Rulemaking No: R.13-09-011
Exhibit No: ___________
Witness: George Katsufrakis

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	R.13-09-011 (Filed September 19, 2013)

PREPARED DIRECT TESTIMONY OF

GEORGE KATSUFRAKIS

CHAPTER IV

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILIITES COMMISSION OF THE STATE OF CALIFORNIA

May 6, 2014

SDGE

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF

GEORGE KATSUFRAKIS

CHAPTER IV

PHASE THREE ISSUES AND QUESTIONS

SUPPLY RESOURCES ISSUES AND LOAD MODIFYING RESOURCES ISSUES

PHASE TWO REMAINING ISSUES AND QUESTIONS

BACK-UP GENERATORS

The purpose of my testimony is to respond to questions posed in Attachment A of the *Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings*, dated April 2, 2014. I am employed by SDG&E and hold the position of Manager of Operations, Customer Programs and Projects. My business address is 8335 Century Park Court, San Diego, CA 92123. My full statement of Witness Qualifications is set forth as part of my Prepared Direct Testimony.

I. SUPPLY RESOURCES ISSUES

Question 1: Parties requested the Commission to analyze the characteristics of each demand response program in order to categorize current and future demand response programs into load modifying resources and supply resources. Provide your list of characteristics that the Commission should use in determining how to categorize a supply resource.

Response 1: A supply resource is defined as: resources that are integrated into the California Independent System Operators energy markets."[1] To be integrated into CAISO markets supply resource should meet SDG&E's Rule 32 requirements to be able to be bid in as a Proxy Demand Resource (PDR) or Reliability Demand Response Resource (RDRR), and have the ability to provide certainty of load drop when called upon.

[1] Decision 14-03-026 of Rulemaking 13-09-011 at p. 28.

Question 2: Using your proposed list of characteristics, describe each demand response program and determine whether that program should be classified as a supply resource, as defined by D.14-03-026. Using your list of characteristics, describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Supply Resources.

Response 2: As it stands today, SDG&E believes that Capacity Bidding and Base Interruptible programs could be modified to meet characteristics required to be a supply resource. These programs could be modified so as to meet SDG&E's Rule 32 requirements because they meet RA requirements and are a good fit for the existing wholesale products. At this current time, other load modifying demand response programs are not a good fit to be classified as supply resource because of the complexity involved in integrating and managing large numbers of customer enrollments into the existing CAISO market products. SDG&E would propose workshops with all stakeholders to determine whether, and if so how existing programs might be modified to fit for supply resource classification. Until modifications of existing programs are adopted, SDG&E plans on integrating a portion of its Capacity Bidding program into the wholesale market to test feasibility and operational complexity. In addition, Rule 32 allows any customer to move to an aggregator to become part of a supply DR resource.

Question 3: Please provide your overall comments on the Demand Response Auction Mechanism (DRAM) provided in Attachment B.

Response 3: SDG&E's response is contained in the testimony of David Barker.

Question 4: In D.14-03-026, the Commission discusses its policy of increasing the amount of demand response integrated into the CAISO market. Provide your thoughts on how we can determine an appropriate annual goal for overall demand response integrated into the CAISO market. Are there terms that we need to identify and define? What should those terms and definitions be?

Response 4: SDG&E's response is contained in the testimony of Dave Barker

Question 5: Do we need to improve forecasting with regard to supply resources that will be integrated into the CAISO energy markets? What are methods to improve the forecasting? What are methods that the Commission can use to modify current demand response programs to meet forecasted needs? What are methods that the Commission can use to design new programs to meet forecasting needs?

Response 5: Most of SDG&E's demand response programs and rates go through both process and load impact evaluations. One method that can improve current programs is to conduct process evaluations. The goal of conducting a process evaluation is to enhance a participants' ability to participate in DR program events, increasing enrollment in DR programs, and improving customer operational efficiency, which reduces costs and increases satisfaction.

Building process evaluation activities into program implementation and using the results of these activities to conduct continuous quality improvement is an important strategy in DR program practice. Both qualitative and quantitative research methods are used in process evaluation, where the qualitative methods provide the more detailed, in-depth, language, context and relationship between ideas that best informs program process. SDG&E currently participates in the Demand Response Measurement and Evaluation Committee (DRMEC) which is the group that oversees the load impact and process evaluation studies for the IOUs.

On April 1st of each year, SDG&E files it's Executive Summary for all of its demand response activities. The executive summary includes ex post information on the previous year's program performance and ex ante information in monthly format for the coming 10 years. Ex ante estimates are provided at the program and portfolio level for 1 in 2 and 1 in 10 weather conditions. These reports are made available to the public and are posted on the utilities' website. The best available information is used for these forecasts at the time it is being developed. In addition to this annual DR forecast, SDG&E provides a daily demand response forecasts for all of its demand response activities. Starting each year on May 1st, prior to 8am the DR forecast is provided as a 7 day rolling forecast daily including weekends and holidays. This forecast is submitted to the CPUC, CAISO and the CEC. This forecast is used when DR events are initiated and it utilizes information such as: past performance, number of customers enrolled, weather conditions, day of the week, month etc.

In response to SONGs being decommissioned, the CPUC issued D.13-07-003 on July 11, 2013, which adopted findings included in a Staff report prepared by Energy Division and directed:

> "…the Demand Response Measurement and Evaluation Committee (DRMEC) to work with the CAISO and Commission staff to develop improved forecasting methodologies beginning, on a limited basis, this summer."[2]

In addition, D.13-07-003 directed SCE and SDG&E, as representatives of DRMEC, to submit a report by January 31, 2014, via a Tier One Advice Letter (Exhibit attached) demonstrating the forecasting methodologies pursued, the results, and recommendations for daily forecasting for 2014 and beyond[3]. The report includes the revised daily forecasting methodologies piloted during the Summer of 2013, forecasting methods by program, and suggestions for improvements for the 2014 daily DR forecast.

Question 6: D.12-04-045 (pages 185-192) discussed the future of demand response and questioned what the roles of the utilities and third party providers would be in administering future programs. We look at the roles of utilities and third party providers in administering supply resources. Provide your comments on whether a utility- centric model for supply resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provide supply resource demand response to meet current and future needs. As discussed in D.12-04-045, should the Utilities continue to offer rate- regulated supply resource demand response if these services are provided through competitive markets? Should the Commission focus on identifying more of these programs as supply resources, thus facilitating broader competition in the market? Should the utilities' role be solely to oversee the competitive procurement?

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[2] D.13-07-003, p 10
[3] D.13-07-003, p13

Response 6: SDG&E believes that third party providers, working closely with the utilities, will be able to help meet future supply demand response needs. Because of the utility's responsibility in providing reliable electrical service, utilities must continue offering ratepayer funded fast acting day-of load modifying programs.

The utility must also maintain control over resources in its territory including third party supply resource providers to help address local distribution needs. SDG&E should have the right, under conditions that prevent opportunities for self-dealing, to participate and compete in providing cost effective supply resources.

Question 7: For supply resources integrated into energy markets without a capacity contract, does the Commission have any role in tracking the resources' load impacts?" If yes, how should the load impacts of these resources be tracked and accounted.

Response 7: Resources integrated into energy markets without a capacity contract should be governed under the existing Rule 32 for direct market participation. Tracking of the load impacts would fall outside the utility jurisdiction.

II. LOAD MODIFYING RESOURCES ISSUES

Question 1: Parties requested the Commission to analyze the characteristics of each demand response program in order to categorize current and future demand response programs into load modifying resources and supply resources. Provide your list of characteristics that the Commission should use in determining how to categorize a Load Modifying Resource.

Response 1: SDG&E recommends classifying all products that do not qualify as supply resources into the load modifying category.

Question 2: Using your proposed list of characteristics, describe each demand response program and determine whether that program should be classified as a supply resource, as defined by D.14-03-026. Using your list of characteristics, describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Load Modifying Resources.

Response 2: All the demand response programs except for capacity bidding and base interruptible should remain as load modifying, subject to the outcome of workshops to determine whether, and if so how existing programs might be modified to fit for supply resource classification. SDG&E is open to ideas and opportunities about moving these resources into the supply category and proposes workshops to help determine if others could be modified to do so.

Question 3: How can the Commission improve current programs designated as load modifying resources in order to meet forecasted needs? As we discussed above, does the Commission need to improve forecasting for Load Modifying Resources? How?

Response 3: See above response to forecasting for supply resources. SDG&E forecasts both supply resources and load modifying resources. As these markets evolve, so will the forecasting requirements and methodologies.

Question 4: In R.07-01-041, the Commission included in the scope of the proceeding, the intention to set annual goals for load impacts. How should the Commission determine those goals for Load Modifying Resources? Does the Commission have any guidelines in place that it could use as a starting point for establishing rules to comply with these goals?

Response 4: On January 25, 2007, the CPUC initiated R.07-01-041, *Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols*. The purpose of the rulemaking was to develop effective demand response programs for investor-owned utilities. This rulemaking had four primary goals:

1. Establish a comprehensive set of protocols for estimating the load impacts of DR programs;

2. Establish methodologies to determine the cost-effectiveness of DR programs;

3. Set DR goals for 2008 and beyond, and develop rules on goal attainment; and,

4. Consider modifications to DR programs needed to support the California Independent System Operator's (CAISO) efforts to incorporate DR into market design protocols.

On April 18, 2007, a scoping memo and ruling was issued that set the scope and procedural schedule for the proceeding. Among other things, the scoping memo directed the utilities to file their 2009-2011 DR programs no later than June 1, 2008. The scoping memo also identified a Phase 1 of the proceeding where goals 1 and 2 were to be worked on in a simultaneous parallel process. Phase 2 of the proceeding was to deal with goal 3 and a yet to be determined phase is to address goal 4.

For reasons identified below, SDG&E does not believe that DR goals are necessary. As discussed previously in the testimony of Liying Wang, the Commission had established goals that were a percentage of SDG&E's total system load, however:

- The DR goals did not take into consideration the loads that Energy Service Providers served, that were counted in the overall system load percentage.
- The current cost effective framework for DR is useful as it helps to identify programs that are cost effective and in identifying those programs that aren't to be discontinued.
- SDG&E has already implemented dynamic rates for its largest customers.
- SDG&E is working with the CPUC and other stakeholders in the current residential rate reform OIR, as well as implementing dynamic rate design for its small commercial customers. SDG&E believes that with the current CE framework and rate reform efforts, that MW targets are not necessary. SDG&E's goal is to deliver accurate price signals to its customers, creating a market that will ultimately lead to the most effective and efficient load impacts.

Currently, a significant portion (51%) of SDG&E's industrial customer class (those over 500 kW) are Direct Access (DA). Additionally SDG&E's commercial class also has approximately 20% of its load DA. The DA customer load was included in the overall system load percentages and therefore was included in the DR goals – which subsequently made the

MW goals impossible for SDG&E to achieve given that most of the available load left was small customer load. In 2007 and 2008, small customer programs were limited.

Decision 08-04-050, dated April 24, 2008, adopted protocols for estimating demand response load impacts. The load impact protocol Decision instructed the utilities to include both the ex-ante and ex-post benefits for programs being offered in the 2009-2011 filing to the extent it is possible.

Decision 10-12-024 *Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities* adopted a set of protocols to be used in evaluating the cost-effectiveness of most demand response activities starting with the 2012 to 2014 program cycle. The protocols utilize the tests described in the Standard Practice Manual and call for the use of non-proprietary data including the avoided costs provided by E3's Avoided Cost Calculator model to increase the transparency and consistency of the analyses. Additionally, the ability for a utility to achieve cost effective demand response and receive credit for resource adequacy is a strong incentive for the utilities to maximize its cost effective DR. If the correct market mechanisms are in place, the utility will make the most efficient and effective use of its demand response resources.

The load impact protocols along with the cost-effectiveness methodologies represent a collaborative effort that identify the quantitative framework in which to identify MW load reductions attributed to DR programs and activities. Subsequently, over the past 6 years SDG&E has concentrated on providing cost effective demand response programs. SDG&E continues to work toward developing accurate price signals with a focus on dynamic rate design.

In May of 2008, SDG&E implemented default CPP rates for its largest customers. Those customers that were not DA that were over 200 kW were defaulted onto the dynamic rate CPP.

As of the end of March, SDG&E has 1,143 accounts on its CPP rate. In 2013 the average load impact from CPP customers was around 20 MWs in demand response. SDG&E has plans to default all bundled customers >20 kW onto CPP in 2015. It is expected that these customers will provide an additional 15 MWs of load reduction when they are defaulted onto CPP in the summer of 2015.

Additionally, from 2008 until current, there have been very few small customer DR activities. Until recently, (January 2014, D.14-01-002), SDG&E has not been able to implement dynamic pricing for its small customers. SDG&E expects to make its dynamic rates available to small commercial customers on May 1, 2014, and default TOU in November 2015. Optional Dynamic pricing for residential customers will become available in January 2015. Currently, less than 1% of SDG&E's residential customers are on TOU pricing. SDG&E recently submitted testimony it the Residential Rate Reform OIR (R.12-06-013) that requested permission to conduct a residential TOU pilot that will test differing summer TOU periods and prices.

Question 5: D.12-04-045 discussed the future of demand response and questioned what the roles of the utilities and third party providers would be in administering future programs. We look at the roles of utilities and third party providers in administering load modifying resources. Provide your comments on whether a utility-centric model for load modifying resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provider Load Modifying Resource demand response to meet current and future needs. As discussed in D.12-04-045, should the Utilities continue to offer rate-regulated load modifying resource demand response if similar services are provided through competitive markets? Should we limit the utilities' role in providing load modifying resource demand response? How?

Response 5: One of SDG&E's core competencies is administering load modifying demand response products and rates. Third parties should have the opportunity to offer them also, as in the case in SDG&E's LTPP Phase 4 preferred resource RFO, where all preferred resources have an equal opportunity to compete for both local distribution as well as system wide needs.

SDG&E can ensure a cost effective implementation and administration of reliable load modifying resources to meet current and future goals.

III. PHASE TWO REMAINING ISSUES AND QUESTIONS

A. BACK-UP GENERATORS

Question 1: In D.11-10-003, Ordering Paragraph No. 3, the Commission adopted a policy statement that any demand response program, whether operated by a Commission-regulated Utility or another entity, that uses fossil-fueled emergency back-up generation (BUG) for demand reduction should not count towards resource adequacy obligations for any Commission-jurisdictional load shedding entity. Provide your understanding of the status of the Utilities' compliance with this policy statement.

Response 1: SDG&E is in the process of changing its tariffs to exclude customers from using BUGs for participating in demand response programs. Aside from one customer who is still participating because of contractual obligations, no other customer is using BUGs for demand response.

Question 2: How should the Utilities collect data on the customer's use of fossil-fuel emergency BUG during the demand response events? Identify the amount of demand response provided by BUG on an on-going basis?

Response 2: SDG&E believes maintaining records of BUGs and/or their usage is not directly within a utility's mandate. BUGs are governed by other state and federal authorities and enforcement of the rules mandated by those authorities should not be the utility's responsibility.

Question 3: How can this policy be further implemented for the Utilities' existing and new demand response programs as Supply Resource and Load Modifying Resources? What methods should the Commission use to exclude demand reduction provided through the use of BUG?

