incentives as an element of the program.

The utilities request that remaining budget dollars from the 2003/2004 large customer programs be made available or "carried over" for development of the 2005 programs. They also request the discretion to allocate total budgeted amounts between various demand response programs and their related activities to allow the utilities the flexibility to respond with those programs the market wants most.

The utilities need the flexibility to determine how to allocate demand response funding across the various programs including marketing and many other activities. Because most of these programs are new, to achieve the desired outcome of developing our load reduction capability, we will need to provide flexibility for the utilities to redirect program funds to capture more load reduction capability to successful programs. Approving an overall level of funding and then allowing the utilities the flexibility to manage the allocation of the overall budget will prevent problems associated with over funding or under funding a given area. This approach complements the existing practice of rolling over unused funds to subsequent program years.

We will approve spending flexibility within the following program categories: Day-Ahead Programs, Reliability-Triggered Programs, and all other programs. The utilities should have the flexibility to shift funds between the programs that we approve within each of these broad categories, consistent with SDG&E's recommended fund shifting guidelines. Under SDG&E's proposed guidelines, the utility can shift up to 25% of one program's funds into another program in the same category without prior Commission approval; the load reduction goals for the programs would also shift accordingly. SDG&E proposes that if the budget shift exceeds 25%, and/or the aggregated load reduction goal needs to be changed, the utility should file an Advice Letter (AL) to request that change. We approve these fund shifting guidelines. SDG&E proposes to use the AL process to propose new programs within the authorized budgets. Because we only authorize 2005 programs in this decision, we need not act on this recommendation.

All three utilities must file revised 2005 program budgets and goals as part of their comments on the draft decision to reflect the programs adopted herein. In addition, the utilities should separately identify any remaining funding from 2003/2004 programs that will be carried over, and how they will distribute that funding amongst the various 2005 program categories. In addition, when presenting these budget estimates, each utility should indicate which costs, if any, are already authorized for recovery by identifying the specific ratemaking treatment and citations to that authorizing language. In this way we will be able to clarify the total expected costs of demand response efforts in 2005, as well as which costs have not yet been authorized for recovery.

5. Proposed 2005 Programs

Because the 2005 proposed programs were submitted in several different filings, we take this opportunity to summarize what has been requested.

Table 1
Summary of Existing and Proposed Utility Demand Response Programs for 2005

2005 PROGRAMS	UTILITY	Administration (O&M)	Capital	M&E	Customer Incentives	TOTAL
Day-Ahead Notification Programs						
Demand Bidding Program (DBP)	PG&E	$1,284,000	$250,000	$0	$3,295,000	$6,550,000
Demand Bidding Program (DBP)	SCE	$828,473	$366,000	$172,500	$0	$1,366,973
Demand Bidding Program (DBP)	SDG&E	$552,000	$1,283,000	$35,000	$520,000	$2,390,000
Critical Peak Pricing Program (CPP)	PG&E	$1,436,000	$0	$0	$540,000	$3,447,000
Critical Peak Pricing Program (CPP)	SCE	$149,013	$0	$172,500	$0	$321,513
Critical Peak Pricing Program (CPP)	SDG&E	$374,000	$680,000	$35,000	$0	$1,089,000
CPA Demand Reserves Partnership Program (DRP)	PG&E	$1,221,000	$750,000	$0	$1,120,000	$3,283,000
CPA Demand Reserves Partnership Program (DRP)	SCE	$821,800	$0	$172,500	$0	$994,300
CPA Demand Reserves Partnership Program (DRP)	SDG&E	$320,000	$250,000	$25,000	$0	$595,000
San Francisco Energy Cooperative Pilot Program	PG&E	$1,500,000	$0	$150,000	$850,000	$2,500,000
E-SAVE	PG&E	$793,000	$200,000	$200,000	$85,000	$1,919,000
20/20 for C&I, AG, & Dom - TOU	SCE	$0	$0	$0	$0	$2,000,000
C&I 20/20 Program	SDG&E	$483,000	$0	$50,000	$2,772,000	$3,305,000
Day-Ahead Trigger Programs Subtotal		$9,762,286	$3,779,000	$1,012,500	$9,182,000	$29,760,786
Reliability Day-Of Programs						
Base Interruptible Program (BIP)	PG&E	$601,000	$0	$100,000	$840,000	$1,541,000
Reopen Non-Firm rates E-19/E-20	PG&E	$225,000	$0	$0	$0	$225,000
A/C RFP 1/	PG&E					
Diesel Retrofit "Clean Gen" Program	PG&E	$1,505,000	$0	$200,000	$2,363,000	$4,068,000
Other existing reliability programs	PG&E					
Base Interruptible Program (BIP)	SCE	$500,000	$0	$0	$0	$500,000
Reopen I-6 Large Power Interruptible Program	SCE	$0	$0	$0	$0	$0
Smart Thermostat - small C&I	SCE	$1,100,000	$1,900,000	$0	$2,200,000	$5,200,000
Other existing reliability programs 2/	SCE					$0
Expanded Air Conditioner Cycling Program - res	SCE	$1,300,000	$6,000,000			$7,300,000
Rolling Blackout Reduction Program (RBRP)	SDG&E	$66,000	$0	$5,000	$248,000	$319,000
Demand Bidding Program (DBP-E modified)	SDG&E	$58,000	$0	$10,000	$200,000	$268,000
Base Interruptible Program (BIP)	SDG&E	$83,000	$0	$5,000	$420,000	$508,000
Critical Peak Pricing (CPP-E new)	SDG&E	$71,000	$90,000	$10,000	$0	$171,000
Other existing reliability programs 3/	SDG&E					
Residential Smart Thermostat (modified)	SDG&E	$431,000	$0	$50,000	$360,000	$841,000
Reliability Programs Subtotal		$5,940,000	$7,990,000	$380,000	$6,631,000	$20,941,000

2005 PROGRAMS	UTILITY	Administration (O&M)	Capital	M&E	Customer Incentives	TOTAL
Technology Assistance and Incentives						
Technical Equipment Incentive	SCE	$0	$0	$112,500	$3,000,000	$3,112,500
Technology Incentives	SDG&E	$1,194,000	$0	$10,000	$2,250,000	$3,454,000
Technical Assistance	SDG&E	$1,059,000	$0	$10,000	$0	$1,069,000
Technology Assistance and Incentives Subtotal		$2,253,000	$0	$132,500	$5,250,000	$7,635,500
Education, Awareness & Outreach						
Flex Your Power Now! (FYPN!)	PG&E	$3,130,000	$600,000	$150,000	$0	$3,880,000
Flex Your Power Now! (FYPN!)	SCE	$2,650,000	$0	$125,000	$0	$2,775,000
Flex Your Power Now! (FYPN!)	SDG&E	$558,000	$0	$50,000	$0	$608,000
EE/DR Partnership Demonstration	SCE	$801,000	$0	$0	$0	$801,000
Customer Education, Awareness & Outreach	SDG&E	$1,990,000	$0	$50,000	$0	$2,040,000
Emerging Markets	SDG&E	$343,000	$100,000	$10,000	$0	$453,000
Water District Partnership (Engg Analysis)	SDG&E	$75,000	$0	$0	$0	$75,000
Community Partnerships (Education Awareness)	SDG&E	$225,000	$0	$50,000	$0	$275,000
Circuit Savers (new)	SDG&E	$76,000	$0	$25,000	$0	$101,000
Peak Student Energy Action	SDG&E	$561,000	$0	$0	$0	$561,000
Education, Awareness & Outreach Subtotal		$10,409,000	$700,000	$460,000	$0	$11,569,000
Other Programs						
20/20 Non-TOU - res	PG&E	$6,500,000	$0		$50,000,000	$56,500,000
20/20 Summer Rebate Program -res	SCE	$30,000,000	$0	$0	$40,000,000	$70,000,000
20/20 "Power Pledge" - res and small commercial	SDG&E	$2,175,000	$0	$100,000	$2,200,000	$4,475,000
Real Time Energy Meters (RTEM)	SCE	$354,000	$0	$0	$0	$354,000
Other Programs Subtotal		$39,029,000	$0	$100,000	$92,200,000	$131,329,000
TOTAL		$67,393,286	$12,469,000	$2,085,000	$113,263,000	$201,235,286

1/ PG&E requested protection of the cost estimate for this program because it was in the process of issuing an RFP and negotiating with vendors for implementation. The ALJ did not rule on the motion at that time.
2/ SCE's Other Existing Reliability Programs includes 33MW for C&I ACCP and 26MW for Ag Interruptibles.
3/ SDG&E's Other Existing Reliability Programs includes 31MW for AL-TOU-CP.

