Application No: A.11-11-002
Exhibit No.:
Witness: Bruce M. Wetzel

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	A.11-11-002 (Filed November 1, 2011)

UPDATED PREPARED DIRECT TESTIMONY

OF BRUCE M. WETZEL

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 1, 2012

TABLE OF CONTENTS

UPDATED PREPARED DIRECT TESTIMONY

OF BRUCE M. WETZEL

I. QUALIFICATIONS

My name is Bruce M. Wetzel. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. I am employed by Southern California Gas Company (SoCalGas) as a Forecasting Advisor in the Regulatory Affairs Department. I am responsible for the preparation and consolidation of natural gas demand forecasts together with the acquisition and analysis of daily weather data used to prepare gas demand forecasts for San Diego Gas & Electric Company (SDG&E) and SoCalGas. I have been in this position since March 2004. I have previously testified before the California Public Utilities Commission (Commission).

My academic and professional qualifications are as follows: I earned an undergraduate degree in mathematics from Drexel University, a Master of Science in Operations Research from George Washington University and a Ph.D. in Public Policy Analysis from the RAND-Pardee Graduate School for Public Policy Analysis (formerly, the RAND Graduate School). In addition, during the past 29 years, I have held analyst positions in the Regulatory Affairs, Commercial and Industrial Services, and Gas Supply Departments of SoCalGas.

My employment outside of SoCalGas has been in the areas of public policy analysis/research and applied mathematics and operations research at the RAND Corporation in Santa Monica and for the U.S. Department of the Air Force in Washington D.C.

II. PURPOSE

The purpose of my testimony is to present the demand forecast for the noncore market segments other than large electric generation (EG) and cogeneration customers (with capacity greater than 20 megawatts (MW)), whose gas demand forecasts are discussed in the prepared direct testimony of Mr. Huang. My testimony also presents the consolidated gas demand forecasts for Average Year and Cold Year temperature conditions along with peak day and peak month demand forecasts, for the years 2013 through 2015 (TCAP period) for SDG&E's and SoCalGas' markets. My consolidated forecasts rely on the forecasts of core customer demand and exchange gas presented by Ms. Payan.

III. SOCALGAS' NONCORE GAS DEMAND FORECASTS

A. Introduction

SoCalGas' service to noncore markets is split between retail and wholesale service. Retail service consists of transportation and distribution of gas directly for end-use consumption. Wholesale service is provided to municipalities or other investor-owned utilities who re-deliver the gas to their end-use customers. SoCalGas' wholesale customers are the City of Long Beach (Long Beach), SDG&E, the City of Vernon (Vernon), and Southwest Gas Company (SWG).

Noncore retail customers typically represent those with much larger individual loads than are characteristic of core customers. Also, noncore customers are generally business establishments with many employees. SoCalGas' overall outlook for customer growth is summarized in Table 1 below. For the TCAP period, SoCalGas expects steady customer growth overall and stable customer counts in its retail noncore markets.

Table 1

SoCalGas Active Meters (annual averages)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Total Core	5,685,996	5,757,810	5,387,120	5,760,309
Noncore				
Noncore C&I	681	682	682	682
Electric Generation	209	209	209	209
EOR	32	32	32	32
Total Retail Noncore	922	923	923	922
Wholesale and International	5	5	5	5
System Total Active Meters	5,686,923	5,578,373	5,838,048	5,761,236

Noncore customer and meter counts are developed from base year 2010 data and projected forward based on observed trends and known activity and plans of existing customers from discussions with account executives. Customer/meter counts for the electric generation market segments are developed in the manner described by Mr. Huang.

B. SoCalGas' Noncore Customer Segment Demand

1. Commercial

During the TCAP period, noncore commercial demand is forecasted to average nearly 17,032 MDth per year, lower than 2010 Heating-Degree Day (HDD)-adjusted actual usage of 19,204 MDth.[1] The decrease in the HDD-adjusted average year demand for 2013 through year 2015 is the net result of expected modest growth in this market net of decreases from expected implementation of mandated Energy Efficiency and Demand-Side Management (EE/DSM) programs.

