Pacific Gas and Electric Company

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415.973.7226

February 21, 2013

Advice 4192-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> Modify Capacity Bidding Program and Demand Bidding Program for Locational Dispatch, and Establish Capacity Bidding Program Withdraw Form

Purpose

The purpose of this Advice Letter is to seek authorization to modify the Capacity Bidding Program (CBP) and the Demand Bidding Program (DBP) to support locational dispatch, and to establish a form for customers to withdraw from the CBP.

Background

In Ordering Paragraph 10 of Decision 12-06-025, dated June 21, 2012, the California Public Utility Commission (CPUC or Commission) stated the following:

> Pacific Gas and Electric Company's Aggregator Managed Program [1], Capacity Bidding Program and Demand Bidding Program shall be counted for Resource Adequacy in the 2013 Resource Adequacy compliance year. These programs must be locally dispatchable by May 1, 2013.

As discussed below, there are several aspects of both CBP and DBP that limit their ability to support locational dispatch. This advice is intended to modify these programs to support locational dispatch.

In a related matter, PG&E filed Advice Letters 4061-E[2] on June 14, 2012, and 4164-E[3] on December 14, 2012. These Advice Letters, filed pursuant to Ordering Paragraphs 44 and 50 of Decision (D.) 12-04-045, seek CPUC authorization to continue the DBP and CBP.

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[1] PG&E's Aggregator Managed Portfolio Agreements, which was approved in D.13-01-024, dated January 24, 2013, included a locational dispatch component.
[2] Advice Letter 4061-E was rejected by the Energy Division on November 15, 2012.
[3] Advice Letter 4164-E is pending.

Tariff Revisions

PG&E is proposing the following changes to the DBP tariff:

Location Based Triggers

The current DBP tariff has triggers that are primarily designed to operate at a system level. Additional triggers are needed to implement locational dispatch.

The current DBP tariff states that an event can be called under any one of the following conditions:

- California Independent System Operation (CAISO)'s day-ahead load forecast exceeds 43,000 MW
- CAISO issues an Alert Notice
- PG&E, in its sole opinion, forecasts that resources may not be adequate

PG&E is proposing to add a temperature based trigger that is specific to each load zone and to modify one existing trigger to support locational dispatch for electric system constraints. With these changes, DBP will have the following triggers:

- California Independent System Operation (CAISO)'s day-ahead load forecast exceeds 43,000 MW
- The CAISO issues an Alert notice or is expected to issue a Warning or higher level notice for the following[4] day
- The forecasted temperature for a Load Zone exceeds the temperature threshold for that Load Zone
- PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate

Participants Utilizing Auto Demand Response

Many DBP participants utilize Auto Demand Response (AutoDR) to implement their program participation[5]. PG&E is concerned that many of these AutoDR participants implemented their business and IT processes with the assumption that all of their sites will be included in each DBP event and that these participants will require time beyond May 1, 2013, to make the necessary changes. Further, PG&E prefers to modify the AutoDR technology for all participants at the same time, so PG&E is proposing to assign the existing and new AutoDR DBP participants to a system-level zone.

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[4] PG&E is proposing this change to clarify that a DBP event can also be called when the CAISO expects to issue a Warning or higher level notice for the following day.

[5] AutoDR is a sophisticated control system that automatically manages all aspects of a DR event for a participant.

Elimination of the Aggregated Group Option for New Participants

Under certain restrictions[6], the DBP tariff allows customers with sites that do not meet the minimum load requirements to associate these sites with one larger site that individually meets the DBP eligibility requirements. The sites can be distributed throughout PG&E's electric service territory. 's current DBP aggregation model does not support locational dispatch.

PG&E proposes to eliminate the aggregated group option for all new participants. Eliminating the aggregated group option (combined with the lowered eligible demands and minimum bids discussed below) makes the DBP less complicated for customers with demands between 50 and 200 kW.

Current participants with this option will be able to continue with their existing grouped sites which will be assigned to a system-level zone.

Lowering the Minimum Eligible Demand and the Minimum Bid

Eliminating the Aggregated Group option makes DBP available to fewer customers. To counter this, PG&E is proposing to lower both the minimum eligible demand and minimum bid. This change would more than mitigate the elimination of the Aggregated Groups by making the proposed DBP available to a larger set of customers than the current DBP.

According to the current DBP tariff, eligible customers must have had a maximum demand equal to or greater than 200 kW within the past 12 billing months. PG&E is proposing to lower this value to 50 kW. The minimum hourly load reduction is currently 50 kW. PG&E is proposing to lower this value to 10 kW.

Continuing to Utilize PG&E's SmartMeter Infrastructure

Under the current DBP, select[7] customers receive an interval meter at no cost that is used to calculate baselines, performance, and incentive payments. PG&E has been utilizing both its SmartMeter and traditional interval meter infrastructure for these customers. The proposed tariff makes the SmartMeter the preferred metering device for those customers with demands less than 200 kW.

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[6] All sites in the group must have the same federal tax identification number, and each site must have a maximum demand greater than or equal to 50 kW to receive an interval meter at no cost.

[7] Includes bundled service, community choice aggregation service, and direct access customers where PG&E is acting as the Meter Data Management Agent with a maximum demand of 200 kW or greater for at least one month in the past 12 billing months. Also includes customers participating in an aggregated group.

Additional DBP Tariff Changes

In addition to the changes necessary to support locational dispatch, PG&E made DBP tariff changes to eliminate the four hour maximum duration for test events, to add Aggregated Managed Portfolio as one of the DR programs for dual participation, to clarify language, and to eliminate language that is no longer applicable.

PG&E is proposing the following changes to the CBP tariff.

Adding Load Zone as a Component of CBP's Monthly Nominations

The CBP is based on a monthly capacity nomination as submitted by the aggregator. This nomination becomes the basis for all capacity payments, events, post event capacity penalties, and energy payments.

The current CBP states that an aggregator's monthly nomination must be grouped into the following categories:

- Option (Day-Ahead or Day-Of)
- Day-Of Adjustment Election
- Product
- Bundled/Direct Access

Adapting CBP for locational dispatch[8] will require that the monthly nominations also be grouped by Load Zone.

