Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2012 through 2014.

Application 11-03-___

CHAPTER V

PREPARED DIRECT TESTIMONY

OF LESLIE WILLOUGHBY/KATHRYN SMITH

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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CHAPTER V

PREPARED DIRECT TESTIMONY OF

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I. PURPOSE

The purpose of this testimony is to present the load impacts of SDG&E's demand response programs, present the budget for the measurement and evaluation of the demand response programs, and to recommend a new baseline for the SDG&E capacity bidding program.

II. BACKGROUND

In D-08-04-051 the commission adopted demand response load impact protocols. These protocols provided rules that specified required output data that must be included in all measurement and evaluation reports. For example these protocols require that every load impact measurement and evaluation report include hourly ex-post load impact results for each event day for the entire program as well as on average per customer. In addition each load impact report is required to contain a 10 year hourly forecast of expected future load impacts for 24 different temperature scenarios. The decision further required that every demand response activity be evaluated every year and that the load impact reports be filed with the CPUC on April 1st of each year. The decision specified that the load impact protocols applied to all demand response activities, which includes both demand response programs and dynamic rates. Since the load impact protocols require a great number of tables to be produced and all reports formally filed with the docket office are required to be printed out in hardcopy the decision was later modified to require that only an executive summary that summarized the results of all the individual reports be filed with the commission. The individual measurement and evaluation reports are still required to be publically posted but not filed.

As required by the load impact protocols SDG&E will file measurement and evaluation studies that will follow the load impact protocols on April 1st of this year. Recognizing this testimony is being filed prior to the April 1st filing date the guidance document[1] for this proceeding states:

> *The utilities' load impact estimates in the 2012-2014 demand response Applications will likely be based on their April 2010 load impact reports (which were based on 2009 ex post data), and because many changes were made to existing programs for summer 2010, the available load impact data may not take into account these recent changes. On April 1, 2011, the utilities will produce their annual demand response load impact report, which will be based on the 2010 ex post data. In order for the Commission to evaluate the demand response load impact and cost effectiveness before approving funding for the next budget cycle, the Commission may (depending on the proceeding schedule) require the utilities to submit revised testimony on load impact and cost effectiveness to reflect the load impact estimates in their April 1, 2011, filings. I encourage the utilities to make their best efforts to use the 2010 ex post data as much possible to avoid the need to submit revised testimony after April 1, 2011.*

SDG&E has used a combination of the reports and forecasts filed previously in April of 2010 and the most recent 2010 draft ex-post results to produce the load impact forecasts included in this testimony. SDG&E has given priority to updating program forecasts to programs up for approval in this proceeding that require cost-effectiveness testing.

Demand Response activities for 2012-2014 include both dynamic rates and demand response programs. The Critical Peak Pricing Default ("CPP-D") rate and Peak Time Rebate ("PTR") were initially described in SDG&E's AMI business case A-05-03-015 and finally adopted in SDG&E's GRC phase II Settlement Agreement in D-08-02-034[2]. The Critical Peak Price Emergency Rate was also adopted in the GRC phase II settlement agreement. Although

[1] Administrative Law Judges Ruling Providing Guidance for the 2012-2014 Demand Response Application 08-27-10

[2] Motion For Adoption Of All Party And All Issue Settlement,, 11/1/07, pp 7-8,

these rates have already been adopted by the CPUC, forecasts for these rates are included in this testimony in order to provide a complete demand response forecast.

In addition SDG&E has two other demand response programs that were previously approved by the CPUC as contracts. SDGE's Summer Saver program contract was approved in 2004 and later amended. The SDGE DemandSMART™ program was also approved as a contract in 2009. Although these contracts have already been approved load impacts forecasts are provided for these programs in order to provide a complete forecast for all of SDG&E's demand response activities.

Demand Response programs for which SDGE is requesting approval in this proceeding as described in the testimony of George Katsufrakis include the Capacity Bidding Program ("CBP"), Base Interruptible Program ("BIP"), Technical Incentives program ("TI"), Permanent Load Shifting ("PLS") and the Small Customer Technology Deployment Program ("SCTD"). Load impacts forecasts for these programs are also included in this testimony.

III. EX-POST LOAD IMPACTS 2009 AND 2010:

This section contains the ex-post load impacts of the demand response activities for which events were called in 2009 and 2010. The 2009 results come from the 2009 measurement and evaluation reports filed in April of 2010. Table KS-1 below contains the 2009 ex-post results for the system peak day (09/03/2009) as well as the average result overall demand response events called in 2009. For the Summer Saver program the percentage reductions in the M&E report were expressed in terms of the percentage reduction of the air-conditioning load. All other percentage load reductions in the table are expressed as the percentage of the entire load of the customers. The CPP-D 2009 ex-post results include results for the entire CPP-D program and do include results for CPP-D customers dually enrolled in BIP and in CBP.

Therefore adding all the load impact results together from Table KS-1 will double count the load reduction from customers enrolled in both CPP-D and CBP. Ex-Post CPP-D results broken down by multiple program participation group were not provided in the 2009 measurement and evaluation report. The ex-ante portfolio CPP-D forecast presented in the 2009 report only included CPP-D customers not enrolled in any other program

Table KS-1

2009 Ex-Post Measurement and Evaluation Load Impact Results (MW)

DR Program	Load Reduction System Peak Day (MW)	Load Reduction Average Event Day (MW)	Percentage Reduction System peak day	Percentage Reduction Average event day
Capacity Bidding Day-Ahead	12	10	28%	26%
Capacity Bidding Day-Of	15	13	20%	18%
CPP-D	29	23	6%	6%
Summer Saver Residential	19	17	53%	55%
Summer Saver Commercial	7	7	29%	25%

Table KS-2 contains the preliminary draft measurement and evaluation ex-post load impacts for demand response activities for which events were called in 2010. These are draft results and will not be final until the April 1st 2011 load impact reports are filed. As in Table KS-1 the percentage reductions for the Summer Saver program are presented as a percentage of air-conditioner usage rather than a percentage of whole house energy use. The BIP results are broken out into results for BIP customers enrolled on CPP-D and BIP customers not enrolled on CPP-D. Only one BIP event was called in 2010 and this event was called on the same day as a CPP-D event. BIP customers enrolled in CPP-D were not eligible to participate in the BIP test event because a CPP-D event had also been called on the same day. However, the BIP customers enrolled on CPP-D did reduce their load in response to the CPP-D event and so their load reduction in response to the CPP-D event which occurred the same day as the BIP test event is included in the table below. The draft 2010 ex-post M&E results for CPP-D are still in the development process so the CPP-D results presented were calculated using a 10 in 10 baseline with a same day adjustment.

Table KS-2 2010 Ex-post Draft Load Impact Results				
DR Program	**Load Reduction System Peak Day (MW)**	**Load Reduction Average Event Day (MW)**	**Percentage Reduction System peak day**	**Percentage Reduction average event day**
Capacity Bidding Day-Ahead	11	10	35%	29%
Capacity Bidding Day-Of	8	9	16%	16%
DemandSMART	6	8	21%	33%
CPP-D	28	30	6%	8%
Summer Saver Residential	26	14	51%	55%
Summer Saver Commercial	8	6	21%	24%
BIP non-CPP	0.4	0.4	17%	17%
BIP CPPD	4	4	82%	82%

The average load impacts in Table KS-2 above contain the results for all customers enrolled on CPP-D including those also enrolled on other programs. Therefore adding these results together will double count the load reduction from customers participating on both CPP-D and CBP, DemandSMART™ or BIP. Table KS-3 below contains the load impacts on the 2010 system peak day when CPP-D, CBP day-of, DemandSMART™ and BIP were all called. Table KS-3 shows that the vast majority of the impacts of the BIP program (91%) come from customers also enrolled on CPP-D. For CBP day-of and DemandSMART™ the percentages of load reduction coming from CPP-D customers is smaller 18% and 36% respectively. These load impacts for CPP-D, CBP and DSP were calculated by SDG&E using a 10 in 10 baseline with a same day adjustments. The BIP calculations come from the draft ex-post 2010 BIP results.