[1] The HDD-adjusted value for 2010 is 19,204 MDth and reflects the small, but statistically significant, sensitivity to HDD where calendar year 2010 had about 74 more HDD than our average year design HDD value of 1,375. The observed value for 2010 was 19,313 MDth.

Table 2
Average Year Noncore Commercial Demand Forecast (MDth/yr)

	2013	2014	2015	3 Year Avg. 2013-2015
Noncore Commercial	17,558	17,066	16,471	17,032

2. Industrial

Retail noncore industrial (non-refinery) demand is expected to grow from 48,842 MDth in 2010 to an average of 49,731 MDth during the TCAP period. Growth of this market segment from 2010 through the TCAP period is also mitigated by decreases in demand from expected implementation of mandated EE/DSM programs.

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial demand is forecasted separately from other industrial demand due to the complex nature of these customers. These customers are characterized by a complex interaction of refinery operations, on-site production of alternate fuels, and changing regulatory requirements impacting the production of petroleum products. Refinery industrial demand is forecasted to average 81,595 MDth per year for calendar years 2013 through 2015. This is 4,640 MDth lower than the 86,235 MDth recorded for 2010. This decrease is mainly due to the refineries' use of alternate fuels such as butane during summer months where natural gas prices are forecasted to be less competitive than the alternate fuel prices. The reduction of refinery gas demand also reflects savings from both Commission-mandated EE programs and other refinery process-related energy-efficient improvements that are ineligible for SoCalGas' EE programs. Additionally, implementation of Low Carbon Fuel Standards and greenhouse gas reduction regulation (AB32) are expected to reduce use of natural gas by refineries beginning in 2013.

Table 3

Average Year Noncore Industrial Demand Forecast (MDth/yr)

	2013	2014	2015	3 Year Avg. 2013-2015
Noncore Industrial	49,824	49,937	49,433	49,731
Industrial Refinery	82,530	81,632	80,623	81,595
Total	132,354	131,569	130,056	131,326

3. Electric Power Generation

This sector includes the markets for all industrial/commercial cogeneration, and non-cogeneration EG. Small Industrial/Commercial and refinery cogeneration demand is included in this testimony; the other sectors of electric power generation demand are discussed by Mr. Huang.

(a) Industrial/Commercial Cogeneration <20 MW

Most of the cogeneration units in this noncore segment are installed mainly to generate electricity for customers' internal consumption rather than for power sales to electric utilities or to the California Independent System Operator. In 2010, gas deliveries to this market were 21,077 MDth. Small Industrial/Commercial cogeneration demand is projected to average 19,704 MDth per year during the TCAP period. The reduction in demand is due to the expected increase in the burner-tip price of natural gas relative to retail electricity over the forecast period.

(b) Refinery Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to remain steady at 24,751 MDth for the TCAP period. This is an 18% increase from the year 2010 recorded throughput of 20,901 MDth that reflects our expectation of the addition of cogeneration equipment for this customer segment.

4. Enhanced Oil Recovery-Cogeneration and Steaming

The EOR demand forecast is prepared based on historical throughput, knowledge of customer operations, and general market conditions. For the 2013 to 2015 TCAP period, SoCalGas forecasts EOR–combined for cogeneration and steaming usage—to average 14,977 MDth per year. This is about a 1.6% decrease from the 2010 recorded gas deliveries of 15,215 MDth. SoCalGas expects this market to have fairly stable throughput throughout the TCAP period.

5. ECOGAS (Mexicali)

For this forecast, SoCalGas used the *2010 California Gas Report (CGR)* forecast prepared by ECOGAS of Mexicali. Mexicali's use is expected to increase from 6,469 MDth in 2010 to an average of 6,638 MDth in the 2013-2015 TCAP period.

6. Wholesale

The forecast of wholesale gas demand includes transportation service to SDG&E, Long Beach, SWG, and Vernon.

The non-EG gas demand forecast for SDG&E is made on a customer class basis. Under average temperature conditions, total non-EG requirements for SDG&E are expected to decrease from 55,142 MDth in 2010 to an average of 55,067 MDth for the TCAP period.