Location Based Triggers

Like DBP, the current CBP tariff has triggers that are primarily designed to operate at a system level. The current CBP tariff states that an event can be called under any one of the following conditions:

- PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the day-ahead[9] market
- When PG&E receives a market award or dispatch instruction from the CAISO for a Proxy Demand Response bid
- When PG&E, in its sole opinion, forecasts that resources may not be adequate

[8] The initial CBP had a locational component that was based on the CAISO's Congestion Zone (NP-15 or ZP-26). See Advice 2839-E-A, filed October 30, 2006.
[9] The CBP Day-Of Option has a similar set of triggers except the heat rate is applicable for the real-time market.

PG&E is proposing to add a temperature based trigger that is specific to each load zone and to modify one existing trigger to support locational dispatch for electric system constraints. With these changes, CBP will have the following triggers:

- PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the day-ahead market
- PG&E receives a market award or dispatch instruction from the CAISO for a Proxy Demand Response bid
- PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate
- Forecasted temperature for a Load Zone exceeds the temperature threshold for the Load Zone

Except as discussed below, each CBP participant will be assigned to a Load Zone. A participant's assigned Load Zone can change over time, and PG&E will provide notice to the Aggregator. All changes to a participant's Load Zone will occur at the end of a calendar month to correspond with CBP's monthly nominations.

Participants Utilizing Auto Demand Response

Like DBP, many CBP participants utilize Auto Demand Response (AutoDR) to implement their program participation.[10] PG&E is concerned that many of these AutoDR participants implemented their business and IT processes with the assumption that all of their sites would be part of the same nomination, and that these participants will require time beyond May 1, 2013, to make the necessary changes. Further, PG&E prefers to modify the AutoDR technology for all participants at the same time, so PG&E is proposing to assign the existing and new AutoDR CBP participants to a system-level zone.

Continuing to Utilize PG&E's SmartMeter Infrastructure

Under the current CBP, select[11] customers receive an interval meter at no cost. PG&E has been utilizing both its SmartMeter and traditional interval meter infrastructure for these customers. The proposed tariff makes the SmartMeter the preferred metering device for those customers with demands less than 200 kW.

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[10] AutoDR is a sophisticated control system that automatically manages all aspects of a DR event for a participant.

[11] Includes bundled service, community choice aggregation service, and direct access customers where PG&E is acting as the Meter Data Management Agent with a maximum demand of 200 kW or greater for three consecutive months in the past 12 billing months.

Additional CBP Tariff Changes

As part of its "APPLICATION FOR APPROVAL OF AGGREGATOR MANAGED DEMAND RESPONSE AGREEMENTS (Application 12-09-004),"[12] PG&E included a form that allows an Aggregator Managed Program (AMP) participant to inform PG&E of its desire to no longer be associated with a specific aggregator. The proposed CBP tariff includes a new "ELECTION TO WITHDRAW FROM THE CAPACITY BIDDING PROGRAM FORM (Form 79-1149)," that provides CBP participants the same option. Additional changes are proposed to clarify language and to eliminate language that is no longer applicable.

Next Steps

PG&E plans to work with the AutoDR participants and systems to allow for locational dispatch.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than March 13, 2013, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Brian K. Cherry
Vice President, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

[12] Filed September 7, 2012. Approved in D.13-01-024 on January 24, 2013.

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Rule 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Rule 3.11).

Effective Date

PG&E requests that this Tier 2 advice filing be approved concurrent with Advice 4164-E no later than March 23, 2013, which is 30 calendar days after the date of this filing. PG&E further requests that the effective date of the tariff changes May 1, 2013.

Notice

In accordance with General Order 96-B, Rule 4, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and parties on the service lists for A.11-03-001 and R.07-01-041. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs

Brian Cherry /sw

Vice President, Regulatory Relations

Attachments

cc: Service Lists A.11-03-001 and R.07-01-041

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. Pacific Gas and Electric Company (ID U39 E)

Utility type:	Contact Person: Shirley Wong
ELC ffi GAS	Phone #: (415) 972-5505
PLC HEAT WATER	E-mail: slwb@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 4192-E Tier: 2

Subject of AL: Modify Capacity Bidding Program (CBP) and Demand Bidding Program (DBP) for Locational Dispatch Locational Dispatch, and Establish Capacity Bidding Program Withdraw Form

Keywords (choose from CPUC listing): Direct Access, Form, Text Changes, Capacity, Compliance

AL filing type: Monthly Quarterly Annual One-Time Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.12-06-025

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for:

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information:

Resolution Required? Yes No

Requested effective date: May 1, 2013, concurrent with Advice 4164-E No. of tariff sheets: 23

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Electric Schedules E-CBP and E-DBP, and Form 79-1149 – Election to Withdraw From the Capacity Bidding Program.

Service affected and changes proposed: Modify the Capacity and Demand Bidding Programs to support locational dispatch, and establish Form 79-1149 – Election to Withdraw From the Capacity Bidding Program.

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
ED Tariff Unit
505 Van Ness Ave., 4th Floor
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry, Vice President, Regulatory Relations
P.O. Box 770000, Mail Code B10C
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

ATTACHMENT 1
Advice 4192-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
32463-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 1	31622-E
32464-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 3	31534-E
32465-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 4	29926-E
32466-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 8	29539-E
32467-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 9	29540-E
32468-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 10	29541-E
32469-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 11	29927-E
32470-E	ELECTRIC SCHEDULE E-CBP CAPACITY BIDDING PROGRAM Sheet 12	29543-E
32471-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 1	27278-E
32472-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 2	27279-E
32473-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 3	29524-E
32474-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 4	29967-E

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
32475-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 5	29526-E
32476-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 6	29968-E
32477-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 7	28629-E
32478-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 8	28630-E
32479-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 9	29969-E
32480-E	ELECTRIC SCHEDULE E-DBP DEMAND BIDDING PROGRAM Sheet 10	29527-E
32481-E	ELECTRIC SAMPLE FORM 79-1149 ELECTION TO WITHDRAW FROM THE CAPACITY BIDDING PROGRAM FORM Sheet 1	
32482-E	ELECTRIC TABLE OF CONTENTS Sheet 1	32456-E
32483-E	ELECTRIC TABLE OF CONTENTS RATE SCHEDULES Sheet 9	31624-E
32484-E	ELECTRIC TABLE OF CONTENTS SAMPLE FORMS Sheet 31	32436-E

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

APPLICABILITY: The Capacity Bidding Program (CBP) is a voluntary demand response program that offers customers incentives for reducing energy consumption when requested by PG&E. Schedule E-CBP is available to PG&E customers receiving bundled service, Community Choice Aggregation (CCA) service, or Direct Access (DA) service and being billed on a PG&E commercial, industrial, or agricultural electric rate schedule. An eligible customer must continue to take service under the provisions of its otherwise applicable schedule (OAS). (T)

TERRITORY: This schedule is available throughout PG&E's electric service area.

