2008 California Gas Report

Prepared by the California Gas and Electric Utilities




2008 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

Southern California Gas Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company
Southwest Gas Corporation
City of Long Beach Gas & Oil Department
Southern California Edison Company

TABLE OF CONTENTS

LIST OF CHARTS AND TABLES

Page No.

SAN DIEGO GAS AND ELECTRIC

2008 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2008 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2030. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision D.95-01-039. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides detail on requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Wild Goose Storage, Inc. and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, and San Diego Gas and Electric Company.

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements (demand) by customer class. Separate sets of these tables are presented for average and cold year temperature conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee, comprised of the representatives from each utility was responsible for compiling the report. The membership of this Committee is listed in the Respondents section at the end of this report.

Workpapers and next year's report are available upon request from PG&E and SoCalGas/SDG&E. Write, fax or email us at the addresses shown in the Reserve Your Subscription at the end of this report.

2008 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

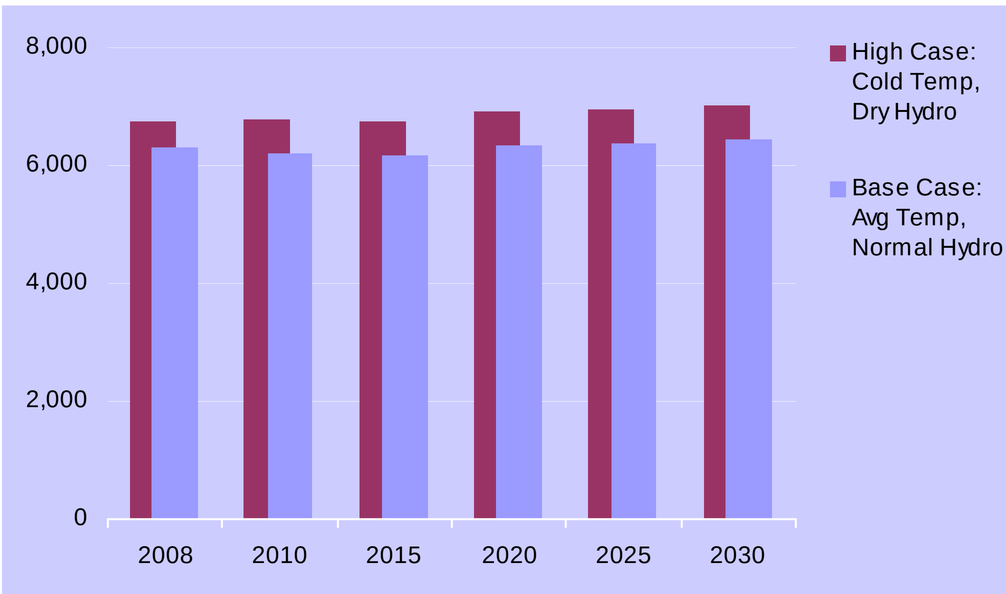
DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to grow at a modest rate of just 0.1 percent per year from 2008 to 2030. Forecast growth is a combination of moderate growth in the residential market, tempered by no growth in gas demand for electric generation and declining demand in the commercial and industrial markets.

Residential gas demand is expected to increase at an annual average rate of 0.3 percent, half the rate that was projected in the *2006 California Gas Report*. Demand in the commercial market is expected to remain unchanged; whereas demand in the industrial sector is estimated to decline by 1.0 percent annually as California continues its transition from a manufacturing-based to a service-based economy. Aggressive energy efficiency programs are expected to make a significant impact in managing growth in the residential, commercial and industrial markets.

For the purpose of load following and backstopping intermittent renewable resource generation, gas-fired generation will continue to be the technology of choice to meet the ever-growing demand for electric power. However, overall gas demand for electric generation is expected to be virtually flat for the next 22 years due to statewide efforts to minimize Greenhouse Gas emissions through aggressive programs pursuing demand side reductions and the acquisition of preferred resources that produced little or no carbon emissions.