The forecast of EG gas demand in SDG&E's service area shows an increase in SDG&E's EG gas requirements from 66,099 MDth in 2010 to an average of 66,582 MDth for the TCAP period. During the TCAP period EG demand is expected to grow about 0.7% per year, from 66,166 MDth in 2013 to 67,037 MDth in 2015.

For Long Beach, the forecast received from Long Beach for the *2010 CGR* was used. SoCalGas' transportation deliveries to Long Beach are forecast at 8,408 MDth per year.

The demand forecast for SWG for SoCalGas deliveries to SWG was based on an updated demand forecast from SWG for its southern California markets. The direct service load to SWG is expected to grow 1.4% per year from 6,628 MDth in 2013 to 6,810 MDth in 2015.

Vernon initiated municipal gas service to its electric power plant in June 2005 and to noncore customers in December 2006. The forecasted annual usage averages 8,060 MDth for the TCAP period. Vernon's commercial and industrial load is based on recorded 2010 usage for commercial and industrial customers already served by Vernon plus those additional customers that are expected to request retail service from Vernon. Results from the power market simulation model (employed by Mr. Huang and described in his testimony) provided the basis for our forecast of Vernon's EG gas demand.

IV. SOCALGAS CONSOLIDATED GAS DEMAND FORECASTS

A. Introduction

For year 2010, SoCalGas' total gas demand, adjusted to Average Year HDD of 1,375 HDD, totaled 964,036 MDth, which is an average of 2,641 MDth/day. In the TCAP period, SoCalGas expects its Average Year gas demand to decline from 2013 through 2015 at about -0.3% annually. The average for the TCAP years is 991,129 MDth, an increase of 2.8% over the 2010 Average Year value.

B. Temperature Assumptions (SoCalGas)

The following section begins with a discussion of temperature assumptions that underlie forecasts for gas demand on the SoCalGas system. The first sub-section discusses two specific cases we use to calculate gas demand under Average Year and Cold Year weather assumptions. The second sub-section describes the temperature design values that we use to forecast peak-day gas demand for temperature-sensitive market segments.

The consolidated gas demand forecasts for SoCalGas under Average Year and Cold Year temperature assumptions are presented in the second part of this section along with consolidated gas demand forecasts for peak day and peak month. These forecasts incorporate the core demand forecasts discussed by Ms. Payan, the electric generation forecast discussed by Mr. Huang and the noncore forecasts presented in Section III above.

Core demand forecasts are prepared for two temperature designs – average and cold – to quantify changes in space heating demand due to weather. Temperature variations can cause significant changes in winter gas demand due to space heating principally in the residential and commercial markets. SoCalGas uses the concept of a HDD[2] to measure the coldness of a month or year as a variable that correlates with the increased natural gas consumption typical in winter months. One HDD is accumulated, daily, for each degree that the daily average temperature is below 65° Fahrenheit. The largest demand increases due to lower temperatures generally occur in the month of December. Historical annual HDD are used to determine specific values of annual HDD to define Average Year and Cold Year temperature conditions. The Average Year HDD value is the simple average of the calendar-year HDD totals for the 20-year period from 1991 through 2010. The Cold Year HDD value is 2.025 standard deviations[3] more than the Average Year HDD total. The Cold Year HDD design temperature conditions are based on a criterion that this particular HDD value would be exceeded with a one-chance-in-35 annual likelihood. Based on the 20-year period 1991 through 2010, a Cold Year HDD value

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[2] For SoCalGas, daily values of system-wide average temperatures are calculated from a six-zone temperature monitoring procedure. From this daily system average temperature data, a corresponding daily value of Heating Degrees (HD) are computed from the following formula: $HD = \max\{0, 65\text{-}T\}$ where T is the daily system average temperature. For each calendar month, the accumulated number of HD are determined from which an annual total is calculated. Accumulated values of HD for a specified number of days (>1) are called Heating-Degree-Days (HDD).
[3] The standard deviation for SoCalGas' annual HDD data for the 20-year period 1991 through 2010 is 138.62 HDD.