Response 3: SDG&E believes maintaining records of BUGs and/or their usage is not directly within a utility's mandate. BUGs are governed by other state and federal authorities and enforcement of the rules mandated by those authorities should not be the utility's responsibility

Question 4: Should the Commission require on-site sub-metering for BUG and/or should the Commission require self-certification with the inclusion of data regarding the intended use of BUG during demand response events? If on-site metering is preferred, how should the costs of the metering be recovered?

Response 4: SDG&E believes maintaining records of BUGs and/or their usage is not directly within a utility's mandate. BUGs are governed by other state and federal authorities and enforcement of the rules mandated by those authorities should not be the utility's responsibility

IV. WITNESS QUALIFICATIONS

My name is George Katsufrakis. My business address is 8335 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric as Manager of Operations for Customer Programs. My responsibilities include design and implementation of energy efficiency and demand response programs for SDG&E. I have been employed by Sempra Energy Utilities since 1996.

I graduated from University of California, Berkeley with a Bachelors of Science degree in Mechanical Engineering and I am a registered professional engineer in California. I have testified before this Commission in both Energy Efficiency and Demand Response proceedings.

EXHIBIT

GK-13

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Megan Scott-Kakures
Vice President, Regulatory Operations

January 31, 2014

ADVICE 3000-E
(Southern California Edison Company – U 338-E)

ADVICE 2572-E
(San Diego Gas & Electric Company – U 902 M)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: 2013 Demand Response Daily Forecast Pilot Results

Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) hereby submit for filing the following 2013 Demand Response Daily Forecast Pilot Results. The analysis report for SCE and SDG&E is included as Attachment A.

PURPOSE

The purpose of this advice filing is to submit a report detailing the SCE and SDG&E forecast methodologies pursued, the results, and the recommendations made for daily forecasting for 2014 and beyond, as ordered in California Public Utilities Commission (Commission) Decision (D.)13-07-003, Ordering Paragraphs (OPs) 3, 4 and 5.

BACKGROUND

On May 1, 2013, pursuant to D.13-04-017, Commission Staff issued a report on the Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs. Included in the report, Commission Staff provided an analysis of SCE's and SDG&E's forecasting methodologies for daily forecasts.

> "The majority of programs either provided a 'mixed' performance (the program both over- and underperformed relative to its forecast) or were poor performers (consistently coming up short relative to its forecast). Of particular note

> are the Utilities' Peak Time Rebate program and SCE's Summer Discount Plan."[1]

On July 16, 2013, the Commission issued D.13-07-003 which adopted findings included in the Staff report and directed:

> "…the Demand Response Measurement and Evaluation Committee (DRMEC) to work with the CAISO and Commission staff to develop improved forecasting methodologies beginning, on a limited basis, this summer."[2]

In addition, D.13-07-003 directed SCE and SDG&E, as representatives of DRMEC, to submit a report by January 31, 2014 via a Tier One Advice Letter demonstrating the forecasting methodologies pursued, the results, and recommendations for daily forecasting for 2014 and beyond. The attached report includes the revised daily forecasting methodologies piloted during the Summer of 2013, forecasting methods by program, and suggestions for 2014.

No cost information is required for this advice filing.

This advice filing will not increase any rate or charge, cause the withdrawal of service, or conflict with any other schedule or rule.

TIER DESIGNATION

Pursuant to OP 4 of D.13-07-003, this advice letter is submitted with a Tier 1 designation.

EFFECTIVE DATE

This advice filing will become effective on January 31, 2014, the same day filed.

NOTICE

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

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1 Commission Staff Report – Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs, May 1, 2013, p. 2.

2 D.13-07-003, Decision Addressing Commission Staff Report on 2012 Demand Response Program Results, p. 10.

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

For SCE:

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
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Leslie E. Starck
Senior Vice President, Regulatory Policy & Affairs
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For SDG&E:

Megan Caulson
Regulatory Tariff Manager
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San Diego, California 92123-1548
Facsimile: (858) 654-1879
E-mail: MCaulson@semprautilities.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4 of General Order (GO) 96-B, SCE is serving copies of this advice filing to the interested parties shown on the attached GO 96-B and A.12-12-016 et al. service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-2930. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Eva Norman at (626) 302-0980 or by electronic mail at Eva.Norman@sce.com.

Southern California Edison Company

/s/ MEGAN SCOTT-KAKURES
Megan Scott-Kakures

MSK:en:sq
Enclosures

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.: Southern California Edison Company (U 338-E)

Utility type:	Contact Person: Darrah Morgan
☑ ELC ☐ GAS	Phone #: (626) 302-2086
☐ PLC ☐ HEAT ☐ WATER	E-mail: Darrah.Morgan@sce.com
	E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE			(Date Filed/ Received Stamp by CPUC)
ELC = Electric	GAS = Gas		
PLC = Pipeline	HEAT = Heat	WATER = Water	

Advice Letter (AL) #: SCE 3000-E/SDG&E 2572-E Tier Designation: 1

Subject of AL: 2013 Demand Response Daily Forecast Pilot Results

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

D.13-07-003

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

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

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution Required? ☐ Yes ☑ No

Requested effective date: 1/31/14 No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

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: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

[1] Discuss in AL if more space is needed.

Protests 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
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
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Attachment A

Demand R
Forecast Pilot

01/31/2014
Southern California Edison
San Diego Gas & Electric
Demand Response Measurement and Evaluation Committee

Contents

Executive Summary

Background

In June of 2012 PG&E, SCE and SDG&E implemented a daily demand response (DR) forecasting process. Forecasting methodologies that could feasibly deploy on a daily basis were implemented for the 2012 event season. Each day the utilities provided a daily forecast of available load reduction by demand response programs to the CAISO and CPUC by 8:00 a.m.

In November of 2012 a letter was issued by the CPUC directing SDG&E and SCE to file an application to augment their DR portfolios for the years 2013 and 2014. In addition, as part of the DR Augmentation proceeding SDG&E and SCE were required to provide detailed load impact data comparing the 1) 2012 daily forecasts by program to the 2) preliminary results that were provided to the CAISO within 7 days as well as 3) the ex-post measurement and evaluation reports that are due April 1st each year. Ordering paragraph 4 of decision D13-07-003 issued July 11th 2013 directed the Demand Response Measurement and Evaluation Committee (DRMEC) to review the daily DR forecasting methods in 2012, implement improvements to daily DR forecasting methods in 2013 and to include its analysis and recommendations in a January 31, 2014 report to the Commission.

Summary of Results - *SDG&E*

SDG&E implemented daily DR forecast improvements for all demand response programs for the summer of 2013. Improvements included:

a. Only customers who opted into PTR alerts were included in the PTR load impact forecast.
b. The Air Conditioning (AC) cycling (known as Summer Saver) daily load impact forecast was more closely tied to the annual ex-ante forecast process.
c. SDG&E adopted a more conservative forecasting approach. The 30th percentile of the ex-post results is now being used rather than the average result as an input assumption into many of the daily program forecasts.

The SDG&E 2013 daily DR forecast for all programs called for each event hour had lower errors than the 2012 daily DR forecast when compared to the preliminary results SDG&E reported to the CAISO and CPUC within 7 days of the event. In 2012, the 10th and 90th percentile of the percentage errors between the daily DR forecast and the 7-day preliminary was -49% and 48% whereas the 10th and 90th percentiles of the percentage differences in 2013 ranged from were -30% and 16%.

Table ES-1 Differences between daily forecast and 7-Day Results				
	(MW)		(%)	
	2013	2012	2013	2012
Average Difference	-2.0	-6.0	-7%	-3%
90th Percentile of Differences	2.4	11.7	16%	48%
10th Percentile of Differences	-7.1	-22.1	-30%	-49%

The SDG&E 2013 hourly forecast also had lower errors than the 2012 forecast when compared to the ex-post results. The differences between the daily forecast and the draft ex-post result higher than differences between the daily forecast and 7-day results in both years. In 2012 on average the daily demand response forecast was 58% higher than the ex-post results whereas in 2013 on average the daily demand response forecast was 23% lower than the ex-post results. The range of errors goes all the way from -13% to 182% in 2012 whereas the error range goes from -46% to 6% in 2013.

Table ES-2 Differences between daily forecast and Draft Ex-Post Results				
	(MW)		(%)	
	2013	2012	2013	2012
Average Difference	-9.8	7.8	-27%	58%
90th Percentile of Differences	-0.6	20.5	-6%	182%
10th Percentile of Differences	-22.7	-2.3	-46%	-13%

Summary of Results - *SCE*

SCE implemented a number of daily DR forecast improvements for demand response programs for the summer of 2013. Improvements included:

- Pilot methodology for the Peak-Time Rebate (PTR) program based on ex ante load impact estimates from the PY2012 PTR Load Impact study, counting only customers enrolled in event notification.
- Pilot methodology for the Summer Discount Plan (SDP) program for direct load control AC cycling. This methodology is based on the ex ante load impact estimates from the Program Year (PY) 2012 SDP Load Impact study, as a function of temperature.
- Methodology adjustment for the aggregator programs, to reflect observed event performance (rather than nominations).
- Methodology adjustment for the Base Interruptible Program (BIP), based on the ex ante load impact estimates and estimates of reference load from the PY2012 BIP Load Impact study.

SCE provides daily forecasts of available demand response. When events are triggered, these daily reports are updated to also include load dispatched (scheduled load), recognizing that frequently a program's resources are only partially dispatched for a given event. SCE provides a report of estimated program results within 7 days of a DR event dispatch. Much of the customer usage data from which program results are estimated are not available or not finalized within that 7-day window. SCE also provides a year-end report to CAISO in which the 7-day report estimates are updated based on customers' final billing data. Analysis of these reports from 2013 finds that the average daily deviation of the daily forecast (from year-end estimates) was -0.4 MW, and the average absolute daily deviation was 21 MW.

To compare the 2013 pilot methodologies to the corresponding 2012 methodologies, and to the ex post findings from the Load Impact studies, the 2013 pilot methodologies were applied to the 2012 event conditions for SDP and PTR. This comparison found that for SDP, the 2012 methodology had an average absolute hourly deviation (from ex post results) of **44 MW**, while the 2013 (pilot) methodology had an average absolute hourly deviation **23 MW**, corresponding to an error reduction of 47%. For PTR, the 2012 methodology had an average absolute hourly deviation (from ex post results) of **88 MW**, while the 2013 (pilot) methodology had an average absolute hourly deviation **32 MW**, corresponding to an error reduction of 64%.

Conclusions and Recommendations:

- Both SCE and SDG&E improved forecasting methods from those used in 2012.
- In 2014 SCE and SDG&E plan to use the same general forecasting methods but with updated inputs and small adjustments. Forecasting methodologies based on ex ante load impact estimates will be updated according to the PY2013 study results.
- Forecasting and estimating a demand response load impact is more challenging than forecasting the entire load of a group of customers. The smaller the percentage load reduction the more difficult it is to measure and forecast. For example, when estimating a 10% load impact a 2% error in estimating the entire load of the customer results in a 20% error in the demand response load impact.
- Forecasting the load reduction from a group of demand response programs is easier than forecasting the load reduction from a single program.
- Variation in customer behavior is another factor that presents challenges for demand response forecasting.
- The CAISO should provide the utilities with feedback on how to best handle demand response forecasting error that cannot be eliminated through forecast methodology improvements or improve program design.

- Utilities will meet with the CAISO at the beginning of summer 2014 to make sure the process for sending the daily forecast and notifying the CAISO when events are triggered meet the needs of all CAISO departments.

I. Forecast Process

Each morning SDG&E and SCE sent out an excel file that included a demand response forecast by program to the CAISO and the CPUC before 8:00 a.m. The excel file contained the hourly forecasted MWs available by program and by notification type. The forecast file also included a load forecast for all programs that had been triggered that day. Since most day-of programs are not triggered by the utilities until after 8:00 a.m., typically only day-ahead programs were included in the load forecast for the program called today line item. In the late afternoon if additional demand response events were triggered both SDG&E and SCE sent out a revised forecast file that included information about all the demand response that had been triggered for that day.

II. Report on Southern California Edison's Demand Response Forecasting Methodologies for 2013

As ordered in Ordering Paragraph (OP) 4 of Decision (D.) 13-07-003, Southern California Edison (SCE) presents this report detailing the forecasting methodologies piloted for its Summer Discount Plan (SDP) and Peak Time Rebate (PTR) programs in 2013. This report includes the results of the forecasting methodologies piloted and provides recommendations for daily forecasting for 2014 and beyond.

OVERVIEW

Starting in 2012, Southern California Edison, San Diego Gas & Electric, and Pacific Gas & Electric ("IOUs") were required to submit daily forecast and seven day post-event demand response (DR) reports to the California Independent System Operator (CAISO). SCE utilized forecasting methodologies that could feasibly calculate and deploy DR resources, by program, on a daily basis for the 2012 event season. SCE applied methodologies that estimated a program or deployment of DR resources that, prior to 2012, had not been precisely measured. For instance, 2012 was the first year that SCE offered its Peak-Time Rebate (PTR) program on a broad basis to nearly all customers in its service territory. Also, 2012 was the first year SCE dispatched its residential SDP program as a price response program rather than a reliability program. After the 2012 event season, SmartConnect™ usage data and multiple event observations enabled an in-depth, customer-level analysis of these programs for the first time.

Prior to the 2013 event season, SCE reviewed and revised its DR forecasting methodologies. In particular, daily forecasting methodologies were developed and piloted[1] for SDP and PTR. The forecasting methodologies piloted for SDP in 2013 included strategies to reduce the impact of the rebound effect on event performance. On December 16, 2013, SCE submitted Advice Letter 2987-E in compliance with D.13-07-003, Ordering Paragraph 11, which reports the results of the SDP program dispatch strategies tested in 2013 to reduce the rebound effect. Some discussion of the impact to reduce the rebound effect and improve accuracy is included in this report; however, discussion of the change of dispatch strategy is not the primary objective of this report. This report focuses on the forecasting methods as required in D.13-07-003, Ordering Paragraph 4.[2]

The SDP and PTR forecasting methodologies piloted in 2013 reduced forecasting variances, compared to the 2012 forecasting methodology, by 47% and 64%, respectively. The SDP average absolute hourly deviation (from ex post estimate) for the 2012 methodology was **44 MW** compared to **23 MW** with the 2013 pilot methodology which resulted in a **variance reduction of 47%.** The PTR average absolute hourly deviation for the 2012 methodology was **88 MW** compared to **32 MW** with the 2013 pilot methodology which resulted in a **variance reduction of 64%**.[3]

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[1] This satisfies Ordering Paragraph (OP) 3 of D.13-07-003, for reference see *http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M071/K738/71738068.PDF*

[2] This satisfies OP 4 of D.13-07-003, for reference see *http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M071/K738/71738068.PDF*

[3] This satisfies OP 5 of D.13-07-003, for reference see *http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M071/K738/71738068.PDF*

REVIEW OF 2012 FORECASTING METHODOLOGIES

TABLE 3-1 – Overview of 2012 SCE Forecasting Methodologies

Demand Bidding Program (DBP)	DBP event performance is calculated using 10-in-10 baseline[4] (with customer-optional day-of adjustment). The average Year-To-Date (YTD) event performance is reported. Prior to the first event, the average of the previous year's events are used.
Critical Peak Pricing (CPP)	CPP event performance is calculated using 10-in-10 adjusted baseline.[5] The average YTD event performance is reported. Prior to the first event, the average of the previous year's events are used.
Capacity Bidding Program (CBP)	CBP forecast is calculated as the current month's nominations by product.
Demand Response Contracts (DRC) - All contracts	DRC forecasts are calculated as the aggregate technical potentials[6] of enrolled DRC accounts.
Peak-Time Rebate (PTR)	PTR forecast is 0.229 kW load reduction per customer (based on Statewide Pricing Pilot[7]).
Summer Discount Plan (SDP)	SDP forecast is calculated based on an AC cycling load reduction algorithm using the actual hourly temperatures from Covina CA. When the temperature in Covina CA is below 70 degrees, the assumption is that no AC Cycling demand response is available
Agricultural & Pumping Interruptible (AP-I)	AP-I forecast is the sum of each account's summer average monthly max on peak demand.
Base Interruptible Program (BIP)	BIP forecast is the sum of each account's contribution to the system peak minus its Firm Service Level[8] (FSL).