California Demand Forecast (MMcf/Day)



The graph on the preceding page summarizes statewide demand under a base case scenario and a high case scenario. The base case refers to expected gas demand for an average temperature year and normal hydroelectric power (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under an average temperature condition and a normal hydro year, gas demand for the state is projected to average 6,291 MMcf/d in 2008 increasing to 6,428 MMcf/d by 2030, a cumulative growth of just 2 percent in 22 years.

Northern California is projected to require an additional 14% of gas supply to meet demand for the high gas demand scenario; whereas Southern California is projected to require an additional 7% of supply to meet the demand under the high scenario condition. This spread between the regions is to be expected since northern California is colder and tends to rely more heavily on hydroelectric power than Southern California. The weather scenario for each year is independent and has the same likelihood of occurring. The annual demand forecast for the base case and high case should therefore not be viewed as a combined event from year to year.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency (CEE) and other Demand-Side Management (DSM) programs in their utility electric and gas resource plans. The 2000-2001 "energy crisis" in California was not limited to electricity, with gas prices at the southern California border reaching levels nearly ten times greater than experienced in its previous history. California utilities are committed to helping their customers make the best possible choices regarding use of this increasingly valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for electric energy efficiency programs and renewable power. The base case forecasts in this report assume that the state will have 20% of its energy needs met with renewable power by 2012, then additional renewable power is added to maintain the 20% level. The state is currently considering setting higher renewable power goals which could further reduce the gas demand from what is included in this forecast.

The state's recently passed greenhouse gas (GHG) reduction law, AB 32, has set aggressive targets for the state to meet to reduce its overall GHG production. This law creates substantial uncertainty in the amount of natural gas that will be used in the outer years of the forecast. There is a high degree of uncertainty regarding what impact will occur in each sector as a result of the implementation of measures to meet the GHG reduction goals.

The table on the following page approximates total gas savings based on the impact of renewables, electric and gas energy efficiency goals on CPUC-jurisdictional utilities. Gas savings from electric energy efficiency goals are based on a generic assumption of heat rate per megawatt hour of electricity produced at gas-fired peaking and combined-cycle power plants.

Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand

	2008	2010	2015	2020	2025	2030
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) [1]						
Electricity Demand (GWh)	196,560	201,673	216,287	229,812	238,505	253,071
20% Reneweables by 2012						
Renewable Electric Generation (GWh/Yr) [2]	26,755	33,792	43,257	45,962	47,701	50,614
Increase over 2005 Level (GWh/Yr) [3]	4,355	11,391	20,857	23,562	25,301	28,214
Gas Savings over 2005 Level (Bcf/Yr)	26	69	127	143	154	171
Electric Energy Efficieny Goals [5]						
Electricity Savings over 2005 Level (GWh/Yr)	8,649	13,652	24,765	26,105	26,309	26,309
Gas Savings over 2005 Level (Bcf/Yr) [4]	52	83	150	158	160	160
Energy Efficiency Goal for Natural Gas Programs [5]						
Gas Savings over 2005 Level (Bcf/Yr)	13	23	53	74	81	82
Total Gas Savings (Bcf/Yr) [6]	92	175	330	375	394	413

Note:

(1) Electricity demand based on the California Energy Commission November 2007 forecast for the Long-Term Procurement Plan (LTTP), net DSM savings goals. California Energy Demand 2008 - 2018: Staff Revised Forecast, FINAL Staff Forecast, 2nd Edition, publication # CEC-200-2007-015-SF2. 11/27/07. Forecast to 2030 was extended by CEC staff.

(2) Renewables goal from 2008 to 2011 is the sum of actual renewables in 2007 of 23,807 GWh from PG&E, SCE and SDG&E's RPS compliance filing dated 04/30/2008 plus prorated volume of annual growth to meet 20% target by 2012. This goal differs from the individual utilities' renewables forecasts, which are based on more complex modeling assumptions. Renewable electric generation, as defined for the purpose of the 20% goal, excludes generation from large hydroelectric plants.

(3) Increase reflects only impacts of equipment installed after 12/31/2005.

(4) Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year (24 * 365), and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approx. 10,000 CF) of natural gas. Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approx. 7000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,760 hours * 10% * 10 MMBtu, plus 8,760 hours * 75% * 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators.