2005 PROGRAMS	UTILITY	July '04 MW Baseline	Estimated Incremental MW	Estimated Summer 2005 Total Potential MW	Estimated $/kW
Day-Ahead Notification Programs					
Demand Bidding Program (DBP)	PG&E	102	75	177	$37
Demand Bidding Program (DBP)	SCE	87	33	120	$11
Demand Bidding Program (DBP)	SDG&E	13	27	40	$60
Critical Peak Pricing Program (CPP)	PG&E	17	5	22	$157
Critical Peak Pricing Program (CPP)	SCE	1	4	5	$64
Critical Peak Pricing Program (CPP)	SDG&E	8	12	20	$54
CPA Demand Reserves Partnership Program (DRP)	PG&E	214	20	234	$14
CPA Demand Reserves Partnership Program (DRP)	SCE	117	0	117	$8
CPA Demand Reserves Partnership Program (DRP)	SDG&E	3	0	3	$198
San Francisco Energy Cooperative Pilot Program	PG&E	0	10	10	$250
E-SAVE	PG&E	11	45	56	$34
20/20 for C&I, AG, & Dom - TOU	SCE	30	50	80	$25
C&I 20/20 Program	SDG&E	0	31	31	$107
Day-Ahead Trigger Programs Subtotal		603	312	915	
Reliability Day-Of Programs					
Base Interruptible Program (BIP)	PG&E	0	25	25	$62
Reopen Non-Firm rates E-19/E-20	PG&E	0	20	20	$11
A/C RFP 1/	PG&E	0	20	20	
Diesel Retrofit "Clean Gen" Program	PG&E	0	10	10	$407
Other existing reliability programs	PG&E	330	0	330	
			PG&E Subtotal	405	
Base Interruptible Program (BIP)	SCE	59	20	79	$25
Reopen I-6 Large Power Interruptible Program	SCE	513	5	518	$0
Smart Thermostat - small C&I	SCE	9	6	15	$867
Other existing reliability programs 2/	SCE	59	0	59	
Expanded Air Conditioner Cycling Program - res	SCE	171	43	214	$170
			SCE Subtotal	885	
Rolling Blackout Reduction Program (RBRP)	SDG&E	24	18	42	$18
Demand Bidding Program (DBP-E modified)	SDG&E	0	5	5	$54
Base Interruptible Program (BIP)	SDG&E	0	5	5	$102
Critical Peak Pricing (CPP-E new)	SDG&E	0	10	10	$17
Other existing reliability programs 3/	SDG&E	31	0	31	
Residential Smart Thermostat (modified)	SDG&E	1	2	3	$421
			SDG&E Subtotal	96	
Reliability Programs Subtotal		1,197	189	1,386	

2005 PROGRAMS	UTILITY	July '04 MW Baseline	Estimated Incremental MW	Estimated Summer 2005 Total Potential MW	Estimated $/kW
Technology Assistance and Incentives					
Technical Equipment Incentive	SCE	not available	not available	not available	not available
Technology Incentives	SDG&E	0	10	10	$345
Technical Assistance	SDG&E	0	5	5	$214
Technology Assistance and Incentives Subtotal		0	15	15	
Education, Awareness & Outreach					
Flex Your Power Now! (FYPN!)	PG&E	not available	not available	not available	not available
Flex Your Power Now! (FYPN!)	SCE	not available	not available	not available	not available
Flex Your Power Now! (FYPN!)	SDG&E	not available	not available	not available	not available
EE/DR Partnership Demonstration	SCE	not available	not available	not available	not available
Customer Education, Awareness & Outreach	SDG&E	not available	not available	not available	not available
Emerging Markets	SDG&E	not available	not available	not available	not available
Water District Partnership (Engg Analysis)	SDG&E		N/A		N/A
Community Partnerships (Education Awareness)	SDG&E		N/A		N/A
Circuit Savers (new)	SDG&E		N/A		N/A
Peak Student Energy Action	SDG&E	not available	not available	not available	not available
Education, Awareness & Outreach Subtotal					
Other Programs					
20/20 Non-TOU - res	PG&E	0	200	200	$283
20/20 Summer Rebate Program -res	SCE	0	100	100	$700
20/20 "Power Pledge" - res and small commercial	SDG&E	0	3	3	$1,790
Real Time Energy Meters (RTEM)	SCE	not available	not available	not available	not available
Other Programs Subtotal		0	303	303	
TOTAL		1,800	819	2,619	

(End of Table 1)

5.1 Day-Ahead Notification Programs

We review the current programs that fall into this category and their proposed changes. We provide a brief overview of each program as it is currently structured, identify key changes to the program proposed for 2005, and then address whether the program should be continued, modified as proposed or in some other manner, expanded to customers statewide, or discontinued. We also address proposed new programs that fall into this category.

5.1.1 Critical Peak Pricing (Statewide)

Under the current tariff, participants are charged critical peak energy rates that are five times higher than what they would pay on their otherwise applicable tariff. In return, participants pay lower on-peak and partial-peak rates for the remainder of the summer (or the year for SCE). The critical peak rates are in effect a maximum of 12 times or 'events' during the summer. A critical peak pricing event (CPP event) is triggered when the utility forecasts high market prices, system constraints or high temperatures. The customer is notified at 5:00 p.m. when the next day is a CPP event with the higher rates in effect.

The utilities have proposed various changes to the existing tariff to:

- Adjust the notification time to 3:00 p.m. (PG&E)
- Extend the bill protection option for first-time participants. (SCE, SDG&E, PG&E)
- Extend bill protection for existing participants (PG&E)
- Reinstate one-day notification. (SCE)
- Eliminate the non-coincident demand charge on CPP event days (SDG&E)
- Allow program to be triggered for reliability reasons, such as an ISO day-ahead alert or warning. (SCE)

- Adjust the temperature trigger so that the program is called up to its maximum. (PG&E)
- Increase the CPP rate differentials so that customers can get higher savings (CPP partial peak rises to $1.29 per kWh and CPP peak rate goes up to $1.75 per kWh). (SCE)
- Create a new CPP rate with an emergency feature that requires participants to reduce load on 30 minutes' notice in exchange for higher discounts. (SDG&E - R)
- Reduce participation threshold to all customers with an IDR meter. (SDG&E)
- Allow for four test events for evaluation purposes. (PG&E)

The current program has 26 MW enrolled statewide. With the proposed changes, each utility expects to enroll additional customers, bringing the total enrollment to 47 MW statewide.[1]

On December 8, 2004 the assigned ALJ and Commissioner issued a ruling directing the utilities to file applications to adopt new default tariffs for customers with demand 200 kW and greater that would incorporate a critical peak price signal designed to encourage the same customers targeted by the voluntary CPP tariff to move their usage out of the critical peak periods. Adoption of a new default rate would eliminate the need for continuation of the voluntary CPP rate or the need to make any changes to it. Therefore we do not adopt the Critical Peak Pricing Program for large customers or any associated budget at this time. The current CPP rate should remain in place until a new

[1] SDG&E also proposed to eliminate its Hourly Pricing Option, a rate that varies each hour based on a day-ahead forecast price. No customers are currently enrolled on the rate. We approve SDG&E's request.

default tariff is adopted or the CPP rate is otherwise modified in this or successor proceeding.

5.1.2 Demand Bidding Program (Statewide)

Each utility currently operates a Demand Bidding Program, an optional program, as an overlay on a customer's normal electricity rate. The program provides incremental opportunities for load reduction over what the customer's normal load would be under the tariff. In this program, participants 'bid' the amount of MWs they can reduce on days that the utility needs demand reduction. The utility can call for bids on a day-ahead basis (the compensation is $0.15/kWh) or on a day-of basis (the compensation is $0.50/kWh). The utilities call the program the day-ahead when forecasted market prices are $0.15/kWh or greater. Participants are compensated only for the actual amount of reduction they provide, and they must reduce at least 100 kW per hour to receive compensation. If they bid, but do not perform, there is no penalty.

The current program has 202 MW[2] enrolled. With the proposed changes, each utility expects to enroll additional customers, bringing the total enrollment to 337 MW statewide.

The utilities all propose the following changes:

- Allow Direct Access customers to participate
- Lower the minimum load reduction requirement from 100 kW to either 50 kW (PG&E and SCE) or 10% of load (SDG&E)
- Allow customers with multiple meters/accounts to aggregate their load to participate

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[2] All MW figures reported as "current" are based on reporting as of July 2004, the date by which the utilities were to meet 2004 goals. As of October 2004, the total enrollment for the Demand Bidding Program was 364 MW.

PG&E also proposes to increase the performance payment for day-ahead bids ($0.10 / kWh over the market price forecast, up to $0.35 / kWh, market price forecast thereafter) and lower the threshold price at which the day-ahead program is triggered to $0.08 / kWh. In support of its proposed change to the price trigger, PG&E points out that the day-ahead program price threshold has never been triggered and thus the only test of the program's capability has been under testing conditions rather than true high price conditions. PG&E proposes various other modifications to its day-ahead program to align it with SCE and SDG&E's program or otherwise streamline the program.

SDG&E proposes to modify the eligibility requirement from 200 kW to 20 kW and lower the minimum load reduction requirement to 10% of the customer's maximum monthly demand. SDG&E proposes to add an additional emergency feature to the Demand Bidding Program that calls for load reductions within an hour and pays participants $2.00 / kWh for that reduction. This feature would be triggered when the same trigger conditions in place for the current program occur after 11:00 a.m. on a given day. SDG&E expects that it will achieve another 5 MW of load reduction capability from this new feature.

The proposals to allow direct access customers and multiple meter customers to aggregate their accounts to participate should be approved, as should the request to lower the minimum load reduction threshold. PG&E's minor program modifications make sense in light of the statewide nature of the program and consistency of implementation. SDG&E's proposal to lower its eligibility threshold to customers with 20 kW in load is also reasonable.[3] None of

[3] These customers must have interval meters installed to participate in the program.

these modifications fundamentally change the way the program operates but provide the utilities with the ability to recruit participants from a much broader customer base, and we adopt them.

After reviewing PG&E's request to lower the day-ahead price trigger and reviewing market price data from Summer 2004, we choose instead to modify the day-ahead program trigger to a system condition trigger, rather than a price trigger. Because of the existing long term contracts and requirements for forward contracting, the 2004 electricity market was not particularly robust and prices did not appear to increase, as economic theory would predict, under high system load conditions. Thus, the program was never triggered as a result of the program price in 2004, despite record system load conditions. Because the purpose of the day-ahead Demand Bidding Program is to assist in reducing high load conditions that are anticipated in advance, we will replace the price trigger for all three utilities with a system conditions trigger. When the forecasted reserve margins for the next day would result in the ISO issuing a Stage 1 alert, the utilities should call the Demand Bidding Program. Because this is a voluntary program designed to provide a day-ahead incentive to reduce load on peak, we set this threshold at Stage 1 rather than Stage 2, which can trigger some of the utilities' reliability programs.

