Attachment 1-Revised APPENDIX X

San Diego Gas & Electric Company

Response to Energy Division Guidance for Post Summer 2012 DR Evaluation and 2013/2014 Summer Planning

1. Demand Response Program Performance

a) <u>Load impact (MWs) and participation</u>

- **Data:** provide the load impact, enrollment and number of participants' information for each of DR programs categorized by: 1) Monthly Nominated Programs, 2) Other Price-Responsive, and 3) Emergency[1] Programs; and by program types (Day Ahead/Day of). The DR program listed under each of these categories should be consistent with the programs referred to in the IOUs DR Weekly Forecasts/Daily Reports that have been submitted to the CPUC and CAISO in summer 2012.
    - Provide the load impact, enrollment, and number of participants for each DR event and a summary table for each of the five summer months (June, 2012 to October, 2012). The monthly value should be determined by the highest load impact (MWs) of the DR events in a given month (similar to the RA monthly load impact). Provide the temperature and system peak load in the utility's service territory for each event day.
    - If separate subgroups of the enrolled customers within a program were dispatched in different DR event hours, the load impact for that event day should be the aggregate of all of the customers triggered. For example, SCE may have dispatched three different groups of residential AC cycling customers in three different event hours; the load impact for the residential AC cycling customers should be the sum of the load impact from each group of customers.
    - The number of participants is defined as the number of customers or accounts that were used to determine the load impact in the seven day results reports submitted to the CPUC and CAISO in 2012. The number of participants may be fewer than the total number of customers enrolled under each program. For example, for SCE's residential default Peak Time Rebate (PTR) program, the total enrollment for this program is the total residential population that is eligible to receive a rebate, but SCE may use the number of customers who signed up for the notification as the number of participants.

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[1] As categorized in the DR Daily Reports and the Weekly Forecasts. Some programs are referred to as Reliability Programs such as the Base Interruptible Program (BIP) and others are referred to as price-responsive programs such as AC cycling.

  - For SCE, provide the Ex Post load impact and number of participants for the South of Orange County and South of Lugo. These two areas should be defined consistent with the same areas identified by the CAISO in the Daily DR Report.

- **Data source**: use the hourly load impact data that were relied upon for the seven-day result reports submitted to the CPUC and CAISO in 2012. Provide a brief summary of the methodologies that describe how the hourly load impact (MWs) were developed.
  - The utility should also provide an update of the load impact and number of participants based on the settlement billing data for each DR event and a summary of the monthly load impact.
  - The utilities may provide an update when the Ex Post load impact data based on the Load Impact Protocols becomes available (no later than January 31, 2013). Provide a brief summary of the methodologies describing how the Ex Post hourly load impact (MWs) were developed.
  - By February 2013, for each DR program provide a historical monthly load impact comparison (for the summer months only) between the seven day results reports provided to the CPUC and CAISO, settlement billing data, and the Ex Post data for 2010 to 2012.

SDG&E Response: Table 1 contains a monthly summary of total demand response load impacts achieved in 2012. A monthly summary of the total demand response load impact must be interpreted carefully because not all programs were called every month, and even in months where programs were called, not all programs were called on the same day. The "maximum load reduction from programs triggered" column contains the sum of the maximum load reductions from the month for each program called at any time during the month. The column "load reduction on the highest overall load reduction day" contains the results for programs called on the event date during the month which had the highest total load impact for the month. For example, the 119 MW value for August is the sum of the maximum results for all programs triggered at any time during August, whereas the 65 MW value includes results only from programs that were triggered on August 10th, which was the event date for which the total demand response load reduction was the highest in August.

Table 1 Prelminary 2012 Load Impacts by Month (MW)				
	Maximum Load Reduction from Programs Trigged	Load Reduction Highest Overall Load Reduction day	Programs Triggered on Highest Overall Load Reduction Day	Programs Triggered at any time during the month
June	0	0	none	none
July	13	13	PTR	PTR
August	119	65	ACSAVER, CBP-DA, PTR	ACSAVER,CBP,CPP,CPP-E, DBP,PTR
September	103	54	ACSAVER, BIP,CBP,CPP-E,DBP	ACSAVER,BIP,CBP, CPP-D,CPP-E, DBP,PTR
October	51	33	ACSAVER,CPP, CBP-DA,DBP	ACSAVER,CBP,CPP-D

Tables 2 through 6 contain the average load impacts from the CAISO reports for each program for each event along with the event times, maximum temperature Fahrenheit, enrollment, the daily demand response forecast, the system peak, and program category. For events that lasted from 11 a.m. – 6 p.m., the average load reduction from 1 p.m. - 6 p.m. is also provided. For events that were less than 5 hours, only the average load reduction from the event period is provided since data is not available for all hours between 1 p.m. and 6 p.m. Event times are reported using hour ending notation. For example, an event that starts hour 14 and ends hour 17 starts at 1:00 p.m. and ends at 5:00 p.m.

Settlement results are provided for the Capacity Bidding Program (CBP), Demand Bidding program (DBP), PTR Residential (PTR-Res) and PTR Small Commercial (PTR-A), since these are the programs for which payments to customers/aggregators are calculated using baselines. Note that for CBP and DBP the settlement results are simply the load impacts using the settlement baselines not the load impacts paid for. The CBP payments are capped at the value nominated by the aggregator and the load reduction paid for is less than the baseline results when the aggregator achieves less than 90% of their nominated value. The DBP settlements are capped at 150% of the customer's nomination. These caps and comparisons to nominations are not included in these settlement calculations; therefore, the load reduction paid for will be less than or equal to the load impacts calculated according to the settlement baselines. Since we use the settlement baselines for the CAISO reporting for CBP and DBP, the final settlement load impacts and CAISO report load impacts are either equal or very close. For PTR-Res and PTR-A there are no caps or nominations to take into account therefore the settlement load impacts presented are equal to the load impacts paid for.

For residential and small commercial programs, we use a one day baseline with a same day adjustment to calculate the load impacts for the CAISO report. The baseline day is not always the day immediately preceding the event day. It is the day we judge to be the most comparable to the event day based on temperature and day of the week. For DBP, we also use a one day baseline with a same day adjustment. For all other programs, we use a 10 day baseline with a same day adjustment. There are limited exceptions to these approaches. For example, a 1 day baseline was used to analyze the CPP-D September 15th Saturday event.

For PTR residential and small commercial the participants represent the customers who proactively opted into alerts and the enrollment number represents all the customers who were eligible to receive a bill credit. Fifty percent of residential customers are enrolled in MyAccount and received an e-mail alert and 30% of small commercial customers are enrolled in MyAccount and received an e-mail alert. The PTR participant column includes only opt-in alert customers not every customer enrolled in MyAccount. However, the PTR CAISO load impacts represent the results for all PTR enrolled customers. For all other programs the number of participants represents the number of customers used to calculate the CAISO load impacts.

