BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902-E) Requesting Approval and Funding for 2018-2022 Demand Response Portfolio in compliance with Decision 16-09-056.	Application No. 17-01-___ (Filed January 17, 2017)

CHAPTER 5

PREPARED DIRECT TESTIMONY

OF BRENDA GETTIG

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

JANUARY 17, 2017

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PREPARED DIRECT TESTIMONY OF
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CHAPTER 5

I. OVERVIEW AND PURPOSE

This chapter discusses the cost effectiveness analysis for the proposed San Diego Gas & Electric Company (SDG&E) demand response (DR) programs for the 2018 through 2022 period. This analysis follows the 2016 Demand Response Protocols ("the Protocols")[1] and the guidance provided in Decision 16-09-056. The analysis was performed using the Commission approved Excel workbook for demand response cost effectiveness, now called the DR Cost-Effectiveness Report, originally developed by Energy and Environmental Economics (E3) in 2011, and more recently modified by the Investor-Owned Utilities (IOUs) for this application.[2] With guidance and approval from the Commission's Energy Division representative, the IOUs made the following primary changes to the DR Cost-Effectiveness Report to update it for this filing:

- Modified the workbook to include inputs for a five-year program cycle (it previously used only three years).
- Updated the inputs from the Avoided Cost Calculator, including, but not limited to, elimination of a resource balance year. The calculator produces a tab labeled "DR Outputs" which is copied into the "Inputs" tab in the DR Cost-Effectiveness Report.[3]
- To facilitate the estimation of the A Factors, the availability and dispatchability tables produced by the RECAP model for estimating A Factors for demand response programs were added to the workbook.

The analysis uses a statewide average of annual generation capacity values and market energy prices obtained from the Avoided Cost Calculator. The annual capacity values are disaggregated into monthly values using a distribution, also obtained from the Avoided Cost

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1 2016 Demand Response Cost Effectiveness Protocols, July 2016, available on the Commission's website at http://www.cpuc.ca.gov/General.aspx?id=7023

2 Relevant documents available at https://www.ethree.com/public_projects/cpucdr.php and http://www.cpuc.ca.gov/General.aspx?id=7023.

3 The version of the Avoided Cost Calculator used for this exercise is 20160801_Avoided_Cost Calculator_v1 (1).xlsb, available on the Commission's website at http://www.cpuc.ca.gov/General.aspx?id=10710.

Calculator, which allocates 26.5% of the annual value to resources available in August, 73.4% of the annual value to resources available in September, and 0.1% of the annual value to resources available in October.

The primary inputs to the cost effectiveness analysis include SDG&E's adjusted ex-ante load impact forecast, the proposed budget, and the program variables that allow for the frequency and duration of the demand response events. Detailed discussions of how each of these was developed are provided in the prepared direct testimony of Leslie Willoughby (Chapter 3), Elaine MacDonald (Chapter 6), and E Bradford Mantz (Chapter 1), submitted in support of this application.

Throughout this chapter, the following acronyms are used:

ACS	AC Saver Program
AFP	Armed Forces Pilot/Program
BIP	Base Interruptible Program
CBP	Capacity Bidding Program
DA	Day Ahead
DO	Day Of
DRAM	Demand Response Auction Mechanism
IT	Information Technology
PLS	Permanent Load Shifting Program
TD	Technology Deployment Program
TI	Technology Incentives Program

The following programs are analyzed individually, and also included in the portfolio analysis: BIP, CBP, ACS, and AFP. The day-ahead and day-of subprograms of CBP and ACS are analyzed separately due to the differences in event notification times; this separation is required by the Protocols.[4] Benefits and costs related to TI and TD, which are supporting programs that provide enabling technology but do not dispatch events, are partially included in CBP DO and ACS DA. The remaining portion of the enabling technology costs are applied to rates and DRAM, and these are excluded from the cost effectiveness tests.

[4] Protocols, p. 7.

A separate result is provided for PLS which is not included in the portfolio tests. SDG&E believes PLS should not be included in the portfolio benefit cost ratios. The goal of this program is market penetration using an incentive level approximately double of what SDG&E recommended.[5] Further, PLS is a different type of DR program, in that it does not provide load reduction when dispatched; rather, the program incentivizes equipment that enables recurring load to shift to off-peak hours.