We agree that the performance payment for the 2005 day-ahead program should be modified as PG&E proposes to be the market price plus 10 cents, and as further described in PG&E's October 15, 2004 filing.[4] Each utility should adopt this modification. We note that by paying a premium over the market

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[4] Because we have eliminated the price trigger, the payment will have no minimum market price and should instead be based on the day-ahead forecast price plus 10 cents.

price for voluntary load reduction from this program, the program will not be cost effective compared to purchasing from the market. However, because market prices do not reflect certain societal costs (like the economic costs of blackouts) or current transmission system constraints, we do not believe that the market prices right now are reflective of the true value of load reduction. In addition, because of transmission constraints limiting the ability of power to move from north to south, in a high load situation, purchasing from the market may not be an option, and therefore load reduction should be encouraged. Therefore, we will adopt a performance payment that exceeds the market price and therefore is not likely to be cost-effective, based on 2005 system conditions. In the program proposals for subsequent years we will reconsider the performance payment and review cost effectiveness under the system conditions for the relevant years.

The voluntary Demand Bidding Program also contains a day-of aspect, and SDG&E has proposed to add an additional day-of option. Like The Utility Reform Network, we are concerned that because of the voluntary nature of this program, the day of options allow for gaming of demand reduction plans. In addition, because the Demand Bidding Program is voluntary and contains no penalties for non-performance, it does not result in reliable demand reduction for emergency purposes. For these reasons, we will eliminate the day-of component of the Demand Bidding Program, instead, the utilities should encourage customers with discretionary load that can be reduced on short notice to participate in their Base Interruptible Program (BIP) which is further described below.

We note that we have significant concerns about counting on the level of enrolled MW as an accurate judge of the number of MW that can be relied upon to respond. The results when the program was triggered during 2004 (under test conditions) were unimpressive, and do not provide us with comfort that customers will actually perform when notified.[5] Because we have modified the program to only focus on day-ahead system condition forecast triggers, we will count the MW targets towards the day-ahead notification category.

Because of the changes that we have adopted for this program the utilities must file updated budget and MW forecasts for their 2005 program. The updated budgets and goals should be filed in their comments on the draft decision.

5.1.3 Demand Reserves Partnership (Statewide)

Developed under the auspices of the California Power Authority (CPA), the Demand Reserves Partnership is transitioning to be operated by PG&E consistent with D.04-11-034. Aggregators are paid a monthly capacity payment based on the amount of load they can deliver via contracts with bundled and direct access participants. The aggregators are also paid an energy payment for the actual amounts of energy reduced. The program is triggered by the utilities for economic reasons or Department of Water Resources (DWR) for reliability reasons. Although the customers signed up to participate in the Demand Reserves Partnership receive their final notification to drop load the day it is needed, the customers receive a day ahead notification to prepare to reduce their load; therefore, the program fits in the day-ahead notification category. The

[5] Exhibit 7-15 of the evaluation report Working Group 2 Demand Response Program Evaluation- Program Year 2004, prepared by Quantum Consulting, shows the number of bidders out of the enrolled population for 2004 events. For example, on the September 23, 2004 test event in SCE's service territory, 24 customers bid to participate, compared to 492 customers who were enrolled but did not participate.

utilities request funds to continue marketing the program, but no changes. The proposed budgets do not include costs associated with capacity reservation payments, which are paid for out of the DWR revenue requirement. For 2005, the Commission is considering a DWR revenue requirement request of $16.9 million for the Demand Reserves Partnership as part of the revenue requirement that it will adopt in A.00-11-038.

The current program has 334 MW enrolled which is expected to remain constant in 2005, but could increase to 500 MW, depending on PG&E's operation of the program.

The utilities helped fund the initial startup costs for the DRP program, contributing approximately $2.7 million to the effort. The expectation was that by the end of 2004, the program would no longer need utility funding, but instead the funds collected from the DWR would cover all program costs. It appears that the DRP has reached a level of self-sufficiency as it has generated a reserve of about $ 2 million. In fact, according to the CPA's business plan for '05 and '06, the program was anticipated to annually generate more revenues than expenses ($917,000 in 2005 and $1.3 m. in 2006) without further utility assistance, based on projected signups in those years. (D.04-11-034.) For these reasons, it is unclear why the utilities, other than PG&E, require the level of funding for this program in 2005 that is requested. To the extent that the costs are associated with installation of meters to allow customers to participate, additional meter installation costs should be recorded as described in Section 4.3 above. Some administrative costs for each utility are to be expected in order to perform certain duties assigned to the utilities and PG&E may require some additional funding to reflect its increased administrative role for 2005. The utilities should file revised budgets for the DRP to reflect their ongoing responsibilities and the fact that there is a reserve for the program at the CPA. To the extent that it appears the program's reserve is beginning to erode, then the utilities may seek supplemental funding.

5.1.4 Programs Without Enrollment Requirements

In response to direction by the ALJ and Assigned Commissioner to propose 20/20 type programs for customers with interval meters, the utilities have proposed programs with different structures that do not require customer enrollment commitment but operate based on day-ahead temperature or load conditions. We describe each and then discuss them all together.

5.1.4.1 E-SAVE (PG&E)[6]

Currently, participants are paid $0.20/kWh for a 20% reduction in load when the program is triggered. PG&E triggers the program when the day-ahead energy market price exceeds $0.20/kWh for more than 4 hrs. There are no penalties if customers choose to do nothing in response.

PG&E's proposed changes will:

- Eliminate the sign-up form and automatically enroll all PG&E customers over 200 kW with interval meters.
- Enable PG&E to trigger the program more frequently using ISO's day-ahead load forecast (43,000 MW) until the ISO develops a day-ahead market price.
- Lower the minimum threshold from a 20% reduction to 100 kWh annually.

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6 Although PG&E had already proposed E-SAVE for its customers over 200 kW in load, in its December 1, 2004 filing PG&E also proposed a 20/20 program for customers with TOU or interval meters that is the same as that for customers under 200 kW. It is unclear why PG&E proposed both E-SAVE and a 20/20 for the 200 KW and larger customers, so we focus only on PG&E's E-SAVE proposal here.

- Modify the baseline time period from noon to 8:00 p.m. to 12:00 to 6:00 p.m. to be aligned with curtailment period (12:00 to 6:00 p.m.).
- Eliminate tariff language referring to multiple meters since there are no provisions for this.
- Modify the program from year-round to summer only.
- Lower the incentive payment from $0.20/kWh to $0.10/kWh due to proposals to change the baseline, the minimum reduction and trigger points.
- Replace bill credits with an annual check for the incentive.
- Eliminate event notification by email or pager and perform notification via InterAct website.

The current program has 11 MW enrolled for PG&E. With the proposed changes, PG&E expects the total amount of load response to be 56 MW at a cost of approximately $34/kW.

E-SAVE is designed to focus specifically on critical peak periods. As PG&E proposes it be modified, it would be triggered by day-ahead forecasted statewide system demand; therefore it fits into the day-ahead notification category for 2005.[7]

5.1.4.2 20/20 Commercial & Industrial Program (SCE)

During 2004, SCE operated a 20/20 program for commercial and industrial customers, where eligible customers were given a 20% credit on their on-peak energy and demand charges for three summer months if their average on-peak usage per day was 20% less than its usage for the same time period the year before. The program had no trigger.

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[7] PG&E notes that until the ISO has a day ahead market to establish a market price forecast, system demand is a proxy for price.

SCE proposes to make the following changes for 2005:

- Expand program to agricultural and residential TOU customers.
- Reward customers who do not reach the average 20% reduction threshold if reductions are made during designated peak days.
- Allow DA customers to participate

The current program has 30 MW participating.[8] With the proposed changes, SCE anticipates an additional 50 MW of participation, for a total of 80 MWs in 2005.

5.1.4.3 20/20 Commercial and Industrial (C&I) (SDG&E)[9]

SDG&E proposes to target customers with peak demands of at least 20 kW who are not currently enrolled in a demand response program and on a TOU rate or have an interval meter in place.[10] Direct access customers would be eligible to participate. No contracts or commitments would be required and no penalties occur if the customer does not reduce load. Day-ahead notification is given based on three possible triggers: temperature, system peak, and special CAISO alerts. Customers are also given access to kWickview, an online data tool

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[8] SCE is currently evaluating the actual load reduction provided by this program in 2004. This figure is SCE's low end of its current estimate.

[9] SDG&E originally proposed a Voluntary Demand Response Program which they expected would result in about 5 MW of additional load reduction. Under that proposal, SDG&E would assist customers with identifying possible load shedding activities and help quantify reduction levels that could be relied upon during an event. Customers participating in the program would be offered kWickview, free of charge. KWickview is SDG&E's on-line data presentment tool that provides customers and SDG&E with hourly consumption information. These elements have been incorporated into SDG&E's current 20/20 proposal for commercial and industrial customers.

[10] If that customer does not already have an interval meter, one would be provided to them.

to allow customers to view their usage history on the Internet. The program could be triggered a maximum of 15 times over the summer month peak hours. Customers who participate would receive a bill credit of 20% on on-peak energy and demand charges for average load reduction of at least 20% below their baseline[11] usage calculation for *all* events called that month.

5.1.4.4 Discussion

The December 8, 2004 ruling required the utilities to prepare applications for new default tariffs for customer 200 kW and over that would incorporate a critical peak price. For that reason, customers over 200 kW that were originally targeted by PG&E's E-SAVE will already be exposed to a critical peak price from the new default tariffs. Therefore, as we decided with respect to modifications to the CPP rates, we need not adopt a modified E-SAVE at this time. In addition, adopting either an E-SAVE or a 20/20 program for customers 200 kW and over, concurrent with implementation of new default tariffs, would make it impossible to know whether the demand reduction was attributed to the E-SAVE or 20/20 program or the customer responding to the price signals inherent in their default rate.