Table 2 Preliminary July Load Impacts by Event

									Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp F	Event Start	Event end	Enrolled	Participants	(event hours)	(1pm-6pm)	Load Reduction Settlements (MW)	Forecast	System Peak Hour	System Peak Load (kW)
Price-Responsive	PTR Res	DAY AHEAD	7/20/12	87	12	18	1218623	34,165	13.3	15.5	160.1	25.0	17	3,527
Price-Responsive	PTR Com	DAY AHEAD	7/20/12	87	12	18	111805	322	0.1	0.1	31.2	1.2	17	3,527

Table 3 Preliminary August Load Impacts by Event part 1

Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrolled	Participants	Ave. Load Reduction CAISO report (MW) (event hours)	Ave. Load Reduction CAISO report (MW) (1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	8/8/12	89	13	16	28,500	28,500	13.7			26.0	16	3,989
Monthly Nominated	CBP-DO	DAY OF	8/8/12	89	14	17	545	318	11.2		11.5	11.7	16	3,989
Price-Responsive	CPP	DAY AHEAD	8/9/12	88	12	18	1,181	1,181	20.9	19.3		13.6	17	3,931
Monthly Nominated	CBP-DA	DAY AHEAD	8/9/12	88	14	17	136	79	9.3		9.4	7.5	17	3,931
Price-Responsive	PTR Res	DAY AHEAD	8/9/12	88	12	18	1,218,334	42,165	26.1	27.6	202.8	12.6	17	3,931
Price-Responsive	PTR Com	DAY AHEAD	8/9/12	88	12	18	111704	388	0.3	0.3	27.4	1.1	17	3,931
Price-Responsive	ACSAVER	DAY OF	8/10/12	92	17	18	28,500	28,500	19.8			27.0	16	4,112
Monthly Nominated	CBP-DA	DAY AHEAD	8/10/12	92	15	18	136	79	9.5		9.5	7.5	16	4,112
Price-Responsive	PTR Res	DAY AHEAD	8/10/12	92	12	18	1,218,037	44,464	28.1	29.7	196.6	12.2	16	4,112
Price-Responsive	PTR Com	DAY AHEAD	8/10/12	92	12	18	111,682	403	8.0	6.9	37.5	0.8	16	4,112
Price-Responsive	CPP	DAY AHEAD	8/11/12	91	12	18	1,170	1,170	12.3	11.8		11.1	16	3,701
Price-Responsive	PTR Res	DAY AHEAD	8/11/12	91	12	18	1207881	45,891	33.6	35.9	231.1	12.9	16	3,701
Price-Responsive	PTR Com	DAY AHEAD	8/11/12	91	12	18	111,288	424	0.0	0.0	26.2	0.8	16	3,701
Price-Responsive	ACSAVER	DAY OF	8/13/12	91	14	17	28,502	28,502	18.2			33.0	16	4,266
Monthly Nominated	CBP-DO	DAY OF	8/13/12	91	14	17	545	318	10.6		10.6	11.7	16	4,266
Emergency Program	CPPE	DAY OF	8/13/12	91	14	18	4	4	1.5			2.0	16	4,266

Table 4 Preliminary August Load Impacts by Event part 2

									Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrolled	Participants	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	CPP	DAY AHEAD	8/14/12	88	12	18	1,169	1,169	27.1	25.4		14.0	16	4,136
Price-Responsive	CBP-DA	DAY AHEAD	8/14/12	88	15	18	136	79	8.3		8.5	9.0	16	4,136
Price-Responsive	DBP	DAY AHEAD	8/14/12	88	14	18	6	1	7.6	7.6	7.6	5.0	16	4,136
Price-Responsive	PTR Res	DAY AHEAD	8/14/12	88	12	18	1216871	47,648	6.9	7.1	239.9	12.8	16	4,136
Price-Responsive	PTR Com	DAY AHEAD	8/14/12	88	12	18	111,691	431	4.8	4.5	29.8	1.2	16	4,136
Price-Responsive	ACSAVER	DAY OF	8/17/12	94	14	17	28,528	28,528	20.6			19.3	15	4,266
Price-Responsive	CPP	DAY AHEAD	8/21/12	83	12	18	1,166	1,166	20.0	19.5		16.0	16	3,638
Price-Responsive	PTR Res	DAY AHEAD	8/21/12	83	12	18	1217877	49,856	10.0	11.3	1,002.8	22.4	16	3,638
Price-Responsive	PTR Com	DAY AHEAD	8/21/12	83	12	18	111,806	437	4.5	4.5	62.0	1.2	16	3,638
Price-Responsive	CPP	DAY AHEAD	8/30/12	90	12	18	1,164	1,164	20.3	19.4		16.0	16	3,962

Table 5 Preliminary September Load Impacts by Event

Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrolled	Participants	Ave. Load Reduction CAISO report (MW) (event hours)	Ave. Load Reduction CAISO report (MW) (1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	9/13/12	81	15	18	27,973	27,973	12.8			16.0	17	3,783
Monthly Nominated I	CBP-DO	DAY OF	9/13/12	81	15	18	545	321	10.5		10.7	12.1	17	3,783
Price-Responsive	ACSAVER	DAY OF	9/14/12	109	14	17	27,973	27,973	21.5			16.0	17	4,592
Emergency Program	BIP A	DAY OF	9/14/12	109	14	17	11	11	1.3			0.3	17	4,592
Monthly Nominated I	CBP-DA	DAY AHEAD	9/14/12	109	15	18	136	78	5.8		5.9	12.1	17	4,592
Monthly Nominated I	CBP-DO	DAY OF	9/14/12	109	15	18	545	321	9.9		10.1	9.0	17	4,592
Emergency Program	CPPE	DAY OF	9/14/12	109	14	17	4	4	1.4			1.6	17	4,592
Price-Responsive	DBP	DAY AHEAD	9/14/12	109	14	18	6	1	9.1	9.1	9.1	5.0	17	4,592
Price-Responsive	ACSAVER	DAY OF	9/15/12	104	14	17	27,973	27,973	3.1			9.0	16	4,313
Price-Responsive	CPP	DAY AHEAD	9/15/12	104	12	18	1,147	1,147	5.5	4.7		11.1	16	4,313
Price-Responsive	PTR Res	DAY AHEAD	9/15/12	104	12	18	1217877	52,686	45.8	48.0	297.6	32.3	16	4,313
Price-Responsive	PTR Com	DAY AHEAD	9/15/12	104	12	18	111,806	440	0.0	0.0	32.8	0.9	16	4,313
Monthly Nominated	CBP-DA	DAY AHEAD	9/17/12	84	15	18	136	78	8.0		8.4	9.0	17	3,681

Table 6 Preliminary October Load Impacts by Event

									Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrolled	Participants	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	10/1/12	92	15	18	**16,231**	**16,231**	9.2			15.0	17	4,155.5
Monthly Nominated I	CBP-DA	DAY AHEAD	10/1/12	92	15	18	**136**	**78**	7.0		7.3	12.1	17	4,155.5
Monthly Nominated I	CBP-DO	DAY OF	10/1/12	92	15	18	**545**	**323**	9.5		9.5	9.0	17	4,155.5
Price-Responsive	CPP	DAY AHEAD	10/2/12	98	12	18	**1,133**	**1,133**	16.1	16.7		16.0	16	4,146.3
Monthly Nominated I	CBP-DA	DAY AHEAD	10/2/12	98	15	18	**136**	**78**	8.0			9.0	16	4,146.3
Price-Responsive	DBP	DAY AHEAD	10/2/12	98	15	18	**6**	**1**	8.4		8.4	5.0	16	4,146.3

- **Averaging period**: for programs that have different hourly load impact, produce two sets of data to determine the daily value for each DR event: 1) the event hours and 2) the RA measurement hours (1 p.m.-6 p.m.)

SDG&E Response: Please see Table 7.