(5) Electricity and natural gas savings goals per CPUC Decision, D.04-09-060, September 23, 2004. Tables 1A, 1B and 1C.

(6) Total gas savings are **annual** savings from equipment installed after 12/31/2005.

NATURAL GAS PROJECTS: PROPOSALS, COMPLETIONS, AND LIQUEFIED NATURAL GAS

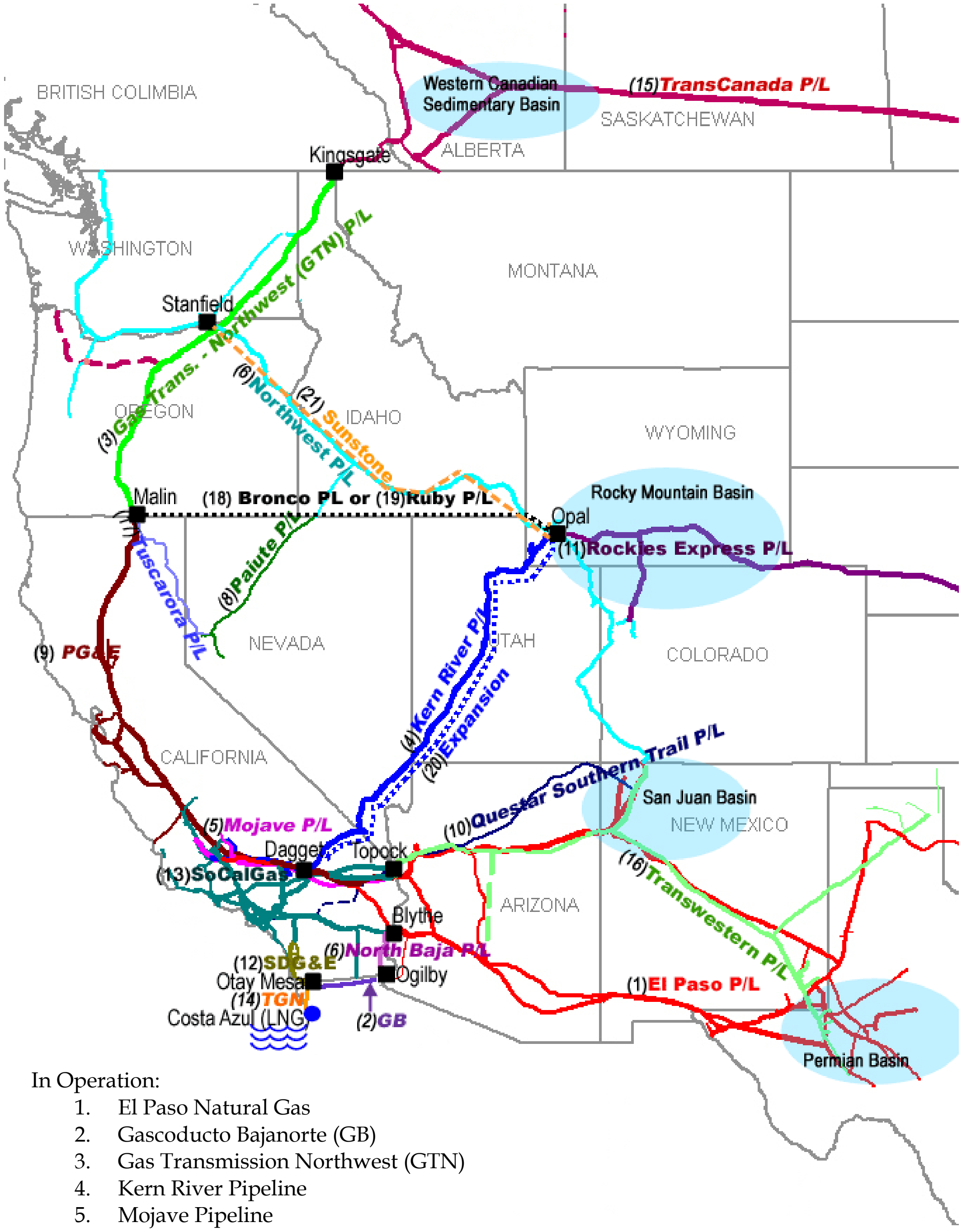
Over the past three years, California natural gas utilities, interstate pipelines, and instate natural gas storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California Energy Commission (Energy Commission) posts a list of natural gas projects on their website, which tracks both completed projects and ones that are being developed or in the proposal stage, along with proposed liquefied natural gas (LNG) projects. To review these project lists check the Energy Commission's website at http://www.energy.ca.gov/naturalgas/.