2012 SDP Forecasting Methodology

SDP forecasts during the 2012 event season were based on a legacy algorithm for AC cycling load impact estimation. The methodology implemented in May, 2012 was taken from the SDP Participation report[9] that captures the MW for each A-bank[10]. Demand Response MW in the SDP Participation report is

4 10-in-10 baseline: Average hourly usage from previous 10 similar non-event days.
5 10-in-10 adjusted baseline: 10-in-10 baseline, adjusted based on same-day usage prior to the event.
6 Technical Potential: estimated available load drop based on customer usage.
7 Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot,* 3/16/2005.
8 Firm Service Level: usage level agreed to by BIP enrollee.
9 SDP Participation Report: internal SCE report.
10 A-Bank: Transmission substation designation

calculated based on the Air Conditioner (AC) cycling load reduction algorithm using the actual hourly temperatures from Covina CA.

The percentage of AC's used is assumed to rise as the temperature rises, as follows:

Temperature	% of AC usage
Summer Weekday > 100	100%
Summer Weekday 95-99	85%
Summer Weekday 91-94	75%
Summer Weekday 85-90	40%
Summer Weekday 81-84	30%
Summer Weekday 75-80	20%
Summer Weekday 70-74	10%
Summer Weekday Below 70	5%

The percentage was used to calculate available MWs from the gross MWs available on the program, while deducting 10% for failed devices and broadcast signal issues. On September 10, 2012 a new methodology was designed, using one temperature (Covina) for all A-banks. This methodology uses a file that captures available kW by A-bank and temperature increments from 70 to 116, the kW is then divided by 1,000 to provide MWs. When the temperature in Covina CA is below 70 degrees, the assumption is that no AC cycling demand response is available

This allows SDP to report MW availability more accurately by using single degree set points. The previous method used increments of 5 degrees to determine MW load. Daily CAISO reports were sent to CAISO a day ahead providing forecasting to determine the approximate available MW load in case of an event. When an event was called, the reporting template was used to calculate MW load by A-bank / sub-LAP[11] (SLAP) using the current temperatures.

2012 PTR Forecasting Methodology

In the absence of event performance data (at the time), the 2012 forecasting methodology for PTR was based on price-elasticity estimates and demographic mix. Price-elasticity estimates from the Statewide Pricing Pilot were applied to incentive levels for various customer groups (CARE and non-CARE, with and without central air conditioning). A weighted average of these group estimates, based on the demographic mix in SCE territory, yielded an average impact estimate of 0.229 kW per customer.

[11] Sub-LAP: CAISO-defined subset within a Default Load Aggregation Point (LAP)

REVIEW OF 2013 FORECASTING METHODOLOGIES

TABLE 3-2 – Overview of 2013 SCE Forecasting Methodologies

Demand Bidding Program (DBP)	Until the first event of the year, DBP forecast is calculated as the previous year's average hourly load reduction for all events, using the previous year's final event reports located in the Demand Response Program (DRP) database[12] as source data. After the first event's preliminary results are available, the DBP forecast is calculated as the year to date event average hourly load reduction. The forecast is updated as billing quality data becomes available and/or additional events occur.
Critical Peak Pricing (CPP)	Until the first event of the year, the CPP forecast is calculated as the previous year's average hourly load reduction for all events, using the previous year's final event reports located in the DRP database as source data. After the first event's preliminary results are available, the CPP forecast is calculated as the year to date event average hourly load reduction. The forecast is updated as billing quality data becomes available and/or additional events occur.
Capacity Bidding Program (CBP)	Until billing quality event data is available, the CBP forecast is calculated as the current month's aggregate 2012 load impact multiplied by the number of nominated accounts by product as per the Monthly Meter Nomination Report[13]. Because not all accounts are linked to an A-bank and nominations are done by SLAP[14], MW are reported in the "Remainder of System" category. The "MW Available by Response Time" tab is checked to ensure that the correct CBP MW are being reported. After event results become available, the CBP forecast is calculated using each product's demonstrated event performance year to date by product.
Demand Response Contracts (DRC) - All contracts	Until billing quality event data is available, the DRC forecast is calculated as the current month's aggregate 2012 load impact multiplied by the number of nominated accounts as per the Monthly Meter Nomination Report in the APX website. Because not all accounts are linked to an A-bank and nominations are done by SLAP, MW are reported in the "Remainder of System" category. The "MW Available by Response Time" tab is checked to ensure that the correct DRC MW are being reported. After event results become available, the DRC forecast is calculated using each product's demonstrated event performance year to date multiplied by the SLAP MW nomination.
Peak-Time Rebate (PTR)	PTR forecast is calculated using 2012 Ex Ante[15] hourly kW reduction per customer enrolled in SCE's Event Notification System (ENS). Enrollment is updated weekly via capsule reports. The Ex Ante value per account changes

12 Ddatabase: Demand Response Program database maintained internally by SCE

13 Monthly Meter Nomination Report: Report on aggregator nominations.

14 SLAP: SubLAP (geographic region)

15 Christensen Associate Energy Consulting, *2012 Load Impact Evaluation of Southern California Edison's Peak Time Rebate Program*, 4/1/2013.

	monthly.
Summer Discount Plan (SDP)	SDP forecast is based on enrolled AC tons, cycling percentage, and temperature sourced from weekly capsule reports[16] and the National Weather service website. The load impact-weather relationship is provided by the 2012 SDP Load Impact Evaluation study[17]. Temperature forecasts for San Dimas are referenced and projected to obtain expected regional temperatures across the service territory. Forecast MW are segregated by geographic region.
Agricultural & Pumping Interruptible (AP-I)	AP-I forecast is determined using the current month's 2012 load impact of an average service account. The service accounts for the month is the number of active service accounts on the last business day of the month. For hours not covered in the 2012 Ex Ante table event estimates[18] (8AM to 1PM and 6PM to 12AM), the 2012 Ex Ante reference load is multiplied by the 2012 Ex Ante switch success rate[19] to determine load impact.
Base Interruptible Program (BIP)	BIP forecast is determined using the current month's 2012 load impact of an average service account. Number of accounts is determined using the number of active accounts on the last business day of the month. For hours not covered in the 2012 ex ante table event estimates (8AM to 1PM and 6PM to 12AM), the 2012 Ex Ante reference load is reduced by the Firm Service Level (FSL) and multiplied by the monthly performance factor by geographic region to determine load impact. Weekends are determined by discounting the weekday reference load, subtracting the FSL, and multiplying by the monthly performance factor. The discount factor is derived by comparing the average weekday usage to average weekend day usage for all BIP customers for the month of April 2013. The summer value compares June through October and the winter value compares November through May. Forecast MWs are segregated by both program option and geographic region.

2013 SDP Forecasting Pilot Methodology

The 2013 SDP forecast pilot is based on the most recent program enrollment report, and a temperature-based estimation of load impact (kW) per enrolled AC ton. The 2013 SDP forecast methodology utilizes a weekly report of enrolled Service Accounts, devices, and AC tons broken down by program (Residential, Non-Res), program option (cycling %, override/non-override), and geographic location

16 Weekly Capsule Report: SDP enrollment report

17 Christensen Associates Energy Consulting, *2012 Load Impact Evaluation of Southern California Edison's Residential Summer Discount Plan (SDP) Program,* 4/1/2013.

18 Freeman, Sullivan & Co., *Load Impact Estimates for Southern California Edison's Demand Response Programs,* 4/1/2013.

19 IBID

(down to the A-Bank level[20]). Hourly temperature forecasts are used as inputs. Weather service forecasts for San Dimas are read (representing SCE core), and projected out to other SLAPs in our service territory. The forecast methodology utilizes a formula that estimates load impact (kW) per enrolled ton based on temperature. This formula is based on the ex ante load impact-weather relationships from the Program Year (PY) 2012 SDP Load Impact Study. There are separate formulas to estimate kW for SCE territory overall (100% cycling customers), South of Lugo customers, South Orange County customers, and 50% cycling customers. The temperature-based load impact is multiplied by enrolled AC tons regionally, and aggregated up to forecast total load impact.

The SDP studies provided the following estimates for load impact (LI) per AC ton:

For overall population, 100% cycling option:

- LI per AC ton = 0.0028 + 0.0102 * CDH70_MA6

For overall population, 50% cycling option:

- LI per AC ton = -0.0291 + 0.0058 * CDH70_MA6

Upon additional request, CAEC[21] provided the following estimates:

For South of Lugo, 100% cycling option:

- LI per AC ton = -0.0120 + 0.0125 * CDH70_MA6

For South Orange County, 100% cycling option:

- LI per AC ton = -0.0598 + 0.0084 * CDH70_MA6

For South of Lugo and South OC, the population of 50% cycling customers was too small for proper estimation. Therefor the overall population of 50% cycling customers will be applied instead of the 50% population of these two regions.

Cooling degrees hours (CDH) is defined (relative to a threshold) as:

- CDH = MAX[0, Temperature – Threshold]

where *Temperature* is the local hourly temperature in °F.

CDH70_MA6 is the moving average of CDH (with a threshold of 70) for the 6 hours prior to the event hour. This weather variable captures heat accumulation. Temperature is a spot read, whereas CDH is a measure of heat accumulation. The two will be related and strongly correlated, but that relationship will depend upon a number of variables, including time of the day.

To estimate the relationship between temperature and CDH70_MA6, temperature observations were taken for each of the event hours included in the ex ante estimation, from weather stations within each

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20 A-Bank level: Transmission substation designation

21 CAEC: Christensen Associates Energy Consulting

SLAP. A quadratic-fit relationship was estimated between temperature and CDH70_MA6, weighted by enrolled AC tons in each SLAP. The estimated relationship is as follows

- CDH70_MA6 = -74.958 + 1.300 * Temp – 0.003 * $(\text{Temp})^2$

The results sections (below) find that the SDP pilot methodology reduced average absolute hourly deviation (from ex post estimate) from **44 MW** for the 2012 methodology to **23 MW** with the pilot methodology, a **variance reduction of 47%**.

2013 PTR Forecasting Pilot Methodology

The PY2012 PTR Load Impact Study provides hourly ex ante load reduction estimates per customer receiving event notification. (Customers not receiving notification are not found to have any significant load reduction.) These per-customer estimates are applied to weekly reports on enrollment levels in SCE's Event Notification System (ENS). Month-specific ex ante estimates are used to generate forecasts. The results sections (below) find that the SDP pilot methodology reduced average absolute hourly deviation (from ex post estimate) from **88 MW** for the 2012 methodology to **32 MW** with the pilot methodology, a **variance reduction of 64%**.

2013 CAISO REPORTING RESULTS

SCE provides daily reports to CAISO forecasting available load shed of its demand response programs. When demand response events are triggered, these daily reports also contain forecasts of load dispatched (*scheduled load*). If the daily report has already been sent when a determination is made to trigger an event, a revised daily report may be sent with updated scheduled load forecasts.

After a DR event has been triggered, within 7 days SCE provides a report of estimated program results (7-day report). Much of the customer usage data from which program results are estimated are not available or not finalized within that 7-day window. SCE also provides a year-end report to CAISO in which the 7-day report estimates are updated based on customers' final billing quality data. Summaries of these reports (daily forecast, 7-day report, year-end report) are provided. In 2013, for the events presented, the average absolute daily deviation of the daily forecast (from year-end estimates) was **21 MW**, and the average absolute daily deviation of the 7-day report (from year-end estimates) was **12 MW**.

SCE 2013 Event Summary Table

Table 3-3 summarizes SCE demand response events from May 2013 through October, 2013. Event dispatches with fewer than 25 participating service accounts are not included in the table, and are excluded from this analysis.

TABLE 3-3 - SCE May-October 2013 DR Event Summary Table*

*Events with < 25 accounts dispatched are not listed

Demand Response Programs	Event Date	Program Type	Number of Participating Service Accounts	Event Start Time (PDT)	Event End Time (PDT)
Aggregator Managed Portfolio (DRC)	05/02/13	Day Ahead	179	1:00 PM	5:00 PM
Aggregator Managed Portfolio (DRC)	05/13/13	Day Ahead	179	1:00 PM	5:00 PM
Capacity Bidding Program 1-4	05/13/13	Day Of	94	1:00 PM	5:00 PM
Capacity Bidding Program 2-6	05/13/13	Day Of	207	12:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC 4)	05/13/13	Day Of	223	1:00 PM	5:00 PM
Aggregator Managed Portfolio (DRC 2)	05/21/13	Day Of	897	3:00 PM	4:00 PM
Aggregator Managed Portfolio (DRC 3)	05/21/13	Day Of	143	3:00 PM	4:00 PM
Demand Bidding Program	06/03/13	Day Ahead	308	12:00 PM	8:00 PM
Aggregator Managed Portfolio (DRC)	06/27/13	Day Ahead	221	1:00 PM	5:00 PM
Demand Bidding Program	06/28/13	Day Ahead	313	12:00 PM	8:00 PM
Aggregator Managed Portfolio (DRC)	06/28/13	Day Ahead	221	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC 2)	06/28/13	Day Of	832	2:00 PM	4:00 PM
Capacity Bidding Program 1-4	06/28/13	Day Of	200	1:00 PM	5:00 PM
Capacity Bidding Program 2-6	06/28/13	Day Of	209	12:00 PM	6:00 PM
Summer Discount Plan - Residential	06/28/13	Day Of	93,425	4:00 PM	6:00 PM
Summer Advantage Incentive	07/01/13	Day Ahead	3,276	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC)	07/01/13	Day Ahead	235	1:00 PM	5:00 PM
Demand Bidding Program	07/02/13	Day Ahead	302	12:00 PM	8:00 PM
Aggregator Managed Portfolio (DRC)	07/02/13	Day Ahead	235	1:00 PM	5:00 PM
Save Power Days	07/02/13	Day Ahead	780,907	2:00 PM	6:00 PM
Summer Discount Plan - Commercial	07/02/13	Day Of	10,409	3:00 PM	4:00 PM
Summer Discount Plan - Residential	07/02/13	Day Of	208,091	4:00 PM	6:00 PM
Summer Advantage Incentive	07/03/13	Day Ahead	3,265	2:00 PM	6:00 PM
Summer Discount Plan - Residential	07/19/13	Day Of	100,707	4:00 PM	5:00 PM
Aggregator Managed Portfolio (DRC 2)	07/31/13	Day Of	645	2:00 PM	4:00 PM
Aggregator Managed Portfolio (DRC 3)	07/31/13	Day Of	60	4:00 PM	5:00 PM
Summer Advantage Incentive	08/21/13	Day Ahead	3,308	2:00 PM	6:00 PM
Summer Discount Plan - Residential	08/22/13	Day Of	154,731	3:00 PM	5:00 PM
Summer Discount Plan - Commercial	08/22/13	Day Of	10,580	4:00 PM	5:00 PM
Demand Bidding Program	08/28/13	Day Ahead	293	12:00 PM	8:00 PM
Summer Advantage Incentive	08/28/13	Day Ahead	3,313	2:00 PM	6:00 PM
Save Power Days	08/28/13	Day Ahead	793,274	2:00 PM	6:00 PM
Summer Discount Plan - Residential	08/28/13	Day Of	211,199	3:00 PM	5:00 PM
Capacity Bidding Program 1-4	08/29/13	Day Of	279	2:00 PM	5:00 PM
Capacity Bidding Program 2-6	08/29/13	Day Of	208	2:00 PM	6:00 PM