Table 7 2012 RA Comparison

Month	Program	2012 RA forecast (MW)	2012 Load Impact Event Period (MW)	2012 Load Impact 1 p.m. - 6 p.m. (MW)	RA forecast Maximum Temperature	2012 Event Date Temperature
July	PTR Res	70	13	16	91	87
July	PTR Com		0	0	91	87
August	ACSAVER	15	21		88	94
August	CBP-DA	10	10		88	92
August	CBP-DO	22	11		88	89
August	CPP-D	12	27	25	88	88
August	CPP-E		2		88	91
August	DBP		8	8	88	88
August	PTR Res	69	34	36	88	91
August	PTR Com		8	7	88	92
September	ACSAVER	17	22		96	109
September	BIP	11	1		96	109
September	CBP-DA	10	8		96	84
September	CBP-DO	23	11		96	81
September	CPP-D	12	6	5	96	104
September	CPP-E		1		96	109
September	DBP		9	9	96	109
September	PTR Res	63	46	48	96	104
September	PTR Com		0	0	96	91
October	ACSAVER	18	9		96	92
October	CBP-DA	10	8		96	98
October	CBP-DO	23	10		96	92
October	CPP-D	14	16	17	96	98
October	DBP		8		96	98

Note: When program event hours were shorter than the RA hours only the load impact for the event period is provided since it is not possible to calculate an average load impact from 1 p.m. to 6 p.m.

- **Comparison analysis:**

  <u>Q.1: How does the DR program load impacts compare with the 2012 DR allocation for RA for each of the summer months (June, 2012 to October, 2012)? Please provide a table that includes all programs.</u>

Response: Table 7 compares the 2012 adopted demand response RA allocation which was based on the demand response forecast filed on April 1st, 2011 to the 2012 load impact values.

The Summer Saver program (ACSAVER) 2012 load impact results are higher than the RA estimates in August and September, which makes sense given that event day temperatures were higher on the 2012 event day compared to the RA forecast's assumed temperatures. The Summer Saver load impact for October is lower however than the RA estimate. Demand response load impacts have been consistently lower in October for the Summer Saver program than they are for August and September, even when October temperatures are high. It may be possible that this could be explained by more detailed weather information, hourly temperature, humidity, cloud cover and so forth instead of just the daily maximum temperature or may be simply that customers have a different mindset as they head into fall and do not use their air-conditioning as often. The CBP day-ahead load impacts are similar to the RA forecast.

Q.2: How does the DR program load impact compare with the 2012 DR allocation for RA, taking into account up-to-date information such as enrollment and weather changes? In other words, did the DR programs perform as expected when the programs were triggered? Please provide a comparison table that includes all programs.

Response: Table 7 compares the 2012 adopted demand response RA allocation which was based on the demand response forecast filed on April 1st, 2011 to the 2012 load impact values.

BIP and CBP day-of both have lower enrollments than were predicted for the RA forecast, which explains the difference between the RA forecast and the 2012 actual load impacts. In August and October, the CPP-D load impact is higher than the RA forecast; however, the CPP-D load impacts for September are lower than the RA forecast because the only September CPP-D event occurred on September 15th - a very hot Saturday. Therefore, CPP-D impacts may be lower because the event was on a Saturday and there may also be measurement error in the load impact estimate itself because there were no non-event Saturdays in 2012 or 2011 or 2010 with temperatures as high as September 15th to use for a baseline. Demand Bidding and Small Commercial PTR forecast were not included in the 2012 RA forecast because these programs are new, and CPP-E was not included because we had proposed to cancel it in 2012 at the time the RA forecast was created.

Q. 3: Did the utility observe any evidence of customer fatigue as a result of consecutive DR events on multiple days? If the answer is yes, how much did the customer fatigue affect the load impact?

Response: Effects of customer fatigue on load impacts are difficult to estimate because even when several event days are called in a row, those event days occur on different days of the week and occur at different temperatures, so it can be difficult to discern whether or not changes in load impact are due to the multiple event days or to other factors. PTR events were called 08/09/2012, 08/10/2012, 08/11/2012 and 08/14/2012, and preliminary load impacts were lowest on 08/14/2012, which may possibly be due to customer fatigue. For all other programs, no evidence of customer fatigue shows up in the load impacts. This does not mean that customer fatigue does not exist, just that it wasn't measurable relative to all the other variations in load impacts between events using baseline methods.

a) DR operation

- **DR program information:** provide a summary of all DR program availability (maximum hours/events per month/year), triggering criteria, by the same categories as in 1.a).

  Provide a summary of the DR programs events including total number of hours and events triggered and the list of triggering conditions in comparison with the program maximum hours and events.. For example, if a DR program is has a maximum of 180 hours and it was triggered a total of 22 hours, the comparison should show both 22 triggered and 180 maximum hours.

Response: Please see Table 8.

Table 8 2012 Demand Response Events

Program	Type	Program Season	Available Annual Events/Hours	Available Monthly Events/Hours	Available Weekly Events/Hours	Available Daily Events/Hours	# of Events Triggered	Available Remaining	Trigger Criteria	Trigger Condition
Critical Peak Pricing-Default (CPP-D)	Day Ahead	Year Round	18 Events	No Limit	No Limit	1 Event Always 7 Hours (11am-6pm)	7 Events	11 Events	**Temperature and system load** *Monday: 86°; 3472 MW *Tues-Fri: 84°; 3837 MW *Saturday: 86°; 3837 MW	Met trigger criteria for all 7 events
Capacity Bidding Program (CBP)	Day Ahead	May-Oct Mon-Fri	No Limit	44 Hours	No Limit	1 Event Up to 8 Hours (11am-7pm)	7 Events Aug: 12 Hours (3 events) Sep: 8 Hours (2 events) Oct: 8 Hours (2 events)	Aug: 32 Hours Sep: 36 Hours Oct: 36 Hours	**Price:** *Mon - Friday only *Market Price equal to or greater than 15,000 btu/kWh heat rate *Other Statewide or local system conditions	Mitigate potential price spikes and load forecast above 4000 MW
Capacity Bidding Program (CBP)	Day Of	May-Oct Mon-Fri	No Limit	44 Hours	No Limit	1 Event Up to 8 Hours (11am-7pm)	5 Events Aug:7 Hours (2 events) Sep: 8 Hours (2 events) Oct: 4 hours (1 event)	Aug: 37 Hours Sep: 36 Hours Oct: 40 Hours	**Price:** *Mon - Friday only *Market Price equal to or greater than 15,000 btu/kWh heat rate *Other Statewide or local system conditions	Mitigate potential price spikes and load forecast abolve 4000 MW and/or Real Time Load came in higher than Day Ahead forecast
Base Interruptibile Program (BIP)	Day Of - 30 minute	Year Round	120 Hours	10 Events		1 Event Up to 4 Hours	1 Event 4 Hours	116 Hours	CAISO forecasts a Stage 1 CAISO declares a Stage 2 CAISO calls for interruptible load Extreme weather or system demands or at SDGE discretion.	1 ComplianceTest 2 Met trigger criteria
Summer Saver	Day Of	May-Oct Holidays Excluded	15 Events or 120 Hours	40 Hours	3 Events	1 Event Noon to 8 pm Min 2/Max 4 Hours	8 Events Aug: 15 Hours (4 events) Sep: 10 Hours (3 events) Oct: 4 Hours (1 events)	Aug: 25 Hours Sep: 30 Hours Oct: 36 Hours Annual 91 Hours	**Temperature and system load** *Monday - Friday: 3800 MW *Saturday - Sunday - Optional Participation *CAISO Stage 1 or 2 *Local or system emergency	Mitigate potential price spikes and load forecast abolve 4000 MW and/or Real Time Load came in higher than Day Ahead forecast
Reduce Your Use	Day Ahead	Year Round	No Limit	No Limit	No Limit	1 Event Always 7 Hours (11am-6pm)	7 Events	No Limit	**Temperature and system load** *Monday: 86°; 3472 MW *Tues-Fri: 84°; 3837 MW *Saturday: 86°; 3837 MW	Met trigger criteria for all 7 events
Critical Peak Pricing-Emergency (CPP-E) Terminates Dec 31	Day Of 30 minute	Year Round	80 Hours	40 Hours	4 Events	1 Event	2 Events Aug:1 Event (5 Hours) Sep:1 Event (4 Hours)	71 Hours	Local utility emergency with intent to avoid any firm load curtailment CAISO calls for interruptible load	Conditions warranted by Utility
Demand Bidding	Day Ahead	Jul - Dec 2012 only	No Limit	No Limit	No Limit	No Limit	3 Events 14 Hours	N/A	CAISO 1,2,or 3 Emergency Transmission or imminent system emergency or as warranted by the utility	Conditions warranted by Utility
Flex Alerts in Effect							08/10/13 08/14/13			

* Table 8 is a summary table. To see details, see Tables 1 through 7.