corresponds to 1,656 HDD; this contrasts with 1,375 HDD for an Average Year. Assumed monthly HDD values are shown in Table 4.[4]

Table 4
SoCalGas Heating Degree Days Weather Design

Month	Cold Year 1-in-35 design	Average Year 1-in-2 design[5]
January	340	282
February	275	229
March	224	186
April	152	126
May	60	50
June	16	14
July	3	2
August	2	2
September	5	4
October	45	37
November	177	147
December	357	296
	1,656	1,375

C. SoCalGas' Peak Day Temperature Designs

SoCalGas plans and designs its system to provide continuous service to its core (retail and wholesale) customers under an extreme peak day event.[6] The extreme peak day design criteria are defined as a 1-in-35 annual event; this corresponds to a system average temperature of 39.7 degrees Fahrenheit or 25.3 HD on a peak day. Although the gas demand for most of our noncore retail markets is not HDD-sensitive, the noncore commercial segment does exhibit a small, but statistically significant HDD load sensitivity. For such SoCalGas noncore markets, we

[4] The monthly values for Average Year HDD were calculated as the simple average of the respective month's 20 years of observed monthly HDD. The monthly values for the Cold Year HDD were calculated from multiplying a proportion for each calendar month times the Cold Year HDD annual value. The proportion for each calendar month is simply that month's HDD total relative to the annual HDD total based on the Average Year data.
[5] SoCalGas also refers to the Average Year HDD data (monthly or annual) as a "1-in-2" design because the average or expected value has the characteristic that there is a 50% (i.e., 1-in-2) chance of observing a larger value.
[6] The temperature SoCalGas uses to define a peak-day is determined from our analysis of annual minimums of SoCalGas' daily system-average temperatures in order to estimate a probability model for the annual minimum daily temperature. The extreme peak-day temperature value is determined from a calculation using this estimated model such that the chance we would observe a lower value than this extreme peak-day temperature is 1/35 or about 0.0286.

use a less extreme, but more frequent, 1-in-10 annual likelihood peak day temperature of 41.6 degrees Fahrenheit or 23.4 HD.

D. Consolidated Gas Demand for Average Year and Cold Year

Table 5 shows the composition of SoCalGas' throughput forecast for 2013, 2014 and 2015 under Average Year temperature conditions and Table 6 shows demand under Cold Year temperature conditions.[7]

Table 5

Composition of SoCalGas Throughput (MDth/Yr) Average Temperature Year

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	249,118	248,263	247,535	248,305
Core C&I	102,025	101,611	100,318	101,318
Gas AC	60	60	53	58
Gas Engine	1,874	1,766	1,756	1,798
NGV	12,745	13,192	13,636	13,191
Total Core	365,822	364,891	363,297	364,670
Noncore				
Noncore C&I	152,584	151,306	149,198	151,029
EG	307,219	309,073	305,5869	307,2926
EOR	14,977	14,977	14,977	14,977
Total Retail Noncore	474,779	475,356	469,761	473,299
Wholesale and International				
Long Beach	8,407	8,356	8,460	8,408
SDG&E	123,088	123,330	123,594	123,337
SWG	6,628	6,714	6,810	6,717
Vernon	7,807	8,060	8,313	8,060
Mexicali	6,605	6,638	6,671	6,638
Total Wholesale & Intl.	152,536	153,097	153,848	153,160
Average Year Throughput (AYTP)	993,137	993,345	986,906	991,129

[7] Gas demand under Average Year temperature conditions is called Average Year Throughput (AYTP) and gas demand under Cold Year temperature conditions is called Cold Year Throughput (CYTP).