II. RESULTS

The benefit cost ratios are provided in BG - BG - Table 1. As shown, the proposed 2018 to 2022 portfolio has a TRC result of 0.8 and a PAC result of 0.7.

BG - TABLE 1: COST EFFECTIVENESS RESULTS FOR 2018 THROUGH 2022

Test	BIP	CBP DA	CBP DO	ACS DA	ACS DO	AFP	Portfolio	PLS
TRC	1.4	0.9	0.8	1.0	0.7	0.6	0.8	0.3
PAC	1.1	0.9	0.7	1.1	0.6	0.6	0.7	0.7
RIM	1.1	0.8	0.7	1.0	0.6	0.5	0.7	0.3
PCT	1.3	1.3	1.3	1.2	2.9	1.3	1.6	0.9

SDG&E also performed an alternate analysis using an A Factor of 95 percent for each program. The rationale for providing this alternate analysis is based on an analysis reported in the Demand Response Potential Study[6] and is described in the section below on alternate scenarios. As shown in BG - BG--Table 2, this results in a portfolio TRC of 0.9 and a PAC of 0.9.

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[5] SDG&E filed a $475 incentive in Advice Letter 2445-E (http://regarchive.sdge.com/tm2/pdf/2445-E.pdf); the proposal of $475 can be found at p. 3. With Resolution E-4586 the Commission approved the filing with modification. The resolution can be found: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M065/K336/65336047.PDF

(Page 2 of the resolution sets SDG&E's incentive to $875/kW).

[6] Lawrence Berkeley National Laboratory, E3, and Nexant; 2015 California Demand Response Potential Study Charting California's Demand Response Future, Final Report on Phase 2 Results; November 14, 2016 in R.13-09-011 (LBNL Report), Appendix I, p. 297.

BG--TABLE 2: ALTERNATE ANALYSIS USING A FACTOR ADJUSTMENT

Test	BIP	CBP DA	CBP DO	ACS DA	ACS DO	AFP	Portfolio	PLS
TRC	1.5	1.4	1.2	1.1	0.8	1.1	0.9	0.4
PAC	1.3	1.3	1.1	0.6	1.2	1.1	0.9	0.9
RIM	1.3	1.2	1.0	0.6	1.1	1.0	0.8	0.4
PCT	1.3	1.3	1.3	2.9	1.2	1.3	1.6	0.9

III. ADJUSTMENT FACTORS

The Protocols allow the capacity and energy benefits to be adjusted by a set of seven adjustment factors, named A through G. These factors were used in the analysis and results in the above tables. These factors are designed to be program specific adjustments to the capacity benefits, energy benefits, and transmission and distribution benefits. Each of the factors is discussed below, along with the values used in this analysis.

A. A Factor

The A Factor adjusts the capacity value according to the availability of the program to dispatch events. For example, if a program event can be called any hour of the day with no restrictions, the A Factor for that program would be 100%. All SDG&E demand response programs have some limitation on when their events can be called, so the A Factors used in the analysis are percentages below 100%.

The IOUs were directed to use E3's RECAP model for this application to estimate the A Factor.[7] The RECAP model captures a program's availability by estimating two separate components of availability and dispatchability; the product of these two components is the A Factor used in the analysis. The tables used to estimate the availability and dispatchability components

[7] D.16-09-056, p. 75 and the Protocols, p. 32.

were produced by the most recent version of the RECAP model and are provided as separate tabs in the demand response cost effectiveness workbook.

BG - BG - Table 3 presents the availability and dispatchability components calculated from the RECAP model tables and the resulting A Factors for each program in this analysis.