Demand Response Programs	Event Date	Program Type	Number of Participating Service Accounts	Event Start Time (PDT)	Event End Time (PDT)
Aggregator Managed Portfolio (DRC 2)	08/29/13	Day Of	984	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC 3)	08/29/13	Day Of	143	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC 4)	08/29/13	Day Of	551	2:00 PM	6:00 PM
Summer Discount Plan - Residential	08/29/13	Day Of	202,941	2:00 PM	5:00 PM
Summer Discount Plan - Commercial	08/29/13	Day Of	10,617	4:00 PM	5:00 PM
Capacity Bidding Program 1-4	08/30/13	Day Of	279	11:00 AM	3:00 PM
Capacity Bidding Program 2-6	08/30/13	Day Of	208	11:00 AM	5:00 PM
Aggregator Managed Portfolio (DRC 2)	08/30/13	Day Of	984	3:00 PM	7:00 PM
Aggregator Managed Portfolio (DRC 4)	08/30/13	Day Of	551	2:00 PM	6:00 PM
Summer Advantage Incentive	08/30/13	Day Ahead	3,321	2:00 PM	6:00 PM
Save Power Days	08/30/13	Day Ahead	793,467	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC)	09/04/13	Day Ahead	286	1:00 PM	5:00 PM
Summer Advantage Incentive	09/04/13	Day Ahead	3,317	2:00 PM	6:00 PM
Summer Discount Plan - Residential	09/04/13	Day Of	150,558	3:00 PM	5:00 PM
Save Power Days	09/05/13	Day Ahead	795,530	2:00 PM	6:00 PM
Summer Discount Plan - Residential	09/05/13	Day Of	155,115	4:00 PM	5:00 PM
Aggregator Managed Portfolio (DRC)	09/06/13	Day Ahead	286	1:00 PM	5:00 PM
Summer Advantage Incentive	09/06/13	Day Ahead	3,322	2:00 PM	6:00 PM
Summer Discount Plan - Residential	09/06/13	Day Of	307,641	2:00 PM	6:00 PM
Demand Bidding Program	09/09/13	Day Ahead	288	12:00 PM	8:00 PM
Aggregator Managed Portfolio (DRC)	09/09/13	Day Ahead	286	1:00 PM	5:00 PM
Save Power Days	09/09/13	Day Ahead	797,727	2:00 PM	6:00 PM
Summer Discount Plan - Residential	09/09/13	Day Of	150,294	3:00 PM	5:00 PM
Summer Discount Plan - Commercial	09/09/13	Day Of	10,646	3:00 PM	4:00 PM
Summer Advantage Incentive	09/13/13	Day Ahead	3,330	2:00 PM	6:00 PM
Base Interruptible Program	09/19/13	Day Of	655	3:00 PM[22]	5:00 PM
Agricultural & Pumping Interruptible	09/19/13	Day Of	1,144	3:45 PM	5:00 PM
Summer Advantage Incentive	09/23/13	Day Ahead	3,311	2:00 PM	6:00 PM
Summer Advantage Incentive	09/30/13	Day Ahead	3,312	2:00 PM	6:00 PM
Summer Discount Plan - Residential	09/30/13	Day Of	308,700	7:00 PM	8:00 PM
Summer Advantage Incentive	10/04/13	Day Ahead	3,328	2:00 PM	6:00 PM
Aggregator Managed Portfolio (DRC 4)	10/17/13	Day Of	636	1:00 PM	3:00 PM
Summer Advantage Incentive	10/17/13	Day Ahead	3,333	2:00 PM	6:00 PM

On 9/19/2013, the reliability programs were not fully dispatched until 3:45p; thus 9/19/13 Hour Ending (HE) 16 is excluded from this analysis.

[22] BIP notifications were started at 3:00p; obligation to shed did not occur for the whole population until 3:45p.

2013 SCE Daily Forecast Table

Table 3-4 summarizes the program MW forecasts (scheduled for dispatch) provided in the 2013 daily reports.

TABLE 3-4 - SCE 2013 Daily DR Forecast Summary - *Scheduled Load* (MW)

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			20	20	20	20			
05/13/13		8	52	52	52	52	8		
05/21/13					83				
06/03/13		78	82	82	82	83	82	86	86
06/27/13			27	27	27	27			
06/28/13		89	101	191	195	228	228	99	98
07/01/13			30	72	73	70	38		
07/02/13		81	115	127	201	312	291	99	98
07/03/13				42	43	40	38		
07/19/13						74			
07/31/13				53	53	5			
08/21/13				34	35	31	30		
08/22/13					144	217			
08/28/13		97	103	154	351	347	156	101	94
08/29/13				376	375	458	157		
08/30/13	21	21	21	127	206	202	191	87	
09/04/13			33	70	216	210	32		
09/05/13				21	22	187	24		
09/06/13			33	401	401	393	355		
09/09/13		93	131	147	285	240	123	100	95
09/13/13				44	47	41	38		
09/19/13						537			
09/23/13				43	47	42	39		
09/30/13				40	43	38	36		47
10/04/13				38	41	36	34		
10/17/13			49	87	41	36	34		

2013 SCE Post-Event 7-Day Report Table

Table 3-5 summarizes the program MW post-event estimates provided in the 2013 post-event 7-day reports.

TABLE 3-5 - SCE 2013 DR Post-Event 7-Day Report Summary (MW)

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			20	20	20	20			
05/13/13		8	49	49	49	49	8		
05/21/13					83				
06/03/13		81	85	81	84	87	96	99	98
06/27/13			27	27	27	27			
06/28/13		108	125	219	221	250	235	95	87
07/01/13			30	56	54	49	20		
07/02/13		107	140	160	234	340	302	104	96
07/03/13				41	46	44	41		
07/19/13						74			
07/31/13				53	53	5			
08/21/13				44	49	40	37		
08/22/13					144	218			
08/28/13		89	85	152	345	335	145	91	92
08/29/13				376	375	458	168		
08/30/13	21	21	21	152	238	233	218	87	
09/04/13			33	78	224	219	37		
09/05/13				23	23	186	23		
09/06/13			33	411	417	410	372		
09/09/13		105	142	156	299	252	132	119	105
09/13/13				35	37	35	34		
09/19/13						709			
09/23/13				16	13	10	9		
09/30/13				21	19	18	15		47
10/04/13				26	24	19	20		
10/17/13			49	86	35	28	26		

2013 SCE Year-End Report Table

Table 3-6 summarizes the program MW updated estimates provided in the 2013 year-end report.

TABLE 3-6 - SCE 2013 Year-End DR Report Summary (MW)

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			5	4	4	3			
05/13/13		10	22	22	22	21	10		
05/21/13					96				
06/03/13		81	85	82	82	83	93	95	93
06/27/13			3	4	4	3			
06/28/13		106	119	216	216	220	210	95	87
07/01/13			-1	26	27	21	20		
07/02/13		90	96	116	191	297	285	86	79
07/03/13				43	48	45	43		
07/19/13						74			
07/31/13				77	78	5			
08/21/13				47	52	44	40		
08/22/13					144	218			
08/28/13		104	103	176	369	358	164	107	103
08/29/13				371	374	453	160		
08/30/13	28	29	29	140	236	232	206	90	
09/04/13			9	49	196	190	34		
09/05/13				23	23	186	23		
09/06/13			2	372	378	373	366		
09/09/13		104	114	129	269	224	132	113	110
09/13/13				19	23	22	22		
09/19/13						733			
09/23/13				7	4	3	2		
09/30/13				11	10	9	7		47
10/04/13				22	25	20	15		
10/17/13			30	55	25	20	18		

2013 Daily Forecast Deviations from Year-End Estimates

Tables 3-7 & 3-8 summarize the deviations of the daily forecasts from the year-end estimates. The average absolute daily deviation of the daily forecast (from year-end estimates) was **21 MW.**

TABLE 3-7 - SCE 2013 Daily Forecast MW Deviations from Year-End Estimates

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			16	16	16	17			
05/13/13		-2	30	30	29	31	-2		
05/21/13					-14				
06/03/13		-3	-3	1	0	0	-11	-10	-7
06/27/13			23	22	22	23			
06/28/13		-18	-18	-24	-22	8	18	4	11
07/01/13			31	47	46	49	18		
07/02/13		-9	19	11	10	15	6	13	19
07/03/13				-1	-5	-5	-5		
07/19/13						0			
07/31/13				-24	-25	0			
08/21/13				-13	-17	-13	-9		
08/22/13					0	-1			
08/28/13		-7	-1	-22	-18	-12	-9	-6	-9
08/29/13				5	1	5	-4		
08/30/13	-7	-8	-9	-13	-30	-30	-15	-3	
09/04/13			24	21	21	20	-1		
09/05/13				-2	0	1	1		
09/06/13			31	29	23	20	-11		
09/09/13		-11	17	19	16	17	-9	-13	-15
09/13/13				25	24	20	16		
09/19/13						-196			
09/23/13				36	43	39	37		
09/30/13				29	33	30	29		0
10/04/13				16	16	16	18		
10/17/13			19	32	15	16	16		

TABLE 3-8 - SCE 2013 Daily Forecast % Deviations from Year-End Estimates

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			341%	362%	432%	597%			
05/13/13		-18%	138%	133%	131%	144%	-20%		
05/21/13					-14%				
06/03/13		-4%	-3%	1%	0%	0%	-12%	-10%	-7%
06/27/13			765%	535%	491%	732%			
06/28/13		-16%	-15%	-11%	-10%	4%	9%	4%	13%
07/01/13			-2622%	182%	172%	238%	89%		
07/02/13		-10%	19%	9%	5%	5%	2%	15%	24%
07/03/13				-2%	-11%	-12%	-11%		
07/19/13						0%			
07/31/13				-31%	-32%	6%			
08/21/13				-28%	-33%	-29%	-24%		
08/22/13					0%	-1%			
08/28/13		-6%	-1%	-13%	-5%	-3%	-5%	-6%	-9%
08/29/13				1%	0%	1%	-2%		
08/30/13	-26%	-28%	-29%	-9%	-13%	-13%	-7%	-4%	
09/04/13			255%	44%	11%	10%	-4%		
09/05/13				-9%	-2%	1%	5%		
09/06/13			1669%	8%	6%	5%	-3%		
09/09/13		-10%	15%	14%	6%	7%	-7%	-11%	-13%
09/13/13				130%	104%	92%	72%		
09/19/13						-27%			
09/23/13				530%	1042%	1335%	2388%		
09/30/13				275%	317%	342%	443%		0%
10/04/13				72%	64%	82%	121%		
10/17/13			62%	59%	61%	81%	88%		

2013 7-Day Reporting Deviations from Year-End Estimates

Tables 3-9 & 3-10 summarize the deviations of the post-event 7-day estimates from the year-end estimates. The average absolute daily deviation of the 7-day report (from year-end estimates) was **12 MW**.

TABLE 3-9 - SCE 2013 Post-Event 7-Day Report MW Deviations from Year-End Estimates

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			16	16	16	17			
05/13/13		-2	28	27	27	28	-2		
05/21/13					-14				
06/03/13		-1	0	-1	2	4	3	4	5
06/27/13			23	22	22	23			
06/28/13		1	6	4	4	30	25	0	0
07/01/13			31	31	28	28	-1		
07/02/13		17	43	44	43	43	18	17	18
07/03/13				-1	-2	-2	-2		
07/19/13						0			
07/31/13				-24	-25	0			
08/21/13				-3	-4	-4	-3		
08/22/13					0	0			
08/28/13		-15	-18	-25	-24	-23	-19	-16	-12
08/29/13				5	1	5	8		
08/30/13	-7	-8	-9	13	3	1	11	-3	
09/04/13			24	29	28	29	4		
09/05/13				0	0	0	0		
09/06/13			31	39	38	37	6		
09/09/13		1	28	27	30	28	0	6	-5
09/13/13				16	14	13	11		
09/19/13						-24			
09/23/13				9	9	8	7		
09/30/13				10	9	9	9		0
10/04/13				4	-1	-1	5		
10/17/13			19	31	10	8	8		

TABLE 3-10 - SCE 2013 Post-Event 7-Day Report % Deviations from Year-End Estimates

Event Date	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20
05/02/13			341%	362%	432%	597%			
05/13/13		-18%	127%	122%	120%	133%	-20%		
05/21/13					-14%				
06/03/13		-1%	0%	-1%	3%	5%	3%	4%	5%
06/27/13			765%	535%	491%	732%			
06/28/13		1%	5%	2%	2%	14%	12%	0%	0%
07/01/13			-2622%	120%	103%	137%	-3%		
07/02/13		19%	45%	38%	23%	15%	6%	20%	22%
07/03/13				-3%	-4%	-4%	-5%		
07/19/13						0%			
07/31/13				-31%	-32%	5%			
08/21/13				-7%	-7%	-9%	-8%		
08/22/13					0%	0%			
08/28/13		-15%	-18%	-14%	-6%	-6%	-12%	-15%	-11%
08/29/13				1%	0%	1%	5%		
08/30/13	-26%	-28%	-29%	9%	1%	0%	6%	-4%	
09/04/13			255%	60%	14%	15%	11%		
09/05/13				0%	0%	0%	0%		
09/06/13			1669%	10%	10%	10%	2%		
09/09/13		1%	24%	21%	11%	13%	0%	5%	-4%
09/13/13				83%	63%	62%	52%		
09/19/13						-3%			
09/23/13				134%	212%	259%	465%		
09/30/13				94%	86%	108%	131%		0%
10/04/13				18%	-2%	-6%	30%		
10/17/13			62%	57%	39%	38%	43%		

PILOT METHODOLOGY RESULTS

2013 SDP Event Dispatch and Measurement

The event dispatch strategy utilized for events can affect the estimation and measurement of load impact. When a group of accounts are dispatched for an event, cooling is disrupted. Once the event ends and cooling is restored, *rebound* is observed, where the cooling load has now increased from the expected baseline to make up for the cooling missed during the event period. This typically does not affect load impact estimates for that dispatch group, as the estimates generally examine the curtailment period only.