ELIGIBILITY: A customer may participate in either the DayAhead or Day-Of option. A customer with multiple service agreements (SA) may nominate demand reductions from a single SA to either the Day-of option or Day-ahead option. A SA may not be nominated to both the Day-of and Day-ahead option during a single program month.

Customers that receive electric power from third parties (other than through direct access and Community Choice Aggregation) and customers billed for standby service are not eligible for Schedule E-CBP. Eligible customers include those receiving partial standby service or services pursuant to one or more of the Net Energy Metering Service schedules except NEMCCSF. (T)

A customer may only enroll in Schedule E-CBP through an Aggregator. An Aggregator is an entity, appointed by a customer, to act on behalf of said customer with respect to all aspects of Schedule E-CBP, including but not limited to: (1) the receipt of notices from PG&E under this program; (2) the receipt of incentive payments from PG&E under this program; and (3) the payment of penalties to PG&E under this program. (T)

Customers on Schedule E-CBP are limited to the following participation options in other demand response programs and rate offerings. Schedule E-CBP customers using the "Day-Ahead" option may also participate in PG&E's E-OBMC program. Schedule E-CBP customers using the "Day-Of" program option can also participate in PG&E's E-DBP or E-SLRP programs. Schedule E-CBP customers using the Day-Of program option may also participate in a PG&E peak day pricing (PDP) offering, where those utilizing the "Day-Ahead" trigger may not. (T)

Aggregators and customers participating in Schedule E-CBP must comply with the terms of this schedule and associated agreements. (T)

SUBSCRIPTION LIMIT: PG&E reserves the right to limit the subscription amount available to participate in Schedule E-CBP, consistent with Commission guidelines. (T)

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

AGGREGATOR'S PORTFOLIO: An Aggregator must submit a Notice to Add or Delete Customers Participating in the Capacity Bidding Program (Form 79-1075) to add a customer's Service Agreements (SAs) to add or delete a customer's SAs from its portfolio. PG&E will review and approve each SA before the SA can be included in an Aggregator's portfolio. Additions to the portfolio will be effective upon PG&E's approval date. Deletions from the portfolio will be effective at the end of the current calendar month in which this notice is received provided PG&E receives this notice at least 15 calendar days prior to the end of the current month. A SA can be included in only one portfolio at a time.

PG&E will assign each CBP customer to a Load Zone. As specified below, the assigned Load Zone will be either a PG&E system-level Load Zone or a PG&E subsystem-level Load Zone, which is referred to as a Load Zone. (N)

Existing AutoDR CBP customers shall be assigned to a PG&E system-level Load Zone. Existing non-AutoDR CBP customers will be assigned to a Load Zone.

New AutoDR CBP customers shall be assigned to a PG&E system-level Load Zone. New non-AutoDR CBP customers will be assigned to a Load Zone.

The CBP customer's assigned Load Zone may change over time. PG&E will provide notice of the Load Zone change to the current Aggregator. The effective date of the change must occur at the end of a calendar month.

Customers participating in Schedule E- CBP can submit an Election To Withdraw (Form 79-1149) to initiate the process to be removed from Schedule E- CBP. Customers electing this option may not join another Portfolio in any of PG&E's Aggregator programs, which includes Schedule E- CBP program and the Aggregator Managed Program (AMP) for the remainder of the DR Season, i.e. the calendar months of May through October.

Election of Customer to withdraw from the Aggregator's Portfolio shall be effective and binding at the end of the then current calendar month in which PG&E received this form identifying the Service Agreement(s) to which the Customer withdrawal applies; provided PG&E receives the form at least fifteen (15) calendar days prior to the end of the then current month. If PG&E receives the form less than fifteen (15) calendar days prior to the end of the then current month, then Customer's withdrawal from Aggregators Portfolio will be effective the following month. (N)

CUSTOMER SPECIFIC ENERGY BASELINE: To participate in this program, a customer must have a valid customer specific energy baseline (CSEB) at least 5 calendar days prior to the first day of the operating month.

CSEB will be valid for purposes of participation if there are at least ten (10) similar days of interval data available in PG&E's CBP Website.

Each Capacity Nomination will have its own CSEB based on its associated aggregated group. The CSEB on any given day during the program is the sum total of each individual SA's baseline in the group. Each individual SA baseline is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this program, or any other interruptible or curtailment programs enrolled by the customer, or days when a rotating outage was called). (T)

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

CUSTOMER SPECIFIC ENERGY BASELINE: (Cont'd.)

The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment will be limited to +/- 40% of each individual SA baseline in the group, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more than one event (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the individual SA's events that day requiring a day-of adjustment. (L)

The hourly load profile on any given day during the program is determined by summing the hour by hour interval data for each of the SAs in the aggregated group.

CAPACITY NOMINATIONS:

Capacity Nominations must be submitted by Aggregators no later than 5 calendar days prior to the operating month. All Capacity Nominations are fixed for their associated operating months. All operating months begin and end at the beginning and ending of its corresponding calendar month. (T) (D)

An Aggregator can include only those SAs that are in its portfolio.

An Aggregator must nominate capacity in the following categories:

Option (Day-Ahead or Day-Of)

Day-Of Adjustment Election

Product

Bundled/Direct Access

Load Zone (N)

No later than 5 calendar days prior to the first day of the operating month, an Aggregator must specify the SAs from its portfolio that shall be included in the aggregated group associated with each Capacity Nomination. The characteristics of selected SAs must match the categories of its associated Capacity Nomination. These aggregated groups will be used to determine the CSEB and performance during the operating month. A SA can be included in only one aggregated group and only one CSEB for a given operating month. (T)

RATES:

The payments under this rate schedule will be determined from the following components.

1. Capacity Price
2. Capacity Payment and Capacity Penalty
3. Energy Payment

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

ENERGY PAYMENT:

All Energy Payments will be determined separately for each Capacity Nomination.