- **Comparison analysis:**

  Q.1: How often was each of the DR programs triggered as compared to the corresponding program availability? Provide a comparison between the program's operating limit and its actual events and hours per month/year.

Response: Please see Table 8.

Q. 2: What were the reasons for any of the DR programs operated under the operating limit, e.g., triggering conditions, customers' annoyance, system load and resource conditions, etc.

Response: **While individual programs may reach temperature and/or load triggers, they may not be activated. This is mainly due to an assessment of need at the time that triggers are met. The program operations group is in constant communication with the energy procurement group and the grid operations group and based on these individual discussions, program operations determines if we have a system need for demand response. If it is determined that we do not need additional load, we do not activate a program. From both a load perspective as well as a customer experience perspective we feel that this is a best practice.**

Q. 3: Provide a comparison of the DR program summer historical operational data for each DR program organized by the three categories listed in I.1.a) from 2006 to 2012: actual number of DR events vs. maximum events, actual total event hours/month or summer vs. maximum event hours/month or summer.

Response: Tables 9 through 11 contain the maximum annual number of events allowed for each program along with the number of events called for each year from 2006-2012. Some programs, like CBP and BIP, have monthly limits on the number of events that can be called as well

Table 9 Number of Events Monthly Nominated Programs						
Category	Program	Year	Maximum Event Hours per year	*Maximum Number of Events*	Number of Event hours called	Number of Events Called
Monthly Nominated Program	CBP-Day Ahead	2006	144	***none***	0	0
Monthly Nominated Program	CBP-Day Ahead	2007	144	***none***	38	8
Monthly Nominated Program	CBP-Day Ahead	2008	144	***none***	4	1
Monthly Nominated Program	CBP-Day Ahead	2009	144	***none***	24	6
Monthly Nominated Program	CBP-Day Ahead	2010	144	***none***	28	7
Monthly Nominated Program	CBP-Day Ahead	2011	144	***none***	19	5
Monthly Nominated Program	CBP-Day Ahead	2012	144	***none***	24	6
Monthly Nominated Program	CBP-Day Of	2006	144	***none***	0	0
Monthly Nominated Program	CBP-Day Of	2007	144	***none***	45	12
Monthly Nominated Program	CBP-Day Of	2008	144	***none***	6	1
Monthly Nominated Program	CBP-Day Of	2009	144	***none***	37	7
Monthly Nominated Program	CBP-Day Of	2010	144	***none***	50	12
Monthly Nominated Program	CBP-Day Of	2011	144	***none***	28	7
Monthly Nominated Program	CBP-Day Of	2012	144	***none***	20	5

Table 10 Number of Events Emergency Programs						
Category	Program	Year	Maximum Event Hours per year	Maximum Number of Events	Number of Event hours called	Number of Events Called
Emergency Program	BIP	2006	120	**10 per month**	2	1
Emergency Program	BIP	2007	120	**10 per month**	4	1
Emergency Program	BIP	2008	120	**10 per month**	No events	0
Emergency Program	BIP	2009	120	**10 per month**	No events	0
Emergency Program	BIP	2010	120	**10 per month**	4	1
Emergency Program	BIP	2011	120	**10 per month**	4	1
Emergency Program	BIP	2012	120	**10 per month**	4	1
Emergency Program	CPP-E	2006	80	**none**	7	2
Emergency Program	CPP-E	2007	80	**none**	14	3
Emergency Program	CPP-E	2008	80	**none**	No events	0
Emergency Program	CPP-E	2009	80	**none**	No events	0
Emergency Program	CPP-E	2010	80	**none**	No events	0
Emergency Program	CPP-E	2011	80	**none**	No events	
Emergency Program	CPP-E	2012	80	**none**	9	2

Table 11 Number of Events Price Responsive Programs						
Category	Program	Year	Maximum Event Hours per year	Maximum Number of Events	Number of Event hours called	Number of Events Called
Price-Responsive	CPP-D	2006	98	12 per year	70	10
Price-Responsive	CPP-D	2007	98	12 per year	63	9
Price-Responsive	CPP-D	2008	126	18 per year	No events	0
Price-Responsive	CPP-D	2009	126	18 per year	56	8
Price-Responsive	CPP-D	2010	126	18 per year	28	4
Price-Responsive	CPP-D	2011	126	18 per year	14	2
Price-Responsive	CPP-D	2012	126	18 per year	49	7
Price-Responsive	PTR	2006	Unlimited	none	No events	0
Price-Responsive	PTR	2007	Unlimited	none	No events	0
Price-Responsive	PTR	2008	Unlimited	none	No events	0
Price-Responsive	PTR	2009	Unlimited	none	No events	0
Price-Responsive	PTR	2010	Unlimited	none	No events	0
Price-Responsive	PTR	2011	Unlimited	none	32	5
Price-Responsive	PTR	2012	Unlimited	none	49	7
Price-Responsive	Summer Saver	2006	120	15 per year	24	8
Price-Responsive	Summer Saver	2007	120	15 per year	43	12
Price-Responsive	Summer Saver	2008	120	15 per year	8	2
Price-Responsive	Summer Saver	2009	120	15 per year	30	7
Price-Responsive	Summer Saver	2010	120	15 per year	44	11
Price-Responsive	Summer Saver	2011	120	15 per year	22	6
Price-Responsive	Summer Saver	2012	120	15 per year	30	8
Price-Responsive	DBP	2006	Unlimited	none	16	4
Price-Responsive	DBP	2007	Unlimited	none	41	9
Price-Responsive	DBP	2008	Unlimited	none	The program was cancelled	0
Price-Responsive	DBP	2009	Unlimited	none	The program was cancelled	0
Price-Responsive	DBP	2010	Unlimited	none	The program was cancelled	0
Price-Responsive	DBP	2011	Unlimited	none	The program was cancelled	0
Price-Responsive	DBP	2012	Unlimited	none	14	3

Q. 4: Provide a comparison of the historical operational data for the utility's peaker plants, e.g, combustion turbines from 2006 to 2012: actual dispatched hours vs. maximum hours allowed by permit.

Response: Historical operational data for our peaker plants are listed in Table 12.

Table 12 – SDG&E's Historical Peaker Plant Operational Hours								
	Cuyamaca		El Cajon Energy Center		Miramar		Orange Grove	
	Run Hours	Emission Allowance	Run Hours	Emission Allowance	Run Hours	Emission Allowance	Run Hours	Emission Allowance
2006					200	5000		
2007					250	5000		
2008	373	N/A			671	5000		
2009	625	N/A			1919	5000		
2010	481	N/A	438.9	2500	2946	5000		
2011	667	N/A	432.8	2500	4306	5000		
2012	1621	N/A	973.9	2500	4805	5000	2147.9	6400

*Please note: some data is missing for certain peaker plants either because they were not in existence at the time or because the plant has not provided the data. The Cuyamaca peaker plant does not have an emission allowance.