However, there remains a need for a program to encourage customers under 200 kW with a TOU or interval meter installed to reduce their on peak consumption. Of the programs proposed for customers under 200 kW with TOU or interval meters installed, we find that the program proposed by SDG&E is preferred because it rewards a customer for reducing its usage in only the month

[11] The Customer Baseline will be the customer's average consumption for the three highest days over the immediately preceding 10 similar days prior to the event. The past 10 similar days are the hours of 11:00 a.m. to 6:00 p.m. Monday through Friday.

when peak reduction is required. SDG&E's approach is most effective in targeting demand reduction during on-peak hours on specific days when the temperature or system peak is forecasted to be relatively high. By calling events on a day-ahead basis, the load reduction can be better managed and since SDG&E notifies the customer the day-ahead of the need to reduce load, we anticipate that customers who can reduce their load will participate. This ameliorates the concern that the random variance in a customer's behavior can cause freeridership on a program structured as SCE proposes. Also, bill credits are granted only if the customer achieves a minimum of 20% demand reduction for *all* events called during the billing period. Again, this ensures that only customers with the intention to participate and reduce load will receive the incentive payment. We therefore adopt SDG&E's 20/20 program proposal approach for all three utilities.

We agree that direct access customers should be able to participate, as proposed by SDG&E, through receiving a bill credit on their distribution bill. Customers already participating in other day-ahead programs authorized by today's decision are not eligible to also earn a rebate under 20/20.

Because of the changes that we have adopted for these programs the utilities must file updated budget and MW forecasts for their 2005 program to implement the program we have approved. The updated budgets and goals should be filed in their comments on the draft decision.

5.1.5 Energy Cooperative (PG&E)

In this proposed pilot, limited to San Francisco, participants are organized into a cooperative committed to a certain amount of load reduction. When called, the cooperative would be responsible for reducing its combined load. The program has not been fully developed but as described, it appears that it can be called either day-ahead or to meet short term emergencies. As proposed, the cooperative would receive both capacity and energy payments; capacity payments for committed reduction levels and energy payments for performance. Individual members would receive payment based on their performance. PG&E expects that 10 MW of committed load reduction could be achieved for 2005.

This program is in its infancy in terms of development, with many of the implementation details to be further fleshed out between The Energy Coalition, PG&E's partner in this project, and PG&E. It is targeted at customers who have not participated in demand response programs to this point and utilizes a unique delivery mechanism.[12] As a general matter, we want to promote development of cooperative relationships between customers and organizations with energy management skills, but we are not clear on why this effort needs to be a stand alone program. The existing Demand Bidding Program and Demand Reserves Partnership programs already offer opportunities to bid to provide load reduction or guarantee demand reduction capability. For example, The Energy Coalition could serve as an aggregator, or partner with an existing aggregator, to participate in the Demand Reserves Partnership, which has essentially the same features as described by PG&E for this program. Unless PG&E can explain why this needs to be operated as a stand alone program, we do not authorize it.

5.2 Reliability-Triggered Programs

We review the current programs and the proposed changes by providing a brief overview of each program as it is currently structured, identifying key

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[12] We note that in R.01-08-028, the Energy Efficiency Rulemaking, another cooperative program was authorized in San Francisco.

changes to the program proposed for 2005, and then addressing whether the program should be continued, modified as proposed or in some other manner, expanded to customers statewide or discontinued. We also address proposed new programs in the reliability-triggered category.

5.2.1 CPP-E (SDG&E)

SDG&E proposes a CPP-E rate option for just 2005 for customers who can reduce most or all of their loads on very short notice (15-30 minutes). The program is triggered for either local reliability problems or via alerts from the ISO and can be called up to five times per year, with a maximum of 80 hours per year, six hours per day, four days per week and 40 hours per month. Customers receive a higher alert period price ($3.45 / kWh), with corresponding lower on-peak ($0.07288 / kWh), semi-peak ($0.04886 / kWh) and off-peak ($0.04886 / kWh) prices on non-alert days.[13] SDG&E also proposes that its "Energy Orb" be used in conjunction with the CPP-E as early warning device to give customers advanced notification to make plans to drop load. SDG&E estimated that 10 MW would be available under this program.

Because we directed the utilities to file rate design proposals on January 20, 2005 to consider just this type of rate design, we do not adopt SDG&E's CPP-E at this time but invite SDG&E to build off of this proposal in its January 20, 2005 application.

[13] For comparison the current SDG&E CPP rates: $0.99 and $0.37 per kWh for CPP events, and $0.92 (peak) and $0.68 (semi and off-peak) for non-alert days.

5.2.2 Reopen Existing Non-Firm/Interruptible Rates (PG&E/SCE)

PG&E and SCE each has non-firm or "interruptible" rates where customers designate a certain amount of load they will reduce when called. In return the customer receives a rate discount on all usage, compared to the otherwise applicable rate. The customer is subject to penalties if they fail to reduce their load. These rates are typically triggered when a Stage 2 alert is called by the ISO and have limits on the number of times they can be triggered. Customers typically have 30 minutes to reduce their load. SCE proposes to reopen its interruptible rate to new customers for 2005 only. PG&E proposes to reopen its non-firm rate to new customers without limit. SCE believes an additional 5 MW would enroll on its I-6 rate for 2005 and PG&E believes an additional 20 MW would enroll on its non-firm rates for 2005.

Because we have called for the utilities to file new rate design applications for customers with demands of 200 KW and greater on January 20, 2005, we will not reopen these rates at this time. The ruling that called for the development of new default rates for large customers expressed a preference for reliability programs structured like E-BIP, which provides a capacity payment and performance payment for committed interruptible capability, in conjunction with a default rate that provides for a strong critical peak price signal over a limited period, rather than an interruptible rate as currently structured. We encourage the utilities to think creatively about how the rates for customers currently served under the non-firm and interruptible rates could be restructured to improve load responsiveness the day-ahead and continue to provide short term relief for emergencies, without jeopardizing economic growth. We encourage the utilities to consult with customer representatives as they develop their January 20, 2005 rate design applications.

5.2.3 Base Interruptible Program (BIP) (Statewide)

The BIP is a program that pays participants a monthly incentive to reduce their loads to a pre-determined level when the ISO issues a curtailment notice at any point in time over the course of the year. Customers who enroll commit to make the reduction and substantial penalties apply if the participant fails to reduce their load to the firm service level during a called event.

Each of the utilities has proposed changes to the current program. Examples of utility proposed changes include:

- Lower demand eligibility requirement from 500 kW to 200 kW (SCE);
- Waive the 12-month commitment requirement for new customers who sign up prior to Summer 2005 (SCE);
- Continue notification of one hour but provide a three hour notice option with a lower incentive payment (PG&E);
- Lower the per event penalty level to one-half of the incentive payment level consistent to be more consistent with the penalty level for non-firm rate customers who performed well the year before (PG&E);
- Limit the total penalty for failure to comply to no more than twice the annual incentive (SDG&E, PG&E).

In 2004, only SCE had participants on this program, with 59 MWs enrolled In 2005, with the proposed changes, each utility expects new enrollments to bring their totals load reduction capabilities to 25 MW for PG&E, 79 MW for SCE, and 5 MW for SDG&E.

We agree with the proposed changes to lower SCE's demand level for eligibility, this change makes SCE's program more consistent with PG&E's eligibility requirements. We agree that SCE's recommendation that customers that join for Summer 2005 receive a one time waiver of the one year enrollment requirement, allowing them to opt out of the program in November 2005. If PG&E or SDG&E also implement a 12 month enrollment requirement for their

BIP, they may waive it for customers that enroll between now and Summer 2005. PG&E's proposal to offer a longer lead time option, at a reduced incentive, also has merit as it expands the number of customers who might potentially participate in the program. We approve this option and require SCE and SDG&E to also offer this option to their customers.

We do not adopt the proposed changes to penalty levels proposed by PG&E and SDG&E. Although PG&E is accurate that under its non-firm program, a customer who has regularly complied with curtailment orders the prior year is penalized at a level of $4.20/kWh, a customer who fails to regularly curtail is penalized at $8.40/kWh, much higher than the $6/kWh penalty under the BIP program. Given the lack of demonstrated curtailment follow through of customers on BIP, it makes sense to retain the higher penalty level. For the new three hour notification option, the utilities should utilize a ratio for the payment to penalty price similar that in place for the one hour notification option. PG&E and SDG&E also recommend limiting the total penalty for failure to comply to no more than twice the annual capacity reservation incentive. We decline to adopt this change because it undermines our ability to rely on load reduction from these programs in emergency situations and could promote gaming by customers in their decision whether to curtail.

Because of the changes that we have adopted for these programs the utilities must file updated budget and MW forecasts for their 2005 program to implement the program we have approved. The updated budgets and goals should be filed in their comments on the draft decision.

5.2.4 Load Control, Cycling, Thermostat Programs

The utilities each proposed various load control programs that incorporate different features. Over the course of several filings, the utilities modified or replaced some of the programs originally proposed. For convenience, we describe each of the programs proposed (including those that have been subsequently withdrawn) and then discuss them together. With the exception of SCE's Smart Thermostat program, which is targeted at commercial and industrial customers, all of the programs proposed are focused on residential customers.

5.2.4.1 Advanced Load Control (SCE)

In its October 15, 2004 program plans, SCE proposed an Advanced Load Control (ALC) program to replace its existing Air Conditioning (AC) Cycling program. The ALC program would feature wireless communicating digital thermostats, which provide participants more comfort options than the current AC cycling program. SCE stated that customers prefer to have their temperature settings modified via a thermostat over the current method of cycling their air conditioning units off and on. SCE states that the ALC program can operate off either a price or reliability trigger. SCE classified this program as price responsive because it could incorporate a price trigger. Under the ALC program, customers would retain the option of having their units cycled off completely in exchange for larger incentive payments. SCE proposes that its ALC technology be combined with its existing communication infrastructure for AC cycling so that there are no substantial up front costs. Under this proposal, SCE expects a total of 190 MWs to be available for load reduction. Because the ALC proposal would replace the existing air conditioner cycling program, the incremental increase is 19 MW.