Table KS-3				
Effects of Multiple Program Participation on Program Load Impacts System Peak Day				
Program	**Load Reduction from CPP-D customers (MW)**	**Load Reduction from Non-CPPD (MW)**	**Load Reduction for the Entire Program (MW)**	**% of total program load reduction contributed by CPP-D customers**
BIP	4.0	0.4	4.4	91%
CBP Day-Of	1.4	6.6	8.0	18%
DSP	2.2	4.0	6.2	36%
CPP-D not dual enrolled	19.9	0.0	19.9	100%

SDG&E TI program contains two subgroups of customers. The first group is comprised of the Auto-DR customers who have enabling technology that can be activated by either the utility or an aggregator. The second group is comprised of customers with enabling technology that can be controlled by the customer rather than by the utility. In this section the TI customers with Auto-DR technology customer are referred to as Auto-DR and TI customers with technology controlled by the customer are referred to as Semi-Auto. TI customers are currently participating on two programs the CPP-D program and the CBP program. TI customers are also eligible to participate on the DemandSMART™ program. The ex-post results for these technology enabled customers were included in the ex-post results presented in Table KS-1 through table KS-3 but for more complete information they are presented in Table KS-4 separately.

Table KS-4 2009 and 2010 Ex-Post M&E results for Auto-DR and TI customers			
Program	**Technology Type**	**2010 Load Impact (kW)**	**2009 Load Impact (kW)**
CBP Day-Ahead	Auto-DR	145	0
CBP Day-Ahead	Semi-Auto	559	157
CBP Day-Of	Auto-DR	943	605
CBP Day-Of	Semi-Auto	66	0
CPP-D	Auto-DR	1577	1371
CPP-D	Semi-Auto	822	714

The Permanent Load Shifting Program

The Permanent Load Shift Program ("PLS") is designed as a permanent peak load reduction program. The phrase "permanent load shift" refers to the shifting of energy usage by one or more customers from one-time period-to another on a recurring basis, and for this program, refers to shifting load during the "peak hours" (11am-6pm) within the "peak period"(May -October) of the year. The program is not part of the energy efficiency initiative or part of demand response. The PLS program resulted from a 2008 CPUC decision (D.06-11.049) directing the CA IOU's to seek Permanent Peak Load Reduction in their service territories. The SDG&E RFP process resulted in two contracts for the PLS program effective through 2011. For the first contract peak load was reduced by replacing the electric on peak load of the air-conditioning systems with gas cooling systems. The second contract used technology used "fly-wheel" technology to allow freezers to operate without mechanical cooling during the on-peak period. Three customers had permanent load shifting technologies installed in 2009 and 2010. Ex-Post verification methods included calculating on-peak load reduction using the on-peak demands of customers before and after the technology was installed and end-use metering. The total ex-post measured load reduction for the program to date is 1,342 kW.

IV. SUMMARY OF LOAD IMPACT FORECAST FOR 2012-2014

Tables KS-4 contains a summary of the forecasted load impacts of SDG&E's demand response activities for 2012-2014 for August monthly peak day in a 1 in 2 weather year. The hours used in the calculation are 1pm-6pm to be consistent with the new summer Resource Adequacy ("RA") counting rules.

The general methodology for the ex-ante commercial demand response activities is as follows. The load forecasts presented in the testimony for CPP-D and Summer Saver are the same forecasts previously filed in April of 2010. The forecast for the CBP and DemandSMART™ programs are based on the 2010 draft M&E results. Since no BIP events were called in 2008 or 2009 the BIP ex-ante forecast is also based on preliminary 2010 draft results. The load impact forecast for Auto-DR customers enrolled on CPP-D and CBP are based on a combination of the previous year's forecast and the 2010 preliminary load impact results. The Auto-DR results are not included in Table KS-4 separately in order to avoid double counting but are available later in this testimony in Table KS-5.

The general methodology for the ex-ante residential and small commercial forecast is as follows. The small customer technology deployment program is a new program and the residential part of the forecast uses percentage load reductions from SDG&E smart thermostat measurement and evaluation study and the Connecticut Light and Power Company ("CLCP") "Plan it Wise" energy pilot. The residential reference load information is based on SDGE's load research sample of central air conditioning customers. The small commercial part of the forecast uses SDG&E's dynamic load profile shape for the reference load combined with the ex-post Auto-DR measurement and evaluation results filed in April of 2010.

The Summer Saver forecast is the same forecast filed in April of 2010. The PTR forecast has been updated since the April 2010 filing to account for new study results from other utility pilots such as the Connecticut Plan it Wise pilot that compare the performance of voluntary critical peak pricing to voluntary PTR.

The forecast in Table KS-5 below is a portfolio forecast. The results for each program can be added together without double counting. The forecast assumes that SDG&E's proposal to end dual participation between CPP-D and DemandSMART^{TM}, CBP and BIP is adopted. The forecast predicts that when customers are given a choice to either remain on their voluntary demand response program or remain on CPP-D the customers choose to remain on their voluntary demand response program. The SCTD estimates are incremental to PTR.

More detailed monthly forecast for each year for a 1 in 2 and 1 in 10 weather year are available in Appendix A of this testimony. In addition, as required by the guidance document the monthly 2011 demand response forecast adopted by the CPUC for RA as qualifying capacity is also included in Appendix A of this testimony.

Table KS-5
Portfolio Load Impact Forecast
August 1 in 2 Peak Day 1pm-6pm
(MW)

DR Activities -	**2011**	**2012**	**2013**	**2014**
Day-Ahead Price Triggered				
PTR- Residential	0	64	65	67
CPPD - Large C&I (>200 kW)	18	19	19	20
CPPD - Medium C&I (20-200 kW)	0	0	32	34
CBP Day-Ahead	9	10	11	11
Small Customer Technology Deployment	0	6	10	12
Day-Of Price Triggered				
CBP Day-Of	11	13	15	17
Demand Smart	12	15	15	15
Summer Saver	24	24	24	24
Day-Of Reliability Trigger				
BIP	7	11	13	16
Other DR Activities				
Permanent Load Shifting (PLS)	1	2	4	5
Total	83	163	207	220

V. EX-ANTE FORECAST DETAILS

1. Capacity Bidding Program (CBP) and DemandSMART^{TM} Program

The forecast for CBP and DSP program are very closely linked because both programs have similar structures and they target the same customers. The DemandSMART^{TM} program is a bilateral contract with whereas the CBP tariff is a standard offer available to any aggregator who chooses to participate. The DemandSMART^{TM} program has a day-of trigger with a minimum notification of 30 minutes whereas the current CBP day-of program has a day-of trigger with a minimum of 3 hours notice. The CBP program allows the aggregator to nominate each month. The DemandSMART^{TM} program uses a committed load reduction rather than a nomination. The performance structure for CBP and DSP that adjusts the capacity payments when the nominated value or committed load reduction is not reached is the same for both programs. Customers with a maximum demand of > 20 kW are eligible for CBP and customers with maximum demands of > 100 kW are eligible for DemandSMART^{TM}. The Demand SMART^{TM} program did not begin until 2010 so the 2010 ex-post results are the first actual results available for this program. Given that the program structures are similar changes to the DSP forecast also affect the CBP forecast. Therefore the CBP and DSP forecasts presented in this testimony have been updated since the forecasts filed in April of 2010 to take into account 2010 preliminary ex-post information.

Table KS-6 below shows the average load impacts for the CBP and DSP programs from 2007 through 2010. Although the weather on event days was not identical for each year these ex-post average event day results are a good general indicator of the nature of program growth. The CBP program grew steadily through 2009. In 2010 the DSP program began. The drop in the CBP day-of program between 2009 and 2010 is due in large part to the fact that many customers left the CBP day-of program and moved over to the DSP program. Although a large number of customers did move between CBP and DSP in 2010 a smaller growth of 3.2 MW was still achieved for the total of the 2 programs together.