2. CAISO Markets

a) Price spikes

- Provide a mapping of the day-ahead or real time wholesale energy price spikes and the DR events for each of the summer months (June, 2012 to October, 2012).

Response: Please see "Attachment F – Price Spikes". **Please see Attachment 3-Price Spikes. SDG&E's Demand Response programs are designed to respond to the day a-head market issues. These programs were not designed to respond to 15 minute price spikes. Attachment 3-Price Spikes illustrates that on a day a-head basis SDG&E DRP program activation appears to have high positive correlation with high prices. Because our**

programs are not designed to respond to the real-time market, there appear to be anomalies where the day ahead prices were very low, resulting in no program activation. This would remain true even if there are real time price spikes the following day.

b) Market analysis

Q.1: Were price-responsive DR programs used to avoid paying for and mitigating these price spikes? If not, why not?

Response: No, price-responsive DR programs are not able to mitigate the price spikes in the real time market. Bidding for the Day-Ahead Market closes at 10AM the day before the trading day and consists of a sequence of processes that determine the hourly Market Clearing Prices for Energy (including physical and Virtual Bids) and Ancillary Services, as well as the incremental procurement in RUC while also mitigating Bids from to address non-competitive constraints. These processes are co-optimized to produce a Day-Ahead Schedule at least cost while meeting local reliability needs.

Bidding for the Real-Time Market (RTM) and Hour-Ahead Scheduling Process (HASP) closes 75 minutes before the beginning of each Trading Hour (which, in turn, begins at the top of each hour). A sequence of processes determines the Marketing Clearing Prices for each Trading Hour. The prices resulting from these processes are used for the HASP and Real-Time Market Settlement. HASP is performed immediately after the Real-Time Market Power Mitigation. All HASP Schedules for the Trading Hour are published approximately 45 minutes before the start of each Trading Hour.

Q.2: If the answer to Q.1 is yes, did the utility observe any change in market prices or impact on supply constraints or congestion experienced in the market?

Response: Not applicable.

Q.3: If the answer is to Q.1 is no, are there any current DR programs that could be modified to address the price spikes (day-ahead or real time)? What are the specific modifications and does it make sense to make those changes?

Response: Due to the timing of the market closing and other processes that determine the hourly market clearing process for energy, it is very difficult to align with the real time market price spikes that occur. We are proposing a 30 minute product for those customers that can contribute large loads, which gets us closer to responding to the hourly pricing. We have noted in our response to question 2.a that for the most part, our programs and processes have done a fairly accurate job of predicting the spikes and the need for load even on a day ahead basis.

Q.4: For DR programs that have a price trigger, was the trigger set too high or too low? Was it reasonable?

Response: Our only DR program with a price trigger is Capacity Bidding Program (CBP). CBP uses a 15,000 btu/kWh heat rate for a proxy. This is a reasonable proxy.

3. Customers' Experience

- **Alignment between DR program operation & design and customers' expectations:**

Q. 1: What was the utility's overall customer experience with the DR programs in summer 2012?

Response: Overall, the customer experience for the summer was very positive. Programs worked hard to deliver notifications to customers earlier than required. These helped customers, both commercial and residential, prepare for the event day. Critical Peak Pricing Default (CPP-D) noticed notification bounce-backs decreased compared to previous years. Peak Time Rebate (PTR) introduced the ability to view event day results online for residential customers. This new experience encountered some issues or confusion that will be clarified through educational efforts about PTR, peak hours, energy consumption, demand response, and our online presentment tool in 2013. Preliminary survey results indicate that most customers reacted positively to the program, and only 129 complaints (0.01% of the eligible population) were received by the Customer Contact Center. We also had 718 calls (0.06%) from customers who wanted clarification on the program. About 28% of the calls were regarding online presentment through My Account.

Q.2: What feedback (complaints or problems) did the utility receive from customers about the DR events?

Response: CPP-D received some customer complaints regarding the various channels of notification. Some customers that were signed up for notification through multiple channels may not have received all of their notifications by 3pm due to firewalls on customer's IT servers.

More than half of the feedback for Summer Saver customers was due to uncomfortable temperatures from the A/C cycling.

For PTR, almost a quarter of customer complaints (24%) were from customers expressing the desire to add outbound dial alerts. A few customers were confused about how the CRL was calculated and displayed in My Account. Since the PTR credit is awarded for whole kilowatt hours, some customers who did not receive a credit felt they deserved a credit for partial kWh reduction below their CRL. A number of callers also wanted the CSR to inform them of their CRL instead of logging in to My Account to view it. PTR also experienced an issue with customers not receiving their alerts on time due to a firewall policy on the internet service provider's (ISP) side. No feedback was received from small commercial customers on PTR.

We were very concerned about potential confusion between Flex Alerts and Reduce Your Use days. We saw the need for very careful education about the difference between the two wherever possible, in order to mitigate customer complaints under the scenario where a Flex Alert could be called, Reduce Your Use not called, and then the customers expect to get a bill credit based on their conservation. The following messaging was crafted and posted to our website as well as distributed via outreach training and the media to help combat customer confusion:

> *Reduce Your Use days vs. Flex Alerts: What's the difference?*
>
> *A Reduce Your Use day is broadcast by SDG&E, and in return for saving energy, we credit you with a reward on your bill when you conserve on these specific days. A Flex*

Alert is issued by the state of California, and while there is no incentive for participating in a Flex Alert, it is important to help the California Independent System Operator (CAISO) maintain reliability by saving energy when one is called.

In the end, we decided to always call a Reduce Your Use day event if Flex Alerts were called by CAISO so that customers would not encounter this particular issue.

The following section is redated.

<u>Q.3: Based on the feedback received by the utility, did any of the customers (and the percentage) feel that there were too many DR events last summer?</u>

Response: Preliminary survey results indicated some Critical Peak Priding Default customers have stated "It costs us a lot of money to have multiple events consecutively." Some customers are concerned that they are going to pay more than they would on an alternative rate and may end up opting out next year. No other programs have received customer feedback regarding the number of events called in the summer of 2012.

<u>Q.4: Did any of the customers (and the percentage) feel that the incentives they received were too low or unfair?</u>

Response: A very small number of residential customers, and were unhappy with incentive levels. Only 10 (>1%) Summer Saver customers out of 28,755 left the program because they felt the incentives were too low or unfair. Based on customer feedback received by the Customer Contact Center, a very small percentage of PTR customers (0.0001%) felt that either the credits for only whole kWh was unfair, or that the credit amount of $0.75 was too low.

Limited commercial customer and aggregator feedback indicates that incentive levels may be lower than customers would like. Aggregators for the Capacity Bidding Program suggest there is potential for increased enrollment in Capacity Bidding Program if the incentives were increased. Higher incentives could potentially create economic viability for enrolling customers with smaller load shed capabilities where it does not exist at today's levels. Two Demand Bidding customers (six accounts), representing 100% of the program population have indicated that incentive levels for the program were not high enough.

Q.5: Are there any lessons learned from the customer perspective particularly for AC cycling, Peak Time Rebate, Demand Bidding Program, Capacity Bidding Program, Critical Peak Pricing, 10-in-10 program?

Response: PTR customers gave us some insight into how residential customers feel about demand response, and how much they know about their energy usage. Some customers were under the impression that we have real–time energy usage data available. This led to some confusion surrounding the availability of the Customer Reference Levels before events, and results after events.