Supply Outlook/Pipeline Capacity

California's existing gas supply portfolio is regionally diverse and includes supplies from California sources (onshore and offshore), Southwestern U.S. supply sources (the Permian, Anadarko, and San Juan Basins), the Rocky Mountains, and Canada. In addition, in May 2008 the Energia Costa Azul LNG (Liquefied Natural Gas) receiving terminal in Baja California was certified, providing another source of supply for California. This project will have the capability of regasifying 1 Bcf/d of LNG. The amount of supply delivered through that project will be based on a host of factors, including world supply availability in the Pacific basin. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

Additional pipeline capacity and open access have contributed to long-term supply availability and gas-on-gas competition for the California market. Interstate pipelines currently serving California include El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission-Northwest, Transwestern Pipeline Company, Questar Southern Trails Pipeline, Tuscarora Pipeline and the Bajanorte/North Baja Pipeline.

Western North American Natural Gas Pipelines



In Operation:

1. El Paso Natural Gas
2. Gascoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed:

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline

Liquefied Natural Gas (LNG)

In the *2006 California Gas Report*, SoCalGas anticipated that re-gasified LNG-based gas will be a significant new source of gas supplies in the U.S. by 2008. Project delays have pushed back that development, and California has not yet seen any significant LNG supplies, but with the completion of the Costa Azul LNG terminal in Baja California, Mexico in May 2008, LNG is likely to still increase significantly as a supplier source to California in the years ahead.

