Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Programs and Budgets for the Years 2009 through 2011.	Application 08-06-002

AMENDED

CHAPTER IV

PREPARED DIRECT TESTIMONY OF

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SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
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CHAPTER IV

PREPARED DIRECT TESTIMONY

OF KEVIN C. McKINLEY

I. PURPOSE

My testimony presents the overall results of the cost effectiveness tests for the 2009-2011 proposed demand response programs and the AMENDED overall portfolio. The associated issues regarding the Load Impacts utilized in these cost effectiveness tests are covered in the testimony of Kathryn Smith.

II. METHODOLOGY

The intent of a demand response program is to reduce peak demand. The benefits of demand response programs are in avoiding costs that would otherwise be increased to meet the peak demand including avoided electric generation capacity costs, T&D costs, and energy costs including commodity costs, line losses and environmental costs. In the *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications* ("2/27 ALJ Ruling"), it states: "It is possible that a cost effectiveness methodology may not be adopted in time to allow IOUs to use it to complete a full cost effectiveness analysis of their proposals before the application is filed. In this case, IOUs should include in their applications a basic cost effectiveness analysis of each program consistent with the parties' CE framework filed November 19, 2007…" SDG&E has relied on the parties' Cost-Effectiveness Framework (CE Framework) for calculating cost effectiveness as described below.

A. Tests

The primary purpose of the cost-effectiveness tests are to measure and evaluate the cost effectiveness of Demand Response (DR) programs in order to properly include these programs as a resource option in the utility's resource planning process. Historically, the Commission has used a broad societal perspective to identify benefits and costs and to determine cost-effective energy efficiency (EE) programs. This generally involves using the Total Resource Cost (TRC) test from the Standard Practice Manual (SPM).

The TRC test is a broad test taking into account all the benefits to DR customers and non-participating customers in terms of avoided generation costs (including line losses), avoided transmission and distribution (T&D) costs, avoided energy costs, and environmental benefits. On the cost side, this perspective includes all the costs associated with the DR program to both participating and non-participating customers. The test ignores all equipment incentive payments and subsidies that are transfers from non-participants to the DR program participants.

The TRC test is one of the tests reported as part of the determination of the cost-effectiveness of energy efficiency programs. DR programs should use this same test for measuring cost-effectiveness for purposes of resource planning to put the programs on an equal footing with energy efficiency. There are, however, significant differences between the characteristics of DR and those of energy efficiency so that the benefits used for cost effectiveness analysis developed for EE cannot be simply applied to DR programs. The current proceeding, R.07-01-040, has described those differences and tried to account for those differences as described in the avoided cost section below. The TRC perspective is appropriate to use to analyze the cost effectiveness of DR using appropriate avoided cost inputs developed specific to the characteristics of demand response.

In the evaluation of demand response programs, SDG&E has also included the cost-effectiveness from SDG&E's perspective in the Program Administrator Cost (PAC) test. Because the TRC test includes the customer cost as a part of the social costs, and because the

PAC test includes the incentive payment as a part of the program administrator cost, when the customer costs equal the incentive payment, the two tests (the TRC and the PAC) have exactly the same result. Another test included is the Ratepayer Impact Measure (RIM) which is reflective of the benefits and costs to non-participating customers.

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The last major test in the SPM is the Participant test. This test is most appropriate for use in designing programs and setting customer incentives. The economic analysis from the participating customer's perspective is typically a business analysis of an investment decision. The customer will look at the present value of expected future net benefits and decide whether or not to participate in the DR program. Customer costs remain an area of needed research in evaluating Demand Response programs. In lieu of any data that quantitatively estimates customer costs when responding to Demand Response programs, SDG&E has used the incentive payment as a proxy for these costs. Theoretically, customers use incentive payments to offset their costs in responding to DSM programs. As a result, the incentive payment, in SDG&E's view, is a reasonable proxy for customer costs until such a time as better information becomes available.[1]

B. Portfolio Evaluation

The cost effectiveness analysis is done on a program-by-program basis for those programs requiring cost effectiveness tests for 2009 through 2011. These programs, plus Customer Education, Awareness and Outreach programs, Permanent Load Shifting Programs, Measurement and Evaluation Costs and Codes and Standards are then aggregated and cost effectiveness is calculated at the portfolio level.[2]

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[1] This approach is consistent with section B.3 of the parties' CE framework.