Table 6

Composition of SoCalGas Throughput (MDth/Yr) 1-in-35 Cold Temperature Year

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	272,737	271,801	271,003	271,847
Core C&I	106,921	106,529	105,223	106,224
Gas AC	60	60	53	58
Gas Engine	1,874	1,766	1,756	1,798
NGV	12,745	13,192	13,636	13,191
Total Core	394,337	393,347	391,671	393,119
Noncore				
Noncore	152,999	151,722	149,613	151,445
EG	307,219	309,073	305,586	307,292
EOR	14,977	14,977	14,977	14,977
Total Retail Noncore	475,194	475,771	470,176	473,714
Wholesale and International				
Long Beach	8,861	8,810	8,915	8,862
SDG&E	127,236	127,470	127,725	127,477
SWG	7,098	7,191	7,294	7,194
Vernon	7,807	8,060	8,313	8,060
Mexicali	6,605	6,638	6,671	6,638
Total Wholesale & Intl.	157,606	158,168	158,918	158,231
Cold Year Throughput (CYTP)	1,027,138	1,027,287	1,020,766	1,025,063

E. Consolidated Peak Day Gas Demand

SoCalGas uses the following consolidated peak day gas demand for cost allocation and rate design purposes. Table 7 below shows the peak day gas demand for each year of the TCAP period as well as the 3-year average for that period.

Table 7

SoCalGas' Peak Day Demand (MDth/d)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	2,499	2,490	2,483	2,490
Core C&I	606	607	603	605
Gas AC	0.1	0.1	0.1	0.1
Gas Engine	3	2	2	2
NGV	42	43	45	43
Total Core	3,149	3,142	3,132	3,141
Noncore				
Noncore C&I	421	417	411	416
EG	873	909	944	909
EOR	41	41	41	41
Total Retail Noncore	1,355	1,367	1,396	1,366
Wholesale and International				
Long Beach	62	62	62	62
SDG&E	606	607	565	592
SWG	59	59	60	59
Vernon	29	29	30	29
Mexicali	17	17	17	17
Total Wholesale & Intl.	772	775	735	761
Total Peak Day Demand	5,257	5,284	5,263	5,268

For retail core HDD-sensitive market segments, peak-day demand was calculated using the applicable 1-in-35 peak-day temperature condition for SoCalGas or SDG&E. For the SoCalGas retail noncore HDD-sensitive market segment, peak-day demand was calculated under a 1-in-10 peak-day temperature condition. For the SoCalGas and SDG&E electric generation facilities included in Mr. Huang's testimony, power market simulation model, peak-day demand was calculated as a coincident peak day for all these facilities. For all other market segments, peak-day load was calculated as average daily December month's demand.

F. Consolidated Peak Month Gas Demand

SoCalGas uses gas demand for the month of December as the peak month, for cost allocation and rate design purposes. Consolidated forecasts of peak month gas demand are shown below in Table 8 for each year of the TCAP period as well as the 3-year average for that period.

Table 8

SoCalGas' Peak Month Demand (MDth/Mo)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	41,332	41,190	41,070	41,197
Core C&I	12,092	12,076	11,962	12,043
Gas AC	4	4	3	4
Gas Engine	89	63	63	72
NGV	1,293	1,338	1,383	1,338
Total Core	54,811	54,671	54,481	54,654
Noncore				
Noncore C&I	12,501	12,383	12,200	12,361
EG	23,078	23,375	23,162	23,205
EOR	1,272	1,272	1,272	1,272
Total Retail Noncore	36,850	37,030	36,634	36,838
Wholesale and International				
Long Beach	1,028	1,023	1,034	1,029
SDG&E	13,849	13,997	13,992	13,946
SWG	1,102	1,119	1,135	1,119
Vernon	889	910	932	910
Mexicali	529	531	534	531
Total Wholesale & Intl.	17,397	17,581	17,627	17,535
Total Peak Month Demand	109,058	109,282	108,741	109,027

For HDD-sensitive market segments, December HDD for cold year temperature designs were used to calculate gas demand.

V. SDG&E'S NONCORE GAS DEMAND FORECASTS

A. SDG&E's Noncore Gas Demand

This forecast presents noncore customer gas demand for SDG&E, with the exception of gas requirements for non-cogeneration EG demand discussed by Mr. Huang. Gas demand forecasts for commercial & industrial and cogeneration are derived by trending recorded data for 2010 based on expected annual growth in employment for these market segments. The data in

Table 9 below shows SDG&E's noncore throughput each year for the TCAP period as well as the 3-year average.