If no CBP Events were called during the operating month, then the monthly Energy Payment is zero (0).

If one or more CBP Events were called during the operating month, then the monthly Energy Payment is obtained by summing the Hourly Energy Payments. The Hourly Energy Payments will be determined as follows:

Nominated Energy $_{HR}$ = Nominated Capacity $_{HR}$

Delivered Energy $_{HR}$ = lesser of Delivered Capacity $_{HR}$ or 1.5 * Nominated Energy $_{HR}$

If Delivered Energy $_{HR}$ >= Nominated Energy $_{HR}$

Energy Payment $_{HR}$ = Delivered Energy $_{HR}$ * Energy Price $_{HR}$

If Delivered Energy $_{HR}$ < Nominated Energy $_{HR}$

Energy Payment $_{HR}$ = Delivered Energy $_{HR}$ * Energy Price $_{HR}$ less (Nominated Energy $_{HR}$ - Delivered Energy $_{HR}$) * the higher of the ex-post energy price for the event hour or the Energy Price $_{HR}$

Where the Energy Price $_{HR}$ = 15,000 BTU/kWh * PG&E citygate midpoint gas price as published by Platts Gas Daily for the date of the CBP Event ($/BTU)

See section below for special conditions regarding DA and CCA service customers' energy payments.

SPECIAL CONDITIONS FOR DIRECT ACCESS AND CCA SERVICE CUSTOMERS:

Aggregators must make the necessary arrangements with the ESP of its DA or CCA service customers before enrolling DA or CCA service customers in this program.

PG&E will not provide energy payments to Aggregator on behalf of a DA or CCA service (D)
customer, for load reductions during CBP events ($0/kWh), due to the Scheduling
Coordinator (SC) to SC trade and payment changes to the CBP program. Aggregators (D)
will still receive capacity payments from PG&E for DA or CCA customers' load as applicable under this Schedule. This provision does not prevent DA or CCA customers from entering into arrangements with their respective ESPs or CCAs to receive part or all of the energy benefits derived from the DA or CCA customers' load reductions during
CBP events. (D)

See Agreement For Aggregators Participating In The Capacity Bidding Program (Form (L)
79-1076) for additional information. (L)

(Continued)

(L)

METERING AND COMMUNICATIONS EQUIPMENT:

Each customer must have an approved interval meter or and approved meter communications equipment installed and operating prior to participating on this program in order to establish a valid CSEB. See Baseline section for additional details.

An approved interval meter is capable of recording usage in 15-minute intervals and being read remotely by PG&E. If the customer is receiving DA service, then a Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's ESP. (D)

The following options are available if a customer's SA does not already have an approved interval meter or SmartMeter: (N)

1) For Bundled Service and CCA service SAs with a maximum demand of 200 kW or greater for three consecutive months in the past 12 billing months, PG&E will provide and install the metering and communication equipment at no cost to the customer.

2) For Bundled Service and CCA Service SAs whose maximum billed demand has not exceeded the level specified in item 1 above, the customer can elect one of the following:

   a. Pay the cost to have PG&E install a non-SmartMeter at the customer's expense pursuant to Electric Rule 2, Special Facilities, or

   b. Wait until a PG&E SmartMeter is installed and remote-read enabled.

3) For Direct Access SAs where PG&E is the MDMA, no incremental fees are required. Metering services shall be provided pursuant to Electric Rule 22.

4) For Direct Access SAs where PG&E is not the MDMA, then the customer will be responsible for any and all costs associated with providing PG&E acceptable interval data on a daily basis, including any additional metering, communication equipment, and fees assessed by the customer's Energy Service Provider (ESP). Metering services shall be provided pursuant to Electric Rule 22.

PG&E is not required to install an interval meter and communication equipment or SmartMeter to provide remote read capability if the installation is impractical or not economically feasible. (N)

(D)

Prior to customer's participation in the program, the customer must be able to successfully transfer meter data according to PG&E's specification on a daily basis for a period of no less than ten (10) calendar days.

All measurements for the CSEB and performance will be determined using the customer's electric revenue interval meter without loss factor adjustments.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

NOTIFICATION EQUIPMENT: Aggregators, at their expense, must have: (1) access to the Internet and an e-mail address to receive notification of a CBP Event; and (2) an alphanumeric pager or cellular telephone that is capable of receiving a text message sent via the Internet, and/or a facsimile machine to receive notification messages. An Aggregator cannot participate in the CBP until all of these requirements have been satisfied.

If a CBP Event occurs, Aggregators will be notified using one or more of the above mentioned systems. It is the responsibility of the Aggregator to notify its aggregated customers.

PG&E will make best efforts to notify Aggregators; however receipt of such notice is the responsibility of the Aggregator. In addition, the Aggregator may check PG&E's CBP website to see if a CBP Event has been triggered. PG&E does not guarantee the reliability of the pager system, e-mail system, or website by which the Aggregator receives notification. (T)

CONTRACTS AND FORMS: Aggregators must submit a signed Agreement For Aggregators Participating In The Capacity Bidding Program (Form 79-1076). Aggregators must submit a Notice to Add or Delete Customers Participating in the Capacity Bidding Program (Form 79-1075) signed by the aggregated customer to add or delete a customer from its portfolio.

CONTRACTUAL ARRANGEMENT BETWEEN CUSTOMER AND AGGREGATOR: The terms and conditions of the agreement governing the relationship between the Aggregator and a customer with respect to such customer's participation in the CBP through such Aggregator are independent of PG&E. Any disputes arising between Aggregator and such customer shall be resolved by the parties.

BILLING DISPUTES: If an Aggregator disputes a bill issued by PG&E, the disputed amount will be deposited by the Aggregator with the California Public Utilities Commission (Commission) pending resolution of the dispute under the existing Commission procedures for resolving such disputes with PG&E. No termination of participation in the CBP will occur for this dispute while the Commission is hearing the matter, provided that the full amount in dispute is deposited with the Commission.