5.2.4.2 Air Conditioning Cycling (SCE)

SCE's current cycling program turns off a participant's air conditioner unit when the utility needs immediate load reductions. Participants receive a bill credit based on the length of time they agree to have their unit 'cycled' off. SCE has 28,500 new participants and a backlog of 5,300 (in 2004) with a total population of 121,800 residential participants. Because the program is triggered in emergency situations, it is considered a reliability program. SCE proposes to expand participation in its current program, instead of pursuing the ALC proposal, by an additional 31,000 to 38,000 customers through the summer of 2005. SCE requested expedited approval for its expanded cycling program and Smart Thermostat programs in Advice Letter (AL) 1840-E.

SCE's current program has 171 MW enrolled. With the proposed expansion, SCE expects to enroll 43 MW of additional customers bringing the 2005 MWs to 214.

5.2.4.3 Air Conditioning Cycling (PG&E)

PG&E is considering a residential/small commercial program where it would employ either smart thermostats or direct load control technology. PG&E could deploy its Air Conditioning Load Control program either as a part of an integrated advanced metering infrastructure system or on a stand-alone basis. For 2005 and 2006, PG&E would implement it as a stand-alone system, and then either maintain or expand the program if PG&E does not deploy an AMI system, or maintain and expand the program by integrating it with its AMI system. PG&E is awaiting the results of a Request for Proposal (RFP) for firm price proposals for supply, installation, operation and maintenance of the program.

5.2.4.4 Commercial Industrial Smart Thermostat (SCE)

SCE currently has a pilot program intended to measure commercial and industrial customer satisfaction with Smart Thermostats. Smart thermostats enable the utility to remotely raise the temperature set points on the thermostat when the utility needs load reductions. Participants on the pilots are allowed to 'override' the utilities' re-setting of the thermostat, but forfeit an amount of the incentive payment they receive.

SCE proposes to expand the Smart Thermostat program to add an additional 5,500 installations from the current 9,000 installed. In addition, SCE proposes to make various changes to the way the program is implemented, including:

- Modifying the trigger from a temperature-based proxy to system reliability or price responsiveness;
- Modifying to a total of 100 hrs. of events, 70 hrs. for reliability and 30 hrs. for economic dispatch;
- Decrease the incentive payments to $100 per year;
- Reduce the deduction for overrides to $5;
- Allow chain accounts to participate;
- Market the Internet programming feature to existing participants;
- Allow 200 kW customers to participate and eliminate the restriction of no more than five thermostats per site;
- Allow two test events that don't count toward incentive payments.

The increase in load reduction capability as a result of the expansion and the program changes is 6 MW, bringing the total reduction from this program to 15 MW.

5.2.4.5 Residential Smart Thermostat (SDG&E)

SDG&E currently has a pilot program intended to measure residential customer satisfaction with Smart Thermostats. Other than the targeted customer class, the features of the program are generally the same as described for SCE's program, the utility can remotely raise the temperature set points on the thermostat to reduce load and participants may 'override' the utilities' re-setting of the thermostat, but forfeit an amount of the incentive payment they would otherwise receive.

Proposed changes by SDG&E would:

- Allow program to be triggered for either ISO Stage 2 alerts, or IOU's peak load trans / distr. Emergencies;
- Decrease the incentive payments;
- Increase the deduction for overrides to $5;
- Reduce the number of events the thermostats are triggered from 20 to 15.

SDG&E's proposed changes are forecasted to increase the available MW from the current 1 MW to 3 MW.

5.2.4.6 Discussion

We have reviewed the proposed load control, cycling, and thermostat program proposals and considered them in the context of our interest in pursuing advanced metering infrastructure deployment and the ability to measure the effectiveness of the programs in achieving demand reduction. In that framework, and given our concerns about Summer 2005 in Southern California, we have decided to focus on expanding the current SCE cycling program, rather than converting to new types of load control efforts, and to focus on improving the program design to current smart thermostat programs rather than expanding them.

SCE's existing air conditioner cycling program results in reliable emergency load reduction, can be targeted geographically, and the marginal cost of installing controllers is fairly small, especially in comparison to SCE's original ALC proposal. For the summer of 2005 these are all highly desirable characteristics. Based on a review of SCE's proposals, we also believe that, although installing additional air conditioner cycling controllers could result in some redundancy if the Commission directs the utilities to deploy an advanced metering infrastructure, the ALC proposal would result in even more potential redundancy or replacement requirements. Direct load control is complementary to small customer TOU and CPP rates because customers will avoid higher or peak prices when their equipment is cycled off. Therefore, we approve SCE's proposal to expand its existing air conditioning cycling program.

The budget information that SCE submitted did not include the expected cost of customer incentives, either for the existing or the expanded program. SCE should include that information in its comments on the draft decision and identify where such costs are already authorized if SCE does not seek funding for customer incentives here. SCE should also identify the number of additional installations of controllers it plans as part of that budget.

PG&E's proposal for its load control efforts is too premature for funding for 2005. Given the timing of its Request for Proposals and the fact that PG&E does not currently have any infrastructure in place to support such a program, in contrast to SCE, and that Summer 2005 demand-supply balance for Northern California is much better than for Southern California, we believe that additional exploration and development of a fleshed out proposal for 2006-2008 programs is warranted. Therefore, we do not authorize funding for PG&E's 2005 cycling/load control program at this time.

SCE requests additional budget to expand its current Smart Thermostat pilot by 5,500 thermostats. SCE has not yet provided any results or analysis of its 2004 program to justify expansion of the program for 2005. We will consider expansion after evaluation results are available. We allow SCE to modify the program to replace the current temperature trigger with a system reliability trigger subject to SCE defining what the specific triggering conditions will be in their comments on the draft decision. We do not adopt a price trigger because of the instability in the current market price and because the focus of this program is to meet day of reliability needs. Because we do not adopt an expanded program or a price trigger, we need not approve the request to allow customers with 200 kW or greater, chain accounts, or those with more than five thermostats per site to participate, nor do we need to allocate the number of hours the program can be triggered between reliability and economic dispatch. We approve SCE's proposals to decrease the incentive payments to $100 per year, reduce the deduction for overrides to $5, allow two test events that don't count toward incentive payments, and market the Internet programming feature to existing participants.

Unlike SCE, SDG&E does not propose to expand its current Smart Thermostat program, but simply to make changes to modify how it is implemented. SDG&E proposes that the utility be allowed to trigger the program not only for ISO Stage 2 alerts, but also when SDG&E experiences localized transmission or distribution emergencies. SDG&E also proposes to decrease the incentive payments, increase the deduction for overrides to $5, and reduce the number of times the thermostats can be triggered under the program from 20 to 15. We approve all of these changes.

5.2.5 Backup Generation Programs

PG&E proposes a new program and SDG&E proposes a modified program as part of their demand response portfolios that rely on shifting load off of the utility system onto backup generation units based on a price or reliability trigger. Both programs are triggered on the day the load is needed, so we characterize them as reliability-triggered programs that do not meet the utilities' price responsive demand goals.

5.2.5.1 Rolling Blackout Reduction Program (SDG&E)

Customers with backup generators are paid for reducing their load on the grid by shifting their loads to their backup generators. Participants must reduce a minimum of 100 kW or 15% of their maximum peak demand (whichever is greater), and are compensated at $0.20 per kWh. The program is triggered when emergencies are imminent, such as an ISO Stage 3 (rolling blackouts) alert. SDG&E proposes to lower the minimum load reduction requirement to 50 kW or 15% of peak demand and to increase the incentive from $0.20/kWh to $0.35/kWh to correspond to increases in diesel fuel costs. In 2004, 24 MWs were enrolled. With the proposed changes, SDG&E expects the total load reduction capability from this program to reach 42 MW.

5.2.5.2 Diesel Retrofit Gen Program (PG&E)

Named "Clean Gen" by PG&E, this program would pay owners of diesel-fueled back-up generators to retrofit their generators with state-of-the-art filtration systems to reduce emissions. In return PG&E may call on these generators for five years during a limited number of hours per year when the day-of price of energy exceeds $0.08 per kWh. PG&E expects to sign up 10 MWs for Summer 2005.

5.2.5.3 Discussion

These two programs are extremely troubling because they are not true demand reduction programs. Instead, they reduce demand on the utility system by shifting load to an onsite generation source. Thus, although they do result in a short term reduction to the grid, there is no net demand reduction occurring as a result of them. SDG&E's program is called only when rolling blackouts are imminent, for example, after a Stage 3 condition is called by the ISO, and results in additional generation being made available to the grid through operation of onsite diesel back up generators. PG&E's proposed program would call on these "clean" diesel units for up to 150 hours, making them available like a peaker plant to serve ongoing demand needs, but also establishes several limitations on ability to participate in order to limit exposure to emissions from the units.

We will approve continuation of SDG&E's program, with the changes proposed, because it is one of SDG&E's few existing reliability programs with any amount of capacity subscribed and because we have significant concerns about the demand and supply balance in Southern California in Summer 2005. However, this type of program, though it may have some value, is not a demand reduction program and in future years should not be funded through the demand response program budgets. In addition, we are troubled that the program relies on diesel generators, one of the dirtiest generation sources available. To the extent that SDG&E seeks to continue to receive ratepayer funding for this program in the future, SDG&E should explain the steps that it has taken to improve the emissions profiles of generators that participate in the program. Because PG&E does not face the same demand and supply imbalance concern for 2005 as the utilities in Southern California, we will not approve PG&E's program because it promotes reliance on diesel generators as part of California's resource mix, in contrast to the Energy Action Plan's loading order preferences.

5.3 Technical and Technology Assistance Incentives (Statewide)

The utilities currently provide technical assistance to customers in the form of energy audits or technical studies to help customers understand how they can best participate in demand response programs. The customer pays for the audit upfront and is provide a rebate for the cost up to $50/kW.