Table 9
Composition of SDG&E Noncore Throughput (MDth/Yr)

	2013	2014	2015	3-Year Avg. 2013-2015
NonCore				
Noncore C&I	4,828	4,870	4,892	4,863
Electric Generation	66,166	66,543	67,037	66,582
Total Retail Noncore	70,994	71,414	71,929	71,445

1. Noncore Commercial and Industrial

SDG&E's noncore commercial and industrial demand is expected to grow about 0.7% per year in the TCAP period, from 4,828 MDth in 2013 to 4,892 MDth by 2015. Noncore commercial and industrial load was 4,472 MDth for 2010.

2. Electric Power Generation

Cogeneration gas demand is included in this testimony; the other sources of electric power generation demand (power plant facilities) are discussed in the testimony of Mr. Huang. SDG&E's cogeneration load was 17,480 MDth in 2010. Cogeneration load is expected to grow 1.7% per year in the TCAP period, from 19,049 in 2013 to 19,701 MDth by 2015.

VI. SDG&E CONSOLIDATED GAS DEMAND FORECASTS

A. Introduction

SDG&E's total throughput (gas sales and transportation), adjusted to Average Year HDD of 1,315 HDD, totaled 120,241 MDth for year 2010, an average of 329 MDth/day. In the 2013 to 2015 TCAP years, SDG&E expects Average Year throughput to grow at about +0.2% annually from 2013 through 2015. Total Average Year throughput for the TCAP years is 121,649 MDth, an increase of 1.2% over the 2010 value.

SDG&E's noncore customer count is expected to be stable while core customers are expected to increase, as explained by Ms. Payan, over the three-year TCAP period.

Table 10

SDG&E Meters (Annual Averages)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Total Core	869,227	880,386	892,785	880,799
Noncore				
Noncore C&I	63	63	63	63
EG	65	66	67	66
Total Retail Noncore	128	129	130	129
System Total Meters	869,355	880,515	892,915	880,928

B. Temperature Assumptions (SDG&E)

The following section begins with a discussion of temperature assumptions for the SDG&E system. Similar to the discussion for SoCalGas, the first sub-section explains Average Year and Cold Year weather assumptions. The second sub-section describes the temperature design values that we use to forecast peak-day gas demand for temperature-sensitive market segments in SDG&E's service area.

The section ends with a discussion of the consolidated gas demand forecasts (annual demand forecasts under Average and Cold Year temperature conditions, peak day demand and peak month demand) for SDG&E. These forecasts incorporate the core demand forecast presented by Ms. Payan, the EG forecast provided by Mr. Huang, and the noncore demand forecast provided in Section V above.

As with SoCalGas, core demand forecasts for SDG&E are prepared for two temperature designs – Average and Cold – to quantify changes in space heating demand due to weather. The largest demand variations due to temperature generally occur in the month of December. HDD for SDG&E are defined similarly as for SoCalGas, but use a daily system-average temperature calculated from a weighted-average of three weather station locations in SDG&E's service territory. The Average Year total is the simple average of the annual (calendar year) HDD totals for the 20-year period from 1991 through 2010 and yields a value of 1,315 HDD. The Cold Year HDD total is based on a criterion that this particular HDD value would be exceeded with a one-chance-in-35 annual likelihood and corresponds to a value of 1,673 HDD. The cold year HDD value is approximately 2.025 standard deviations[8] *more* than the average year HDD value. Assumed monthly[9] HDD values are shown in Table 11.

Table 11
SDG&E Heating Degree Days Weather Design

	Cold Year	Average Year
Month	**1-in-35 design**	**1-in-2 design**
January	333	262
February	278	219
March	245	192
April	165	130
May	72	57
June	17	14
July	1	1
August	0	0
September	2	1
October	36	28
November	171	134
December	353	278
	1,673	1,315

[8] The standard deviation for SDG&E's annual HDD data for the 20-year period 1991 through 2010 is 176.94 HDD.
[9] The monthly values for Average Year HDD were calculated as the simple average of the respective month's 20 years of observed monthly HDD. The monthly values for the Cold Year HDD were calculated from multiplying a proportion for each calendar month times the Cold Year HDD annual value. The proportion for each calendar month is simply that month's HDD total relative to the annual HDD total based on the Average Year data.