BG - TABLE 3: A FACTORS FOR SDG&E DEMAND RESPONSE PROGRAMS

Program	Call Times	Max Events per Month	Max Events per Year	Avail-ability	Dispatch-ability	A Factor
BIP	Jan to Dec, 24 hours, all days	40	120	100%	86%	86%
CBP	May to Oct, 11am to 7 pm, weekdays	24	144	71%	86%	61%
ACS	May to Oct, Noon to 9 pm, all days	24	80	100%	86%	86%
AFP	May to Oct, 1 pm to 6 pm, weekdays	24	144	49%	86%	42%
PLS	May to Oct, 11 am to 7 pm, weekdays	All weekdays	All weekdays	71%	98%	70%

B. B Factor

The B Factor adjusts the capacity value for differences in notification times. The Protocols specify that day-ahead programs shall use a B Factor of 88%, day-of programs that can be called in 30 minutes or less shall use a B Factor of 100%, and day-of programs that require more than 30-minute notification shall use a B Factor of 94%.[8] Two of SDG&E's programs require day ahead notification: CBP DA and ACS DA. For these two programs, a B Factor of 88% was used in the analysis. One day-of program, AFP, requires a three-hour notification time and therefore a B Factor

[8] Protocols, p. 33.

of 94% was used in the analysis. The remaining day-of programs allow for a notification of 30 minutes or less and therefore a B Factor of 100% was used in the analysis.

C. C Factor

The C Factor adjusts the capacity value for differences in triggers or the conditions under which a program can be dispatched. The Protocols allow for a C Factor of 100% when the program can be called at the utility's discretion. All of SDG&E's demand response programs can be called at the utility's discretion; therefore, a C Factor of 100% was used for all programs in this analysis.

D. D Factor

The D Factor adjusts the transmission and distribution (T&D) benefits according to a set of four criteria: right time, right place, right certainty, and right availability. SDG&E is not claiming T&D benefits for any of its programs; therefore, a D Factor of 0% was used for all programs in this analysis. The Potential for T&D value is discussed further in the testimony of E Bradford Mantz.

E. E Factor

The E Factor adjusts energy benefits to account for the likelihood that demand response events occur when energy prices are at their highest. The market price used in the analysis is the on-peak market price averaged over the year. One would expect the on-peak price to be higher than the annual average during a demand response event, since the event is typically called when resources are low and therefore prices are at their highest.

SDG&E downloaded 2015 and 2016 locational marginal prices for the day ahead market for node DLAP_SDGE-APND from the California Independent System Operator (CAISO) OASIS database. Using this dataset, an average annual price from October 2015 through October 2016 was calculated. The result was multiplied by the on-peak multiplier for 2016 taken from the Avoided Cost Calculator Demand Response Inputs tab to arrive at an average annual on-peak price. Then, a separate calculation was made to determine the average annual price for the hours in the typical demand response event window, hours ending 3 PM to 9 PM. A ratio of these two annual prices (the average annual price during typical demand response hours over the average annual on peak price) resulted in a factor of 143%. This was used as the E factor for all programs in this analysis except for PLS. PLS differs from dispatchable programs in that it provides load shift daily during specified hours and not just on the highest demand days. Therefore, the PLS analysis uses an E factor of 100% .

F. F Factor

The F Factor allows additional value for programs that can provide flexible demand response and can meet CAISO's Flexible Resource Adequacy Must Offer Obligation (FRAC-MOO) criteria. The SDG&E programs in this application are not currently designed to meet the FRAC-MOO criteria and therefore SDG&E is not claiming this additional benefit for any of the programs in this analysis.

G. G Factor

The G Factor allows additional value for programs that can provide demand response resources in certain constrained geographical regions. The 2016 Protocols state "[f]or SDG&E, the default G factor adder shall be 10%, thus the G Factor will be 110%."[9] Therefore, SDG&E used a G Factor of 110% for all programs in this analysis.

IV. LOAD IMPACTS

SDG&E used the forecasted 50th percentile ex-ante load impacts based on a 1-in-2 weather year, with participation adjusted for the portfolio level, as required by the Protocols.[10] The estimation process of the ex-ante load impacts is explained in detail in the Prepared Direct Testimony of Leslie Willoughby.

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[9] Protocols, p. 34.

[10] Protocols, p. 12.