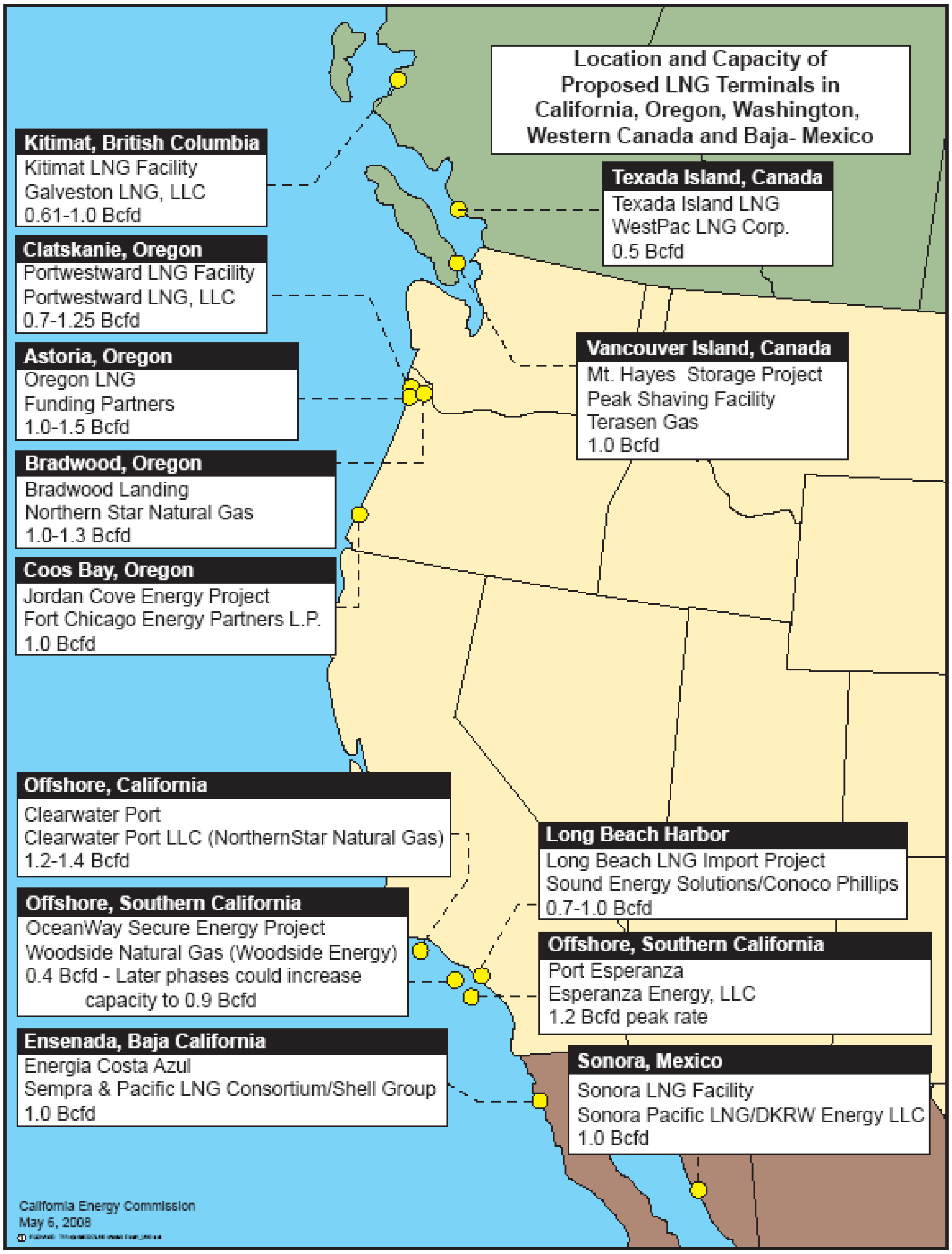
The 1,000 MMcf/d Energia Costa Azul LNG Terminal located in Baja California, Mexico received its first cargo on April 18, 2008 followed by a second cargo on May 6, 2008. These initial cargos were used to complete performance testing of the new terminal and on May 15, 2008, the Costa Azul terminal declared itself ready for commercial operations. Costa Azul will provide the potential for LNG derived natural gas supplies to be delivered to the SoCalGas system. There remains some uncertainty about the volume of LNG supplies that will be delivered to California from the Costa Azul terminal in the coming years, but it is likely that these supplies will begin to play a more significant role in serving demand in the Southern California area. The Costa Azul terminal also has the potential to expand its capabilities to 2,500 MMcf/d in the future.

In addition to the Costa Azul terminal in Mexico, a few other LNG terminal projects have been proposed on the West Coast that could ultimately result in additional LNG derived supplies being delivered to California. In particular there are two proposed projects in the Southern California area; 1) the Clearwater Port project off the coast of Oxnard; and 2) the Ocean Way Secure Energy Project off the coast of Los Angeles. Each of these projects is in the environmental review process and has not begun construction. Additionally, the Jordan Cove LNG project in Coos Bay, Oregon would bring supplies directed to Malin, which would provide benefits to the state without the need for additional infrastructure in California. One additional project, also off the coast of Long Beach, has been proposed by Esperanza Energy, but they have yet to file a formal application with state and federal agencies. It is too early at this point to estimate expected supplies that would be available from these facilities or when they may be available, however, it is possible that one or more of these projects could be on-line during the forecast period present in the California Gas Report.

Attached is a map from the California Energy Commission highlighting all of the proposed LNG projects on the West Coast[1]. At this point, aside from the Energia Costa Azul facility, each of these projects is still awaiting necessary government approvals and has not begun construction. Additional information on these projects is available at www.energy.ca.gov/naturalgas/.

[1] The attached map from the CEC still identifies the Long Beach LNG Import Facility as a potential project, but as of June 7, 2008, the project applicants had withdrawn their application with the FERC.

Proposed West Coast LNG Terminals



STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of projected gas supplies and gas requirements (demand) from 2008 to 2030 for average temperature and normal hydro years and cold temperature and dry hydro years.

Gas sales and transportation volumes are consolidated under the general category of system gas requirements. Details of gas transportation for individual utilities are given in the tabular data for northern California and Southern California. The wholesale category includes the City of Long Beach Gas and Oil Department, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Vernon, Alpine Natural Gas, Island Energy, West Coast Gas, Inc, and the municipalities of Coalinga and Palo Alto.