C. SDG&E's Peak Day Temperature Designs

SDG&E plans and designs its system to provide continuous service to its core customers under an extreme peak day event.[10] The extreme peak day design criteria are defined as a 1-in-35 annual event; this corresponds to a system average temperature of 42.5 degrees Fahrenheit or 22.5 HD on a peak day.

D. Consolidated Gas Demand for Average Year and Cold Year

Tables 12 and 13 show details of SDG&E's forecasted annual gas demand under Average-Year and 1-in-35 Cold-Year temperature conditions.

Table 12

Composition of SDG&E Throughput (MDth/Yr) Average Temperature Year

		2013	2014	2015	3-Year Avg. 2013-2015
Core					
	Residential	30,740	30,775	30,837	30,784
	Core C&I	18,544	18,292	17,942	18,259
	NGV	1,127	1,160	1,195	1,161
	Total Core	50,410	50,228	49,974	50,204
Noncore					
	Noncore C&I	4,828	4,870	4,892	4,863
	Electric Generation	66,166	66,543	67,037	66,582
	Total Retail Noncore	70,994	71,414	71,929	71,445
Average Year Throughput (AYTP)		121,404	121,642	121,903	121,649

[10] The temperature SDG&E uses to define a peak-day is determined from our analysis of annual minimums of SDG&E's daily system-average temperatures in order to estimate a probability model for the annual minimum daily temperature. The extreme peak-day temperature value is determined from a calculation using this estimated model such that the chance we would observe a lower value than this extreme peak-day temperature is 1/35 or about 0.0286.

Table 13
Composition of SDG&E Throughput (MDth/Yr) 1-in-35 Cold Year Temperature

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	34,008	34,047	34,115	34,057
Core C&I	19,367	19,104	18,739	19,070
NGV	1,127	1,160	1,195	1,161
Total Core	54,501	54,312	54,049	54,287
Noncore				
Noncore C&I	4,828	4,870	4,892	4,863
EG	66,166	66,543	67,037	66,582
Total Retail Noncore	70,994	71,414	71,929	71,445
Cold Year Throughput (CYTP)	125,495	125,725	125,977	125,732

E. Consolidated Peak Day Gas Demand

SDG&E uses the following consolidated peak day gas demand for cost allocation and rate design purposes. Table 14 below shows the peak day gas demand.

Table 14
SDG&E's Peak Day Demand (MDth/d)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	280	280	281	280
Core C&I	90	88	87	88
NGV	3	3	3	3
Total Core	373	372	371	372
Noncore				
Noncore C&I	13	13	13	13
Electric Generation	211	213	173	199
Total Retail Noncore	225	227	187	213
Total Peak Day Demand	597	598	557	584

For SDG&E's HDD-sensitive core market segments, peak-day demand was calculated under a 1-in-35 peak-day temperature condition. For the SDG&E (and SoCalGas) electric generation facilities included in Mr. Huang's power market simulation model, peak-day demand was calculated as a coincident peak day for all these facilities. For all other market segments, peak-day load was calculated as average daily December month's demand.

F. Consolidated Peak Month Gas Demand

SDG&E uses gas demand for the month of December as the peak month, for cost allocation and rate design purposes. Consolidated forecasts of peak month gas demand are shown in Table 15 below.

Table 15
SDG&E's Peak Month Demand (MDth/Mo)

	2013	2014	2015	3-Year Avg. 2013-2015
Core				
Residential	5,089	5,095	5,105	5,097
Core C&I	2,077	2,048	2,009	2,045
NGV	100	103	106	103
Total Core	7,266	7,246	7,220	7,244
Noncore				
Noncore C&I	410	413	414	412
EG	5,983	6,147	6,166	6,099
Total Retail Noncore	6,393	6,560	6,580	6,511
Total Peak Month Demand	13,659	13,806	13,800	13,755

For HDD-sensitive market segments, December HDD for SDG&E's cold year temperature design was used to calculate gas demand.

This concludes my updated prepared direct testimony.