V. ALLOCATION OF INDIRECT COSTS

Certain costs in the proposed budget were allocated across programs as specified in the Protocols. The Protocols state that indirect costs that support a group of programs should be allocated across those programs based on their total program budgets for the cost effectiveness analysis.[11]

The general administration budget that provides policy and program support for programs in general was allocated across all programs in this analysis based on the program budgets used in the cost effectiveness tests. Other areas where costs were allocated across programs include the budgets for marketing, IT, and Measurement and Evaluation. In each of these cases, the budgets included project costs specified by program and labor costs not specified by program. For each of these, the labor costs supporting the projects were allocated across programs according to each program's project costs. The resulting sum of project costs plus allocated labor per program was used in the cost effectiveness tests.

VI. AMORTIZATION OF CAPITAL COSTS

The Protocols allow for the amortization of capital costs paid by either the utility or the participant. The following costs were amortized: thermostats to be installed through the TD program, enabling technology to be installed through the TI program, thermal energy storage systems to be installed through the PLS program, and anticipated IT project costs budgeted for multiple programs. BG- BG - Table 4 presents a summary of the allocated cost amounts and periods.

[11] Protocols, p. 24.

BG - TABLE 4: AMORTIZED CAPITAL COSTS

Description	Program(s)	Amount Amortized	Amortization Period (Years)
Thermostats	ACS DA	$1,050,368	5
Auto DR technology	CBP DO	$724,762	7.5
Thermal Energy Systems	PLS	$12,846,075	20
IT Project Costs	BIP, ACS-DA, ACS-DO, AFP, TI, PLS	$2,328,139	5

The Protocols require that the base case amortization period be the midpoint of the expected life and the program cycle period.[12] Thus the base case amortization period for thermostats and IT costs is five years (i.e. the midpoint of five-year life plus five-year cycle), and the base case amortization period for Auto DR is 7.5 years (*i.e.*, the midpoint of ten-year life plus five-year cycle). For thermal energy systems installed through PLS, the modified PLS methodology allows a 20-year amortization period.

VII. PARTICIPANT COSTS

This section discusses the participant costs included in the tests. The Protocols allow for participant costs including transaction costs, equipment and other project costs, and non-monetary or non-energy costs and benefits to be included in the tests.[13] Each program tested includes an estimate of participant transaction costs calculated as a percentage of incentives plus bill savings less any equipment or capital costs.[14] The percentage used for this estimate is 75% for all programs except for ACS. The Protocols state to "use 35% of incentives as base value of the proxy measurement for

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[12] Protocols, pp. 16, 39-40.

[13] Protocols, pp. 15, 46-48.

[14] The calculations for the PLS tests, as approved by the Commission, exclude this estimate.

value of service lost and transaction costs for AC cycling programs."[15] Therefore, 35% was used for ACS.

Certain programs also include equipment costs. In particular, ACS DA includes the cost of thermostats incentivized through the TD program, CBP DO includes the cost of Auto DR equipment incentivized through the TI program, and PLS includes thermal energy storage equipment incentivized through that program. For each of these, the cost of the equipment is paid partially by the utility and partially by the participant.

The Demand Response Potential Study identified additional economic benefits for customers using enabling technology and called these "co-benefits." These co-benefits are additional benefits that customers receive as a result of installing "technologies or device upgrades that enable DR."[16]

For SDG&E's cost effectiveness analysis, these co-benefits are assumed to exist at the same value of the participants' cost of equipment in excess of the incentive payment. This assumption follows the reasoning in the Protocols which states "[i]t is reasonable to assume that participants in voluntary DR programs perceive their costs as being less than the benefits, or at the very least participants perceive that they are 'breaking even.' Therefore, the maximum possible value of their costs is equal to the value of the benefits."[17]

The tests for ACS DA include the participants' full cost for thermostats and the co-benefit is calculated as equal to this cost less the incentive. The tests for CBP DO (which include TI or Auto DR costs) do not directly include the participants' equipment costs in excess of the incentive as these vary greatly across participants; however, the costs in excess of the incentive and the co-benefits are assumed in the analysis to offset each other.

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[15] Protocols, p. 47.

[16] LBNL Report, page 4-5. The technologies identified in the study include smart thermostats, building energy management systems (EMS) and lighting controls.

[17] Protocols, p. 46.

VIII. EXCLUDED COSTS

Certain costs in the application budget were applicable only on a portfolio basis; these costs were not included in the individual program tests. This includes the Emerging Technologies Demand Response program budget, and a portion of the Measurement and Evaluation budget, which is held in reserve for unspecified studies.