Some columns may not sum precisely, because of modeling accuracy and rounding differences, and do not imply curtailments.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Average Temperature and Normal Hydro Year
MMcf/Day

	2008	2010	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	468	468	468	468	468	468
Out-of-State	4,515	4,458	4,378	4,510	4,500	4,534
Utility Total	4,983	4,926	4,846	4,978	4,968	5,002
Non-Utility Served Load (1)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Supply Sources Total	**6,454**	**6,363**	**6,299**	**6,457**	**6,465**	**6,518**
California's Requirements						
Utility						
Residential	1,213	1,232	1,250	1,255	1,269	1,284
Commercial	504	508	506	493	492	496
Natural Gas Vehicles	30	37	54	75	103	132
Industrial	861	826	800	757	721	689
Electric Generation (2)	1,873	1,826	1,768	1,924	1,929	1,932
Enhanced Oil Recovery Steaming	35	28	28	29	28	28
Wholesale/International+Exchange	227	231	237	243	254	264
Company Use and Unaccounted-for	76	75	78	78	82	87
Utility Total	4,820	4,763	4,721	4,853	4,878	4,912
Non-Utility						
Enhanced Oil Recovery Steaming	781	784	785	787	797	807
EOR Cogeneration/Industrial	164	164	163	166	168	170
Electric Generation	525	490	506	526	533	540
Non-Utility Served Load (1)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Requirements Total (3)	**6,291**	**6,200**	**6,174**	**6,332**	**6,375**	**6,428**

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

(2) Includes utility generation, wholesale generation, and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
Average Temperature and Normal Hydro Year
MMcf/Day

Utility	**2008**	**2010**	**2015**	**2020**	**2025**	**2030**
Northern California						
California Sources (1)	158	158	158	158	158	158
Out-of-State	2,131	2,172	2,064	2,181	2,144	2,135
Northern California Total	2,289	2,330	2,222	2,339	2,302	2,293
Southern California						
California Sources (2)	310	310	310	310	310	310
Out-of-State	2,384	2,286	2,314	2,329	2,355	2,399
Southern California Total	2,694	2,596	2,624	2,639	2,665	2,709
Utility Total	4,983	4,926	4,846	4,978	4,968	5,002
Non-Utility Served Load (3)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Supply Sources Total	**6,454**	**6,363**	**6,299**	**6,457**	**6,465**	**6,518**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Average Temperature and Normal Hydro Year
MMcf/Day

	2008	2010	2015	2020	2025	2030
Utility						
Northern California						
Residential	552	577	596	613	625	630
Commercial - Core	233	236	239	238	238	238
Natural Gas Vehicles - Core	4	4	5	8	13	18
Natural Gas Vehicles - Noncore	1	1	2	3	4	6
Industrial - Noncore	468	449	432	411	388	362
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	122	118	122	122	122	122
Electric Generation (2)	696	730	647	765	765	765
Exchange (CA and Southwest Gas)	1	1	1	1	1	1
Company Use and Unaccounted-for	39	40	42	42	46	50
Northern California Total (3)	2,126	2,167	2,097	2,214	2,212	2,203
Southern California						
Residential	661	655	654	642	644	654
Commercial - Core	217	217	212	202	200	204
Commercial - Noncore	54	55	55	53	53	54
Natural Gas Vehicles - Core	25	32	47	64	86	108
Industrial - Core	59	57	56	53	50	49
Industrial - Noncore	334	320	311	293	283	278
Wholesale	216	220	226	232	243	253
SDG&E+Vernon Electric Generation	200	214	217	225	227	229
Electric Generation (4)	854	763	782	811	815	816
Enhanced Oil Recovery - Steaming	35	28	28	29	28	28
Company Use and Unaccounted-for	37	35	36	36	36	37
Southern California Total	2,694	2,596	2,624	2,639	2,665	2,709
Utility Total	4,820	4,763	4,721	4,853	4,878	4,912
Non-Utility Served Load (5)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Gas Requirements Total (6)	**6,291**	**6,200**	**6,174**	**6,332**	**6,375**	**6,428**