All three utilities propose that the current technical assistance program be replaced by a three-step program (1) a cursory evaluation of DR potential by the utility using 'what-if' analytical tools; (2) if the customer is interested in more, then provide a free in-depth DR audit performed by a consultant; (3) items identified in the audit are eligible for an incentive if the customer signs up for a DR program. Payment of the incentive is capped at $100/kW of verified load reduction. Eligible items include smart thermostats, energy management systems, remote switches, dual-level lighting, software upgrades and addition of control points. Only SDG&E provides an estimate of load reduction capability attributable to this program, at 15 MW.

We will approve the proposed changes to the program to focus on assisting customers both with technical assistance in evaluating their demand response capability and with lowering the cost of enabling technology that should allow them to be able to more effectively reduce their load in response to critical peak price signals that we anticipate will occur under the new default tariff applications that will be filed January 20, 2005. Although this type of program is unlikely to be cost-effective on a stand alone basis, expanded programs to provide this assistance are especially important for 2005 because, with the anticipated conversion to new default tariffs, having incentives available for enabling technology upfront will ease customer transition to new rates and facilitate moving load off the critical peak period. Our objective is to incrementally decrease the technology incentive over time as customers become more accustomed to new default rates. Because all customers will be on new default rates that send critical peak price signals, there is no longer any need to condition receiving the technical/technology incentives on signing up for programs like the Demand Bidding Program.

We do not eliminate the requirement that a California Energy Commission (CEC)-certified consultant perform the study/audit of customer facilities as PG&E proposes. Because the program was not optimally structured in the past, it is unclear whether this requirement is an impediment to participation. Therefore, we will retain the requirement that the survey/audit be performed by a CEC certified consultant. We welcome additional proposals for mechanisms to certify consultants other than by the CEC in order to expand the list of certified consultants.

PG&E's budget for technical and technology incentives is rolled into the Operation and Maintenance (O&M) component of its CPP and Demand Bidding Program. Because we eliminate the requirement that customers enroll in CPP or the Demand Bidding Program to be eligible for the incentives, PG&E needs to separately identify the technical/technology assistance budget when it files revised program budgets and goals in its comments on the draft decision.

We note that SDG&E's proposed budget for this effort is approximately $4.5 million, SCE's is approximately $3.1 million, and PG&E's is approximately $1.0 million. Because of the additional need for these incentives due to the new default tariff and elimination of the CPP or Demand Bidding Program enrollment requirement, we believe that 2005 efforts more in scale with SDG&E's proposed program are appropriate. Therefore, in their comments on the draft decision, the utilities need to update their budgets and, if at all possible, MW goals for the Technical and Technology Assistance Incentives program.

5.4 Education, Awareness and Outreach

In many cases, the utility budgets for education, awareness, and outreach efforts are embedded in specific program budgets. For example, PG&E's budget for Energy Orbs is subsumed in budgets for its CPP and Demand Bidding Programs because of its plan to distribute them as part of the CPP or Demand Bidding Programs, whereas SCE includes costs for Energy Orbs and other outreach efforts in its budget for an Energy Efficiency / Demand Reserve Partnership Demonstration. SDG&E, on the other hand, identified specific stand alone education, awareness, and outreach efforts it would be pursuing that are separate from operation of any particular program. In their comments on the draft decision, the supplemental budget information that the utilities present should separate out the costs for Education, Awareness, and Outreach efforts that are not directly targeted at increasing enrollment in particular programs, as SDG&E has.

The utilities have various customer education and outreach programs that they wish to continue. Included among these programs is participation in the statewide **Flex Your Power Now** campaign. The utilities are requesting additional marketing and customer education tools such as use of websites, display monitors, partnerships with schools and research centers to further demand response understanding and capability. Here we provide a brief overview of each new program proposed for 2005, and then address whether the program should be approved and / or modified in some manner, expanded to customers statewide or not approved.

5.4.1 Flex Your Power Now (Statewide – existing)

All three utilities participated in 2004 in an existing statewide marketing campaign targeted to all customers using radio, print, website, email, and various written material to encourage customers to reduce demand, and how to reduce demand, on days when supply is particularly tight. The program is operated by the Department of Consumer Affairs. Between the three utilities they propose to contribute an additional $7.3 million to expand the effort for 2005 and include demand response messaging.[14] There are no estimates on potential MW savings in 2004 or for 2005 because attribution of demand response to media campaigns is difficult and very expensive.

Especially in light of the new default tariffs that will send a strong critical peak signal, educating customers about the new rates and implications is increasingly important. Some of the budget approved today should be directed towards messages to reflect new default rates and concerns about reliability for Summer 2005, in addition to the messaging efforts already planned. The proposed budgets by each utility for this program are approved.

5.4.2 PEAK Student Energy Action Program (SDG&E)

PEAK, operated by the Energy Coalition, is an existing program in other states where students learn about energy efficiency, conservation and demand response. SDG&E proposes to bring the program to San Diego schools through 2008, engaging a total of 6,000 students in that time. SCE has a similar proposal where PEAK students participate in a demand response 'experiment' with volunteer households in the development stage. It is unclear from SDG&E's filing whether it proposes funding this program solely from its demand response

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14 A total of $4.3 million was authorized from demand response budgets in response to utility ALs filed in June 2004.

budget or whether its proposal is incremental to funding already authorized in its energy efficiency programs.

As we have described above, we support the efforts of the utilities to educate and inform their customers about energy efficiency and demand response capabilities in an integrated fashion. As such, any program targeting students should also utilize a shared budget and approach. We will not authorize a standalone PEAK program but approve the concept for further exploration in the context of the utilities IDSM efforts.

5.4.3 Community Partnership Program (SDG&E)

SDG&E proposes a customer education program focused on local cities, schools, government / military facilities, as well as business, trade, and chamber organizations designed to educate and facilitate participation in load reduction programs. SDG&E proposes to broaden the awareness of demand responsive programs by specifically targeting small and medium business customers with monthly demands under 100 kW. Although SCE does not propose a separate program, it identifies similar efforts as part of its Energy Efficiency / Demand Response Partnership Demonstration.

SDG&E's program should be approved. We believe that each utility should implement a similar type of integrated energy usage education program targeted at small and medium business customers. The utilities should identify what portions of their previously filed budgets are targeted at these customers, and if they were not targeted, the utilities should propose a budget in their comments on the draft decision.

5.4.4 Circuit Saver Program (SDG&E)

The Circuit Saver program is designed to inform and educate customers who are on the top 20 highly loaded electric distribution circuits regarding reliability programs that are available to them to help reduce load on these circuits during summer peak periods. The program prioritizes the application of demand response technologies and programs to those circuits or areas that are experiencing high equipment loading or that experience higher than normal energy usage during peak conditions.

We find this concept intriguing and approve it for SDG&E. We find it particularly appealing for Summer 2005 because of our concern about meeting peak demand. We are unclear whether this is a feasible approach for SCE or PG&E given the size of their service territories, but encourage them to investigate the concept for their 2006-2008 program plans.

5.4.5 Emerging Markets Program (SDG&E)

The Emerging Markets Program, as described by SDG&E, is a new effort where utilities will participate in and co-sponsor demand response research through local, statewide and national studies and technology pilots. This research will assist in developing new programs and demand response technology. The utilities should dedicate a portion of their budgets to research. We approve this program described by SDG&E and direct SCE and PG&E to propose budgets in their comments on the draft decision for this purpose as well.

5.5 Other Programs

Programs addressed here do not fall easily into any of the categories already covered: Day-Ahead Triggered, Reliability-Triggered, Technology and Assistance Incentives, or Education, Awareness and Outreach.

5.5.1 Residential 20/20 Program (Statewide)

In the November 5, 2004 ACR, the Commission directed the utilities to file programs similar to the 2001/2002 residential and small commercial 20/20 program, but to address certain drawbacks of the earlier programs. In response, each utility has proposed a slightly different program structure. PG&E and SCE propose fairly similar structures that incorporate automatic enrollment, eligibility for all customers below 200 kW that do not have TOU or interval meters, with a few exceptions. To receive the 20% bill credit, the customer must show a 20% or greater reduction in average daily energy usage over the four-month billing period of June through September, as compared with the same period in 2004. PG&E would require the customer to have been at the same location for the 12 previous months and for the four billing cycle months, whereas SCE would allow customers to earn a rebate if they establish service prior to June 1, 2005. SCE would show the monthly level of reduction on the customer's monthly bill but only provide a credit if they reach the 20% reduction for the entire summer period. SCE clarifies that the 20% rebate would apply to the aggregated summer bills, excluding state and utility user taxes. PG&E forecasts potential MW to be 200 MW, SCE forecasts 100 MW.

Unlike PG&E and SCE, SDG&E's "Power Pledge" would require eligible customers (residential and small commercial bundled service customers with peak demands 20kW) to sign a "Power Pledge" to be eligible to earn a monthly bill credit of $5 for residential and $20 for small commercial customers if they demonstrate at least a 5% load reduction; customers that meet the 20% load reduction will get the higher of the 20/20 credit or the $5/$20 incentive. As part of its proposed program, SDG&E will contact customers the day before and on the day-of to notify them of the temperature or system peak trigger events. SDG&E forecasts 3 MW of potential.

SDG&E's program is designed to try to address the fact it is impossible to determine whether customers reduced their usage during a critical peak event unless that customer has an interval meter. However, even though SDG&E's

program incorporates personalized notification to customers, because the participants still do not have interval meters, it is impossible to tell whether their reduction in usage is the result of being notified or normal variation. Therefore, we prefer a program structured like PG&E (and SCE) has proposed. The improvements made by PG&E and SCE to have the credit be paid only if average daily usage goes down by 20% over the entire course of the summer address our concerns over free-ridership. We direct SDG&E to file a budget and associated MW potential consistent with this program design in its comments on the draft decision.

We note that although PG&E and SCE's programs have very similar designs, they have very different administrative costs. We cannot determine why SCE's administrative costs are five times higher than those of PG&E for a comparable size program. SCE should explain this difference in its comments on the proposed decision but we indicate now that we are unlikely to approve such a significant portion of the program costs going to administration.