[2] Caution should be used in interpreting the "portfolio level" results since several large DR programs are not included since they were adopted in other proceedings and are excluded here per the 2/27 ALJ Ruling, page 14.

III. BENEFITS

A. Avoided Generation Capacity Costs

The Parties' CE Framework, filed November 19, 2007, provided that the generation capacity costs avoided by a DR program will be based on the annual market price ($/kW-year) of the capacity of a new combustion turbine (CT), annualized using a real economic carrying charge rate that takes into account return, income taxes, ad valorem taxes and depreciation, with fixed O&M added, and reduced to reflect expected "gross margins" earned by selling energy ("CT cost").[3]

SDG&E is committed to using public data in its analysis of the cost-effectiveness of demand response programs to the extent possible. The latest available public information on the cost of peaking capacity in San Diego County is the cost of the Miramar II peaking plant, proposed for completion in 2009.[4] This type of peaking plant, an LM 6000 combustion turbine, is typical of the type of plant SDG&E would expect to be installed in its service territory in the 2009-2011 time frame but for demand response programs.[5]

The cost of the Miramar II plant includes construction and environmental costs specific to San Diego as well as other fixed costs including property taxes that are also specific to San Diego. The capital costs of $1,215 per kW are contained in SDG&E's RFO Contract Approval

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[3] CE Framework, C.1, pages 2-3.

[4] Consistent with CE framework section C.4, a plant in SDG&E's service territory was utilized for analysis.

[5] The Miramar II plant is based on wet cooling technology and also includes "black start" capability. The costs should be adjusted downward to remove the cost of black start capability which DR cannot provide, but increased for the cost of dry cooling since future plants are likely to have dry cooling. The cost of dry cooling is assumed to be roughly equal to the cost of black start capability.

Request, filed June 16, 2008,[6] while the O&M costs are assumed to be consistent with the operating characteristics of Miramar I as filed in SDG&E Advice Letter 1621-E.[7]

The 2009 CT installed costs are then converted to an annual kW-year figure based on a real economic carrying charge (RECC) similar to the approach shown in the direct testimony of James S. Parsons in SDG&E's GRC Phase 2 (A.07-01-041) except to update the cost of capital from 8.23 percent to 8.40 percent, consistent with the recent Commission-adopted change in SDG&E's cost of capital. The RECC factor is based on a 25 year book life, 15 year federal tax life, 20 year state tax life, federal tax rate of 35 percent, state tax rate of 8.84 percent, and an ad valorum tax rate of 1.207 percent (ad valorum taxes are included within the RECC factor rather than the fixed O&M). The full capacity value is calculated as $135 per kW-year.[8]

As described in section C.1 of the parties' CE Framework, the above capacity value is reduced to reflect expected "gross margins" that could be earned by the CT in selling energy into the wholesale market. SDG&E has calculated "gross margins" using the same expected electric market prices as are used in the electricity price calculation based on the hourly price profile from the year 2012 of the LTPP adjusted for average electric market prices in 2009-2011. A stochastic method was employed to reflect the uncertainty of and the correlation between wholesale market electric price and natural gas prices, and the relationship between those prices when the CT is operating. Based on a simulation analysis, gross margins were calculated to be $19 per kW-year.[9]

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[6] SDG&E's RFO Contract Approval Request, filed June 16, 2008, page 27, $56.5 million for the 46.5 MW plant.
[7] The Miramar II plant is based on the same LM6000 technology as the Miramar I plant. Operating costs are assumed to be similar, so the escalated cost data from Miramar I is used where comparable data is not available on Miramar II.
[8] See workpapers for more detail.
[9] The simulations were completed using Crystal Ball software based on historical data on mean reversion rates, correlations, and market price volatilities. The characteristics of the CT are averages over the lifetime of the CT and