Preliminary analysis on customer participation and reduction levels indicates that awareness of the program and events are key to a customer's success on event days. Customers who actively signed up for event alerts, along with customers who were enrolled in a special program (San Diego Energy Challenge, HAN program or Pilot, etc.) had much higher average reduction levels than those customers who either received an alert as a result of being registered in My Account or who received no alert. We will continue to focus on increasing customer awareness, and thus participation in 2013 and 2014. Many customers requested an outbound dial option to alert them of events. Although that was not available in 2012, it is something that we are working on for 2013 and beyond.

The addition of PTR for Small Commercial customers in 2012 gave us the chance to evaluate the reaction of non-residential customers to this type of program. These customers signed up for alerts at a much lower rate than residential customers, and provided less load reduction. This is likely due to the structure of the program, and their limited ability to reduce their energy use between the hours of 11:00 am and 6:00 pm.

The 2012 Summer Saver program (AC Cycling) exhibited patterns that were consistent with previous year's responses. There are several program controls in place to help mitigate customer concerns surrounding these findings.

- **Customer awareness and participation:** provide an analysis of the Peak Time Rebate program on customer participation and free ridership.

Q. 1: Which group(s) of customers (those who signed up for notification, those who received notification through My Account, those without direct notification) provided the most load reduction under each DR program and what was the reason(s)?

Response: Customers who signed up for notification provided the most load reduction. Differences in load impacts between customer enrolled in My Account and those without direct notification were not large enough to be measured with preliminary estimation methods. However, one should not conclude that there was no difference in load impacts between these two groups of customers until formal measurement and evaluation results are available.

Q.2: Were the DR event notification systems effective?

Response: PTR event notifications were largely effective, enabling program staff to alert customers via email or text message in a timely matter the day before an event. Customers who received the email through an action on their part (signing up) produced the most load reduction, compared to those who received the alerts by default, or those who received no alerts.

During the 2012 season, 3,565,858 pre-event alerts were sent to residential customers for PTR, and 124,073 were sent to commercial customers.

One email provider's system held and throttled our emails, resulting in quite a few customers receiving their email alerts late (up to a few days after the event). This issue could not be resolved with the provider, but a workaround was established between us and the alert vendor.

- **Program Evaluation**: it is our understanding that SCE is doing a program evaluation of its 10-in-10 program and SDG&E is doing an evaluation of its Peak Time Rebate program. To the extent that these evaluations are available by January 2013, the utilities should submit these reports to the CPUC for consideration.

Response: We will submit the evaluation of our Peak time Rebate program to the CPUC for consideration as soon as it is available.

4. **Coordination with CAISO and Utility Operations**

- Daily and Weekly DR Reporting

  Q.1: From the IOUs' perspective, was the daily and weekly DR reporting helpful to the utility? What could be improved?

Response: Initially, the demand response forecast reporting requirements for 2012 summer were difficult to provide by the times that the ISO and ED wanted. Our software was not configured to provide output in the format that the ISO and ED desired. Once initial changes were designed and implemented the process went relatively smoothly, until the next change was identified by the ISO and ED. The software that we use to prepare our DR forecast is in a production environment and requires programming and testing as it resides on a server supported by our IT group. All changes (even seemingly small ones) must go through IT's processes for testing before going into production. Therefore, we request 30 day-ahead notification for any changes to the DR forecast template.

When the day-ahead events are triggered, the DR forecast is updated near the end of the work day and provided to our internal distribution. The DR program area then sends the forecast to the ISO, ED and CEC. The forecast that is provided before 8am daily only has information from the prior day (for any day ahead events that may have been triggered). Therefore, when the DR Program and/or the electric procurement groups initiate the triggering for our "day of" programs, it is appropriate that those groups send the updates out to the external groups when the decision to trigger the event has been made.

We would like to recommend that the group where the forecast originates (Load Analysis) send the initial DR forecast that it provides to the ISO, ED and CEC. This would alleviate some of the redundancy that currently exists in the process. Currently, the Load Analysis group sends the DR Forecast to our internal personnel, and then the DR program personnel, in turn, provide it to the external groups: ED, CEC and ISO personnel.

We also recommend that the weekend DR forecast be sent on Friday afternoon and that it covers the forecast days: Saturday Sunday and Monday. Additionally, we propose that this weekend forecast will only be updated in the event that DR events are triggered for Saturday, Sunday or

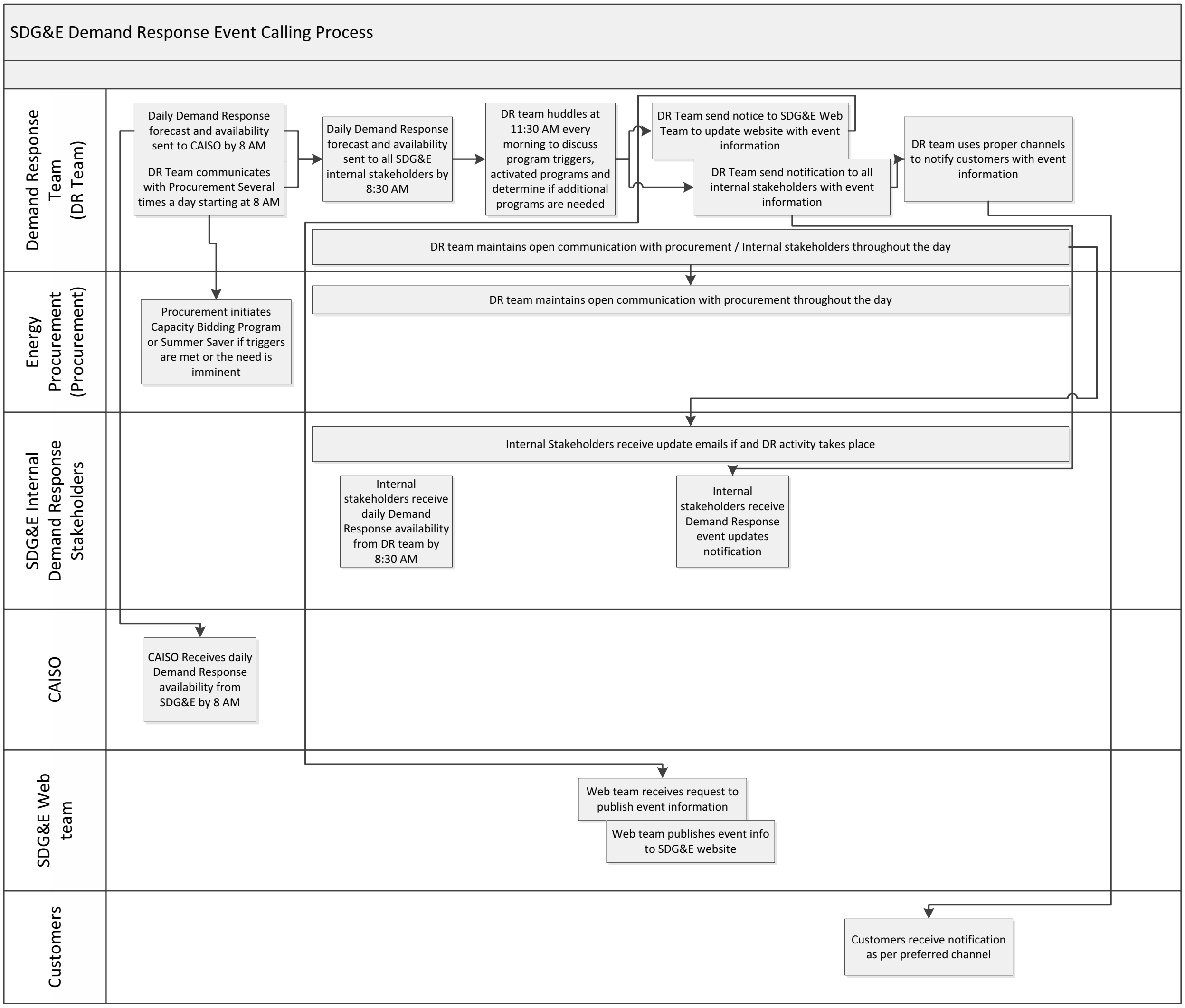
Monday (day of for Saturday and Sunday and day ahead programs for Sunday and Monday). The normal weekday DR Forecast process would resume Monday mornings.