Table KS-6
Ex-Post M&E Load Impact average event day (MW)

Year	CBP DA	CBP DO	DemandSMART	Total	Growth
2007	6.6	1.2	0	7.8	7.8
2008	10.3	6.2	0	16.5	8.7
2009	10.3	12.5	0	22.8	6.3
2010	9.6	8.6	7.8	26.0	3.2

Table KS-7
CBP and DSP load impact forecast 2011-2014 (MW)

Program	2011	2012	2013	2014
CBP Day-Ahead	9.3	10.4	11.0	11.1
CBP Day-Of	10.9	12.6	14.6	16.7
DemandSMART	12.0	15.1	15.1	15.1
Total	32.3	38.0	40.6	42.9

Table KS-7 shows the 2011 – 2014 forecast for CBP and DemandSMART™. For the CBP Day-Ahead program the forecast assumes the load impact results for 2011 are very similar to the 2010 ex-post results. The forecast 2012-2014 assumes that very modest growth occurs due to the CBP program improvements proposed by SDG&E in this application for 2012-2014. The growth forecast for CBP day-of assumes that all customers who plan to move from CBP day-of to DemandSMART™ have already done so. The forecast assumes that due to competition with DSP and the elimination of dual participation with CPP-D the growth rate for the CBP program will drop substantially from the historical growth rate of approximately 6 MW per year to roughly 2 MW per year. The DSP programs is forecasted to grow only through 2012 because the financial incentives are stronger for customers to be signed up by the end of 2012 and because in general aggregators are more active in signing up customers the first few years and after that maintain the program. Since the CBP program is made up of several aggregators recruiting at different times the same assumption does not apply. For the details of the monthly analysis the monthly load shape used for the CBP program and the DemandSMART™ program forecast are the same load shapes filed in April of 2010.

2. BIP

The SDG&E BIP program currently has 20 accounts enrolled in BIP-A the 30 minute notification option and one customer enrolled in BIP-B the 3 hour notification option. Customers enrolled on BIP receive a monthly capacity payment in exchange for pledging to reduce their load during events down to a firm service level on event days. Out-of -pocket penalties apply for failing to reduce to the firm service level. The trigger for this program is more restrictive than some of the other programs therefore no BIP events were called in 2008 or 2009. However a test event was called in 2010 on September 27th. A CPP-D event was also called on the same day. According to the current tariff rules CPP-D customers are not allowed to participate in a BIP event when CPP-D has been called. Therefore only the BIP customers not enrolled on CPP-D were notified of the BIP event. The BIP customers not enrolled on CPP-D provided a load reduction of 0.4 MW. Although the BIP customers enrolled on CPP-D were not notified of the BIP event and were not subject to BIP penalties they reduced their load 4.0 MW load impact in response to the CPP-D price signal. A full load reduction all the way down to their firm service level would have been a 5 MW reduction for the BIP customers enrolled on CPP-D.

The ex-ante analysis predicts that since the CPP-D BIP customers responded so well to CPP-D events that they will reduce their load down to their firm service level for an actual BIP event. The forecast assumes that the currently enrolled non-CPP BIP customers would continue to reduce to the same level they reduced to in the test event. This results in an overall compliance rate of 70% which is the compliance rate use for all new customers joining the program. Previously this program has not been marketed by SDG&E, but the goal for 2014 is for the program to grow to 16 MW. Given that the BIP programs at PG&E and SCE are substantially larger than the SDG&E BIP program this goal is reasonable.

The CPP-D forecast presented in the filing is the same forecast filed with the CPUC on April of 2010. The CPP-D forecast does not affect the cost-effectiveness results in this proceeding. The fully updated CPP-D forecast will be available to all parties on April 1st of 2011.

3. Summer Saver

The Summer Saver ex-ante forecast presented in this testimony is the same forecast filed in April of 2010. This program was already approved by contract and therefore is not up for approval in this proceeding and is not being cost-effectiveness tested in this proceeding. Therefore the load impacts are being provided only for informational purposes. The preliminary ex-post 2010 load impact results are similar to the 2009 load impacts therefore the updated Summer Saver forecast is expected to be very similar to the forecast previously filed.

4. TI forecast

Beginning in 2012 SDG&E proposes to eliminate the semi-automated option of the TI program and only to offer utility controlled Auto-DR. Therefore all customers forecasted to be enrolled in the TI program from 2012-2014 are Auto-DR customers. The existing semi-automated TI customers are still included in the Auto-DR forecast totals. In 2010 7 % of the CBP day-ahead load impacts and 12% of CBP day-of load impacts came from customers enrolled in TI. The load impact forecast for the CBP day-ahead TI program assumes that no new TI customers join. The percentage of CBP load impacts achieved through the future TI program remains at 12% the same as it was in 2010. For the CPP-D program the forecast filed previously in April of 2010 assumed that the CPP-D TI load impacts would grow at 0.6 MW per year from 2010 through 2014. Since SDG&E proposes in this proceeding to offer a payment to aggregators for enrolling CPP-D customers on Auto-DR and the incremental Auto-DR growth rate is forecasted to be 0.6 MW for 2010-2011, 1.0 MW for 2011-2012, 1.5 MW for 2012-2013 and 1.5 MW for 2013-2014, TI customers are eligible to participate on DemandSMART™ as well. Although the current participation is lower than day-of CBP since the program are similar the forecast predicts that the percentage of DemandSMART™ enrolled in TI will reach 11.7%. Although BIP customers are allowed to participate on TI the TI forecast for BIP customers is zero given that all the customers enrolled on this program in summer of 2010 pledged reduce their loads to zero or near zero. The total TI forecast for 2011-2014 for is presented in Table KS-8 below.

Table KS-8						
Ex-Ante Auto-DR Load Impacts August Peak Day						
Year	CPP-D Auto-DR	CBP Day-Ahead Auto-DR	CBP Day-Of Auto-DR	Demand Smart	BIP	Total
2011	2.1	0.7	1.3	1.4	0	5.5
2012	3.1	0.7	1.5	1.8	0	7.0
2013	4.6	0.7	1.7	1.8	0	8.8
2014	6.1	0.7	2.0	1.8	0	10.5

The SDG&E PLS program is also a technology program. For 2012-2014 the PLS program will not be restricted to two types of PLS technology like it was for the 2009-2011 cycle. Any technology that qualifies as PLS will be eligible. The program is predicted to grow to 2 MW in 2012 4 MW in 2013 and 5 MW in 2014.

5. PTR

The MW estimates for PTR were calculated following the load impact protocols. Due to new information from PTR pilot results some adjustments have been made to the assumptions used in the previous PTR forecast filed. A key assumption in the previous PTR forecast was that PTR will provide the same percentage load impacts as a CPP rate for customers who are aware of PTR. This assumption was justified by two PTR pilots. The first pilot was the Anaheim PTR pilot conducted in 2005[3]. This pilot only offered a PTR rate but SDG&E compared the results of the Anaheim pilot to the results of California Statewide Pricing Pilot which offered critical peak pricing rates. Comparing the two studies showed the load reduction from PTR and CPP rates was very similar. The second pilot was the Baltimore Gas and Electric 2008 pilot[4] which tested the effect of critical peak pricing rate and PTR programs on customer behavior and showed

[3] Residential Customer Response to Real Time pricing : The Anaheim Critical Peak Pricing Experiment Frank Wolak March 14th 2006

[4] BGE's Smart Energy Pricing Pilot Summer 2008 Impact Evaluation April 2009 Brattle Group

similar load reduction for critical peak pricing and PTR. The differences between the load reductions from CPP and PTR were statistically insignificant in this pilot. On account of these two pilots all PTR forecasts filed previously have assumed that PTR would provide the same percentage reduction as CPP. However results from two other pilots became available in 2010 that show different load impacts between CPP rates and PTR rates. The Power Cents DC program final report[5] published in September of 2010 showed a percentage load reduction of 34% for a CPP rate versus a 13% load reduction for a PTR rate. Also the Connecticut Plan it Wise pilot[6] results showed a 16.1% load reduction in response to a CPP rate versus a 10.9% response rate for PTR. The PTR forecast filed in this testimony assumes that PTR impacts for aware customer will be 67% of CPP impacts would be based on the Connecticut pilot. The awareness rate for PTR used in the PTR forecast is 50% which is consistent with AMI Decision D-07-04-043. The reference load the PTR load impacts calculated uses the forecasted residential load for an August monthly peak 1in 2 day as required by the load impact protocols. The meter deployment rate for residential electric AMI meters is on time with 1.1 million smart meters meter currently installed. Therefore the 2012 through 2014 PTR forecast assumes full smart meter deployment.