If a customer has a billing dispute with its Aggregator, the customer will remain obligated to pay PG&E charges for its OAS in a timely manner. Neither the Aggregator nor the customer shall withhold payment of PG&E charges pending resolution of a dispute between the customer and Aggregator.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

PROGRAM TRIGGER AND NOTIFICATION:

PG&E may call up to two (2) test CBP Events per calendar year. Test CBP Events will be treated as actual CBP Events, including payments and penalties, and will count towards the product limits. (N)

Day-Ahead Option:

PG&E may trigger a Day-Ahead CBP Event for one or more Load Zones when: 1) PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the day-ahead market, 2) PG&E receives a market award or dispatch instruction from the CAISO for a Proxy Demand Response bid, 3) when PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate, or 4) for forecasted temperature for a Load Zone exceeds the temperature threshold for the Load Zone. (T) PG&E reserves the right not to call an event even when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources may be adequate.

PG&E will notify the affected Aggregators by 3:00 p.m. on a day-ahead basis of a CBP Event for the following business day. Notices will be issued by 3:00 p.m. on the business day immediately prior to a PG&E holiday or weekend if a CBP Event is planned for the first business day following the PG&E holiday or weekend. (T)

(D)

Day-Of Option:

PG&E may trigger a Day-Of Event for one or more Load Zones when: 1) PG&E's procurement stack is expected to require the dispatch of electric generation facilities with heat rates of 15,000 BTU/kWh or greater for the real-time market, 2) PG&E receives a market award or dispatch instruction from the CAISO for a Proxy Demand Response bid, 3) PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate, or 4) the forecasted temperature for a Load Zone exceeds the temperature threshold for the Load Zone. (T) PG&E reserves the right not to call an event even when these thresholds are reached when PG&E, in its sole opinion, forecasts that resources may be adequate.

PG&E will notify the affected Aggregators on a day-of basis, with at least three hours notice prior to the start of a Day-Of Event. (T)

(D)

PROGRAM RESEARCH AND ANALYSIS:

All customers participating on this program agree to allow personnel from the California Energy Commission (CEC), PG&E, and their contracting agents, reasonable access to conduct a site visit for measurement and evaluation, access to the customer's interval meter data, and agree to complete any surveys needed to enhance this program.

PG&E may release customer information to the CAISO in order to facilitate direct participation of retail demand response resources in the CAISO wholesale market.

(Continued)

ELECTRIC SCHEDULE E-CBP
CAPACITY BIDDING PROGRAM

ACCESS TO CUSTOMER SPECIFIC USAGE DATA:	PG&E will provide an aggregated customer's electric usage and electric meter data for the Service Agreements to its Aggregator so Aggregator can determine the payment payable to and penalties chargeable to Customer under Schedule E-CBP.
PROGRAM TERMS:	The initial term is 12 months. After the initial 12 months, an Aggregator may request to terminate its participation in this program by submitting to PG&E a completed Cancellation of Contract (Form 62-4778). The termination will be effective on the later of: (1) the beginning of the calendar month that is immediately after the initial 12 month term; and (2) the beginning of the calendar month that is closest to but at least thirty (30) calendar days after PG&E received the Cancellation of Contract. The Schedule E-CBP will remain available unless and until Schedule E-CBP is revised or terminated as directed by the CPUC. (D)
PAYMENTS, AND AFFECT ON CUSTOMER'S BILL FOR THE OAS:	Payments due under this program will be sent as a check to the Aggregator within 60 calendar days after the end of the operating month. The charges under the OAS for an aggregated customer will not be adjusted.

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

APPLICABILITY: The Schedule E-DBP Demand Bidding Program (Program) offers customers incentives for reducing energy consumption and demand when requested by Pacific Gas and Electric Company (PG&E) to increase system reliability. This Program is optional for customers with billed maximum demand of 50 kilowatts (kW) or greater during any one of the past 12 billing months and who voluntarily commit to reduce a minimum of 10 kW for at least two consecutive hours during an E-DBP event. PG&E will determine E-DBP Bid acceptances for energy reductions. Interval metering is required to participate in this Program. Customers must receive service on a demand Time-of-Use (TOU) electric rate schedule. Customers on Schedules AG-R, AG-V, NEMCCSF, or S are not eligible for this Program. This schedule is available until modified or cancelled by the California Public Utilities Commission (CPUC). (T)

TERRITORY: This schedule is available throughout PG&E electric service area.

ELIGIBILITY: This schedule is available to individual PG&E bundled-service customers, Community Choice Aggregation Service (CCA Service) customers, and Direct Access (DA) customers. Each customer must take service under the provisions of their otherwise-applicable rate schedule. Customers participating in the Program must be on an eligible rate schedule and able to reduce load by at least 10 kW during an E-DBP event. (T)

Customers who are “Essential Customers” under PG&E’s Electric Emergency Plan and as defined by the Commission in Rulemaking 00-10-002, must submit to PG&E a written declaration that states that the customer is, to the best of that customer’s understanding, an Essential Customer under Commission rules and exempted from rotating outages. The declaration must also state that the customer voluntarily elects to participate in this interruptible Program for part or all of its load upon request by PG&E under the terms of E-DBP, while continuing to adequately meet its essential needs with backup generation or other means. In addition, an Essential Customer may commit no more than a total of 50 percent (50%) of its average peak load to all interruptible programs for each participating service agreement (SA). (T)

Prior to May 1, 2013, customers with SAs throughout PG&E’s electric service territory with individual meters with demands less than 200 kW (as described in the Applicability Section) had the option to participate in this Program under the provisions stated in the Aggregated Group Section of this rate schedule. Those SAs participating as an Aggregated Group as of May 1, 2013, may continue to participate as an Aggregated Group. (T)

ENROLLMENT: Customers must enroll using PG&E demand response enrollment website.

LOAD ZONES: PG&E will assign each DBP participant to a Load Zone. As specified below, the assigned Load Zone will be either a PG&E system-level Load Zone or a PG&E subsystem-level Load Zone, which is referred to as a Load Zone. The participant’s assigned Load Zone may change over time. (N)

Existing AutoDR participants and existing Aggregated Group participants shall be assigned to a PG&E system-level Load Zone.

Existing participants that are neither AutoDR nor Aggregated Group participants will be assigned to a Load Zone.

New AutoDR participants shall be assigned to a PG&E system-level Load Zone. New non-AutoDR participants will be assigned to a Load Zone. (N)

(Continued)

METERING EQUIPMENT:	Each participating customer SA must have an interval meter or a SmartMeter capable of recording usage in 15-minute or shorter intervals and being read remotely by PG&E.	(T) (T)

The following options are available if a SA does not already have an approved interval meter or SmartMeter: (N)

1) For Bundled Service and CCA Service SAs with a maximum demand of 200 kW or greater for at least one month in the past 12 billing months, PG&E will provide and install the metering and communication equipment at no cost to the customer.