<u>Q.2: Please describe communication and coordination efforts between utility DR program staff and utility procurement staff and grid operation staff on day-to-day usage of demand response programs.</u>

Response: The Demand Response (DR) team sends out daily forecasts for demand response availability to CAISO by 8 a.m. The DR team also distributes email communication containing information regarding available demand response resources and any program activation to all internal stakeholders by 9 a.m. Updated communications are sent out as situations change. DR staff also monitors San Diego Gas & Electric's website to ensure correct event information is posted and/or removed at the correct time.

The DR team starts communication with energy procurement at 8 a.m. every day and maintains an open communication channel with multiple contacts throughout the day. At 8 a.m. procurement informs the DR team of the need to activate Capacity Bidding Program day-of or Summer Saver program. If the programs need to be activated, the DR team will ask the San Diego Gas & Electric web team to publish event information on the website. The DR team then updates all internal stakeholders with event information and sends out customer notifications through proper program based channels.

The DR team huddles at 11:30 a.m. every day to discuss program triggers, currently activated programs and determine if additional programs need to be activated. If the situation warrants, the DR team requests changes made to the website, notifies internal stakeholders and send out appropriate customer notifications.



- DR coordination/communication

  Q.3: What are the utility's internal operational procedures for the DR programs (price responsive and emergency)? Provide examples of how the utility triggered and communicated DR events with its energy center and grid operator for August 8, 9, 10, & 14, 2012, September 14, 2012, and October 2, 2012.

Response: Please see the response to Q2. The processes for price responsive and emergency programs are the same as all other programs.

  Q.4: Were the DR forecast communicated to the utility's energy center and grid operation consistent with what had been reported to the CAISO in the Daily DR Reports? If not, why?

Response: Our DR forecast is the same forecast file that is provided internally and externally and is consistent with what is reported to the CAISO.

  Q.5: Are there other coordination/communication issues between the IOUs and CAISO that the Commission should address by summer 2013?

Response: In our responses to question 6 "Flex Alerts", we address coordination/communication issues specific to Flex Alerts. As outlined below, there is a lack of understanding and coordination between the IOUs and CAISO on triggers for Flex Alerts and how/why they may be called. For this reason, we requests that CAISO provide specific triggers for how/when Flex Alerts are called, as well as provide advanced notification of at least two hours before the information is distributed to the media and general public so that we can adequately prepare our own systems and coordination with local media.

5. **Emergency DR Dispatch Order**

Dispatch order: Under the CAISO's current emergency operational procedure (No.4420, Section 3.3.2) and pursuant to the Settlement Agreement adopted in D.10-06-034), the utilities' Base Interruptible Program (BIP) and SCE's API program and commercial AC cycling program cannot be dispatched until after the CAISO dispatches non-RA resources and canvases other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties.

Q.1: If CAISO's dispatch order was revised such that non-RA resources and other entities /balancing authorities are dispatched AFTER BIP, AP-I, and commercial AC cycling programs are dispatched, would that revision have resulted in additional BIP, AP-I and commercial AC cycling events in 2012? If so, how many events, and on what days?

Response: In order to fully answer this question we would need the number of times and days that the CAISO had to dispatch non-RA resources and canvas other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties in San Diego service territory. We have requested this information from the CAISO and have yet to receive the data.

Q.2: Should this dispatch order be moved up in the operational procedure so the CAISO can dispatch the emergency DR before dispatching non-RA resource and canvassing resources from outside of its system? If the answer is no, explain why emergency DR (which is an RA resource) should be dispatched after the CAISO dispatches non-RA resources.

Response: At this time the load reduction capabilities of Base Interruptible Program (BIP) are very small and we do not see the value that would be gained from modifying the Settlement that was reached in Resolution E-4220. BIP has had all of its individual marketing dollars disallowed, so it is unlikely that we can effectively grow this program to a size that would have a significant impact on this discussion.

Q.3: If the answer is yes, how can the dispatch ordered be changed? What is the best process to address this issue?

Response: Not applicable.

6. **Flex Alert (If the utility needs additional time for the analysis, it can be provided in the January 31, 2013 updates or supplemental testimony).**

- **Effectiveness:** provide a mapping of the CAISO's Flex Alert(s) and the utility's DR events. For the Flex Alert(s) that coincided with the utility's DR event(s), provide the utility's best estimate of the load impact that can be attributed to the Flex Alert(s).

Response: There were only two Flex Alerts called in 2012. Both occurred in August (10th and 14th). On both dates, our Reduce Your Use programs for Residential and Commercial were activated. SDG&E has no way of ascertaining the load impacts for Flex Alerts.

If there was no DR event during a Flex Alert, provide the utility's best estimate of the load reduction that it observed, that can be attributed to the Flex Alert(s).

Response: In order to avoid customer confusion, PTR events were called on all flex alert days so there were no flex alert days without demand response. An alternate method of attempting to quantify the effects of flex alert day in theory would be to look at the load reductions on PTR event days when no flex alert was issued compared to PTR days when a flex alert was issued. However, the three PTR event days for which a flex alert was not called are not comparable to the 4 PTR events when a flex alert was also called[2]. Two event days had significantly cooler temperature than the flex alert PTR days, and the third was the extremely hot Saturday, September 15th, which is a very unique event with no comparable non-event days available that will be difficult to estimate. In addition, preliminary results indicate that PTR load reductions were 4% or less, and the difference in load impacts between a PTR event with a flex alert and a PTR event without a flex alert will be even smaller and there are limits on how precisely load impacts can be measured.

Provide the methodology (ies) for the estimates, e.g., methods similar to the Ex Post load impact analysis.

Q 1: What was the utility's experience with the Flex Alert? Was there any communication between the CAISO and the utility prior to the issuance of the Flex Alert and coordination for the DR events?

Response: The CAISO media/information office held weekly 30 minute conference calls beginning in early July that ended at the end of September. During those calls, the media/information office would share a weather forecast for the upcoming week and some general comments about whether or not they felt that Flex Alerts were potentially on the horizon. We requested specific Flex Alert triggers from CAISO on several occasions, but never received that information. The biggest gap in communication came when the two Flex Alerts this summer were actually triggered on 8/9 (for 8/10, 11 and 12) and on 8/13 (for 8/14). The IOUs did not receive any kind of official advanced notification that Flex Alerts would be called; we only received the same media alert (email and phone call) as the news media, the general public, etc. The same situation occurred when CAISO ended up cancelling the Flex Alert for 8/11 and 8/12. We received no advanced notification from CAISO, only the same media release that was issued statewide. This caused a good amount of confusion both internally at SDG&E as well as with the local media who were trying to decipher whether or not conservation was still necessary based on messages coming from CAISO regarding Flex Alerts and messages coming from us regarding the concurrently running Reduce Your Use days.