6. Small Customer Technology Deployment

The small customer technology deployment program ("SCTD") is a new program that will provide enabling technology to residential customers and small commercial customers. For residential customers the two major technologies that are accounted for the load impact forecast for this program are pool pumps and programmable thermostats. No incentives other than the enabling technology itself are provided since by 2012 all residential customers will be enrolled in

[5] PowerCents DC Program Final Report September 2010 E-Meter strategic consulting
[6] CL&P's Plan-it Wise Program Summer 2009 Impact Evaluation Brattle Group

PTR. Since PTR will be in place it is also important that the incremental impacts of enabling technology above a PTR impact alone be estimated.

Previous SDG&E Smart Thermostat studies and Summer Saver studies have shown that one factor that decreases the load impacts and cost-effectiveness of these programs is that customers who never or seldom use their air-conditioners join the program and receive an incentive. The SCTD program improves this issue in two ways. One way this issue is improved is that no flat incentive is provided. Only a PTR incentive is provided and a PTR incentive is only paid if a customer's usage is lower than their customer reference level. The other improvement this program makes is that Smart Meter data will be used to market the program to customers likely to have high on-peak air-conditioner usage. Hourly Smart Meter whole house data can be used to identify customers who are likely use their air-conditioner on-peak. In order to estimate the effects that targeting customers using hourly whole house smart meter data will have on the load impacts Freeman Sullivan and Company ("FSC") conducted analysis on behalf of SDG&E using the load data from the load research air-conditioning sample. This sample is a randomly selected sample of customers with central air-conditioning. These customers have a meter both on their home and on their air-conditioner. Using the whole house data only, FSC ran a regression model and identified the top 35% of customer most likely to have high on-peak air-conditioning usage. The air-conditioning usage of these top customers was then used to create the reference load for the residential Programmable Communicating Thermostat ("PCT") forecast.

The percentage load impacts for residential PCT program are incremental to the PTR percentage load impacts for the 50% of customers who are aware of PTR events. For the 50% of customers unaware of PTR events the full percentage load reduction achieved by PCT was used.

The full percentage load reduction used for the forecast comes from the SDG&E Smart Thermostat studies. The incremental load reduction above and beyond the PTR rate was informed by the Connecticut "Plan it Wise" pilot. This pilot offered both a PTR rate and a PTR rate with enabling technology to customers. Based on the results of this pilot a 16% incremental impact of enabling technology was assumed for the 50% of customers being aware of PTR events. The 16% is the percentage of air-conditioning load reduced, not the percentage of whole house load reduced. The load impacts from pool pumps were calculated based on a pool pump demand response potential study [7]conducted by SCE. The forecasted number of residential customers enrolled in the pilot is 7,500 by 2012, 12,500 by 2013 and 15,000 by 2014. One-third of participants are forecasted to accept pool pump technology.

The small customer technology deployment program will also provide enabling technology to small commercial customers enrolled on the Peak Shift at Home rate. The reference load for the small commercial forecast is based on SDG&E dynamic load profile hourly small commercial customer load shape. Since the Statewide Pricing Pilot small commercial update results[8] showed no statically significant load reduction in response to the CPP rate alone an incremental load impact forecast is not necessary. The percentage load impact in response to enabling technology used in the forecast is 19.3% consistent with the 2009 SDG&E CPP-D Auto-DR M&E results. The forecast assumes that 1,000 customers enroll by 2012, 2,000 by 2013 and 3,000 by 2014.

[7] Pool Pump Demand Response Potential June 2008 Design and Engineering Services SCE
[8] California Statewide Pricing Pilot Commercial and Industrial Analysis Update June 28 2006 CRA International

VI. MEASUREMENT AND EVALUATION BUDGET FOR 2012-2014.

In decision D-08-04-51 the CPUC adopted the load impact protocols. This decision requires that every demand response activity including voluntary demand response programs and dynamic rates be evaluated every year by April 1st. These evaluations must include all the output required by the load impact protocols. Examples of the output requirements are; hourly ex-post results for each event, the hourly reference load for each event, confidence intervals for each ex-post event, and a monthly hourly 10 year forecast for each program for 24 different temperatures. The complete outputs provided by reports following these protocols have been useful in many ways. The availability of complete 24 hour ex-post program level estimates has been useful for answering data requests from the California Independent System Operator as well as SDG&E resource planners who need to be able to add the hourly demand response load impacts back to the system load in order to determine what the system load would have been without demand response. Additionally, the monthly ex-ante forecasts are used each year in the Resource Adequacy ("RA") proceeding and the forecasts are also useful for other long term resource planning proceedings. The hourly ex-ante forecast have been used to double check internal hourly short term forecasts that are required to be sent to SDG&E's electric procurement group, the CAISO and the Energy Division when demand response events are called. The evaluation reports that followed the requirement of the load impact protocols are more complete than the previous load impact reports which reduces the frequency of analysts going back to an older evaluation report but not being able to find the desired information. Therefore, a major goal of the measurement and evaluation budget is to fund the load impact evaluations as required by the CPUC.

Since the load impact protocol requirements apply to both dynamic rates and voluntary demand response programs both are included in the M&E budget presented in Table KS-9 below. This budget includes funding for the evaluation of dynamic rates like PTR and CPP-D that were approved in the SDG&E's GRC Phase 2 D.08-02-034. The 2009-2011 M&E budget for these two dynamic rates was adopted by the CPUC in D-09-08-027. This budget also includes funding for the evaluations of two dynamic rates that have been proposed by SDG&E in A.10-07-009.

These are the Peak Shift at Home rate ("PSH") which is a critical peak pricing program for residential customers and the Peak Shift at Work rate ("PSW") which is a default critical peak pricing program for small commercial customers. The testimony of Bill Saxe Chapter 3 page WGS-30 lines 6-11 and the testimony of Glen Breed page GCB-39 lines 19-23 in A.10-07-009 explain that measurement and evaluation funding for the PSH and PSW will be requested in this proceeding. Since the load impact protocols apply to both voluntary demand response programs and dynamic rates keeping the evaluation budget for all load impact protocols required evaluation studies all in one proceeding is preferred by SDG&E.

For budget planning there are four main categories that programs fall into. The first category is existing statewide demand response activities for which the load impact evaluation are conducted statewide. This category includes CBP, BIP, CPP-D, PTR and TA/TI. The budget for CBP, BIP and TA/TI includes SDG&E portion of the costs of a statewide load impact evaluation for each year. No funding for process/marketing evaluations is included in the budget for these three programs since these programs have been in place for several years. However, since roughly 20,000 new medium commercial customers will be defaulted to CPP-D in 2013 funding for one process evaluation along with the annual statewide load impact evaluations is included in the budget. Similarly, since PTR is also new funding for one process/marketing evaluation is included along with funding for the annual load impact evaluations

The second category includes both new and existing demand response activities that SDG&E will need to conduct annual load impact studies for. For existing programs this includes the Summer Saver program evaluated individually by SDG&E. Future activities in this category include the PSW, PSH, SCTD and PLS. Since PSW, PSH, and SCTD are new, therefore funding for one process/marketing evaluation is included in the budget. In addition, funding for annual load impact evaluations are also included in the budget. SCTD has a higher budget because it includes both the small commercial and residential programs.