In *sequential dispatch*, multiple dispatch groups are curtailed in sequence, with one group initiating curtailment when another group restores. When considering the load impact of all dispatch groups as a unit, the rebound from an earlier group coincides with the curtailment of the subsequent group, lowering the overall load impact. In order to accurately forecast a sequential-dispatch event, the methodology would need to include rebound estimates. Sequential dispatch was utilized extensively in 2012 but not at all in 2013 for residential SDP; therefore the 2013 methodology does not include rebound estimates. In order to assess the performance of the methodologies themselves, load impact from individual *dispatch groups* were considered in this analysis.[23]

Another aspect to consider is *partial-hour dispatch*. Analysis was performed using hourly customer interval usage data. This provided a decent representation of event windows in whole-hour increments. It is difficult to accurately measure a half-hour incremental event, because a customer curtailing for a half-hour then rebounds, affecting the interval usage observation. Four half-hour events[24] were dispatched in 2012, and none in 2013. Only whole-hour incremental events were included in this analysis.

2012 & 2013 SDP Methodology Comparison

Table 11 depicts a comparison of the ex post estimates of 2012 residential SDP events to the 2012 & 2013 forecasting methodologies. (2013 ex post estimates are not yet available.) Included were price-triggered whole hour increment events for which ex post estimates were available. Not included were test events, reliability events, and partial-hour events. Also, estimates *per dispatch group* were considered (not whole-event impacts). The 2013 pilot methodology was retroactively applied to provide estimates of 2012 events.

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[23] For additional discussion, see Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs May 1, 2013. for link: *http://www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf*

[24] One multi-hour reliability event was also dispatched in 2012.

TABLE 11 – SDP Ex Post Estimates (Dispatch Group Results) and 2012 & 2013 Methodology Forecasts

Event Date	Hour Ending	# of Accounts Dispatched	Temp (°F)	2012 Ex Post Est. (MW)	2012 Methodology Forecast (MW)	2013 Methodology Forecast (MW)
7/10/2012	14	85,746	96	47	29	83
	15	125,505	96	73	42	121
	16	93,002	94	82	88	88
8/1/2012	16	85,746	86	55	29	59
	17	125,505	85	44	30	82
	18	93,496	83	60	47	57
8/3/2012	16	85,746	82	40	29	51
	17	125,505	81	72	22	71
	18	93,496	80	49	47	47
8/8/2012	16	85,746	97	110	68	91
	17	125,505	94	101	66	125
	18	93,496	90	136	99	84
8/9/2012	16	93,496	95	133	68	89
	17	125,505	93	102	66	119
	18	85,746	91	127	99	82
8/14/2012	16	85,746	94	136	61	86
8/15/2012	16	93,496	81	79	89	66
	17	125,505	79	97	42	86
	18	85,746	77	81	40	57
8/17/2012	17	93,496	96	161	103	76
	18	94,732	94	104	42	76
8/21/2012	16	93,496	85	77	53	63
	17	125,505	83	84	30	80
	18	85,746	80	60	29	52
8/22/2012	16	93,496	83	44	29	54
	17	125,505	81	76	30	73
	18	85,746	79	62	47	46
8/28/2012	16	93,496	95	80	130	86
	17	125,505	93	101	84	114
	18	85,746	91	85	72	77
8/29/2012	16	85,746	94	84	83	81
	17	125,505	92	106	66	110
	18	93,496	88	133	108	71
9/10/2012	16	93,496	88	97	73	56
	17	125,505	86	87	78	76
	18	85,746	82	72	19	50

Event Date	Hour Ending	# of Accounts Dispatched	Temp (°F)	2012 Ex Post Est. (MW)	2012 Methodology Forecast (MW)	2013 Methodology Forecast (MW)
9/21/2012	16	93,496	90	71	131	78
	17	125,505	87	67	169	105
	18	85,746	86	81	105	67
10/2/2012	15	166,217	97	89	309	165
	16	166,217	94	104	289	161
	17	138,530	90	140	236	125
	18	138,530	85	135	160	110
10/17/2012	16	93,603	95	65	127	79
	17	103,833	91	76	147	87
	18	109,730	88	66	92	89

Chart 1 shows how the 2013 SDP Pilot Methodology follows the 2012 SDP Ex Post MW load profile more closely than the 2012 Post-Event Estimate.

Chart 1 – SDP Event Hour Comparison

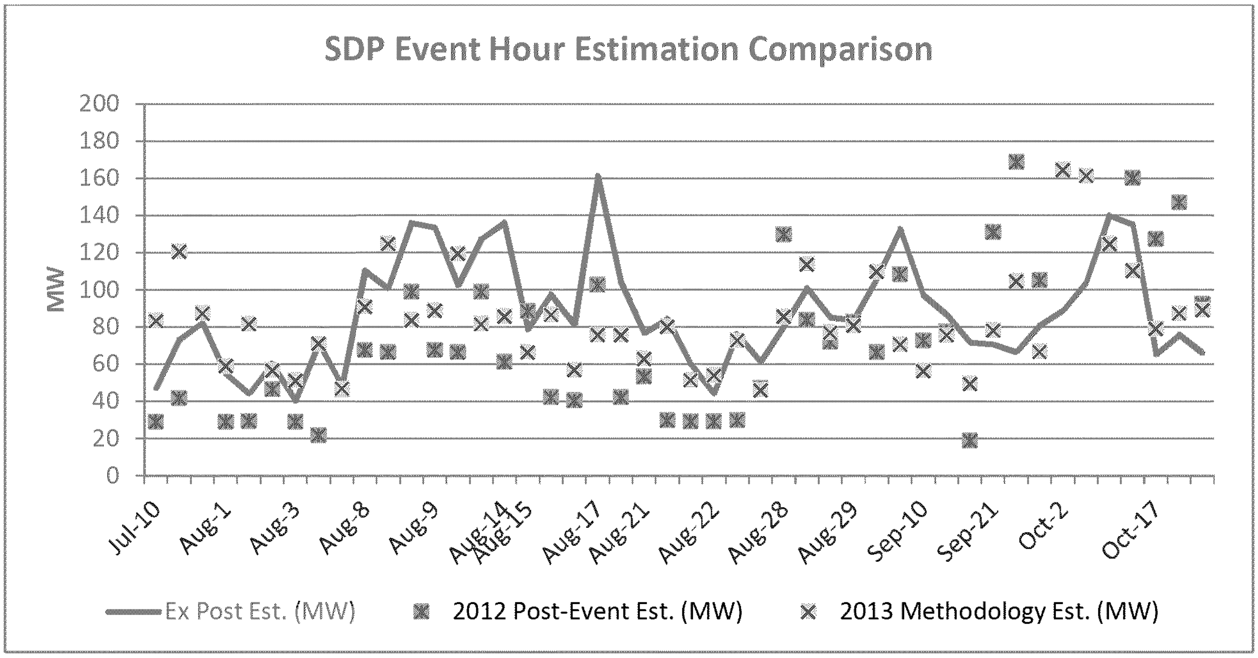

Table 12 depicts the deviations of the 2012 and the 2013 forecasting methodologies from the 2012 ex post estimates. The average absolute hourly deviation fell from **44 MW** (with the 2012 methodology) to **23 MW** (with the 2013 methodology), a **variance reduction of 47%** with the new methodology.

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TABLE 12 - 2012 & 2013 Methodology Deviations from 2012 Ex Post Estimates

Event Date	Hour Ending	2012 Methodology - MW Dev. from ex post	2013 Methodology - MW Dev. from ex post	2012 Methodology - % Dev. from ex post	2013 Methodology - % Dev. from ex post
7/10/2012	14	-18	36	-38%	77%
	15	-31	47	-43%	65%
	16	5	5	6%	6%
8/1/2012	16	-26	4	-47%	8%
	17	-15	37	-33%	84%
	18	-14	-3	-23%	-6%
8/3/2012	16	-11	11	-28%	27%
	17	-50	0	-70%	-1%
	18	-2	-2	-4%	-3%
8/8/2012	16	-43	-19	-39%	-17%
	17	-34	24	-34%	24%
	18	-37	-52	-27%	-38%
8/9/2012	16	-66	-44	-49%	-33%
	17	-36	17	-35%	17%
	18	-28	-45	-22%	-36%
8/14/2012	16	-75	-50	-55%	-37%
8/15/2012	16	10	-12	13%	-15%
	17	-55	-11	-57%	-11%
	18	-41	-24	-50%	-30%
8/17/2012	17	-59	-85	-36%	-53%
	18	-62	-29	-60%	-27%
8/21/2012	16	-23	-14	-30%	-18%
	17	-54	-4	-65%	-5%
	18	-31	-9	-51%	-15%
8/22/2012	16	-15	10	-34%	22%
	17	-46	-3	-61%	-4%
	18	-14	-15	-24%	-25%
8/28/2012	16	49	5	61%	6%
	17	-17	13	-17%	13%
	18	-13	-8	-16%	-9%
8/29/2012	16	-1	-3	-1%	-4%
	17	-39	4	-37%	4%
	18	-24	-62	-18%	-47%
9/10/2012	16	-24	-41	-25%	-42%
	17	-9	-11	-11%	-13%

Event Date	Hour Ending	2012 Methodology - MW Dev. from ex post	2013 Methodology - MW Dev. from ex post	2012 Methodology - % Dev. from ex post	2013 Methodology - % Dev. from ex post
	18	-53	-22	-74%	-31%
9/21/2012	16	60	8	86%	11%
	17	102	38	153%	57%
	18	24	-14	30%	-18%
10/2/2012	15	220	76	248%	85%
	16	185	57	178%	55%
	17	97	-15	69%	-11%
	18	25	-25	19%	-18%
10/17/2012	16	62	14	95%	21%
	17	71	11	94%	15%
	18	26	23	40%	35%

2012 & 2013 PTR Methodology Comparison

Table 12 depicts a comparison of the ex post estimates of 2012 PTR events[25] to the 2012 & 2013 forecasting methodologies. (2013 ex post estimates are not yet available.) The 2013 pilot methodology was retroactively applied to provide estimates of 2012 events.

TABLE 13 – PTR 2012 Ex Post Estimates and 2012 & 2013 Methodology Forecasts

Event Date	Hour Ending	# of Accounts Enrolled in Notification	Temp (°F)	2012 Ex Post Est. (MW)	2012 Methodology Forecast (MW)	2013 Methodology Forecast (MW)
8/10/2012	15	482,459	94	86	107	12
	16	482,459	95	112	107	13
	17	482,459	95	96	107	14
	18	482,459	94	89	107	15
8/16/2012	15	482,407	90	-5	108	12
	16	482,407	90	17	108	13
	17	482,407	90	36	108	14
	18	482,407	91	50	108	15
8/29/2012	15	482,315	92	39	109	12
	16	482,315	92	45	109	13
	17	482,315	91	20	109	14
	18	482,315	87	-16	109	15

25 The July 12 PTR event was excluded from the Load Impact Study ex post analysis due to the large number of customers enrolled in notification between that event and the next one (on August 10).

Event Date	Hour Ending	# of Accounts Enrolled in Notification	Temp (°F)	2012 Ex Post Est. (MW)	2012 Methodology Forecast (MW)	2013 Methodology Forecast (MW)
8/31/2012	15	482,276	88	6	109	12
	16	482,276	88	5	109	13
	17	482,276	87	-16	109	14
	18	482,276	86	5	109	15
9/7/2012	15	482,271	86	-33	109	11
	16	482,271	87	-29	109	12
	17	482,271	86	-28	109	12
	18	482,271	85	-2	109	12
9/10/2012	15	482,247	83	-44	109	11
	16	482,247	85	8	109	12
	17	482,247	84	21	109	12
	18	482,247	82	22	109	12

Chart 2 demonstrates how the 2013 PTR Pilot Methodology follows the 2012 PTR Ex Post MW load profile more closely than the 2012 Post-Event Estimates.

Chart 2 – 2012 PTR Event Hour Comparison

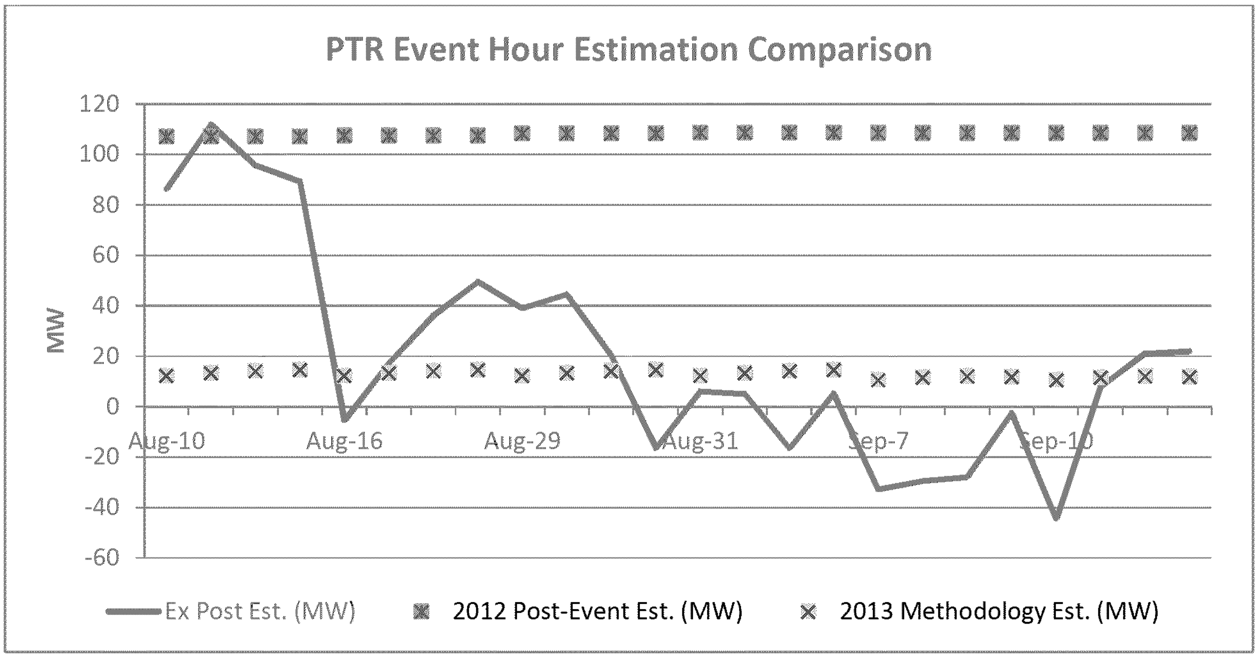

Table 14 depicts the deviations of the 2012 and the 2013 methodologies from the 2012 ex post estimates. The average absolute hourly deviation fell from **88 MW** (with the 2012 methodology) to **32 MW** (with the 2013 methodology), a **variance reduction of 64%** with the new methodology.