Notes:
(1) Includes transportation gas.
(2) Northern Calfornia Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants. Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(6) Does not include off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Cold Temperature and Dry Hydro Year
MMcf/Day

	2008	2010	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	468	468	468	468	468	468
Out-of-State	4,870	4,944	4,856	4,997	4,990	5,026
Utility Total	5,338	5,412	5,324	5,465	5,458	5,494
Non-Utility Served Load (1)	1,569	1,535	1,548	1,578	1,598	1,618
Statewide Supply Sources Total	**6,907**	**6,947**	**6,873**	**7,043**	**7,056**	**7,111**
California's Requirements						
Utility						
Residential	1,286	1,348	1,367	1,374	1,389	1,405
Commercial	525	540	538	525	523	528
Natural Gas Vehicles	30	37	54	75	103	132
Industrial	863	827	801	758	722	690
Electric Generation (2)	2,116	2,138	2,071	2,235	2,241	2,243
Enhanced Oil Recovery Steaming	35	28	28	29	28	28
Wholesale/International+Exchange	242	247	253	259	271	282
Company Use and Unaccounted-for	78	83	86	86	91	95
Utility Total	5,175	5,249	5,199	5,340	5,368	5,404
Non-Utility						
Enhanced Oil Recovery Steaming	781	784	785	787	797	807
EOR Cogeneration/Industrial	164	164	163	166	168	170
Electric Generation	624	587	600	625	633	641
Non-Utility Served Load (1)	1,569	1,535	1,548	1,578	1,598	1,618
Statewide Requirements Total (3)	**6,744**	**6,784**	**6,748**	**6,918**	**6,966**	**7,021**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
Cold Temperature and Dry Hydro Year
MMcf/Day

Utility	**2008**	**2010**	**2015**	**2020**	**2025**	**2030**
Northern California						
California Sources (1)	158	158	158	158	158	158
Out-of-State	2,391	2,463	2,370	2,495	2,459	2,450
Northern California Total	2,549	2,621	2,528	2,653	2,617	2,608
Southern California						
California Sources (2)	310	310	310	310	310	310
Out-of-State	2,478	2,481	2,486	2,503	2,531	2,576
Southern California Total	2,788	2,791	2,796	2,813	2,841	2,886
Utility Total	5,338	5,412	5,324	5,465	5,458	5,494
Non-Utility Served Load (3)	1,569	1,535	1,548	1,578	1,598	1,618
Statewide Supply Sources Total	**6,907**	**6,947**	**6,873**	**7,043**	**7,056**	**7,111**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Cold Temperature and Dry Hydro Year
MMcf/Day

	2008	2010	2015	2020	2025	2030
Utility						
Northern California						
Residential	561	630	651	670	683	688
Commercial - Core	240	255	259	257	257	258
Natural Gas Vehicles - Core	4	4	5	8	13	18
Natural Gas Vehicles - Noncore	1	1	2	3	4	6
Industrial - Noncore	468	449	432	411	388	362
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	122	118	122	122	122	122
Electric Generation (2)	939	944	873	997	997	997
Exchange (CA and Southwest Gas)	1	1	1	1	1	1
Company Use and Unaccounted-for	40	45	48	48	52	56
Northern California Total	2,386	2,458	2,403	2,528	2,527	2,518
Southern California						
Residential	725	718	717	704	706	717
Commercial - Core	229	229	224	212	211	215
Commercial - Noncore	56	56	56	55	55	56
Natural Gas Vehicles - Core	25	32	47	64	86	108
Industrial - Core	60	58	57	54	51	50
Industrial - Noncore	334	320	311	293	283	278
Wholesale	231	236	242	248	260	271
SDG&E+Vernon Electric Generation	200	230	232	241	243	245
Electric Generation (3)	854	846	843	875	879	880
Enhanced Oil Recovery Steaming	35	28	28	29	28	28
Company Use and Unaccounted-for	38	38	38	38	39	39
Southern California Total	2,788	2,791	2,796	2,813	2,841	2,886
Utility Total	5,175	5,249	5,199	5,340	5,368	5,404
Non-Utility Served Load (4)	1,569	1,535	1,548	1,578	1,598	1,618
Statewide Gas Requirements Total (5)	**6,744**	**6,784**	**6,748**	**6,918**	**6,966**	**7,021**

Notes:
(1) Includes transportation gas.
(2) Northern California Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(4) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants. Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(5) Does not include off-system deliveries.