The tests include only the portion of the budgeted incentive dollars that align with the ex-ante forecast. The remaining budgeted incentive dollars are not included in the tests but are necessary to cover additional growth beyond the forecast used in the analysis.

Forecasted enabling technology investments that are attributed to customers enrolling in Critical Peak Pricing (CPP) rates are not included in the portfolio test. This includes Auto DR technology installed through the TI program and thermostats installed through the TD program. Costs budgeted to continue to signal these devices and measure the load drop during demand response events were disaggregated from the TI, TD and ACS program budgets and excluded from the analysis. Furthermore, costs specified for DRAM, Electric Rule 32, and the Over Generation Pilot were not included in the tests. The amounts and rationale for excluding these costs are shown in BG - BG - Table 5.

BG - TABLE 5: COSTS EXCLUDED FROM THE TESTS

Description	Amount Excluded[18]	Reason for Excluding
DRAM	$ 7,714,163	DRAM costs are external to the DR Portfolio; this includes the portion of TI costs that are expected to go to DRAM projects.
Electric Rule 32	$ 3,574,146	Electric Rule 32 costs are external to the DR Portfolio
Over Generation Pilot	$ 3,982,944	Pilots are allowed to be excluded when the ex-ante impacts are too uncertain to include in the forecast.

[18] Includes applicable allocations of the general administration budget.

A portion of incentive costs	$22,538,849	The difference between budgeted maximum participation incentive levels and the incentive levels calculated to go with the forecasted MW based on historical data.
A portion of signaling costs for ACS DA	$ 638,112	The signaling costs for ACS DA vary by the number of installed devices. Similar to the incentives, the proposed budget includes an additional amount to allow for growth beyond the forecasted amount.
Rates	$ 4,090,403	This includes costs related to rates including marketing, licensing, and a portion of TI and TD costs for customers who participate in rate design programs.
Total	$ 42,538,617	

The PLS calculations were not included in the portfolio results due to the different nature of this resource as discussed above.

IX. SENSITIVITY ANALYSES

The Protocols require sensitivity analyses showing the impact on the TRC resulting from a change in key variables. In particular, the variables specified are the A Factor, the ex-ante load impacts, participant costs, the generation capacity value, and the number of years used to amortize capital costs. Each of these is described below.[19]

To evaluate how sensitive the TRC is to changes in the A Factor, SDG&E used a value of 10% lower than the base case as the low value, and a value of 100% as the high value. BG - BG - Table 6 shows the results for each program.

[19] In addition, the Protocols state that sensitivity analyses should be performed on the values used for Transmission and Distribution (T&D) Benefits (Protocols, page. 15). SDG&E did not include any T&D benefits in the cost effectiveness tests; therefore, no sensitivity analysis was done on this variable.

BG - TABLE 6: SENSITIVITY ANALYSIS OF IMPACT OF CHANGES IN A FACTOR ON TRC

Program	Base Case		Sensitivity			
	A Factor	TRC	A Factor	TRC	A Factor	TRC
BIP	86%	1.4	77%	1.2	100%	1.6
CBP DA	61%	0.9	55%	0.8	100%	1.5
CBP DO	61%	0.8	55%	0.7	100%	1.2
ACS DA	86%	1.0	77%	1.0	100%	1.2
ACS DO	86%	0.7	77%	0.7	100%	0.9
AFP	42%	0.6	38%	0.6	100%	1.1
Portfolio	n/a	0.8	n/a	0.7	n/a	1.0
PLS	70%	0.3	63%	0.3	100%	0.4

The protocols specify to use the 10th and 90th percentile values of the load impacts in the sensitivity analysis. BG - BG - Table 7 shows the results of the analysis. Note that the 10th and 90th percentile tables do not include PLS, therefore this sensitivity analysis excludes PLS.