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TABLE 14 - 2012 & 2013 Methodology Deviations from 2012 Ex Post Estimates

Event Date	Hour Ending	2012 Methodology - MW Dev. from ex post	2013 Methodology - MW Dev. from ex post	2012 Methodology - % Dev. from ex post	2013 Methodology - % Dev. from ex post
8/10/2012	15	21	-74	24%	-86%
	16	-5	-98	-4%	-88%
	17	12	-81	12%	-85%
	18	18	-75	20%	-84%
8/16/2012	15	113	18	-2087%	-328%
	16	90	-4	521%	-22%
	17	71	-22	197%	-61%
	18	58	-35	117%	-70%
8/29/2012	15	69	-27	177%	-68%
	16	64	-31	143%	-70%
	17	88	-6	431%	-30%
	18	125	31	-760%	-189%
8/31/2012	15	103	6	1655%	99%
	16	104	8	2027%	163%
	17	125	31	-760%	-186%
	18	103	9	1968%	179%
9/7/2012	15	141	43	-432%	-133%
	16	138	41	-469%	-140%
	17	136	40	-491%	-144%
	18	111	14	-4614%	-591%
9/10/2012	15	153	55	-344%	-124%
	16	101	4	1260%	47%
	17	87	-9	413%	-42%
	18	87	-10	395%	-46%

FINDINGS AND OBSERVATIONS

The forecasting methodologies piloted in 2013 substantially reduced variances between forecasts and ex post results, compared to the 2012 methodology, for both the SDP and PTR programs. The SDP pilot methodology reduced average absolute hourly deviation from **44 MW** for the 2012 methodology to **23 MW** with the pilot methodology, a variance **reduction of 47%**. The PTR pilot methodology reduced average absolute hourly deviation from **88 MW** for the 2012 methodology to **32 MW** with the pilot methodology, a **variance reduction of 64%**.

Deviations between forecasts and ex post results seem to remain due to discrepancies in capturing weather conditions and temperature dependency. In order to be usable on a daily basis, the pilot algorithm captures only a simple approximation of temperature dependency. The forecast reports utilize an hourly temperature forecast, and the post event updates to spot temperature reading. The load impact studies have the opportunity to utilize a greater range of measures of conditions, particularly considering heat accumulation, which is a better predictor of AC load than current temperature. Cooling load is generally lower on a rather hot day that immediately follows a cool stretch than on a moderately warm day at the tail end of a heat wave.

Even controlling for weather conditions in a much more sophisticated manner, substantial variation in event-to-event (and even hour-to-hour) results would remain due to variation in customer behavior. Some of this variation may be correlated with the calendar; early- and late-summer (or early fall) events often reflect different customer behavior patterns than is observed in the high summer. However, much of the variability in customer behavior remains unobserved and inherently unpredictable to the more sophisticated forecasting models available.

Variability in customer behavior is even more apparent in the event results for PTR. SDP, as a direct-load control program, removes some of the layers of unpredictability out of the equation (and yet the measurement results retain a great deal of volatility). PTR, with the exception of a few technology-enabled customers in test programs, is entirely dependent on customers choosing to respond to an event call-to-action. It is also a new and unfamiliar program to customers, with a no-penalty, incentive-only payment structure. The event response observed in 2012 is consistent with rapid customer seasonal fatigue; customers responding most strongly to the earliest events in the season, but ignoring / forgetting about later event notices. (This interpretation is a purely speculative hypothesis; it cannot be determined from the study data whether this is a true description of customer behavior and attitudes.) The 2012 methodology seems to reflect the program potential, or what the program might achieve in near-to-ideal circumstances. The 2013 methodology appears to be much closer to the overall expected outcome of any given event in the course of a season.

RECOMMENDATIONS

Basing the SDP and PTR forecasts on the ex ante study findings (as is the case in both pilot methodologies), provides an approach that is reasonable in expected value to measured event performance. These new forecast methodologies are also analytically grounded, achievable and implementable, as well as consistent with the PY 2012 Load Impact studies for SDP and PTR and resource adequacy filings[26]. Updating these methodologies based on the PY2013 ex ante estimates would be the next logical step for the 2014 event season.

[26] Resource Adequacy Filing: R.11-10-023, D.13-06-024

Any further refinement of the methodologies is best driven by specific purpose and need. Additional significant enhancements would be difficult and costly to implement, yet would likely result in marginal forecasting improvements. If forecasts fail to meet a specific designed purpose, it would be best to identify and explore the forecasting purpose to determine the level of precision needed and if such requirements are achievable with any similar forecasting methodology.

III. SDG&E Results

SDG&E Forecast Methodology

The section includes detailed descriptions of the SDG&E forecasting methodology for 2012 and 2013 as well as the methodology used to calculate the preliminary 7-day report results and the ex-post results. On page 12-13 at the end of this section a summary table is provided containing a brief description of each methodology by program. More detailed descriptions of the methodologies are provided in the discussion below.

SDG&E forecasting methods vary by program but there are four main categories:

1. Forecasts for non-weather sensitive load reductions are based on nominations or previous event results.

2. Forecasts for weather sensitive programs with approximately constant percentage load reductions are created by modeling the entire load of the customers using regression and multiplying this by a fixed percentage load impact.

3. Forecasts for weather sensitive programs with percentage load reduction that are not constant were created by modeling the load reductions based on temperature. This was accomplished by asking the consultants who do the formal annual ex-ante forecasts to provide load impact forecasts for additional weather scenarios.

4. Forecasts to programs in which customers commit to use no more than a firm service level (FSL) were created by forecasting the entire load of the customers and subtracting the FSL.

SDG&E uses MetrixIDR software to generate forecasts for each SDG&E demand response program using the methods described below. MetrixIDR gets its name from the term "Interval Data Recorder" (IDR), which is the device used to collect load data at a customer site. MetrixIDR imports a list of customers, interval (IDR) data, weather data and forecast, and calendar data. SDG&E then sets up a regression model for each demand response program within the software. Finally, MetrixIDR runs each morning and exports the daily forecast impacts by program once per day to a Microsoft Excel Spreadsheet. An analyst reviews the excel spreadsheet, makes corrections if necessary, and e-mails the report out to the distribution list.

Category 1: Non-Weather Sensitive Programs

Capacity Bidding Program (CBP):

A) 2012: The CBP load impact is not weather sensitive therefore the CBP demand response forecasts do not change with weather. The CBP forecast was based on historical performance and monthly nominations.

B) 2013: The CBP forecast is based on the lower of 90% of monthly nominated MW or the actual load impact preliminary results for this year.

Improvement between 2012 and 2013:

The SDG&E CBP day-of forecast tracked very well with the ex-post results expect that it was consistently high. This was due to the fact that the preliminary results using the 10 day baseline with a same day adjustment came out higher than the final ex-post results. Therefore, in 2013 SDG&E used the lower of the preliminary results and 90% of the nomination for the forecast.

Demand Bidding Program (DBP):

A) 2012: The forecast was based on the minimum bid of 5 MW.

B) 2013: The forecast is based on the minimum bid of 5 MW and actual load impact results. A zero value is assigned for hours and days of the week when customer uses less than 5 MW.

Improvement between 2012 and 2013:

The program is available 24 hours a day 7 days a week but in the 2013 forecast the hours in which the customer typically uses less than 5 MW are set to zero.

Category 2: Weather sensitive with constant percent impacts

Critical Peak Pricing-Default (CPP-D):

A) 2012: A forecast for the entire load was created using regression analysis. The inputs to the regression analysis were the average daily temperature, day of week, month, and holidays. Then the forecast of the entire load is then multiplied by a fixed percentage load reduction. The percentage load reduction was taken from the Ex-Post results from the previous year.

B) 2013: A forecast for the entire load is created using regression analysis. The inputs to the regression analysis are the average daily weather and day of week. Then the forecast of the entire load is then multiplied by a fixed hourly percentage load reduction. The percentage load reduction is taken from of the 30th percentile Ex-Post results from the previous year. Since customers can only opt-out of CPP once a year there are usually not large changes in the number of customers enrolled.

Improvement between 2012 and 2013:

The fixed percentage load reduction now varies by hour instead of being the same for all hours as it was in 2012.

Peak Time Rebate (PTR):

A) 2012: The forecast was based on a regression model using the day of the week, month, and temperature variables. The official residential load shape from Electric Load Analysis was used for residential customers. Then the load is multiplied by a fixed percent. The percentage load reduction was taken initially from of the 2011 PTR pilot and later adjusted downwards based on preliminary results. Since all SDG&E residential customers were enrolled in the program, the forecast included all customers.

B) 2013: The forecast is based on a regression model using the day of the week and temperature variables. Since the 2012 ex-post results showed no statistically significant load reduction from the general population, only residential PTR opt-in customers[27] are included in the daily forecast model. Then the load is multiplied by a fixed percent. The percentage load reduction is taken from of the 30th percentile of ex-post results from the previous year. To account for growing enrollment SDG&E divide the forecast by the number of customer included to get a per customer reduction and multiplies this by the number of customers enrolled.

Improvement between 2012 and 2013:

Although all residential customers are currently enrolled in PTR, only opt-in customers are included in the forecast, consistent with the 2012 ex-post results.

[27] Opt-in PTR customers are customers who went to the SDG&E website and proactively asked to receive e-mail or text alerts about PTR event days.

Category 3: Weather sensitive programs with non-constant percent impacts

Summer Saver (AC Cycling):

A) 2012: A forecast for the air-conditioning load rather than the entire house or building load was created using regression analysis. The inputs to the regression analysis were the average daily weather and day of week. Then the forecast of the air-conditioning load was then multiplied by a fixed percentage load reduction. The percentage load reduction was based on the cycling strategy. The forecast is then divided by the number of tons to get a per ton forecast and multiplied by the current number of tons enrolled on the program to account for enrollment changes. The customer list was updated weekly.

B) 2013: SDG&E sent the consulting firm who performed the annual ex-ante forecast 30 weather scenarios and asked for a forecast of the 30th percentile of the load impacts for each weather scenario. In essence this creates a lookup table where one can look up a temperature and get the load forecasted load reduction. However, MetrixIDR software does not support using lookup tables. Therefore we entered the load impacts as data into the Metrix IDR regression model and ran a regression model with the load impacts as the dependent variables and average daily temperature as the independent variable. The forecast is then divided by the number of tons used in the ex-ante forecast to get a per ton forecast and multiplied by the current number of tons enrolled on the program to account for enrollment changes. The number of tons enrolled is updated weekly. The summer saver commercial 50 cycle forecast is capped based on the adjusted impact average 30th percentile on the ex-ante results from previous year.

Improvement between 2012 and 2013:

Although the concept of our 2012 summer save methodology was sound the sample of customers with an extra meter/logger on the air-conditioner is small and this may have caused some of the discrepancies between the forecast and the ex-post results. The 2012 ex-post methodology used a larger sample of customers and used the whole house data for the analysis. When using whole house data the percentage load reduction for the summer saver program is not constant so we could not use that methodology. Therefore, by requesting FSC to provide ex-ante load impact estimates for 30 weather scenario our forecast will be consistent with FSC methods.

Category 4 Programs with a firm service level

Base Interruptible Program (BIP):

A) 2012: A forecast of the entire load of participating customers was created using regression analysis. The inputs to the regression analysis were the average daily weather and day of week. Then the load is multiplied by a fixed percent. The percentage load reduction is taken from of the Ex-Post results from the previous year.

B) 2013: The forecast is based on a regression model using the day of the week and temperature variables minus FSL. A zero value is assigned when load forecast is less than FSL. There are only 7 customers enrolled in this program customer cannot opt out the program until November so enrollment changes are not expected. However, if new customers join SDG&E will re-estimate the regression models to include the new customers.

Improvement between 2012 and 2013:

Since the BIP program requires customers to use no more than their firm service level our 2013 methodology more closely matches the program design. In particular, more hours are correctly forecasted as zero because when customers are already using less than their firm service level they have no incentive to reduce load.

Table 4-1 below contains a summary of the SDG&E forecast methodology along with the SDG&E methodology for calculating the 7-day report and ex-post results. A detailed description of the SG&E methodology for calculating the 7-day report and ex-post results is included in Appendix A.

Table 4-1 SDG&E Forecast Methodologies						
Program	Daily Forecast Report - 2012	Daily Forecast Report - 2013	7-days Report - 2012	7-days Report - 2013	Ex-Post Results 2012	Ex-Post Results 2013
BIP	Regression forecast of entire customer load multiplied by a fixed percentage load reduction	Regression forecast of entire load minus the firm service level.	Individual 10 of 10 baselines with a same day adjustment.	Individual 10 of 10 baselines with a same day adjustment.	Individual Regression	Individual Regression
CBP	Based on the monthly nomination and preliminary results	Based on the lower of 90% of monthly nominated MW and preliminary results.	Individual 10 of 10 baselines with a same day adjustment.	Individual 10 of 10 baselines with a same day adjustment.	Individual Regression	Individual Regression
CPP	Regression forecast of entire customer load multiplied by a fixed percentage load reduction	Regression forecast of entire customer load multiplied by a fixed percentage load reduction	Weekday: individual 10 of 10 baseline with same day adjustment. Weekend: 1 day baseline multiplied by a same day adjustment.	Matched control groups	Matched control groups	Matched control group
DBP	Minimum bid of 5 MW	The forecast is based on the monthly nominated MW and actual load impact results. A zero value is assigned for hours and days of the week when customer uses less than 5 MW.	Customer specific baseline based on the similar weekday or weekend prior to the Event with a same day adjustment.	Baseline is an average consumption for the three (3) days with the most similar temperatures to the event days with a same day adjustment	Individual Regression	Individual Regression

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PTR	Regression forecast of entire customer load multiplied by a fixed percentage load reduction. Customer who did not opt-in to alerts were included in the forecast.	Regression forecast of entire customer load multiplied by a fixed percentage load reduction. Customers who did not opt-in to alerts were excluded from the forecast.	Baseline is an average consumption for the two (2) similar days (most similar weather conditions to the event day) prior to the Event with a same day adjustment.	Matched control group.	Individual Regression	Matched control group
Summer Saver	Regression forecast of air-conditioning load was multiplied by a fixed percentage based on the cycling strategy.	Regression forecast of load reductions based on temperature.	Baseline is an average consumption for the two (2) similar days (most similar weather conditions to the event day) prior to the Event with a same day adjustment.	Residential: Randomized Control group Commercial: 2 day baseline with a same day adjustment	Residential: Randomized Control Group Commercial: Aggregate Regression	Residential: Randomized Control Group Commercial: Matched control group

Table 4-2 summarizes the demand response events that were called by SDG&E in 2013.

Table 4-2 SDG&E 2013 May-Oct Event Summary Table					
Programs	Date	Program Type	# of Accounts	Event Start Time (PDT)	Event End Time (PDT)
CBP-DO Total	6/28/2013	DAY OF	244	HE15	HE18
CBP-DA Total	7/1/2013	DAY AHEAD	133	HE15	HE18
CBP-DO Total	8/28/2013	DAY OF	267	HE16	HE19
Summer Saver Total	8/28/2013	DAY OF	22,061	HE16	HE19
CBP-DA Total	8/29/2013	DAY AHEAD	145	HE16	HE19
CBP-DO Total	8/29/2013	DAY OF	267	HE15	HE18
CPPD	8/29/2013	DAY AHEAD	1,117	HE12	HE18
Summer Saver Total	8/29/2013	DAY OF	22,061	HE15	HE18
CBP-DA Total	8/30/2013	DAY AHEAD	145	HE15	HE18
CBP-DO Total	8/30/2013	DAY OF	267	HE14	HE17
DBP	8/30/2013	DAY OF	1	HE13	HE16
Summer Saver Total	8/30/2013	DAY OF	22,061	HE14	HE17
RYU/PTR	8/31/2013	DAY AHEAD	57,376	HE12	HE18
CBP-DO Total	9/3/2013	DAY OF	264	HE14	HE17
Summer Saver Total	9/3/2013	DAY OF	22,061	HE14	HE17
CBP-DA Total	9/4/2013	DAY AHEAD	147	HE14	HE17
CBP-DO Total	9/4/2013	DAY OF	264	HE14	HE17
CPPD	9/4/2013	DAY AHEAD	1,117	HE12	HE18
BIP	9/5/2013	DAY OF	7	HE14	HE17
CBP-DA Total	9/5/2013	DAY AHEAD	147	HE14	HE17
CBP-DO Total	9/5/2013	DAY OF	264	HE14	HE17
CPPD	9/5/2013	DAY AHEAD	1,117	HE12	HE18
DBP	9/5/2013	DAY OF	1	HE14	HE17
Summer Saver Total	9/5/2013	DAY OF	22,061	HE14	HE17
CBP-DA Total	9/6/2013	DAY AHEAD	147	HE14	HE17
CBP-DO Total	9/6/2013	DAY OF	264	HE14	HE17
CPPD	9/6/2013	DAY AHEAD	1,117	HE12	HE18
DBP-Navy	9/6/2013	DAY OF	1	HE14	HE17
Summer Saver Total	9/6/2013	DAY OF	22,061	HE14	HE17

Comparison of SDG&E 2013 Forecast to 7-day results

Tables 4-3 and 4-4 below contain the hourly SDG&E forecasts and preliminary results in total for all programs called for each event hour in 2013. SDG&E called at least one demand response event on 10 days and all events occurred between hour ending 12 (11 a.m. – 12p.m) and hour ending 19 (6p.m.- 7 p.m.). The minimum forecast was 7.9 MW and the maximum was 51.7 MW based on the number of programs that were called that hour.