The third category "Other Evaluation Activities" includes a line item called Customer Research Studies. Customer Research Studies include funding for studies that are not program specific evaluations. Examples of some of the historical customer research studies include potential studies, baseline studies, or high load high variance studies. The end-use metering category includes funding for data loggers that can be used to meter air-conditioner usage and possibly other end uses. The demand response forecast application development category includes the ongoing costs of maintaining the demand response forecasting software that SDG&E has implemented and customized so that hourly forecasts of demand response load impacts can be provided to SDG&E's electric procurement group and to the CAISO as required by MTRU. The last category shows the labor required to support these demand response studies. SDG&E is requesting two FTE's to support these studies.

Table KS-9 2012-2014 Measurement and Evaluation Budget			
SDG&E M&E Activities	**2012**	**2013**	**2014**
Statewide Program Evaluations			
Critical Peak Pricing Default	$100,000	$175,000	$75,000
Peak Time Rebate	$300,000	$175,000	$175,000
Base Interruptible Program	$30,000	$30,000	$30,000
TA and TI	$15,000	$65,000	$15,000
Capacity Bidding Program	$50,000	$50,000	$50,000
SDG&E Evaluations			
Summer Saver	$175,000	$250,000	$175,000
Small Customer Technology Deployment	$349,966	$150,000	$150,000
Peak Shift at Work	$0	$150,000	$75,000
Peak Shift at Home	$0	$200,000	$100,000
Permanent Load Shifting Evaluation	$25,000	$25,000	$25,000
Other Evaluation Activities			
Customer Research Studies	$100,000	$100,000	$100,000
Demand Response Forecasting App Development	$50,000	$50,000	$50,000
End Use Metering	$260,000	$260,000	$260,000
Labor to support studies			
M&E Analytical Support 2 FTE's	$220,491	$233,116	$246,525
Total M&E related costs	$2,295,422	$2,458,116	$1,946,525

VII. CAPACITY BIDDING BASELINE ANALYSIS

In the final decision on the 2009-2011 demand response program filing D-09-08-027 the CPUC adopted a new statewide baseline for the CBP program along with a few other programs. At SDG&E the only program affected was the CBP program. The baseline adopted consists of the average of the previous 10 non-event weekday days with a same day adjustment. The adjustment is equal to the ratio of the usage the first three of the 4 hours prior to the event on the event day divided by the usage during the first three of the 4 hours prior to the event hour in the baseline calculation. The adjustment factor was capped at 20% and therefore could be no lower than 0.8 or higher than 1.2. The baseline is calculated individually for each customer, the cap is applied individually for each customer, and then the results for each customer are summed to get the result for the aggregator. For the remainder of this testimony this baseline will be referred to as the individual 10 in 10 adjusted baseline with a 20% cap.

SDG&E proposes to change the CBP baseline to an aggregate 10 in 10 baseline with a same day adjustment with a 40% cap. The reason for the change is that both the Highly Volatile Load Customer study conducted by Christensen Consulting and SDG&E 2010 CBP event results have demonstrated the 10 in 10 individual baseline with a 20% cap on the adjustment is inaccurate and is underestimating the program performance and aggregator payments. This change in baseline is necessary to ensure the continued success of the CBP program.

The 10 in 10 individual baseline with a same day adjustment was shown to be highly accurate in two studies that were cited in the decision D-09-08-027. One was the KEMA 2003 baseline study[9] and the other was the Quantum 2006 baseline study.[10] However, the 20% cap was a new addition to the baseline which had not been studied. The KEMA 2003 study had used no cap on the baseline adjustment and in the Quantum study the adjustment factor could be no greater than 2 (a 100% cap) and could be no lower than 0.5. (a 50% cap) Thus the adoption of the 20% cap was a substantial deviation from the baseline that had been used in these previous measurements and evaluation studies that described the range in which the baseline was

[9] Protocol Development for Demand Response Calculation Findings and Recommendations KEMA-XENERGY Feb 2003

[10] Evaluation OF 2005 Statewide Large Non-residential day-ahead and reliability Demand response programs April 28th 2006 Quantum Consulting p 6-12

considered accurate. However, the decision also required that a high load high variance study be conducted that would provide a definition of high load high variance customers and the study would also report the number of customers who chose the same day adjustment who went over the cap. The Highly–Volatile Load Customer ("HVLC") study conducted by Christensen Associates shows in the executive summary in table ES-3, that 55% of SDG&E, 55% of SCE and 56% of PG&E CBP customers exceeded the 20% cap for at least hour of one event. In addition the study shows that exceeding the cap was not just a one event or one hour occurrence for most customers. When CBP customers did exceed the cap they did so for an average of 52% of the event hours for SDG&E, 69% for SCE and 63% for PG&E. This demonstrates that for the majority of the customers and for a very high percentage of hours, adjustment factors of greater than 1.2 are necessary in order to properly estimate load changes in response to weather or other factors.

One reason so many customers went over this cap is that the cap is applied at the individual customer level rather than at the aggregate portfolio level for the aggregators. For example if an aggregator has three customers of equal size enrolled in their program and 1 customer requires a 1.10 adjustment factor, the second a 1.05 adjustment factor and a third a 1.35 adjustment factor if the cap is applied individually the baseline of customer three will be capped. If the results for all three customers are added together first the overall adjustment required for the portfolio is only 1.17 and nothing needs to be capped. Since the vast majority of adjustment factors go up rather than down due to the fact that demand response events typically have hotter weather than the previous days a baseline cap applied at the individual level will usually produce a lower load impact result than when the cap is applied at the aggregate level. Therefore individual baselines with caps are more likely to underestimate demand response results than aggregate baseline with caps.

While the results from the HVLC study showing the large number of customers with adjustment factors over the cap provide very strong evidence that the cap is too low the real test is whether or not the capped baseline provides accurate results. SDG&E analysis comparing the results from individual 10 in 10 baseline with the 20% cap to the draft 2010 M&E results show that the baselines are producing impacts that are significantly lower than measurement and evaluation results. The effects of the underestimation on aggregator's payments are compounded by the performance structure of the CBP program. According to the CBP performance structure if the aggregator achieves less than 90% of their nomination they payment is reduced by 50% and if they achieve less than 75% of their nomination they receive no payment. In terms of the baseline this means that if an aggregator's customers perform but the baseline underestimates the load reduction by 11% the aggregator is underpaid by 50% and if the baseline underestimates the load reduction by 26% then the aggregator receives no payment at all. Therefore it is imperative that the CBP program use a baseline that is very accurate for the vast majority of customers.

Table KS-10 below shows the results of the individual 10 in 10 adjusted 20% cap baseline as a percentage of the draft M&E results for each month for the CBP day-ahead, CBP day-of and the DemandSMART^{TM} program. The baseline for the DemandSMART^{TM} program cannot be changed in this proceeding; however the results are still relevant to the information about the accuracy of the baseline in general. The results for the CBP day-ahead program were the most accurate although the 90% of M&E result is just 1% away from causing a 50% underpayment. CBP day- of baseline results for July and September are less than 75% of the M&E results which if the entire program were one aggregator would result in a zero payment.

The DemandSMART™ results are the worst with the baseline well under 75% of M&E for both July and August. In September the negative value indicates that the baseline predicted that customers increased load when in fact according to the M&E they reduced load.