BG - TABLE 7: SENSITIVITY ANALYSIS OF IMPACT OF CHANGES IN LOAD IMPACTS ON TRC

Program	50th Percentile (Base Case)1-in-2 Portfolio Ex-Ante Impacts		10% Percentile		90th Percentile	
	Average August MW	TRC	Average August MW	TRC	Average August MW	TRC
BIP	6.9	1.4	4.9	1.0	8.9	1.6
CBP DA	8.1	0.9	7.6	0.9	8.7	1.0
CBP DO	5.6	0.8	5.2	0.8	5.9	0.8
ACS DA	12.8	1.0	8.6	0.8	17.0	1.3
ACS DO	9.6	0.7	0.0	0.0	19.6	1.5
AFP	3.9	0.6	0.0	0.0	9.8	1.3
Portfolio	46.9	0.8	26.3	0.4	69.9	1.1

Participant costs used in the cost effectiveness tests include transaction costs, value of service lost, and financial expenditures for equipment or other capital costs related to the program. The Protocols specify to use a percentage of the value of incentives paid to the participant plus their bill reductions less their capital costs as a proxy for transaction costs plus value of service lost. For most programs, the percentage used for this is 75%. In addition, the low and high values for sensitivity analysis are 50% and 100%. A modification is specified in the Protocols for voluntary AC cycling programs. For these, the base case is 35% and the low and high values for sensitivity analysis are 10% and 60% respectively.[20] BG - BG - Table 8 presents the change in TRC as a result of a change in participant costs.

BG - TABLE 8: SENSITIVITY ANALYSIS OF IMPACT OF CHANGES IN PARTICIPANT COSTS ON TRC

Program	Base Case		Sensitivity			
	% Used in Proxy	TRC	% Used in Proxy	TRC	% Used in Proxy	TRC
BIP	75%	1.4	50%	1.7	100%	1.1
CBP DA	75%	0.9	50%	1.2	100%	0.8
CBP DO	75%	0.8	50%	0.9	100%	0.7
ACS DA	35%	1.0	10%	1.0	60%	1.0
ACS DO	35%	0.7	10%	0.9	60%	0.7
AFP	75%	0.6	50%	0.7	100%	0.5
Portfolio	n/a	0.8	n/a	0.9	n/a	0.7

The sensitivity test on participant costs for PLS is different. This sensitivity looks at the resulting TRC when equipment costs are half of what they are in the base case, and also when equipment costs are 1.5 times what they are in the base case. The TRC results using these changes in equipment cost for PLS are 0.4 and 0.2 respectively.

For sensitivity tests on the adjusted generation capacity values, the values were lowered and raised by 30%. BG - BG - Table 9 shows the results of changes to the TRC for each program when

20 Protocols, p. 47.

the adjusted generation capacity values are adjusted 30% lower or 30% higher than the values used in the base case analysis.

BG - TABLE 9: SENSITIVITY ANALYSIS OF IMPACT OF CHANGES IN ADJUSTED CAPACITY VALUE ON TRC

Program	Base Case TRC	TRC with Adjusted Capacity Value Reduced 30%	TRC with Adjusted Capacity Value Increased 30%
BIP	1.4	1.0	1.8
CBP DA	0.9	0.7	1.2
CBP DO	0.8	0.6	1.0
ACS DA	1.0	0.8	1.3
ACS DO	0.7	0.5	1.0
AFP	0.6	0.5	0.7
Portfolio	0.8	0.6	1.0
PLS	0.3	0.2	0.4

The Protocols state that the length of the program cycle (in this case, five years) should be used as the amortization period for the high value of amortized capital costs. For the low value, the useful life of the investment should be used as the amortization period. The base case is the midpoint between the high and low values. The default value for the useful life of capital equipment is ten years and the default value for the useful life of IT investments is five years.

SDG&E amortized three types of capital costs. IT project costs planned for BIP, ACS, AFP, TI and PLS were amortized over five years. Thermostats installed with TD incentives were amortized over five years. Because the length of the useful life and the reporting period are both five years for these investments, there is no difference between the base case and the high and low values. Therefore, sensitivity analysis was not performed for investments in IT and TD technology.