6. Ratemaking Treatment

PG&E proposes that all of the costs associated with its programs be recorded in its Advanced Metering and Demand Response Account (AMDRA) and recovered annually through an AL filing requesting recovery, with one exception.[15] PG&E proposes that any customer bill credits paid under the residential 20/20 program be reflected in PG&E's Utility Generation Balancing

[15] PG&E proposed that incremental administrative costs associated with reopening its non-firm rates be recorded in its Procurement Energy Efficiency Balancing Account, with capital costs booked to AMDRA. Because we do not approve reopening these rates, we need not approve this proposal.

Account (UGBA). PG&E requests that cost recovery review of the amounts recorded in AMDRA and UGBA be limited to auditing that the amounts were spent on the approved programs, with no reasonableness review regarding implementation of the programs. After approval of AMDRA balances occurs (presumably after audit), PG&E would transfer the approved AMDRA balance to its Distribution Revenue Adjustment Mechanism (DRAM) for rate recovery. PG&E does not currently have a provision in its AMDRA to recover capital costs, although both SDG&E and SCE do, so PG&E asks to conform its AMDRA language to provide for recovery of capital costs.[16] PG&E's cost recovery proposal is reasonable with the clarification that our limitation on review of the amounts recorded in UGBA is specific to PG&E's costs associated with its residential 20/20 program and is not intended to supersede any review required of non-demand response costs recorded in the UGBA.

SCE currently records costs for demand response programs in several different memo accounts. To simplify cost recovery, SCE proposes to establish a Demand Response Program Balancing Account (DRPBA) effective January 1, 2005 to consolidate the ratemaking for all programs. SCE would record all costs, except incentive costs, in the DRPBA. SCE proposes that in this proceeding the Commission adopt a specific 2005 Demand Response Program Revenue Requirement (excluding incentive and capital costs, grossed up for Franchise Fees and Uncollectibles to be recorded in the DRPBA, and ultimately,

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[16] On October 15, 2004, PG&E filed AL 2569-E to implement the proposed changes with respect to the capital cost recovery and to seek approval of the balance in AMDRA as of October 15, 2004 for rate recovery. Energy Division is currently reviewing the costs recorded in AMDRA and, assuming their review finds that the amounts recorded were spent on the approved programs, we expect they will approve AL 2569-E.

in SCE's distribution rate levels.[17] SCE proposes that the operation of the DRPBA be reviewed and audited annually in its Energy Resource Recovery Account (ERRA) Reasonableness proceeding.[18] SCE proposes that any implementation costs from and credits paid under its Summer 2005 20/20 rebate program be reflected in SCE's ERRA.

We agree with SCE that only one account is necessary to accurately record and track costs associated with demand response programs, with the exception of 20/20 program costs; however, we prefer the approach PG&E has utilized of recording costs in a memorandum account and then transferring them upon approval into a balancing account for cost recovery. SCE should record its demand response program costs in its Advanced Metering and Demand Response Memorandum Account (AMDRMA), with the exception of 20/20 program costs, which should be recorded in the ERRA. In each annual ERRA proceeding, the AMDRMA should be audited and approved amounts should be consolidated with other approved revenue requirement changes for reflection in distribution rates.

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[17] SCE states it "will not be necessary to include the Demand Response Program incentive payments in the operation of the DRPBA since the reduction in SCE's Distribution revenue due to the incentives provided to customers will be recovered in distribution rates from other customers." (SCE 10/15/04 filing, p. 79.) We do not understand this statement and direct SCE to identify the expected customer incentive costs and the specific funding source for payment of those incentives if they are already funded, as directed elsewhere in this decision.

[18] SCE stated that the funding mechanism for reopening its I-6 rate and funding those incentives was already in place and incremental administrative costs would be small. Because we do not approve reopening this rate, we need not address cost recovery.

SDG&E currently records all program costs associated with its CPP, DBP, HPO, and DRP programs in its AMDRMA. For 2005 programs, SDG&E proposes that O&M and capital expenditures and any customer capacity incentives, for programs it characterized as price responsive, be recorded in its AMDRMA, with energy incentive payments recorded in its ERRA. For reliability triggered programs, SDG&E proposes the creation of a new account, the Reliability Demand Response Programs Memorandum Account. SDG&E would record O&M, Capital, and capacity incentives in that account, with energy incentives recorded in the ERRA. In all cases, the approved recorded amounts would be transferred annually to SDG&E's Rewards and Penalties Balancing Account (RPBA) for amortization into distribution rates. We find SDG&E's approach to generally be reasonable but see no reason to create a new memorandum account to record costs associated with reliability triggered programs, independent of its pre-existing AMDRMA.

To the extent that any of the utilities need to modify the language of their AMDRA (PG&E) or AMDRMA (SCE and SDG&E) accounts to allow for recording a broader set of program costs, they should file an AL to implement this provision within 10 days of the effective date of this decision. Capacity incentive costs should be recorded in these accounts, with energy incentive costs recorded in PG&E's UGBA or SCE and SDG&E's ERRA accounts. Each utility should annually seek approval of the recorded amounts, subject to audit that the funds were spent on approved programs, and transfer the approved amounts to their appropriate ratemaking account (DRAM for PG&E, ERRA for SCE, and RPBA for SDG&E) for rate recovery.

7. Reporting, Measurement, and Evaluation

7.1 Reporting

The utilities currently provide monthly reports on both their interruptible and price-triggered programs to Energy Division and the service lists for R.02-06-001 and R.00-10-002. Because the reports are served on two different service lists and SCE provides two different reports, there is confusion about what reports to rely on. The reports reflect monthly expenses, accounts enrolled, MW forecasts, and details concerning the events called, if any. Because the monthly reports reflect the 'upper bound' in terms of potential demand response, the MWs in the monthly reports are inaccurate, and at worst, misleading for planning and forecast purposes. For example, DBP MWs included in the reports assume every participant will bid when called, and will bid 15% of their average on-peak demand. Based on the program evaluation information to date, this result is unlikely. To be useful for planning purposes, the reports need to be modified to reflect a more realistic MW value for all the programs going forward.

Therefore, we direct the utilities to meet with CEC and Energy Division staff to determine alternative ways of reporting MWs and any other data that misstates load reduction capability or may be inaccurate. SCE should also only prepare one report (like the other two utilities). We recognize that while demand response programs are still fairly new and relatively untested, there is a tension between efforts to reach the day-ahead notification program MW goals, and realistic MWs for planning purposes. For now, we direct the utilities to, at a minimum, include both figures, demand response potential and expected/actual demand reduction when called, in their reports. This will allow us to better assess how to reflect these programs in future long term procurement plans.

7.2 Measurement and Evaluation

The utilities propose a joint utility measurement and evaluation (M&E) program similar to what is currently in place, with a focus on assessing marketing and implementation, surveys of participants and non-participants, and determining load impacts of the programs. The utilities propose evaluating the following programs: CPP, DBP, CPA DRP, Technical Assistance and Incentives, Integrated Demand Side Management and the FYPN Campaign. SDG&E proposes M&E for its interruptible programs as well. The utilities also propose an annual summary report (due the 1st quarter of the following year).

Although SDG&E was the only utility to propose evaluation of its interruptible program for load impacts, the time appears ripe to do a more comprehensive analysis of reliability-triggered programs in 2005 so that we can readily compare the costs and benefits between programs. The evaluation of the programs will only be useful to the extent that the programs are triggered. Given the relatively few times the programs were triggered in 2004, the evaluation findings and conclusions have several caveats and disclaimers, making the M&E effort somewhat limited in its usefulness. As a result, we will authorize funding for process and impact evaluation of both reliability and day-ahead triggered programs but direct the utilities to work with Energy Division and CEC staff to identify which specific programs would provide the most useful analytical information based on how frequently the programs are triggered. We approve the general scope of proposed M&E activities, but direct the utilities to identify revised budgets to remove M&E for programs that were not approved, and to augment funding, if needed based on the changes we have made to various programs.

8. Comments on Draft Decision

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Section 311(g)(1) of the Public Utilities Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____.

9. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Michelle Cooke is the assigned ALJ in this proceeding.

Findings of Fact

1. D.04-12-048 adopted **2005 price responsive goals** of 450 MW for PG&E, 628 MW for SCE, and 125 MW for SDG&E.

2. Day-ahead notification programs are valuable for reducing predictable high peak loads.

3. Reliability-triggered programs, with shorter notification periods, serve as an important tool in mitigating unexpected shortages that could result in system failure.

4. Providing customers with an integrated presentation of their energy management options, addressing demand reduction strategies, energy efficiency, and other options will assist customers in making the best decisions about how to more effectively manage their energy requirements.

5. Recording capital and operating costs associated with meeting our goal of having interval meters in place for all customers with demand of 200 kW and greater in a memorandum account if these costs are not already authorized as part of the utility's authorized revenue requirement is reasonable.

6. Multi-year funding of demand response programs is desirable, but, given the lack of track record of demonstrated value to ratepayers, should not be authorized for the 2005 program year.

7. Approving an overall level of funding and allowing the utilities the flexibility to manage the allocation of the overall budget will prevent problems associated with over funding or under funding a particular program.

8. Adoption of a new default tariff will eliminate the need for continuation of a voluntary CPP rate.

9. No customers are currently enrolled in SDG&E's Hourly Pricing Option.

10. The minor modifications proposed to the DBP and expanded eligibility requirements improve consistency of this statewide program across service territories and expand the customers that can be recruited to participate.

11. Prices in the 2004 electricity market generally did not increase under high system load conditions because of the extent of forward contracting in the current market.

12. The market price threshold for triggering the DBP was never reached in 2004.

13. Paying a premium over the market price for voluntary load reduction from the DBP will make the program less cost effective, compared to purchasing from the market.

14. The Demand Reserves Partnership program is triggered by utilities for economic reasons or by DWR for reliability reasons.