Table KS-10 Baseline Load impacts as a percentage of draft 2010 M&E results				
Baseline	**Program**	**July**	**August**	**September**
10 in 10 individual 20% cap	CBP Day-Ahead	90%	97%	93%
10 in 10 individual 20% cap	CBP Day-Of	74%	89%	67%
10 in 10 individual 20% cap	DemandSMART	51%	61%	-19%

Since the individual 10 in 10 baseline with a 20% is clearly underestimating and aggregate baselines with caps are less likely to underestimate than individual caps a logical option to consider is switching to an aggregate baseline but keeping the 20% cap. The table below shows that the aggregate baseline with a 20% cap is in fact an improvement over the individual baseline but it still significantly below the load impact M&E results for the CBP day-of in July and September and for the demand in all months. Assuming the entire program is one portfolio and that the nomination was equal to the M&E results in CBP day-of program an underpayment of 50% would still occur in July and September and for DemandSMART™ a zero payment would have been made for July and out of pocket penalties would have been charged for September even with the aggregated baseline.

Table KS-11 Baseline Load impact as a percentage of draft 2010 M&E results				
Baseline	**Program**	**July**	**August**	**September**
10 in 10 aggregate 20% cap	CBP Day-Ahead	94%	101%	104%
10 in 10 aggregate 20% cap	CBP Day-Of	83%	100%	75%
10 in 10 aggregate 20% cap	DemandSMART™	61%	78%	1%

SDG&E carefully investigated how high the cap should be to improve the accuracy of the baseline. SDG&E suggests that an aggregate 10 in10 baseline with a 40% cap is more accurate than the aggregate baseline with a 20% cap. With this baseline the results for both the CBP day-ahead and CBP day-of programs are at least 90% of the M&E results. There are some very minor overestimations of 104% for Sep day-ahead CBP and 104% of day-of August CBP. However, CBP payments are capped at the nominated load reduction so if the aggregator had nominated the M&E results no overpayment would have occurred. Due to the load shapes of the participating customers this baseline is still under 90% of the measurement and evaluation results for DemandSMART™ for July and September.

Table KS-12
Baseline Load impacts as a percentage of draft 2010 M&E results

Baseline	Program	July	August	September
10 in 10 aggregate 40% cap	CBP Day-Ahead	102%	100%	104%
10 in 10 aggregate 40% cap	CBP Day-Of	95%	104%	91%
10 in 10 aggregate 40% cap	DemandSMART™	86%	108%	39%

A reasonable question is whether or not there should be any cap on the baseline at all. Any cap is somewhat arbitrary and may work for some customers or weather scenarios but not for others. The baseline studies conducted by KEMA and Quantum Consulting of the 10 in10 with no cap or a very high cap have shown that the 10 in 10 baseline is still accurate under these circumstances. One reason the cap was included for the baseline initially was to prevent participants from “gaming” the baseline results. Since the baseline uses the load data before the event occurs it is possible for a participant to increase their usage before the event begins in order to increase the baseline. However, the CBP program has other factors in place that discourage gaming besides the cap. The performance structure itself is a significant deterrent to gaming of the baseline. It is not possible with the CBP performance structure for a participant to game the baseline on an occasional basis. There is only one nomination for the entire month, no payments above the nominated value can be made and payments are sharply reduced to zero or even to our of pocket penalties for results lower than the nominated results. In addition the same day adjustment omits the hour right before the event and uses three entire hours of pre-event usage. Therefore a customer would have to increase their morning load for a solid three hours in order to have a substantial affect on the baseline.

SDG&E proposes to keep a 40% on the baseline as a final check against gaming of the baseline or against overpayments simply due to unusual customer usage. Since it is difficult but not impossible to game the baseline SDG&E is not proposing to remove the baseline cap completely. SDG&E does however believe that the current baseline is inaccurate and too focused on preventing gaming at the expense of underpaying aggregators. Because the CBP program structure has other attributes that prevent gaming besides the cap SDG&E is comfortable increasing the cap to 40%. The CBP program has been successful at SDG&E since 2007 according to measurement and evaluation load impact studies and the aggregators deserve to be compensated fairly. The change to a more accurate 10 in 10 aggregate baseline with a 40% cap will help ensure the continued success of this program.

VIII. QUALIFICATIONS – KATHRYN SMITH

My name is Kathryn E. Smith. My business address is 8306 Century Park Court, San Diego, California, 92123-1569. I am employed by San Diego Gas & Electric Company ("SDG&E") as a Senior Market Analyst in the Load Research Department. In my position I am responsible for providing statistical analysis related to electric load research.

I graduated from the University of California Berkeley with a Bachelor of Arts degree in Mathematics in 1999. I received a Master of Science in Statistics from San Diego State University in 2004. I have been employed by SDG&E and Sempra Energy in the Load Research department since 2005.

I have previously testified before the Commission.

IX. QUALIFICATIONS – LESLIE WILLOUGHBY

My name is Leslie Willoughby. My business address is 8306 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric Company ("SDG&E") as Electric Load Analysis Manager in the Strategic Analysis and Pricing Department. In my current position, I am responsible for managing and conducting load and energy research analysis.

I attended San Diego State University in San Diego, CA, where I graduated with a Bachelor of Science in Business Administration in 1983. I continued to attend San Diego State University where I graduated with an MA in Economics in 1989. In 1990, I was employed by SDG&E to work in the Load Research Section of the Marketing Department as an Associate Economic Analyst. Over the past 20 years I have held positions of increasing responsibility within the company that have included Load and Energy Research. I have previously testified before the Commission.

Appendix A: Ex-Ante Monthly Load Impact Forecasts

SDG&E Load Impacts Adopted for RA

DR 2011 Load Impact Estimates

MWs

Expected Capacity at Coincident Peak based on Load Impact Protocols (MW)

Average of Hourly Ex Ante Load Impacts (MW/hour) from 2 to 6 PM If Simultaneous Events Are Called on Monthly Peak Load Days Under 1-in-2 Weather Year Conditions, Before Adjusting for Avoided Line Losses

Program Name	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
BIP	6.20	5.90	6.10	6.20	6.10	6.20	6.40	6.50	6.40	6.60	6.00	5.90
Summer Saver Residential and Commercial	-	-	-	-	17.00	6.00	20.00	24.00	29.00	23.00	-	-
AMP	-	-	-	-	19.00	18.00	24.00	25.00	25.00	23.00		
CBP - Day of	-	-	-	-	13.00	13.00	14.00	14.00	15.00	15.00	-	-
CBP- Day ahead	-	-	-	-	11.00	10.00	11.00	11.00	12.00	11.00	-	-
CPP Emergency	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
PTR	-	-	-	-	68.00	62.00	95.00	93.00	86.00	71.00	54.00	62.00
CPP-D * Medium and Large C&I	15.00	16.00	16.00	19.00	20.00	18.00	21.00	21.00	21.00	21.00	18.00	16.00
Total Allocated Event Based Resources	**23.20**	**23.90**	**24.10**	**27.20**	**156.10**	**135.20**	**193.40**	**196.50**	**196.40**	**172.60**	**80.00**	**85.90**

Ex-Ante portfolio forecast 1 in 2 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2011	1 in 2	Aggregator Managed Progam	0	0	0	0	8	7	11	12	12	10	0	0
Aggregator Managed Progam Subtotal	2011	1 in 2		0	0	0	0	8	7	11	12	12	10	0	0
BIP	2011	1 in 2	Emergency Program	6.644	6.291	6.404	7.142	7.0063	7.092	7.43	7.434	7.419	7.641	6.358	6.255
Emergency Program Subtotal	2011	1 in 2		7	6	6	7	7	7	7	7	7	8	6	6
CBP day-ahead	2011	1in 2	Price Responsive Program	0	0	0	0	9	9	9	9	10	9	0	0
CBP day-of	2011	1 in 2	Price Responsive Program	0	0	0	0	10	10	11	11	11	11	0	0
CPPD Large	2011	1 in 2	Price Responsive Program	14	15	14	17	18	17	19	18	19	19	16	14
CPPD Medium	2011	1 in 2	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
PTR	2011	1 in 2	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
Small Customer Technology Deployment	2011	1in 2	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
Summer Saver	2011	1 in 2	Price Responsive Program	0	0	0	0	17	6	20	24	29	23	0	0
Price Responsive Program Subtotal	2011	1 in 2		14	15	14	17	54	41	59	62	69	62	16	14
PLS	2011	1 in 2	Non-Event Based Resource	1	1	1	1	1	1	1	1	1	1	1	1
Total	2011	1 in 2		22	22	22	26	70	57	79	83	90	81	24	22