Table 4-3 SDG&E 2013 Daily DR Forecast Summary								
Event date	**HE12 MW**	**HE13 MW**	**HE14 MW**	**HE15 MW**	**HE16 MW**	**HE17 MW**	**HE18 MW**	**HE19 MW**
6/28/2013				9.0	9.0	9.0	9.0	
7/1/2013				7.9	7.9	7.9	7.9	
8/28/2013				0.0	21.3	21.4	17.6	17.1
8/29/2013	15.2	15.6	12.5	33.2	43.1	45.5	37.8	8.0
8/30/2013		5.0	27.6	36.2	38.0	33.2	8.0	
8/31/2013	3.4	3.7	3.8	3.9	4.0	4.0	4.0	
9/3/2013			20.8	21.3	22.8	22.9		
9/4/2013	16.0	16.6	30.5	28.9	29.2	31.5	10.8	
9/5/2013	16.1	16.6	51.3	48.2	49.9	51.7	15.9	
9/6/2013	15.9	16.4	46.5	45.4	47.5	49.6	10.6	

Table 4-4 SDG&E 2013 DR Post Event 7-day report								
Event date	**HE12 MW**	**HE13 MW**	**HE14 MW**	**HE15 MW**	**HE16 MW**	**HE17 MW**	**HE18 MW**	**HE19 MW**
6/28/2013				8.6	8.7	8.5	8.5	
7/1/2013				8.1	8.1	8.1	7.8	
8/28/2013					21.4	24.0	23.6	21.0
8/29/2013	13.8	13.7	18.9	36.8	40.2	36.3	35.1	9.0
8/30/2013		3.8	29.2	45.0	46.7	41.9	9.4	
8/31/2013	3.6	5.2	6.0	5.9	6.1	6.0	5.7	
9/3/2013			20.7	26.3	28.4	28.4		
9/4/2013	16.4	18.2	36.4	35.3	37.5	35.9	12.2	
9/5/2013	12.7	16.3	52.3	54.8	55.2	53.8	12.6	
9/6/2013	13.6	13.0	46.8	53.6	59.3	55.4	9.2	

Table 4-5 below contains the difference between the SDG&E forecast and the preliminary event results. A negative value indicates that the forecast was lower than the results whereas the positive value indicates that the forecast was higher than the results. The average forecast error is -2.0 MW with 90% of the hourly errors falling between -6.7 MW and 2.3 MW.

Table 4-5 SDG&E 2013 Forecast Deviations from 7-day report								
Event date	**HE12 MW**	**HE13 MW**	**HE14 MW**	**HE15 MW**	**HE16 MW**	**HE17 MW**	**HE18 MW**	**HE19 MW**
6/28/2013				-0.4	-0.3	-0.5	-0.5	
7/1/2013				0.2	0.2	0.2	-0.1	
8/28/2013				0.0	0.1	2.6	6.0	3.9
8/29/2013	-1.4	-1.9	6.4	3.6	-2.8	-9.3	-2.6	1.0
8/30/2013		-1.2	1.6	8.8	8.7	8.7	1.4	
8/31/2013	0.1	1.6	2.2	2.0	2.1	2.0	1.7	
9/3/2013			-0.1	5.0	5.6	5.4		
9/4/2013	0.4	1.7	5.9	6.3	8.3	4.5	1.4	
9/5/2013	-3.4	-0.3	1.0	6.6	5.4	2.1	-3.2	
9/6/2013	-2.2	-3.4	0.3	8.3	11.8	5.8	-1.5	

The table below contains the percentage difference between the SDG&E forecast and the preliminary event results. A negative value indicates that the forecast was lower than the results whereas the positive value indicates that the forecast was higher than the results. The average percentage forecast error is -7% with 90% of the hourly percentage errors falling between -30% and 16%.

Table 4-6 SDG&E 2013 Forecast Percentage Deviations from Post Event 7-day report								
Event date	**HE12**	**HE13**	**HE14**	**HE15**	**HE16**	**HE17**	**HE18**	**HE19**
6/28/2013				-5%	-3%	-5%	-6%	
7/1/2013				3%	3%	3%	-1%	
8/28/2013					1%	11%	26%	19%
8/29/2013	-10%	-14%	34%	10%	-7%	-26%	-7%	11%
8/30/2013		-32%	5%	19%	19%	21%	15%	
8/31/2013	3%	30%	37%	34%	34%	33%	31%	
9/3/2013			-1%	19%	20%	19%		
9/4/2013	2%	9%	16%	18%	22%	12%	11%	
9/5/2013	-27%	-2%	2%	12%	10%	4%	-25%	
9/6/2013	-16%	-26%	1%	15%	20%	11%	-16%	

Comparison of Forecast to Draft Ex-Post Results

Overall the draft ex-post results turned out to be higher than the 7-day report results. The average load reduction over all events in 2013 was 32 MW according to the ex-post results whereas it was 24 MW according to the preliminary 7-day report results. Since the daily forecast was close but generally lower than the 7-day results the difference between the forecast and draft ex-post results are larger than those between the daily forecast and the 7-day results.

The average absolute difference between the forecast and draft ex-post results is -9.8 MW with a 90th percentile of -22.7 MW and a 10th percentile of -0.6 MW and the average percentage difference is -27% with a 10th percentile of -46% and a 90th percentile of -6%.

Table 4-7 SDGE 2013 Draft Ex-Post Results

Event date	HE12 MW	HE13 MW	HE14 MW	HE15 MW	HE16 MW	HE17 MW	HE18 MW	HE19 MW
6/28/2013				9.1	9.6	8.8	8.7	
7/1/2013				8.4	8.7	8.9	8.4	
8/28/2013				0.0	26.4	29.5	28.2	21.7
8/29/2013	26.5	28.1	24.9	42.8	50.2	57.8	47.3	11.8
8/30/2013		2.8	31.3	47.1	49.1	46.4	9.3	
8/31/2013	5.3	6.8	7.5	7.6	7.5	6.8	5.2	
9/3/2013			24.4	30.0	32.4	32.2	0.0	
9/4/2013	25.4	28.0	48.4	50.6	51.8	46.7	25.2	
9/5/2013	21.1	26.0	63.4	71.0	74.8	74.9	23.8	
9/6/2013	21.7	24.6	67.4	77.7	84.4	84.4	20.1	

Table 4-8 SDG&E 2013 Daly DR Forecast Deviations from 7-day report results

Event date	HE12 MW	HE13 MW	HE14 MW	HE15 MW	HE16 MW	HE17 MW	HE18 MW	HE19 MW
6/28/2013				-0.1	-0.6	0.2	0.3	
7/1/2013				-0.5	-0.8	-1.0	-0.5	
8/28/2013				0.0	-5.1	-8.1	-10.7	-4.6
8/29/2013	-11.4	-12.6	-12.5	-9.7	-7.1	-12.3	-9.6	-3.8
8/30/2013	0.0	2.2	-3.7	-10.8	-11.1	-13.3	-1.3	
8/31/2013	-1.9	-3.1	-3.7	-3.7	-3.5	-2.7	-1.2	
9/3/2013	0.0	0.0	-3.6	-8.7	-9.6	-9.3	0.0	
9/4/2013	-9.4	-11.5	-17.9	-21.6	-22.6	-15.2	-14.3	
9/5/2013	-5.0	-9.4	-12.1	-22.8	-25.0	-23.2	-7.9	
9/6/2013	-5.8	-8.2	-20.9	-32.3	-37.0	-34.8	-9.4	

Table 4-9 SDG&E 2013 Daly DR Forecast % Deviations from Draft Ex-Post Results								
Event date	**HE12**	**HE13**	**HE14**	**HE15**	**HE16**	**HE17**	**HE18**	**HE19**
6/28/2013				-1%	-6%	3%	3%	
7/1/2013				-6%	-9%	-11%	-6%	
8/28/2013					-19%	-27%	-38%	-21%
8/29/2013	-43%	-45%	-50%	-23%	-14%	-21%	-20%	-32%
8/30/2013		78%	-12%	-23%	-23%	-29%	-14%	
8/31/2013	-35%	-46%	-50%	-49%	-47%	-40%	-24%	
9/3/2013			-15%	-29%	-30%	-29%		
9/4/2013	-37%	-41%	-37%	-43%	-44%	-33%	-57%	
9/5/2013	-24%	-36%	-19%	-32%	-33%	-31%	-33%	
9/6/2013	-27%	-33%	-31%	-42%	-44%	-41%	-47%	

SDG&E Forecast results for the Summer Saver, PTR and CBP programs

Decision D-13-07-003 specifically directed SDG&E to improve the forecast for its Summer Saver, PTR and CBP programs. Therefore this section of the report focuses on these three programs.

The improvement that SDG&E made to the PTR forecast in 2013 was to only include customers who opted into alerts in the forecast. In 2012 all residential customers were included in the forecast since all residential customers were enrolled in the program. However, the ex-post measurement and evaluation report showed no statistically significant load reduction from customers who did not opt into alerts. This resulted in a 2012 PTR forecast that was 514% (18 MW) higher than the ex-post results. The 2013 PTR forecast was 44% lower (2.9 MW) than the ex-post results. This is mainly due to the fact that 2013 ex-post results were higher than the 2012 ex-post results that informed the 2013 forecast.

The improvement that SDG&E made to the summer saver forecast in2013 was to create a forecast of the load reductions themselves based on temperature instead of forecasting the total AC load. SDG&E accomplished this by asking the consulting firm who calculated the annual ex-ante analysis to provide an ex-ante forecast for a list of 30 weather scenarios and used this data to create a regression model of the load reduction based on temperature. SDG&E also took a more conservative approach to the forecast by using the 30th percentile of the ex-ante forecast rather than the 50th percentile. The summer saver forecast in 2013 is more consistent than the 2012 forecast. The 7-day results were also closer to the ex-post results than the 2012 ex-post results.

SDG&E made no major changes to the CBP forecast except that a slightly more conservative approach of using the lower of 90% of the nomination or the most recent results was put in place. The 2013 CBP forecast errors are smaller than they were in 2012. In 2013 forecast was also typically lower than the ex-post results whereas in 2012 the forecast was typically higher than the ex-post forecast.

Table 4-10 SDG&E 2012 Forecast Comparison to Ex-Post and 7-day Results						
Program_	Month	7-day report	Forecast	Ex-Post	% Forecast versus Ex-Post	% Forecast versus 7-day
CBP-DA	8	9	7.5	7.6	-1%	-17%
CBP-DA	9	6.9	9	6.8	33%	31%
CBP-DA	10	7.5	9	4.2	117%	20%
CBP-DO	8	10.9	11.7	9.8	20%	7%
CBP-DO	9	10.2	12.1	10.6	15%	19%
CBP-DO	10	9.5	12.1	9.2	32%	28%
Summer Saver	8	18.1	26.5	19.2	38%	47%
Summer Saver	9	12.5	13.3	14.6	-9%	7%
Summer Saver	10	9.2	14.5	18	-19%	58%
PTR Res	7	13.3	23.9	6.3	277%	80%
PTR Res	8	20.9	15.1	2.5	514%	-28%
PTR Res	9	45.8	32.3	8.3	289%	-29%

Table 4-11 SDG&E 2013 DR Forecast for Summer Saver, CBP and PTR						
Program	Month	7-day report	Forecast	Ex-Post	% Forecast versus Ex-Post	% Forecast versus 7-day
CBP-DA	7	8.0	7.9	8.6	-8.0%	-1.3%
CBP-DA	8	10.2	8.0	10.8	-25.7%	-26.9%
CBP-DA	9	8.7	8.0	10.8	-25.8%	-9.2%
CBP-DO	6	8.6	9.0	9.0	-0.3%	4.4%
CBP-DO	8	9.2	8.6	10.9	-21.1%	-7.4%
CBP-DO	9	11.5	9.1	11.2	-19.5%	-26.5%
RYU/PTR	8	5.5	3.8	6.7	-43.3%	-44.7%
Summer Saver	8	14.8	13.3	17.5	-24.3%	-11.8%
Summer Saver	9	16.9	14.2	21.3	-33.5%	-18.9%

Hourly Detail 2013 Forecast results for Summer Saver, PTR and CBP

Tables 4-12 below include the hourly forecast by event for Summer Saver. The hourly detail shows that for summer saver the highest error occurred during the hottest event day which was 09/06/2014. Since the 2013 forecast was also very consistently lower than the draft ex-post results. This is to be expected to some extent because SDG&E did use the 30th percentile of the 2012 ex-ante forecast but the magnitude of the difference was larger than expected. SDG&E will work with the consulting firm to improve these aspects of the forecast for 2014.

Table 4-12 Summer Saver Hourly Forecast						
Date	Hour	7-day	Forecast	Ex-Post	% Forecast vs. Ex-Post	% Forecast vs. 7-day
08/28/2013	16	11.5	12.7	14.8	-14%	11%
08/28/2013	17	14.2	12.8	17.5	-27%	-9%
08/28/2013	18	14.0	9.0	16.4	-45%	-36%
08/28/2013	19	12.1	8.5	10.5	-19%	-30%
08/29/2013	15	6.7	13.5	9.3	45%	103%
08/29/2013	16	9.0	15.1	13.4	13%	67%
08/29/2013	17	13.5	15.3	18.2	-16%	13%
08/29/2013	18	16.8	10.7	20.9	-49%	-36%
08/30/2013	14	15.6	14.0	17.7	-21%	-10%
08/30/2013	15	20.1	14.6	22.4	-35%	-27%
08/30/2013	16	21.9	16.4	24.1	-32%	-25%
08/30/2013	17	23.1	16.6	25.0	-34%	-28%
09/03/2013	14	9.4	12.2	14.4	-16%	30%
09/03/2013	15	14.5	12.7	19.5	-35%	-12%
09/03/2013	16	16.5	14.2	21.7	-35%	-14%
09/03/2013	17	17.0	14.3	21.6	-34%	-16%
09/05/2013	14	11.0	13.1	14.0	-7%	19%
09/05/2013	15	14.7	13.5	18.4	-26%	-8%
09/05/2013	16	16.9	15.3	20.7	-26%	-9%
09/05/2013	17	18.7	15.2	22.6	-32%	-18%
09/06/2013	14	13.1	13.7	16.9	-19%	5%
09/06/2013	15	20.6	14.2	26.0	-46%	-31%
09/06/2013	16	23.7	16.1	29.3	-45%	-32%
09/06/2013	17	26.8	16.0	31.2	-49%	-40%

Table 4-13 contains the hourly 2013 forecast for PTR. SDG&E called only 1 PTR event in 2013 on a Saturday and the percentage load reduction for this event was higher than observed in 2012. SDG&E will take into account both the 2012 and 2013 PTR results when setting up the 2014 PTR forecast.