2) For Bundled Service and CCA Service SAs whose maximum billed demand has not exceeded the level specified in item 1 above, the customer can elect one of the following:

   a. Pay the cost to have PG&E install a non-SmartMeter at the customer's expense pursuant to Electric Rule 2, Special Facilities, or

   b. Wait until a PG&E SmartMeter is installed and remote-read enabled.

3) For Direct Access SAs where PG&E is the Meter Data Management Agent (MDMA), no incremental fees are required. Metering services shall be provided pursuant to Electric Rule 22.

4) For Direct Access SAs where PG&E is not the MDMA, then the customer will be responsible for any and all costs associated with providing PG&E acceptable interval data on a daily basis, including any additional metering, communication equipment, and fees assessed by the customer's Energy Service Provider (ESP). Metering services shall be provided pursuant to Electric Rule 22.

PG&E is not required to install an interval meter and communication equipment or SmartMeter to provide remote read capability if the installation is impractical or not economically feasible. (N)

A MDMA may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP) if a customer is receiving Direct Access Service. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least ten (10) days prior to participating in the Program to establish baseline. (T)

Bundled Service and CCA Service customers with SAs participating prior to April 1, 2013, under the Aggregated Group will continue to receive an interval meter at no additional cost (see Aggregated Group Section). PG&E will continue to provide meter data retrieval at no cost to those Bundled Service and CCA Service customers receiving free meters through this tariff until otherwise directed by the CPUC. (T)

ONGOING METER DATA ACCESS:	If the SA is receiving Bundled Service, CCA Service, or DA Service and PG&E is the MDMA, then there will be no additional costs to the either ESP or customer for ongoing meter data access.	(N)
	If the SA is receiving DA Service and PG&E is not the MDMA, then the customer will be responsible for any and all costs associated with providing PG&E acceptable interval meter data into the PG&E system on a daily basis.	(N)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

NOTIFICATION EQUIPMENT: To receive notification regarding Program operations, customers, at their expense, must have an e-mail address and cellular telephone that is capable of receiving a text message sent via the Internet. Customers, at their expense, must also have access to the Internet to submit E-DBP bids. A customer cannot participate in the Program until all of these requirements have been satisfied. (L)(T)

DEMAND RESPONSE OPERATIONS WEBSITE: Customers must use PG&E's Demand Response operations website located at https://inter-act.pge.com for load curtailment event notifications, curtailments, and communications. (T)

If an E-DBP event occurs, customers will be notified using one or more of the above-mentioned systems. PG&E does not guarantee the reliability of the text message system, e mail system, telephone system, or Internet site by which the customer receives notification. It is the customer's responsibility to ensure receipt of event notification and check PG&E's website for curtailment notices. No evaluation will be performed or payment made for load reductions undertaken during an E-DBP event without such advance notification. (N)

The customer's actual energy usage is available at PG&E's Demand Response operations website. This data may not match billing quality data and will be used to calculate all incentive payments. (T)

E-DBP EVENT NOTICE AND TRIGGER: DAY-AHEAD NOTIFICATION

PG&E may issue, to one or more DBP customers, a day-ahead E-DBP event notification by 12:00 Noon under one or more of the following conditions: (T)

1. The California Independent System Operation (CAISO)'s day-ahead load forecast exceeds 43,000 MW.

2. The CAISO issues an Alert notice or is expected to issue a Warning or higher level notice for the following day.

3. The forecasted temperature for a Load Zone exceeds the temperature threshold for that Load Zone (see www.pge.com for the current thresholds).

4. PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate.

PG&E reserves the right not to call an event when these conditions are reached when PG&E, in its sole opinion, forecasts that resources will be adequate.

An E-DBP Event will only be called Monday through Friday between the hours of 12:00 Noon and 8:00 p.m., excluding PG&E holidays.

PG&E will notify the selected customers by 12:00 Noon on a day-ahead basis when an E-DBP event will occur the next business day. Notices will be issued by 12:00 Noon on the business day immediately prior to a PG&E holiday or weekend if an E-DBP event is planned for the first business day following the PG&E holiday or weekend. (T)

(Continued)

E-DBP EVENT NOTICE AND TRIGGER: (Cont'd.)

The selected SAs may elect to submit bids to the Program's website between 12:00 noon and 3:00 p.m. the day the E-DBP event notice was issued. After 4:00 p.m. the day the E-DBP event notice was issued, customers will receive confirmation of bid acceptance or rejection on the website. Unless a specific megawatt (MW) limit is requested, PG&E will accept all bids. In the event bids are restricted PG&E will accept bids on a first-come, first-served basis. If the customer's bid is accepted for a particular SA, then incentive payments will be determined separately for each SA and as specified in the Incentive Payments section. Once a customer's bid has been accepted, that bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer's actual performance. (L)(T) (T) (L)

ENERGY BID:

E-DBP bidding shall be accepted for non-PG&E holiday weekdays only. The E-DBP bid shall indicate the amount of kW curtailment that the participant is offering for each hour of the E-DBP Event. The participant may submit only one bid for each E-DBP Notification. Each bid must be for a minimum of two (2) consecutive hours during the E-DBP event and meet the minimum energy reduction of 10 kW. The participant must submit their bid within the timeframe specified in the E-DBP event notice. (T)

Each E-DBP bid submitted via the DR operations website shall be for an E-DBP event that takes place the next eligible weekday, excluding PG&E holidays. Notification of E-DBP bid acceptances will be posted to PG&E's DR website. Posting of accepted bids may be delayed due to unforeseen problems in transmitting or receiving the bids. PG&E cannot guarantee the reliability of the Internet site by which customers submit bids and may use and accept alternate means of notification as necessary. PG&E will communicate the following information on the website regarding accepted E-DBP bids: (T)

1. The Date and the Time Period of the E-DBP events; and (T)

2. The Customer Baseline (CB) on any given day during the Program is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events of this Program, or any other interruptible or curtailment Programs enrolled in by the customer, or days when a rotating outage was called). (T) (T) (T)

   The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment to the CB will be limited to +/- 20%, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more than one event (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the events that day requiring a day-of adjustment.