Ex-Ante portfolio forecast 1 in 2 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2012	1 in 2	Aggregator Managed Progam	0	0	0	0	9	9	14	15	15	12	0	0
Aggregator Managed Progam Subtotal	2012	1 in 2		0	0	0	0	9	9	14	15	15	12	0	0
BIP	2012	1 in 2	Emergency Program	9.43	8.929	9.089	10.14	9.9444	10.07	10.5	10.55	10.53	10.85	9.024	8.878
Emergency Program Subtotal	2012	1 in 2		9	9	9	10	10	10	11	11	11	11	9	9
CBP day-ahead	2012	1in 2	Price Responsive Program	0	0	0	0	10	10	10	10	11	11	0	0
CBP day-of	2012	1 in 2	Price Responsive Program	0	0	0	0	12	11	13	13	13	13	0	0
CPPD Large	2012	1 in 2	Price Responsive Program	14	15	14	17	18	17	19	19	19	19	17	14
CPPD Medium	2012	1 in 2	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
PTR	2012	1 in 2	Price Responsive Program	49	46	37	40	47	42	65	64	59	49	37	42
Small Customer Technology Deployment	2012	1in 2	Price Responsive Program	1	1	1	3	5	4	5	6	6	6	1	1
Summer Saver	2012	1 in 2	Price Responsive Program	0	0	0	0	18	6	21	24	29	23	0	0
Price Responsive Program Subtotal	2012	1 in 2		63	62	53	60	109	90	133	135	138	120	55	57
PLS	2012	1 in 2	Non-Event Based Resource	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total	2012	1 in 2		75	73	64	72	131	111	159	163	166	145	66	68

Ex-Ante portfolio forecast 1 in 2 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2013		Aggregator Managed Progam	0	0	0	0	9	9	14	15	15	12	0	0
Aggregator Managed Progam Subtotal	2013	1 in 2		0	0	0	0	9	9	14	15	15	12	0	0
BIP	2013	1 in 2	Emergency Program	11.36	10.75	10.95	12.21	11.978	12.12	12.7	12.71	12.68	13.06	10.87	10.69
Emergency Program Subtotal	2013	1 in 2		11	11	11	12	12	12	13	13	13	13	11	11
CBP day-ahead	2013	1in 2	Price Responsive Program	0	0	0	0	11	10	11	11	11	11	0	0
CBP day-of	2013	1 in 2	Price Responsive Program	0	0	0	0	14	13	14	15	15	15	0	0
CPPD Large	2013	1 in 2	Price Responsive Program	14	15	15	17	18	17	19	19	20	20	17	15
CPPD Medium	2013	1 in 2	Price Responsive Program	13	15	16	21	24	23	29	32	37	34	31	23
PTR	2013	1 in 2	Price Responsive Program	50	47	38	41	48	43	67	65	60	50	37	43
Small Customer Technology Deployment	2013	1in 2	Price Responsive Program	2	2	2	5	9	6	9	10	10	10	2	2
Summer Saver	2013	1 in 2	Price Responsive Program	0	0	0	0	18	6	21	24	29	23	0	0
Price Responsive Program subtotal	2013	1in 2		78	78	70	84	141	120	170	176	183	162	88	82
PLS	2013	1in2	Non-Event Based Resource	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total	2013	1in 2		5	93	85	100	166	144	200	207	214	191	102	97

Ex-Ante portfolio forecast 1 in 2 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2014	1 in 2	Aggregator Managed Progam	0	0	0	0	9	9	14	15	15	12	0	0
Aggregator Managed Progam Subtotal	2014	1in 2		0	0	0	0	9	9	14	15	15	12	0	0
BIP	2014	1 in 2	Emergency Program	13.93	13.19	13.43	14.98	14.691	14.87	15.6	15.59	15.56	16.02	13.33	13.12
Emergency Program Subtotal	2014	1in 2		14	13	13	15	15	15	16	16	16	16	13	13
CBP day-ahead	2014	1in 2	Price Responsive Program	0	0	0	0	11	10	11	11	12	11	0	0
CBP day-of	2014	1 in 2	Price Responsive Program	0	0	0	0	16	15	17	17	18	17	0	0
CPPD Large	2014	1 in 2	Price Responsive Program	14	15	15	18	19	18	20	20	21	20	18	15
CPPD Medium	2014	1 in 2	Price Responsive Program	22	24	23	28	31	28	33	34	37	33	28	24
PTR	2014	1 in 2	Price Responsive Program	51	48	39	41	49	44	68	67	61	51	38	44
Small Customer Technology Deployment	2014	1in 2	Price Responsive Program	2	2	2	6	11	8	11	12	13	12	3	2
Summer Saver	2014	1 in 2	Price Responsive Program	0	0	0	0	18	6	21	24	29	23	0	0
Price Responsive Program Subtotal	2014	1 in 2		89	89	79	94	154	129	180	185	190	167	87	85
PLS	2014	1 in 2	Non-Event Based Resource	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Total	2014	1in 2		108	107	98	114	183	158	215	220	226	200	105	103

Ex-Ante portfolio forecast 1 in 10 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2011	1 in 10	Aggregator Managed Progam	0	0	0	0	8	8	11	13	13	11	0	0
Aggregator Managed Progam Subtotal	2011	2 in 10		0	0	0	0	8	8	11	13	13	11	0	0
BIP	2011	1 in 10	Emergency Program	6	5	6	7	7	7	7	7	7	8	6	6
Emergency Program Subtotal	2011	1 in 10		6	5	6	7	7	7	7	7	7	8	6	6
CBP day-ahead	2011	1 in 10	Price Responsive Program	0	0	0	0	10	9	9	10	10	10	0	0
CBP day-of	2011	1 in 10	Price Responsive Program	0	0	0	0	11	11	11	11	12	11	0	0
CPPD Large	2011	1 in 10	Price Responsive Program	14	16	17	18	18	18	19	19	20	19	15	14
CPPD Medium	2011	1 in 10	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
PTR	2011	1 in 10	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
Small Customer Technology Deployment	2011	1 in 10	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
Summer Saver	2011	1 in 10	Price Responsive Program	0	0	0	0	19	25	26	29	32	25	0	0
Price Responsive Program Subtotal	2011	1 in 10		14	16	17	18	57	64	66	69	74	65	15	14
PLS	2011	1 in 10	Non-Event Based Resource	1	1	1	1	1	1	1	1	1	1	1	1
Total	2011	1 in 10		22	23	25	26	74	80	86	90	95	85	22	21

Ex-Ante portfolio forecast 1 in 10 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2012	1 in 10	Aggregator Managed Progam	0	0	0	0	10	10	14	16	16	14	0	0
Aggregator Managed Progam Subtotal	2012	1in 10		0	0	0	0	10	10	14	16	16	14	0	0
BIP	2012	1 in 10	Emergency Program	9	7	9	10	10	10	10	10	10	11	9	9
Emergency Program Subtotal	2012	1 in 10		9	7	9	10	10	10	10	10	10	11	9	9
CBP day-ahead	2012	1 in 10	Price Responsive Program	0	0	0	0	10	10	10	11	11	11	0	0
CBP day-of	2012	1 in 10	Price Responsive Program	0	0	0	0	12	12	13	13	13	13	0	0
CPPD Large	2012	1 in 10	Price Responsive Program	14	16	17	18	18	19	19	19	20	20	15	14
CPPD Medium	2012	1 in 10	Price Responsive Program	0	0	0	0	0	0	0	0	0	0	0	0
PTR	2012	1 in 10	Price Responsive Program	50	50	38	65	76	76	84	85	86	76	53	46
Small Customer Technology Deployment	2012	1 in 10	Price Responsive Program	1	1	2	4	6	5	6	6	6	6	1	1
Summer Saver	2012	1 in 10	Price Responsive Program	0	0	0	0	20	26	27	30	33	25	0	0
Price Responsive Program Subtotal	2012	1in 10		64	67	58	87	142	148	159	163	170	151	69	61
PLS	2012	1 in 10	Non-Event Based Resource	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Total	2012	1 in 10		76	76	69	100	165	171	186	192	198	178	80	72