The third type of capital costs are for enabling technology installed with TI or PLS incentives. The useful lives of these technologies are ten years for TI projects and 20 years for PLS projects. Sensitivity analysis was performed for investments in TI enabling technology with a useful life of ten years. In this case, the base case TRC used a period of 7.5 years to amortize the equipment costs (the midpoint between the useful life of the equipment and the length of the reporting cycle). Amortized values using five and ten year periods were used for the high and low results of the sensitivity analysis. The values specified for PLS sensitivity analysis include a base case of 20 years as the amortization period and 10 and 30 years for the high and low cases. The results are shown in BG - BG - Table 10.

BG - TABLE 10: SENSITIVITY ANALYSIS OF IMPACT OF CHANGES IN AMORTIZATION PERIOD ON TRC

Program	**Base Case**		**Sensitivity**			
	Amortization Years (midpoint)	TRC	Amortization Years (useful life)	TRC	Amortization Years (program cycle)	TRC
TI in CBP-DO	7.5	0.8	10	0.8	5	0.8
PLS	20	0.3	30	0.3	10	0.2

X. ALTERNATE SCENARIOS

This section describes alternate cost effectiveness analyses performed by SDG&E in addition to the sensitivities required by the Protocols. The alternate analyses include: 1) an adjustment to the A Factor; and 2) an analysis with CBP customers enrolling in two new subprograms.

As described in the opening section of this testimony, SDG&E provides an alternate set of resulting TRCs using an adjusted A Factor. In particular, SDG&E adjusted the A Factor for each program in the portfolio to 95%. The rationale for this adjustment is based on an analysis described in the Demand Response Potential Study. The study reported that the loss of load probabilities (LOLP) examined over a period of 63 years using the RECAP model existed almost entirely in the top 100 net load hours and roughly 95% was captured in the top 50 hours.[21] Each program in the SDG&E demand response portfolio is able to be dispatched more than 50 hours in a year, thus meeting this criterion for a 95% A Factor. The results of this alternate analysis are presented in BG - BG--Table 2 above and repeated below in BG - BG - Table 11.

BG - TABLE 11: TRC RESULTS WITH A FACTOR EQUAL TO 95%

Program	Base Case		Scenario
	A Factor	TRC	TRC When A Factor is 95%
BIP	86%	1.4	1.5
CBP DA	61%	0.9	1.4
CBP DO	61%	0.8	1.2
ACS DA	86%	1.0	1.1
ACS DO	86%	0.7	0.8
AFP	73%	0.9	1.1
Portfolio		0.8	0.9
PLS	70%	0.3	0.4

SDG&E also presents an analysis of two additional subprograms for CBP. CBP is offering DO and DA options where the hours during which an event can be called are extended to 9 pm in return for a slightly higher incentive. In order to test how cost effective these options are, SDG&E is providing alternate scenario results in which all CBP customers choose to be on each of these options. The A Factor for these alternate options is 73%, whereas the A factor for the 11 a.m. to 7 p.m. options presented in the base case analysis is 61%. The increase in the A Factor is due to capturing the additional loss of load probabilities in the hours ending 8 p.m. and 9 p.m. The result for this alternate scenario is shown in BG - BG - Table 12. As shown, the results are cost effective.

[21] LBNL Report, Appendix I, figure I-3, page 297.

BG - TABLE 12: ALTERNATE SCENARIO FOR CBP HOUR CHANGES

Test	CBP-DA 1 to 9 (all in scenario)	CBP-DO 1 to 9 (all in scenario)
TRC	1.2	1.3
PAC	1.1	1.1
RIM	1.1	1.1
PCT	1.3	1.3

As required by the Protocols, SDG&E has provided an analysis of qualitative benefits and costs of demand response in the workpapers submitted with this chapter. Included in the workpaper analysis is a scenario using the quantified qualitative benefits described in that analysis.

XI. QUALIFICATIONS

My name is Brenda Gettig. My business address is 8335 Century Park Court, San Diego, California 92123. I have been employed by SDG&E as a Senior Business Analyst in the Measurement and Evaluation Group for Customer Programs since 2006. My responsibilities include the evaluation and cost effectiveness analysis of SDG&E's demand response and low-income programs. I have a Master of Business Administration from the University of South Florida and a Master's of Arts in Economics from the University of California San Diego. I have not previously testified before the California Public Utilities Commission.

This concludes my prepared direct testimony.