The resulting $116 per kW-year is adjusted upward for two factors per section C.1 of the parties' CE Framework – line losses and avoided reserve margin. The line loss factor is estimated to be 9.34 percent based on losses at peak from the California Energy Commission ("CEC") report, CEC-200-2007-015-SF. The line loss factor from the CEC report is specific to peak line losses in San Diego. The annual generation capacity reserve margin SDG&E must maintain during the program evaluation period to comply with resource adequacy requirements established by the CPUC is 15 percent. For each MW of peak reduction, the DR program also reduces the need for SDG&E to add capacity to maintain a 15 percent reserve margin. The capacity value of DR programs without usage or availability constraints equivalent to the full annualized and adjusted CT cost is thus calculated to be $146 per kW-year.

For DR programs with constraints on their availability and/or how often they can be used, SDG&E uses an hourly stochastic method consistent with parties' CE Framework section C.2 that takes into consideration the capacity value of the DR programs during those the highest-valued periods in which the program is available and can be used. The value of generation capacity in those periods is determined by allocating the annual market value of generation capacity among the hours of the year in proportion to the relative need for capacity in those hours but for the DR programs. For DR programs available from May through October from 11 am to 6 pm on weekdays, the value of this capacity is 73 percent of the full cost of a CT.[10] That is, the likelihood of the need for added capacity will occur 73 percent of the time in those hours that the DR programs are available. The remainder will occur in the winter on-peak periods,

forward price relationships from forward markets in 2009-2011 are assumed to be representative of the average price relationships over the lifetime of the CT. See workpapers for more details.

[10] See workpapers for added description.

summer semi-peak periods, and on summer off-peak hours (weekend and holiday afternoon hours).

SDG&E has used the 73 percent value for all DR programs available during the summer, even those with a limit of 4 hours, because they are available for any consecutive 4 hours within the 11-6 pm time period. Because of the flexibility in design, SDG&E has the ability to call any consecutive 4 hours within the 11- 6 time frame, thus likely avoiding demand in the peak hours within the period. On the other hand, the BIP program, which can be called 30 times at any time of the year, has its value reduced to only 98 percent of the full, adjusted value of a CT.

B. Transmission and Distribution Avoided Costs

In D.03-02-068, the Commission describes a distribution planning process that accounts for distributed generation (DG) on the utility distribution system. The process is based on the record developed in R.99-10-025 and the Distribution Report published by the Energy Division on April 17, 2000, which discusses in depth how SDG&E operates and plans its distribution system and the impact of DG on the distribution system. D.03-02-068 requires DG to meet four criteria - - right time, right size, right place, and “physical assurance” - -in order to allow SDG&E to avoid any T&D costs. Physical assurance provides a guarantee that the customer load will not increase if the DG unit does not perform; this minimizes the impact of the customer on the distribution system. The same principles apply to DR programs. For most DR programs, customer participation is voluntary and typically involves no long-term commitment, thus providing no assurance of load reduction (physical assurance). Further, in some cases there are no penalties for non-performance, making the estimate of load reduction highly uncertain.

But for some programs, physical assurance is created by a technology solution giving the utility control of equipment. In those cases, there are avoided T&D costs if the remaining criteria of D.03-02-068 are present: right location, right size, and right time. In addition, with enough dispersed small load reductions, there will be some statistical regularity in the aggregation of many small sources that can be relied on. The statistical regularities provide a form of physical assurance.

The parties' CE Framework for T&D in section E.2 calls for utilities to establish a default avoided T&D cost which will be applied to DR programs which meet "right place" and "right certainty" criteria. The default avoided T&D costs is calculated from marginal transmission and distribution costs by using the component of these marginal costs associated with non-ISO transmission and distribution substation equipment, which is principally related to transformer capacity.[11] For DR programs with physical assurance through technological solutions, the default 2009 T&D avoided cost is $28 kW-year. This value is based on the analysis of incremental distribution costs avoided or deferred by lowering peak demand through the demand response programs enabled by the automated metering infrastructure proposed in A.05-03-015. The 2005 value of $22 per kW-year was adjusted to an RECC basis and updated for the escalation in costs since 2005.