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[2]Strictly speaking there were only 2 flex alert days August 10th and August 14th. However, a flex alert was originally issued on August 9th for August 10th-Augsut 12th but the Aug 11th and 12th alerts were later canceled. Therefore SDG&E does not believe it would be valid to treat the PTR events on August 9th and August 11th as non flex alert days for the purposes of load impact analysis.

Q.2: What was the customers overall experience with Flex Alert? Were there any customer confusions between the Flex Alert and the utility DR event notifications?

Response: We have not yet officially evaluated customer confusion between Flex Alerts and Reduce Your Use days (or other DR programs). However, internal discussions have focused on the difficulty of educating the media, stakeholders and customers regarding the difference. As addressed in Question 3 on Customer Experience, we crafted a message point for distribution to help differentiate the two programs, but it was apparent through watching news stories and via social media monitoring that a good level of understanding was not there. We would recommend that a formal evaluation take place on customer understanding of the differences between local demand response programs, like Reduce Your Use, and Flex Alerts in order to help inform both the IOUs and CAISO on future messaging and differentiation.

Q.3: Should the Flex Alert be continued for 2013 and 2014? If so, are there ways to improve the effectiveness of the Flex Alert program?

Response: We have requested funding for continuation of the Flex Alert program in 2013 and 2014 as part of the Statewide Marketing, Education and Outreach (SW MEO) application, A. 12-08-009. The funding requested for two years is $2M, which was based on the authorized amount of $1M for 2012 in D. 12-04-045. ~~**Based on the success of our local outreach effort, as described further below, we are formally requesting with this application that we move $200,000 currently requested for Flex Alerts from the Statewide Marketing, Education and Outreach proceeding (A. 12-08-009) for continuation of the Conservation Partners campaign, as described below.**~~

Based on our support of SCE's proposals regarding continuation of Flex Alerts that they describe in A.12-08-008, funding for Flex Alerts could entirely be removed from the SW MEO applications and management oversight be transferred back to the DRP proceeding, so that the Commission and IOUs would be able to appropriate direct, measure and evaluate the effectiveness of any further Flex Alert efforts. SDG&E will make this consideration A.12.08-009.

Based on experience from the summer of 2012, we are proposing one modification to the Flex Alert program as proposed in A. 12-08-009. In May of 2012, the Commission expressed a clear objective regarding the need to educate lower income and hard-to-reach communities on the need for conservation. The contractor/implementer of the Flex Alert campaign, who also happens to own the trademark to the Flex Alert brand name, expressed an inability to effectively undertake the requested community outreach. At an April 23, 2012 meeting with CAISO, Commissioner Sandoval and staff, representatives from the Commission's Energy Division, Public Information Office and Business Community Outreach offices, and the three electric IOUs, it was agreed that SDG&E and SCE would implement this community outreach in their respective service territories. Based on this direction, we budgeted $100,000 and created the "Community Partners" program. Through this program we requested local community-based organizations (CBOs) to submit proposals on how they could best communicate with their own constituencies. We scored the proposals based on demographic reach, the organizations ability to meet education objectives, their creativity and a proposed timeline.

Thirty-six CBOs received a total of $91,000 in funding from us to promote education around conservation, including both Reduce Your Use days and Flex Alerts. The remaining $9,000 was used to fund the creation and distribution of flyers, posters and videos, and the costs associated with training days for the CBOs. The agencies were all brought together in July 2012 for a training session, where the materials were provided. The agencies then took the materials and used them to execute their own tactical plans, including contests and games for children, extensive social media outreach, videos, blogs, education for disabled adults and other grassroots outreach through events and media. On Reduce Your Use and Flex Alert days, the agencies were able to use their own extensive social networks to tweet and post messages about the need for conservation during that day.

Campaign results indicate that we reached 250,000 additional hard-to-reach customers through the social media efforts of the CBOs, including total daily reach of 44,000 customers through Facebook on event days, increased reach through Twitter, 5,000 video views of Flex Alert ads in Vietnamese, and 12,000 listeners hearing Vietnamese translated Flex Alert ads five times on the one in-language radio station in the San Diego media market.

With regard to continuation of Flex Alerts as a mass media campaign, we support SCE's recommendations in their SW MEO testimony for A.12-08-007 as outlined in testimony, Chapter 3, Section E (page 25.)

> **"E. Long-Term Planning for Statewide Emergency Alert Program**
>
> Although the IOUs are committed to continue funding for statewide emergency alerts (i.e., Flex Alert) in 2013-2014, SCE suggests that the Commission reevaluate beginning in 2015 whether CAISO should take over full control of the statewide emergency alert program. Since its inception in 2004, the IOUs have provided exclusive funding for both messaging and operations of the program although there has only been one emergency alert event called in the previous five years (in 2007). A key reason for0 this declining need for emergency alerts is due to the growth in IOU DR programs, which have1 positively impacted grid reliability. Additionally, energy use has decreased as an outcome of the economic downturn.
>
> In those historical instances where an event was called, the statewide emergency alert program benefitted not only CAISO, but also the other load serving entities (LSEs) throughout the *entire* State of California. SCE has determined that the current funding mechanism for CAISO's emergency alert program is detrimental to California IOU ratepayers, because neither the CAISO nor the other LSEs within the state contribute any funding for the management and messaging of the program.
>
> As such, SCE recommends that beginning in 2015 the Commission no longer direct the IOUs to fund operations of the CAISO's statewide emergency alert program and should fully transition the responsibility to the CAISO. This will allow sufficient time for the Commission to evaluate and implement the transition to CAISO such that it may seek funding through its Grid Management Charge (GMC) cost recovery. This will provide equity to all California ratepayers that everyone is contributing to the statewide emergency alert messaging. This inequity with emergency alerts does not exist with IOU local programs because not all LSEs have DSM programs.
>
> Furthermore, CAISO supports the sole use of the existing emergency alert brand (i.e., Flex Alert), whereas the IOUs are open to alternatives. CAISO has recommended, and the Commission has directed, that the IOUs continue to use the existing brand. However, this limits the IOUs' ability to contract the marketing functions because the ownership of the trademark does not reside with either the IOUs or the Commission. Rather, the contractor that initially

established the campaign in 2004 owns the trademark. As a result, the IOUs are currently funding a program name to which they have no claim or legal authority. Unless CAISO supports a different brand name, the IOUs will be required to continue a sole source contract with the owner of the existing statewide emergency alert brand and trademark.

Additionally, IOUs managing the statewide emergency alert program do not have the discretion of when to launch the program. Since CAISO is the only entity that can launch the program, the IOUs' role is limited and thus highlights the need for CAISO to assume total ownership.

Finally, managing the program to accommodate CAISO's desired scope while balancing IOU specific regulatory constraints can be difficult. For instance in summer 2012, CAISO requested the IOUs share statewide emergency alert messaging with the Federal Electricity Commission (CFE) in Baja, Mexico, in an effort to promote energy conservation in that region, despite the fact that the existing ratepayer-funded statewide emergency alert program messaging would air outside of the IOUs' service territories.

For these reasons, SCE recommends the Commission remove the requirement for the IOUs to solely fund the CAISO's statewide emergency alert program after December 31, 2014. SCE further recommends that the Commission defer this authority to CAISO. This transition should be directed to occur during the 2013-2014 bridge cycle to address the funding and operational challenges for the IOUs highlighted above and to provide the CAISO the opportunity to seek funding in its GMC cost recovery."[3]

[3] A.12-08-008. SCE testimony of Kazuko "Marti" Ochiai. Section 3E, page 25.