Ex-Ante portfolio forecast 1 in 10 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2013	1 in 10	Aggregator Managed Progam	0	0	0	0	10	10	14	16	16	14	0	0
Aggregator Managed Progam Subtotal	2013	1 in 10		0	0	0	0	10	10	14	16	16	14	0	0
BIP	2013	1 in 10	Emergency Program	11	9	11	12	13	12	13	13	13	13	11	11
Emergency Program Subtotal	2013	1 in 10		11	9	11	12	13	12	13	13	13	13	11	11
CBP day-ahead	2013	1 in 10	Price Responsive Program	0	0	0	0	11	11	11	11	12	12	0	0
CBP day-of	2013	1 in 10	Price Responsive Program	0	0	0	0	14	14	15	15	15	15	0	0
CPPD Large	2013	1 in 10	Price Responsive Program	14	16	18	18	19	19	20	20	20	20	15	14
CPPD Medium	2013	1 in 10	Price Responsive Program	13	17	19	22	25	28	30	34	38	27	22	35
PTR	2013	1 in 10	Price Responsive Program	51	51	39	67	77	78	86	86	88	78	55	47
Small Customer Technology Deployment	2013	1 in 10	Price Responsive Program	2	2	4	7	10	9	10	10	11	10	2	2
Summer Saver	2013	1 in 10	Price Responsive Program	0	0	0	0	20	26	27	30	33	25	0	0
Price Responsive Program Subtotal	2013	1 in 10		79	86	80	113	176	184	198	207	217	187	94	98
PLS	2013	1 in 10	Non-Event Based Resource	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Total	2013	1 in 10		94	98	94	129	203	210	228	238	249	218	108	112

Ex-Ante portfolio forecast 1 in 10 weather year

Program	Year	Weather	Program Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Smart	2014	1 in 10	Aggregator Managed Progam	0	0	0	0	10	10	14	16	16	14	0	0
Aggregator Managed Progam Subtotal	2014	1 in 10		0	0	0	0	10	10	14	16	16	14	0	0
BIP	2014	1 in 10	Emergency Program	14	13	13	15	15	15	16	16	16	16	13	13
Emergency Program Subtotal	2014	1 in 10		14	13	13	15	15	15	16	16	16	16	13	13
CBP day-ahead	2014	1 in 10	Price Responsive Program	0	0	0	0	11	11	11	11	12	12	0	0
CBP day-of	2014	1 in 10	Price Responsive Program	0	0	0	0	16	16	17	17	18	17	0	0
CPPD Large	2014	1 in 10	Price Responsive Program	14	17	18	19	19	20	20	21	21	21	16	15
CPPD Medium	2014	1 in 10	Price Responsive Program	23	26	28	29	31	33	34	36	38	25	23	33
PTR	2014	1 in 10	Price Responsive Program	52	52	40	68	79	79	88	88	90	80	56	48
Small Customer Technology Deployment	2014	1 in 10	Price Responsive Program	2	3	5	9	13	11	12	13	13	13	2	2
Summer Saver	2014	1 in 10	Price Responsive Program	0	0	0	0	20	26	27	30	33	25	0	0
Price Responsive Program	2014	1 in 10		91	97	91	125	190	196	209	216	225	192	97	98
PLS	2014	1 in 10	Non-Event Based Resource	5	5	5	5	5	5	5	5	5	5	5	5
Total	2014	1 in 10		110	115	109	145	220	226	244	252	261	227	115	116

Appendix B: Ex-Post Monthly Load Impact Results

2010 Draft Ex-Post Measruement and Evaluation Results													
Program	**Description**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
CBP day-ahead	Number of Customers	152	152	152	152	152	121	121	116	83	83	83	83
	Average Ex-Post M&E Load Impact							10	8	11			
	Number of Events	0	0	0	0	0	0	1	5	1	0	0	0
CBP day-of	Number of Customers	235	235	235	235	235	260	284	277	251	283	283	283
	Average Ex-Post M&E Load Impact							9	9	8			
	Number of Events	0	0	0	0	0	0	3	6	3	0	0	0
CPP	Number of Customers	1498	1478	1481	1470	1445	1343	1333	1334	1333	1334	1335	1339
	Average Ex-Post M&E Load Impact								32	29			
	Number of Events	0	0	0	0	0	0	0	2	2	0	0	0
CPP-E	Number of Customers	10	10	10	8	8	8	8	8	8	8	8	8
	Average Ex-Post M&E Load Impact												
	Number of Events	0	0	0	0	0	0	0	0	0	0	0	0
Demand Smart	Number of Customers	0	0	0	0	87	87	87	101	105	105	105	105
	Average Ex-Post M&E Load Impact							8	8	6			
	Number of Events	0	0	0	0	0	0	3	5	1	0	0	0
BIP	Number of Customers	19	19	19	19	19	19	19	19	19	21	21	21
	Average Ex-Post M&E Load Impact									0.4 / 4			
	Number of Events	0	0	0	0	0	0	0	0	1	0	0	0
Summer Saver Commercial	Number of Customers	13104	13104	13104	13104	13104	13406	13399	13390	13328	12567	12692	12977
	Average Ex-Post M&E Load Impact							6	6	7			
	Number of Events	0	0	0	0	0	0	2	6	3	0	0	0
Summer Saver Residential	Number of Customers	30032	30032	30032	30032	30032	30725	30669	30648	30582	29729	29430	29993
	Average Ex-Post M&E Load Impact							14	12	16			
	Number of Events	0	0	0	0	0	0	2	6	3	0	0	0

2009 Ex-Post Measruement and Evaluation Results													
Program	**Description**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
CBP day-ahead	Number of Customers	164	164	164	164	164	80	108	114	128	103	103	103
	Average Ex-Post M&E Load Impact								10	10			
	Number of Events	0	0	0	0	0	0	0	3	5	0	0	0
CBP day-of	Number of Customers	131	131	131	131	131	223	252	259	271	264	264	264
	Average Ex-Post M&E Load Impact								14	12			
	Number of Events	0	0	0	0	0	0	0	3	5	0	0	0
	Budget												
CPP	Number of Customers	1374	1386	1404	1589	1601	1525	1514	1516	1516	1518	1519	1521
	Average Ex-Post M&E Load Impact								22	24			
	Number of Events	0	0	0	0	0	0	0	4	4	0	0	0
CPP-E	Number of Customers	10	10	10	10	10	10	10	10	10	10	10	10
	Average Ex-Post M&E Load Impact												
	Number of Events	0	0	0	0	0	0	0	0	0	0	0	0
	Budget												
BIP	Number of Customers	20	20	20	21	21	21	21	22	19	19	19	19
	Average Ex-Post M&E Load Impact												
	Number of Events	0	0	0	0	0	0	0	0	0	0	0	0
Summer Saver Commercial	Number of Customers	10134	10334	10823	11474	13177	12517	14047	12744	12698	12694	12881	13027
	Average Ex-Post M&E Load Impact							5	7	8			
	Number of Events	0	0	0	0	0	0	1	3	3	0	0	0
Summer Saver Residential	Number of Customers	23227	23683	24806	26297	30199	28686	32153	29168	29136	30031	29869	30109
	Average Ex-Post M&E Load Impact							13	17	20			
	Number of Events	0	0	0	0	0	0	1	3	3	0	0	0