For DR programs with physical assurance through statistical regularities of widespread participation of small customers, the $28/kW-year figure is discounted by the ratio of MWs avoided at the 10th percentile to the MWs avoided at the 50th percentile as measured by the load impact protocols. The more uncertain the load reduction, the lower the value of the DR program in avoiding T&D costs.[12]

[11] Consistent with CE Framework section E.3.
[12] CE Framework section E.4 includes a requirement that the DR have sufficient certainty of providing long-term reduction.

C. Avoided Energy-related Costs

Consistent with the parties' CE framework, the value of avoided electricity generation is based on wholesale energy prices averaged over the highest-price hours of an hourly price forecast based on average year conditions. For DR programs where the trigger is not a price trigger, SDG&E has used the hourly load profile from its resource planning model in conjunction with average forward market electric prices in 2009 through 2011 to calculate energy prices in the highest-price hours. For programs with specific price triggers, SDG&E has used the higher of the price trigger and the wholesale energy prices averaged over the highest-price hours.

With DR resources, SDG&E would purchase less energy during summer peak hours. Therefore, DR programs allow SDG&E to avoid electric transmission and distribution line losses on the SDG&E system since the energy would not be transported through the SDG&E system. The calculation of this benefit is based on the summer on-peak line losses at the secondary level adopted for energy efficiency in D. 05-04-024 of 8.1 percent.

Environmental avoided costs are based on section F.4 of the parties' CE Framework. DR reduces CO_2 by avoiding the energy that would otherwise be produced by a CT, resulting in greenhouse gas (GHG) benefits compared to the operation of a CT. The values of these benefits are based on the maximum pollution rates and the avoided cost values in the Energy Efficiency analysis, adopted in D.05-04-024. [13]

For DR programs that shift load away from peak hours, an offset in benefit is included for the hours in which increased energy is used. The hourly prices are calculated consistently with the avoided energy costs described above.

[13] See spreadsheet, cpucavoided26.xls, emissions tab, available at www.ethree.com.

D. Notification Period

SDG&E has attempted to quantify only the relative value of day-ahead versus day-of notification programs. In the ancillary services market, a CT with 10 minute start-up capability can earn revenues for being available if needed. These revenues are part of the revenue stream along with gross margins earned in the energy market. SDG&E has assumed that the value for any day-of notification DR program is the same as provided by a CT for purposes of this valuation.[14] No discount or adjustment is proposed for notification periods longer than 10 minutes; and similarly, no adjustment is made for DR programs that can provide load reductions faster than 10 minutes.

However, SDG&E has provided for a discount to day-ahead programs based on potential forecast errors and potential unexpected events. In a day-ahead DR program, the customer must be notified the day prior to being called upon to reduce load. In most cases, forecasts will be sufficiently close to actual outcomes, and the day-ahead program will provide as much value as a day-of program. However, in cases where unexpected events occur or weather forecasts badly miss the mark, a DR program's load reduction could be needed, but would not be available because it was not called the day before. SDG&E has tried to quantify this effect in a simple and understandable way based on historical data.

For this analysis, SDG&E has assumed that "system stress" occurs when its peak exceeds 3,800 mW and peak CAISO loads exceed 44,000 MW. SDG&E DR programs are generally not triggered when peak load is less than 3,800 MW. The statewide value was determined by the

[14] This is consistent with section F.2 of the parties' Consensus Framework, that a CT will not be given any more value than a DR program because it can provide ancillary services versus day-of DR programs with longer notification periods.

lowest peak demand associated with a CAISO called stage 1 alert in the summer months over 2004-2007.