   A customer may elect the day-of adjustment each time it submits a bid. (T)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

ENERGY BID: (Cont'd.)	3. The hourly pricing incentive that PG&E intends to offer for qualifying load reductions.	(L)
PROGRAM TESTING:	PG&E may activate an E-DBP event with a simulated emergency event test trigger twice per year. During the test event, the customer shall be responsible for curtailing load consistent with the terms of this schedule. Participants will receive an incentive payment of $0.50/kWh for qualifying load reduction during each hour of an E-DBP test event.	(T) | | (T)
INCENTIVE PAYMENTS:	PG&E will evaluate and pay for the customer's hourly load reductions realized under the Program within ninety (90) days after each E-DBP event, depending on where the E-DBP event falls within the participant's actual billing cycle. The incentive payments will be reflected in the customer's regular monthly bill as an adjustment.	(T) (T)
	If the customer submitted a bid under the Day Ahead Notification, energy reduction for an E-DBP event hour will be determined as the difference between the customer specific energy baseline (CSEB) for that hour and the customer's actual energy usage during that hour. Participants will be paid for load reductions up to a maximum of 150 percent (150%) of their accepted day-ahead bid (kW) on an hourly basis. Participants must drop at least 50 percent (50%) of their bid to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 10 kW.	(T) (T) (T)

(Continued)

INCENTIVE PAYMENTS: (Cont'd.)

The E-DBP event incentives will be calculated on an hourly basis, and will be equal to the product of the qualified kWh energy reduction for each hour a bid was accepted and the incentive price of $0.50/kWh. (T)

AGGREGATED GROUP:

The Aggregated Group option is closed to additional SAs effective May 1, 2013. SAs participating in an Aggregated Group as of May 1, 2013, may continue to participate as an Aggregated Group. (N)

Customers that have multiple SAs throughout the PG&E electric service territory were eligible, prior to May 1, 2013, for the Aggregated Group provisions of the Program. The following conditions under the Aggregate Group option of this Program supersedes the individual participation conditions where applicable: (T)

1. Each individual SA must currently take service on an applicable PG&E rate schedule and have an installed interval meter or SmartMeter as stated in the Metering Equipment Section of this schedule. If necessary, a customer may change a SA's rate schedule, and PG&E will provide and install an interval meter at no additional cost for each individual Bundled Service or CCA SA. (T)

(Continued)

AGGREGATED GROUP: (Cont'd)

participating under the provisions of an Aggregated Group whose maximum demand is greater than or equal to fifty (50) kW during any one of the past twelve (12) billing months, provided that the SA remains on the program for a minimum of 12 months. SA with an average demand that is less than fifty (50) kW must pay for the required Interval Meter prior to participation. The installation of interval meters for a Direct Access customer is the responsibility of their Energy Service Provider or their agent. Fees associated with a rate change will be the responsibility of the customer. (T)

2. The customer must have at least one SA with a maximum demand of 200 kW or greater for at least one or more of the past 12 billing months within each Aggregated Group that will be designated as the primary SA for the Aggregated Group. The primary SA will oversee all activities of the group, including event notification and the receiving of the incentive payment. It is up to the lead SA to determine the dispersal of the credit to the other SAs in the group. (T)

3. All SAs that are part of the Aggregated Group must take service from PG&E under the same federal tax identification number and be listed on the Demand Response Program Application. Individual SAs, (excluding the lead SA), with less than 200 kW (as described in the Applicability Section) may participate in the program as part of the Aggregated Group. (T)

4. SAs that are participating as an aggregated group will be exempt from the individual minimum load reduction amount. Instead SAs in the aggregated group will have a Group Minimum Load requirement of 200 kW. The Group Minimum Load represents: (1) the group's aggregated coincidental minimum load to qualify for the program; (2) the minimum bid amount that the aggregated group can submit for an E-DBP event; and (3) the group's minimum threshold they must achieve to earn an incentive during an E-DBP event. (T)

5. Energy reduction during an E-DBP event will be based on performance of all SAs within the aggregated group and will be calculated as follows: (T)

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

AGGREGATED GROUP: (Cont'd)

a. The Group's Energy Baseline (GEB) is used to determine the aggregated group's average energy usage prior to an E-DBP event. The GEB is on any given day during the program is the sum total of each individual SA's baseline in the group. Each individual SA baseline is the average for each hour based on the immediate past ten (10) similar weekdays prior to an event with the option of a day-of adjustment. The load during each hour of the ten days will be averaged to calculate an hourly baseline for each hour. The past ten (10) similar days will include Monday through Friday, excluding PG&E holidays and event days prior to the event (including events for this program, or any (T) other interruptible or curtailment programs enrolled in by the customer, or days when a rotating outage was called).

The day-of adjustment is the ratio of a) the average load of the first three of the four hours prior to the event to b) the average load of the corresponding hours from the past 10 similar weekdays, as discussed above. The day-of adjustment will be limited to +/- 20% of each individual SA baseline in the group, and will be based on the first three of the four hours prior to the start of the event. The day-of adjustment is applied by multiplying it by each hourly baseline value. Customers must elect or opt-in to receive this adjustment. The customer is responsible for determining the applicable baseline day-of adjustment amount at the time of an event. PG&E will only be responsible for determining the applicable baseline day-of adjustment following each event for the purpose of evaluating customer compliance. If more than one event (T) (either within the same or across multiple programs) occurs on the same day, the day-of adjustment from the event with the earliest start time will be used for the individual SA's events that day requiring a day-of adjustment.

b. The Group's energy usage during an E-DBP event is the total coincidental load of all the SAs in the group measured during each hour of the event. (T)

c. Energy reduction during an E-DBP event will be calculated as the difference between the GEB and the group's actual total usages during each hour of the event.

6. Deletions from the SA listing of an aggregated group may only occur during the (T) March contract review period. During the contract review period customers may submit a written request to PG&E requesting removal of SAs within the aggregated (T) group. Changes to the aggregated group will become effective after the customer's April billing cycle.

7. If one or more of the SAs on the aggregated group, other than the lead SA, (T) terminates service with PG&E prior to the contract review period, the other SAs in | the group will be responsible to maintain the 200 kW Group's Minimum Load (T) requirement of the program until the contract can be adjusted during the next contract review period.