15. The utilities helped fund the initial startup costs for the DRP programs, contributing approximately $2.7 million, with the expectation that by the end of 2004 the program would no longer need utility funding.

16. The CPA business plan for 2005 and 2006 anticipates generating more revenues than expenses for the DRP.

17. Adoption of a new default tariff will eliminate the need for PG&E's E-SAVE, SDG&E's CPP-E, or a 20/20 program for customers with demand of 200 kW or greater or reopening SCE's I-6 or PG&E's non-firm rates.

18. There remains a need for a program to encourage customers under 200 kW in demand with a TOU or interval meter in place to reduce their on peak consumption.

19. SDG&E's approach to a 20/20 program for customers between 20 and 200 kW is most effective by targeting demand reduction during on-peak hours on specific days when temperature or system peak is forecasted to be relatively high.

20. Development of cooperative relationships between customers and organizations with energy management skills should be promoted.

21. PG&E's proposal to offer a three-hour lead time option in its BIP expands the number of customers who might be willing to participate in the program.

22. There is a lack of demonstrated curtailment experience under the BIP program.

23. SCE's existing air conditioner cycling program results in reliable emergency load reduction, and can be targeted geographically at a fairly low marginal cost.

24. Installing additional air conditioner cycling controllers could result in some redundancy if the Commission directs the utilities to deploy an advanced metering infrastructure, but SCE's original ALC proposal would result in even more redundancy or replacement requirements.

25. SDG&E's Rolling Blackout Reduction Program and PG&E's Diesel Retrofit Generation Program reduce demand on the utility system by shifting load to onsite generation.

26. The Rolling Blackout Reduction Program is one of SDG&E's few existing reliability programs with subscribed capacity.

27. Focusing on providing customers with both technical assistance in evaluating their demand response capability and with lowering the cost of enabling technology will allow customers to more effectively reduce their load in response to critical peak price signals.

28. Although technical and technology assistance programs are unlikely to be cost-effective on a standalone basis, expanded programs of this nature are especially important in 2005 because of the anticipated conversion to new default rates that include a critical peak price.

29. Research pursued as part of the Emerging Markets Program will assist in developing new programs and demand response technology.

30. The improvements to the 20/20 residential program payment methodology address our concerns over free-ridership of the program.

31. SCE's residential 20/20 administrative costs are five times higher than those of PG&E for a comparable size program.

32. Evaluation of reliability-triggered programs will allow us to more readily compare the costs and benefits between programs, but the evaluation of demand response programs will only be useful to the extent that the programs are triggered.

Conclusions of Law

1. Any demand response program that is designed to be triggered the day ahead, whether for price, temperature, or system demand conditions, should count towards meeting the utilities goals for price responsive demand.

2. The utilities should install interval meters for all customers with loads 200 kW and greater and place those customers on time differentiated rates.

3. Any utility whose current tariff language references installation of an AB1X 29 meter as a requirement for being placed on a TOU rate should modify that language to simply require installation of an interval meter.

4. We should approve spending flexibility, consistent with SDG&E's recommended fund shifting guidelines, within the following program categories: Day-Ahead Notification Programs, Reliability-Triggered Programs, and all other programs.

5. The current CPP rate should remain in place until a new default tariff is adopted or the CPP rate is otherwise modified in this or successor proceeding.

6. Allowing direct access customers and multiple meter customers to participate in the DBP facilitates additional customer enrollment in the program.

7. Allowing SDG&E customers with demand 20 kW or greater who have interval meters installed to participate in the DBP facilitates additional customer enrollment in the program.

8. The price trigger for the DBP should be replaced by a system conditions trigger.

9. Because current market prices do not reflect existing transmission system constraints, the utilities should pay day-ahead DBP customers the market price plus 10 cents for load reduction when system conditions would result in a Stage 1 call the day-ahead.

10. Because the DBP is voluntary, it does not result in reliable demand reduction for emergency purposes and therefore the day-of provisions of the program should be cancelled.

11. Based on the current reserve in the DRP program, the utilities should no longer be required to fund operating costs for the DRP.

12. SDG&E's 20/20 program for customers between 20 and 200 kW ensures that only customers with the intention to participate and reduce load will receive the incentive payment.

13. In order to expand participation in the program, direct access customers should be able to participate in the 20/20 program for customers between 20 and 200 kW, through receiving a credit on their distribution bill.

14. The existing DBP and DRP programs already offer opportunities to bid to provide load reduction or guarantee demand reduction capability, but it is unclear whether a stand alone program like the Energy Cooperative is needed.

15. The one year enrollment requirement for BIP programs should be waived for 2005.

16. All three utilities should offer a three-hour notification option for their BIP program.

17. Adopting PG&E's proposed change to the BIP non-performance penalty could undermine our ability to rely on load reduction from the program.

18. SCE's expanded air conditioner cycling program should be approved.

19. SCE has not yet provided any results or analysis of its 2004 Commercial and Industrial Smart Thermostat program to justify expansion, but the proposals to modify the incentive payment, reduce the deduction for overrides, allow two test events that do not count towards the incentive payment and expanded marketing of the internet programming feature should be approved.

20. SDG&E should modify the incentive payments and deduction for overrides, and reduce the number of times its residential Smart Thermostat program can be triggered.

21. Because of our concerns about Southern California supply-demand balance for 2005, SDG&E's Rolling Blackout Reduction Program modifications should be approved.

22. Although the Rolling Blackout Reduction Program may have some value, it is not a true demand reduction program and should not be funded through the demand response program budgets after 2005.

23. Because it promotes reliance on diesel generators as part of California's resource mix and Northern California does not face the same demand and supply imbalance problem in 2005 a Southern California, we should not approve PG&E's Diesel Retrofit Generation Program

24. Because of the additional need for technical and technology assistance due to new default rates and the elimination of the CPP or DBP enrollment requirement, program funding in scale with SDG&E's proposed program is appropriate.

25. The utility proposed budgets for Flex Your Power Now! should be approved and some portion of that funding should be directed toward messages about the new default rates for Summer 2005.

26. Education programs targeting students should utilize a shared budget and information approach consistent with the utilities' IDSM efforts.

27. SDG&E's Community Partnership Program should be approved, and SCE and PG&E should implement a similar type of integrated energy usage education program targeted at small and medium business customers.

28. SDG&E's Circuit Saver Program should be approved to assist in meeting peak demand concerns for Summer 2005.

29. The utilities should dedicate some portion of their budgets to research.

30. A residential 20/20 program structured like PG&E proposes is preferred to the SDG&E Power Pledge approach.

31. PG&E's cost recovery proposal is reasonable with the clarification that our limitation on review of the amounts recorded in UGBA is specific to PG&E's residential 20/20 program costs.

32. After review of recorded amounts, PG&E should annually transfer the approved recorded amounts to its DRAM for rate recovery.

33. SCE should record its demand response program costs in its AMDRA, with the exception of 20/20 programs costs, which should be recorded in its ERRA.

34. In SCE's annual ERRA proceeding, its AMDRMA should be audited and approved amounts should be consolidated with other approved revenue requirement changes for reflection in distribution rates.

35. SDG&E's cost recovery proposal is generally reasonable, but it should record costs associated with reliability-triggered programs in its pre-existing AMDRMA.

36. After review of recorded amounts, SDG&E should annually transfer the approved recorded amounts to its Rewards and Penalties Balancing Account for amortization into distribution rates.

37. We should authorize funding for process and impact evaluation of both reliability and day-ahead triggered programs but direct the utilities to work with Energy Division and CEC staff to identify which programs will provide the most useful analytical information based on how frequently the programs are triggered.

O R D E R

IT IS ORDERED that:

1. The following programs are approved for implementation by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) in 2005, as described herein:

- Day-Ahead Notification Programs
  - Statewide DBP;
  - Statewide Demand Reserve Partnership; and
  - Statewide 20/20 Program for Commercial/Industrial Customers between 20 and 200 kW with interval or time-of-use meters, structured as proposed by SDG&E.
- Reliability-Triggered Programs
  - Statewide Base Interruptible Program;
  - SCE's Air Conditioner Cycling Program Expansion;
  - SCE's Commercial/Industrial Smart Thermostat Program (without expansion);
  - SDG&E's Residential Smart Thermostat Program (without expansion);
- Statewide Technical and Technology Assistance Programs (as modified herein)
- Statewide Customer Education, Awareness, and Outreach
  - Flex Your Power Now!
  - Community Partnership Program
  - Emerging Markets
- Utility Specific Customer Education, Awareness, and Outreach
  - Circuit Saver Program (SDG&E)
- Other Programs

- Statewide 20/20 Residential Program, structured as proposed by PG&E

2. SDG&E's Hourly Pricing Option rate is terminated.

3. SCE, SDG&E, and PG&E shall file 2006-2008 demand response program plans on June 1, 2005, concurrent with their 2006-2008 energy efficiency applications.

4. The utilities may shift funds within the following program categories--Day-Ahead Notification Programs, Reliability-Triggered Programs, and all other programs—without additional authorizations provided that the shift does not exceed 25% of one program's funds and/or change the aggregated load reduction goal.

5. SCE and PG&E shall explore whether SDG&E's Circuit Saver Program could be applied to their service territories and include such a program, if appropriate, in their 2006-2008 program plans.

6. The utilities shall meet with staff from the California Energy Commission and Energy Division to identify alternative ways of reporting load reduction capability of demand response programs.

7. SCE shall prepare one combined report on demand response and reliability-triggered programs, consistent with the approach taken by PG&E and SDG&E.

8. When reporting on demand response programs, the utilities shall report both demand response potential and expected/actual demand reduction when the program is called.

9. The utilities shall work with Energy Division and California Energy Commission staff to identify specific measurement and evaluation activities within the general scope proposed.

10. The utilities shall file ALs to implement the modifications to existing programs, new programs, and cost recovery provisions of this decision, as necessary, within 10 days of the effective date of this decision.

This order is effective today.

Dated ___________, at San Francisco, California.