The first type of DR program trigger for SDG&E is a weather trigger for San Diego. Analysis of the weather trigger of 87 degrees at the Miramar weather station on the top twelve peak load days shows that over the period 2004 through 2007, the forecast trigger would have failed to call the DR program on an actual peak day 23 percent of the time. However, for many of those days, the statewide system was not stressed and statewide resources would be more than adequate to handle the San Diego weather forecast failure. However, overall 8 percent of the time, peak days in San Diego occurred when the day-ahead weather trigger failed and the statewide system was under stress (peak greater than 44,000 MW) and the statewide day-ahead forecast was an underestimate of the resources needed the next day. In the times when the system is in stress and the CAISO is dealing with an under-forecast statewide, the CAISO would not have excess resources available to provide to San Diego. Thus 8 percent of the time the failure of the day-ahead trigger would have deprived SDG&E of significant resources needed to meet peak demand.[15]

The second type of trigger is a price trigger based on market prices. For example, the Capacity Bidding Program trigger is based on the day-ahead price for the SP-15 “super peak” product. The program may be called when the market price exceeds the trigger price based on 15 MMbtu/MWh times the burnertip gas price expressed in MMBtu. The market prices are based on market participants’ expectations of the next day prices, which in turn are based on expected demand and supply for electricity. To the extent the forecast of market participants in

[15] It is noted that the weather forecast failure figure increases to 17 percent if the statewide stress criteria were to be lowered to 43,000 MW.

the day-ahead market significantly underestimates the next day's conditions, a DR program based on the price trigger may not be called.

To assess the forecast error for this trigger, SDG&E analyzed peak load data on the days between July and September for 2004 through 2007. Market participants' expectations are assumed to be the same as the CAISO's day-ahead forecast. Analysis of the errors in the trigger involves looking at days with CAISO actual demand in excess of 44,000 MWs. For each of those days, a forecast error was determined to have occurred if the demand forecast was more than 1,000 MWs less that the actual system load (2.2 percent). Based on the data reviewed, forecast errors that were significant underestimates occurred roughly 13 percent of the time with both a 44,000 MW stress level and a 43,000 MW stress level criteria.

Based on the data reviewed, a discount for day-ahead programs of 10 percent seems reasonable and appropriate.

IV. OTHER ANALYSIS ASSUMPTIONS

A. Discount Rate

SDG&E used an 8.4% discount rate for discounting future benefits and costs to present value, the same value as is currently being used in the E3 calculator and is SDG&E's current cost of capital.

B. Program Life

For most programs the measure life is the number of years for which funding is being requested. Summer Saver however has an expected life of 10 years. For purposes of this analysis it is assumed the project will last over the three years of the program cycle. However, because the capacity payment is reduced dramatically in 2011, the average capacity payment over the life of the program was used. This was done to ensure that the costs of the program were not overstated. For TA/TI it was assumed that the investments made in the program would last for 10 years. To keep the analysis conservative, benefits were assumed to be constant from the fourth to the tenth year.

C. Measurement and Evaluation (M&E) Costs

SDG&E has included M&E costs as part of the costs for the cost effectiveness analysis at the portfolio level. Theoretically, however, there is an argument that M&E costs should be excluded since M&E is not necessary to achieving the demand reduction, only to measure it.

D. Capital

For simplification, the small amount of capital associated with the programs was assumed to be expensed each year. This eliminates the need for calculating the impacts of ratebasing small capital expenditures.

E. Load Forecast

The load forecasts for the cost effectiveness calculations were based on a 1 in 10 year peak value.

F. Customer Costs

As stated earlier, the incentive payments were used as a proxy for customer costs in all appropriate tests.

V. COST-EFFECTIVENESS ANALYSIS RESULTS

The following is a summary of the Cost Effectiveness analyses estimated for the different SDG&E Demand Response programs requiring a Cost Effectiveness calculation.