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

TECHNICAL ASSISTANCE AND TECHNOLOGY INCENTIVES:	Technical Assistance and Technology Incentives may be available to enhance the customer's ability to respond to curtailment requests for on-peak demand reductions.	(T)
FAILURE TO REDUCE LOAD:	Except as provided in the Incentive Payment section of this schedule, no additional monetary penalties will be assessed under this Program for a customer's failure to comply (reduce energy) during any or all hours of an E-DBP event.	(T)
PROGRAM TERMS:	Customers' participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-DBP participation by giving a minimum of 30 days written notice. Cancellation will become effective with the first regular billing cycle after the 30-day notice period. PG&E may terminate a participant's E-DBP participation at any time after giving a thirty (30) day written notice to participants.	

(Continued)

ELECTRIC SCHEDULE E-DBP
DEMAND BIDDING PROGRAM

INTERACTION WITH CUSTOMER'S OTHER APPLICABLE PROGRAMS AND CHARGES:	Participating customers' regular electric service bills will continue to be calculated each month based on their actual recorded monthly demands and energy usage.	
	Customers who participate in a non-PG&E demand response program must immediately notify PG&E of such activity.	(T) (T)
	Customers may participate in one of the following: PG&E's Base Interruptible Program (Schedule E-BIP), the "Day Of" option of its Capacity Bidding Program (E-CBP), the Aggregator Managed Portfolio (AMP) in a "Day Of" product, or Optional Binding Mandatory Curtailment Program (Schedule E-OBMC). If a customer is enrolled in two programs with simultaneous or overlapping events, the customer will receive payment for the capacity program and not for the simultaneous hours of the energy program.	(N) (N) (T)
EMERGENCY STANDBY GENERATION:	Customers may achieve energy reductions by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.	
COMMUNITY CHOICE AGGREGATION SERVICE CUSTOMERS AND DIRECT ACCESS SERVICE CUSTOMERS	Customers participating in this Program and receiving service under CCA Service/DA must notify their Community Choice Aggregator/Energy Service Provider that they are participating in this Program and when they participate in a DBP event. The per event notification must include the amount of hourly bid for each accepted bid.	(T) | | (T) (D)
PROGRAM RESEARCH AND ANALYSIS:	Customers receiving service under this tariff must agree to allow personnel from the California Energy Commission (CEC), or its contracting agent, to conduct a site visit for measurement and evaluation, access to customer's interval meter data, and agree to complete any surveys needed to enhance the Program.	(T)

ELECTRIC SAMPLE FORM 79-1149 Sheet 1 (N)
ELECTION TO WITHDRAW FROM THE (N)
CAPACITY BIDDING PROGRAM FORM (N)

Please Refer To Attached Sample Form

ELECTION TO WITHDRAW FROM THE CAPACITY BIDDING PROGRAM FORM

Pacific Gas and Electric Company

Instructions: Customers use this notice to officially withdraw from the Capacity Bidding Program (CBP). Send the completed notice to PG&E's Demand Response Program Department by U.S. mail, email, or fax, with a copy to Aggregator from whose Portfolio the Customer is to be withdrawn.

Fax to:
Pacific Gas and Electric Company
Demand Response Program Department
Attn: CBP Manager
FAX: 415.973.4177

Mail signed original to:
Pacific Gas and Electric Company
Demand Response Program Department
Attn: CBP Manager
P.O. Box 770000, Mail Code N3E
San Francisco, CA 94177

Email:
CBPProgram@pge.com

I, ______________________ ***{Insert Customer Name here}***, request to be removed from ______________________ ***{Insert Aggregator's Name}'s*** Portfolio in the Capacity Bidding Program (CBP) for Pacific Gas and Electric Company.

I acknowledge that ______________________ ***{Insert Customer Name here}*** may not join another Portfolio in any of PG&E's Aggregator programs, which includes the CBP and the Aggregator Managed Portfolio (AMP) program for the remainder of the DR Season, i.e., the calendar months of May through October.

Effective Date of Customer Withdrawal from CBP

Election of Customer to withdraw from Aggregator's Portfolio shall be effective and binding at the end of the then current calendar month in which PG&E received this form identifying the Service Agreement(s) to which the Customer withdrawal applies; provided PG&E receives this form at least fifteen (15) calendar days prior to the end of the then current month. If PG&E receives this form less than fifteen (15) calendar days prior to the end of the then current month, then Customer's withdrawal from Aggregator's Portfolio will be effective the following month.

Customer Name or Authorized Representative of Customer: ______________________

Title: ______________________

Signature: ______________________

Date: ______________________

	Customer Site Name	PG&E Service Agreement Number	Electric Meter Number	Service Address and City
1.				
2.				
3.				
4.				
5.				

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Sheet 1

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Sheet 9

SCHEDULE	TITLE OF SHEET	CAL P.U.C. SHEET NO.	

Rate Schedules
Curtailment Options

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79-984	Interval Meter Installation Service Agreement	18693-E
79-985	Interval Meter Data Management Service Agreement	18708-E
79-993	Agreement for Schedule E-POBMC	27810-E
79-995	Agreement for Customers Taking Service on Schedule E-31	20623-E
79-1006	Municipal Departing Load - Nonbypassable Charge Statement	32124-E
79-1029	Community Choice Aggregator (CCA) Service Agreement	27499-E
79-1031	Community Choice Aggregator (CCA) Non-Disclosure Agreement	32235-E
79-1039	Agricultural, Commercial, Residential Rate Schedule Selection Customer Agreement	30095-E
79-1040	Non-Disclosure and Use of Information Agreement	23601-E
79-1050	Contract for Customer Provision of Physically Assured Load Reduction	24956-E
79-1075	Notice to Add or Delete Customers Participating in the Capacity Bidding Program	-E
79-1076	Agreement for Aggregators Participating in the Capacity Bidding Program	28277-E
79-1079	Agreement for Aggregators Participating in the Base Interruptible Load Program	28420-E
79-1080	Notice to Add or Delete Customers Participating in the Base Interruptible Program	28421-E
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79-1126	Off-Bill and On-Bill Financing Loan Agreement for Self-Installed Projects	29686-E
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79-1138	Power Purchase and Sale Agreement - Contract For Eligible CHP Facilities with Power Rating of Less Than 500 KW	32150-E
79-1141	Agreement for Schedule A-15 Fixed Usage Estimate	31456-E
79-1149	Election to Withdraw From the Capacity Bidding Program Form	32481-E (N)

(Continued)

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