Table 4-13 SDG&E 2013 PTR Hourly Forecast						
Date	Hour	7-day	Forecast	Ex-Post	% Forecast vs. Ex-Post	% Forecast vs. 7-day
08/31/2013	12	3.6	3.4	5.3	-35%	-3%
	13	5.2	3.7	6.8	-46%	-30%
	14	6.0	3.8	7.5	-50%	-37%
	15	5.9	3.9	7.6	-49%	-34%
	16	6.1	4.0	7.5	-47%	-34%
	17	6.0	4.0	6.8	-40%	-33%
	18	5.7	4.0	5.2	-24%	-31%

Table 4-14 contain the hourly 2013 forecast for CBP. The CBP day-ahead program produced more consistent load impacts than it did in 2012 therefore the forecast errors were also smaller and more consistent than they were in 2012. The CBP day-of load impact were also very stable and the forecast was stable as well. Since eight CBP events were called within a two week period and the CBP forecast within 20% of the 7-day results most of the time the CBP forecast did not need to be updated often based on results.

Table 4-14 SDG&E 2013 CBP Hourly Forecast							
Program Option	Date	Hour	7-day	Forecast	Ex-Post	% Forecast vs. Ex-Post	% Forecast vs. 7-day
CBP DA	07/01/2013	15	8.1	7.9	8.4	-6%	-3%
CBP DA	07/01/2013	16	8.1	7.9	8.7	-9%	-3%
CBP DA	07/01/2013	17	8.1	7.9	8.9	-11%	-3%
CBP DA	07/01/2013	18	7.8	7.9	8.4	-6%	1%
CBP DA	08/29/2013	16	10.4	8.0	5.9	37%	-23%
CBP DA	08/29/2013	17	10.0	8.0	12.6	-37%	-20%
CBP DA	08/29/2013	18	9.3	8.0	12.4	-35%	-14%
CBP DA	08/29/2013	19	9.0	8.0	11.8	-32%	-11%
CBP DA	08/30/2013	15	11.2	8.0	11.4	-30%	-28%
CBP DA	08/30/2013	16	11.1	8.0	11.3	-29%	-28%
CBP DA	08/30/2013	17	10.7	8.0	11.5	-30%	-25%

Table 4-14 SDG&E 2013 CBP Hourly Forecast							
Program Option	Date	Hour	7-day	Forecast	Ex-Post	% Forecast vs. Ex-Post	% Forecast vs. 7-day
CBP DA	08/30/2013	18	9.4	8.0	9.3	-14%	-15%
CBP DA	09/04/2013	14	8.7	8.0	11.4	-30%	-8%
CBP DA	09/04/2013	15	10.0	8.0	11.9	-33%	-20%
CBP DA	09/04/2013	16	10.1	8.0	11.6	-31%	-21%
CBP DA	09/04/2013	17	9.4	8.0	5.5	45%	-15%
CBP DA	09/05/2013	14	8.2	8.0	11.1	-28%	-2%
CBP DA	09/05/2013	15	8.3	8.0	10.2	-22%	-3%
CBP DA	09/05/2013	16	7.9	8.0	10.4	-23%	1%
CBP DA	09/05/2013	17	7.6	8.0	10.3	-22%	5%
CBP DA	09/06/2013	14	7.8	8.0	11.1	-28%	2%
CBP DA	09/06/2013	15	8.6	8.0	11.2	-29%	-7%
CBP DA	09/06/2013	16	9.2	8.0	12.5	-36%	-13%
CBP DA	09/06/2013	17	9.1	8.0	12.2	-34%	-12%
CBP DO	06/28/2013	15	8.6	9.0	9.1	-1%	5%
CBP DO	06/28/2013	16	8.7	9.0	9.6	-6%	3%
CBP DO	06/28/2013	17	8.5	9.0	8.8	3%	5%
CBP DO	06/28/2013	18	8.5	9.0	8.7	3%	6%
CBP DO	08/28/2013	16	9.9	8.6	11.6	-26%	-13%
CBP DO	08/28/2013	17	9.9	8.6	12.0	-28%	-13%
CBP DO	08/28/2013	18	9.7	8.6	11.8	-27%	-11%
CBP DO	08/28/2013	19	8.9	8.6	11.2	-23%	-4%
CBP DO	08/29/2013	15	10.8	8.6	12.8	-33%	-20%
CBP DO	08/29/2013	16	9.6	8.6	12.0	-28%	-11%
CBP DO	08/29/2013	17	8.7	8.6	11.8	-27%	-1%
CBP DO	08/29/2013	18	8.7	8.6	5.9	45%	-1%
CBP DO	08/30/2013	14	9.0	8.6	10.7	-20%	-5%
CBP DO	08/30/2013	15	9.1	8.6	10.6	-19%	-6%
CBP DO	08/30/2013	16	8.7	8.6	10.5	-18%	-1%
CBP DO	08/30/2013	17	8.1	8.6	9.9	-13%	6%
CBP DO	09/03/2013	14	11.3	8.6	10.0	-14%	-24%
CBP DO	09/03/2013	15	11.9	8.6	10.5	-18%	-27%
CBP DO	09/03/2013	16	11.9	8.6	10.7	-20%	-28%
CBP DO	09/03/2013	17	11.4	8.6	10.7	-19%	-25%
CBP DO	09/04/2013	14	11.3	9.2	11.9	-22%	-19%
CBP DO	09/04/2013	15	11.9	9.2	11.6	-21%	-22%
CBP DO	09/04/2013	16	11.9	9.2	11.5	-20%	-22%

Table 4-14 SDG&E 2013 CBP Hourly Forecast							
Program Option	Date	Hour	7-day	Forecast	Ex-Post	% Forecast vs. Ex-Post	% Forecast vs. 7-day
CBP DO	09/04/2013	17	11.4	9.2	11.6	-21%	-19%
CBP DO	09/05/2013	14	11.3	9.2	11.2	-18%	-19%
CBP DO	09/05/2013	15	11.6	9.2	11.2	-18%	-21%
CBP DO	09/05/2013	16	11.3	9.2	11.4	-19%	-19%
CBP DO	09/05/2013	17	10.6	9.2	10.8	-15%	-13%
CBP DO	09/06/2013	14	11.4	9.2	11.7	-21%	-20%
CBP DO	09/06/2013	15	11.4	9.2	11.8	-22%	-19%
CBP DO	09/06/2013	16	10.9	9.2	12.0	-23%	-16%
CBP DO	09/06/2013	17	10.2	9.2	11.3	-18%	-10%

Error in draft Ex-Post estimates:

When comparing a forecast to a draft ex-post result it is important to keep in mind that the draft ex-post results are also an estimate and not an exact value. Estimating a demand response load impact requires an estimate to be made of what the entire load of the customer would have been if no event had occurred. The smaller the percentage load reduction more difficult it is to measure precisely. For example, when estimating a 10% load impact a 2% error in estimating the entire load of the customer results in a 20% error in the demand response load impact.

This is concept is also summarized on the table below. In the first column the customer would actually have used 100 kW if no event had been called. The measurement and evaluation estimates that the customer would have used 98 kW if no event had been called which is only 2% lower than the actual value. During the event the customer used 90 kW. The actual demand response load impact was 10 kW but the estimated load impact was 8 kW. So the very small 2% error in the estimate of the entire load of the customer results in a 20% error in the estimate of the demand response load impact.

Table 4-15 Example of Effects of Errors on Load Impacts			
	Entire Customer Load if no event had occurred	Actual Energy Use on event day	Demand Response Load Impact
Actual	100	90	10
Estimated	98	90	8
Difference	2	0	2
Percent Difference	2%	0	20%

SDG&E specific Conclusions and Recommendations

SDG&E was successful in improving the forecasts for its demand response programs. SDG&E plans to use the same general forecasting methods in 2014 as we did in 2013 with the following minor modifications.

a. SDG&E will work with the consulting firm who performs the ex-ante summer saver forecast to improve the forecast for 2014.

b. Forecasting PTR for 2014 summer involves some challenges because load reductions due to PTR were higher in 2013 than 2012 but there was only one event called in 2013 and it occurred on a Saturday. We will work with the consulting firm who performs the annual PTR ex-ante forecast to incorporate both 2012 and 2013 event results into the 2014 forecast.

c. SDG&E will seek feedback from the CAISO on whether to continue using the 30th percentile of the ex-post results for forecasting or to use the average results.

V General Conclusions and Recommendations:

- Both SCE and SDG&E improved forecasting methods from those used in 2012.

- In 2014 SCE and SDG&E plan to use the same general forecasting methods but with updated inputs and small adjustments. Forecasting methodologies based on ex ante load impact estimates will be updated according to the PY2013 study results.

- Forecasting and estimating a demand response load impact is more challenging than forecasting the entire load of a group of customers. The smaller the percentage load reduction more difficult it is to measure and forecast. For example, when estimating a 10% load impact a 2% error in estimating the entire load of the customer results in a 20% error in the demand response load impact.

- Forecasting the load reduction from a group of demand response programs is easier than forecasting the load reduction from a single program.

- Variation in customer behavior is another factor that presents challenging for demand response forecasting.

- The CAISO should provide the utilities with feedback on how to best handle demand response forecasting error that cannot be eliminated through forecast methodology improvements or improve program design.

- Utilities will meet with the CAISO at the beginning of summer 2014 to make sure the process for sending the daily forecast and notifying the CAISO when events are triggered meet the needs of all CAISO departments.

Appendix A

SDG&E methodology for calculation of 7-day report and draft ex-post results

SDG&E Methodology for calculating the 7-day and Ex-Post results

When events are called the utilities are required to produce preliminary results to the CAISO and CPUC within 7 days of the event.

Capacity Bidding Program (CBP):

7-day report results - 2012 and 2013: In both 2012 and 2013 the 7-day report results were calculated using the CBP 10 of 10 baseline with a same day adjustment that is also used to calculate payments to aggregators. The 10 in 10 baseline with same day adjustment calculation begins by taking the average energy usage during the 10 previous similar days prior to event to calculate a preliminary baseline. Similar days exclude weekends, holidays, and days in which demand response events were called. Then this preliminary baseline is multiplied by same day adjustment factor to get the final baseline. The same day adjustment factor is calculated by taking the energy usage during the first 3 of the 4 hours prior to the event on the event day and dividing it by the energy use during the first 3 of the 4 hours prior to the event from the preliminary baseline. The same day adjustment factor can be no higher than 1.4 and not lower than 0.6.

Ex-Post results – 2012 and 2013: The CBP ex-post results for both 2012 and 2013 were calculated by creating a regression model for each individual customer and summing them. The regression models used variables such as day of the week, month, and temperature to forecast the energy that would have been used if no event had occurred.

Demand Bidding Program (DBP):

7-day results 2012: Customer specific baseline based on the similar weekday or weekend prior to the Event with a same day adjustment.
7-day results 2013: Baseline is an average consumption for the three (3) highest days from within the immediately preceding three (3) similar days prior to the Event.
Ex post results - 2012 and 2013: The DBP ex-post results for both 2012 and 2013 were calculated by creating a regression model for each individual customer and summing them. The regression models used variables such as day of the week, month, and temperature to forecast the energy that would have been used if no event had occurred.

Critical Peak Pricing-Default

7-day report results - 2012: Similar to the CBP results a 10 of 10 baseline with same day adjustment was used to calculate the 7-day report results. The hours used to calculate the adjustment factor was the usage from 9am-10am and the adjustment factor could be no higher than 1.8 and no lower than 0.2. For weekend events a 1 day baseline with a same day adjustment was used. The 1 day was chosen to be the day in the past with the most similar weather to the event day.

7-day report results - 2013: Results were calculated by subtracting the energy use of CPP customers from a matched group of control customers. The matched control group was created by FSC as part of the 2012 ex-post analysis.

Ex-Post results - 2012 and 2013: Ex-Post results were calculated by subtracting the energy use of CPP customers from a matched group of control customers and applying a difference of differences adjustment.

Peak Time Rebate (PTR):

7-day results - 2012: The 7-day results were calculated using an aggregate 2 of 2 baseline with a same day adjustment. A sample of both opt-in alert customer and other customers was used for the calculations.

7-day results - 2013: A control group was created to match the customers enrolled in opt-in alerts using stratified sampling based on energy usage on 3 warm non-event days. The energy usage of the customers who requested opt-in alerts was subtracted from the energy use of the control group customers and a difference of differences adjustment was applied.

Ex-Post results - 2012: Regression models for individual customers that included variables such as temperature, day of the week, and month were used to calculate the ex-post results.

Ex-Post results - 2012: A control group was created using propensity score matching to closely match the customer enrolled in PTR alerts. Overall energy use as well as energy usage on warm Saturdays was used to match the customers. The energy use of the customers enrolled in PTR alerts was subtracted from the energy use of the control group and a difference of difference adjustment was applied.

Summer Saver:

7-day results - 2012: An aggregate 1 or 2 day baseline with a same day adjustment was used to calculate the event results. The days were chosen to be the 2 days with the most similar temperature to the event days. The adjustment window was the hour before the event and no cap was necessary since the baselines were aggregate. All summer saver participants were included in the calculation.

7-day results - 2013: For residential customers a sample of summer saver customers were randomly assigned to two different groups at the beginning of the summer season. For each event one of the groups was not curtailed during the event and the other group was curtailed. The energy usage of the curtailed group was subtracted from the energy usage of the group Results per ton for each cycling strategy were calculated using the sample and then scaled up to represent the population by multiplying the total number of tons enrolled for each cycling strategy.
Results for commercial customers were calculated using the same baselines that were used in 2012. All commercial participants were included in the calculation.

Ex-Post results – 2012 and 2013: For residential customers a sample of summer saver customers were randomly assigned to two different groups at the beginning of the summer season. For each event one of the groups was not curtailed during the event and the other group was curtailed. The energy usage of the curtailed group was subtracted from the energy usage of the group that was not curtailed and a difference of differences was applied when necessary. Results per ton for each cycling strategy were calculated using the sample and then scaled up to represent the population by multiplying the total number of tons enrolled for each cycling strategy.

Base Interruptible Program (BIP):

7 day results – 2012 and 2013: The 7-day results for both 2012 and 2013 were calculated a 10 of 10 baseline with a same day adjustment. The adjustment window and cap on the adjustment factor were the same as for CBP.

Ex-Post results – 2012 and 2013: The BIP ex-post results for both 2012 and 2013 were calculated by creating a regression model for each individual customer and summing the results for each customer to obtain a forecast for the entire program. The regression models used variables such as day of the week, month, and temperature to forecast the energy that would have been used if no event had occurred.