CBP Day-Ahead

	TRC	Participant	RIM	PAC
Benefits	$5,537,911	$2,290,801	$5,537,911	$5,537,911
Costs	$3,822,583	$1,880,265	$4,233,118	$3,822,583
Ratio	1.45	1.22	1.31	1.45

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CBP Day-of

	TRC	Participant	RIM	PAC
Benefits	$1,201,803	$495,725	$1,201,803	$1,201,803
Costs	$955,646	$470,066	$981,304	$955,646
Ratio	1.26	1.05	1.22	1.26

Summer Saver - Residential

	TRC	Participant	RIM	PAC
Benefits	$8,800,731	$7,939,474	$8,800,731	$8,800,731
Costs	$7,691,530	$7,447,428	$8,183,576	$7,691,530
Ratio	1.14	1.07	1.08	1.14

Summer Saver - Non Residential

	TRC	Participant	RIM	PAC
Benefits	$7,237,418	$5,075,654	$7,237,418	$7,237,418
Costs	$4,876,161	$4,696,377	$5,255,437	$4,876,161
Ratio	1.48	1.08	1.38	1.48

BIP

	TRC	Participant	RIM	PAC
Benefits	$2,093,540	$1,305,017	$2,093,540	$2,093,540
Costs	$1,414,437	$1,074,616	$1,644,838	$1,414,437
Ratio	1.48	1.21	1.27	1.48

CPPE

	TRC	Participant	RIM	PAC
Benefits	$900,631	$39,418	$900,631	$900,631
Costs	$321,847	$39,418	$321,847	$282,429
Ratio	2.80	1.00	2.80	3.19

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TA/TI

	TRC	Participant	RIM	PAC
Benefits	$32,146,789	$38,532,210	$32,146,789	$32,146,789
Costs	$19,357,963	$13,816,490	$22,300,478	$19,357,963
Ratio	1.66	2.79	1.44	1.66

TOTAL OF ALL PROGRAMS REQUIRING COST EFFECTIVENESS

	TRC	Participant	RIM	PAC
Benefits	$57,918,822	$55,678,298	$57,918,822	$57,918,822
Costs	$38,440,166	$29,424,661	$42,920,599	$38,400,749
Ratio	1.51	1.89	1.35	1.51

A. 2009-2011 Cost Effectiveness for Total Demand Response Portfolio

The following table summarizes the cost effectiveness for 2009-2011 for all demand response programs. The added programs considered in the total portfolio include Customer Education Awareness and Outreach, Permanent Load Shifting, Measurement and Evaluation and Codes and Standards. All values are present valued to the beginning of 2009.

ALL OTHER PROGRAMS AND EXPENDITURES

	TRC	Participant	RIM	PAC
Benefits	$0	$0	$0	$0
Costs	$15,888,304	$0	$15,888,304	$15,888,304
Ratio	0.00	#DIV/0!	0.00	0.00

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TOTAL PORTFOLIO

	TRC	Participant	RIM	PAC
Benefits	$57,918,822	$55,678,298	$57,918,822	$57,918,822
Costs	$54,328,470	$29,424,661	$58,808,903	$54,289,053
Ratio	1.07	1.89	0.98	1.07

QUALIFICATIONS

My name is Kevin C. McKinley. My business address is 8335 Century Park Court, San Diego, CA, 92123. I am currently employed at San Diego Gas & Electric Company (SDG&E) as the Supervisor of Measurement and Evaluation.

I originally joined SDG&E in 1978 and held a variety of management positions in financial analysis, customer forecasting, fuel planning and marketing. During the 1990s, I was the Manager of Marketing Analysis for SDG&E where my responsibilities included producing a series of regulatory filings for Demand Side Management (DSM) forecasts, DSM earnings claims, and program measurement studies. I was heavily involved in the development of the original Protocols used for measurement and evaluation in California during the 1990s. I was a member and also Chairman of the California Demand Side Management Advisor Committee (CADMAC) during part of this period.

I left SDG&E in late 1998 and consulted in the measurement and evaluation area for the next several years. I rejoined SDG&E in April 2005. My current responsibilities include the Measurement and Evaluation of DSM programs for both SDG&E and Southern California Gas Company for Energy Efficiency, Demand Response, and Low Income programs. I am also a part-time instructor and have taught at several colleges and universities in the San Diego area including San Diego State University, the University of San Diego, University of Redlands and the University of Phoenix. I hold two masters degrees, one in Economics and the other in Latin American studies, both from San Diego State University and a Bachelors degree in Business Administration from Gonzaga University. I have previously testified before this Commission.