STATEWIDE RECORDED SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary is intended to complement the existing five-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows, by customer class, the composition of supplies from both out-of-state and California sources and is based on the utilities' accounting records and on available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciling adjustments. In addition, some of the data are based on allocations and assignments that, by necessity, rely on estimated information. These tables have been updated to reflect the most current information.

Some columns may not sum exactly, because of factored allocation and rounding differences, and do not imply curtailments.

Recorded 2003 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	57	575	245	23	26	5	6	938
Noncore Commercial/Industrial	63	68	64	53	139	14	11	411
EG (3)	121	130	122	101	267	27	21	789
EOR	7	7	6	5	14	1	1	42
Wholesale/Resale/International (4)	58	197	66	55	37	13	(49)	377
Total	306	976	503	238	483	61	(11)	2,557
Pacific Gas and Electric Company (5)								
Core	-	146	9	569	9	-	-	733
Noncore Commercial/Industrial/EG/Resale (3)	155	305	78	595	157	-	64	1,354
Total	155	451	87	1,164	166	-	64	2,087
Other Northern California								
Core (5)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (6)								
Direct Sales/Bypass	451	-	-	-	600	86	-	1,137
TOTAL SUPPLIER	912	1,427	590	1,402	1,249	147	64	5,791

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	3	43	14	49	12	0	13	135
Noncore Commercial/Industrial	0	136	45	1	0	0	0	183
Total	3	179	60	50	12	0	13	317

(5) Includes Southwest Gas Corp., Avista and Tuscarora data.

(6) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2004 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	71	599	226	45	43	-	8	994
Noncore Commercial/Industrial	56	63	54	91	142	10	0	416
EG (3)	105	118	101	171	266	19	1	781
EOR	5	5	5	8	12	1	0	35
Wholesale/Resale/International (4)	57	158	134	52	48	10	(33)	427
Total	294	943	520	367	511	40	(23)	2,653
Pacific Gas and Electric Company (5)								
Core	-	158	65	578	18	-	-	819
Noncore Industrial/Wholesale/EG (3)	104	294	22	609	252	-	-	1,281
Total	104	452	87	1,187	270	-	-	2,100
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load								
Direct Sales/Bypass	475	-	-	-	757	91	-	1,323
TOTAL SUPPLIER	873	1,395	607	1,554	1,538	131	(12)	6,087

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	5	29	25	47	-	-	44	150
Noncore Commercial/Industrial	0	114	97	1	-	-	1	213
Total	5	144	122	47	-	-	45	363

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.

(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data

(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2005 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	60	600	208	18	106	-	(16)	976
Noncore Commercial/Industrial	56	43	59	52	172	7	16	404
EG (3)	94	71	99	87	287	11	26	676
EOR	5	4	5	4	14	1	1	34
Wholesale/Resale/International (4)	55	161	107	52	48	7	(35)	393
Total	270	878	478	213	627	25	(8)	2,483
Pacific Gas and Electric Company (5)								
Core	-	193	52	535	11	-	-	791
Noncore Industrial/Wholesale/EG (3)	117	306	55	592	151	-	-	1,221
Total	117	499	107	1,127	162	-	-	2,012
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (7)								
Direct Sales/Bypass	474	-	-	-	675	108	-	1,257
TOTAL SUPPLIER	861	1,377	585	1,340	1,464	133	3	5,763

Notes:
(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.
(2) Includes NGV volumes, unaccouted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	42	28	46	1	-	26	149
Noncore Commercial/Industrial	0	104	69	1	-	-	-	174
Total	6	146	97	47	1	-	26	323

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.
(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2006 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN / PG&E	Kern River	Mojave (9)	Other (1)	Total
Southern California Gas Company								
Core (2)	7	704	182	13	92	10	20	1,029
Noncore Commercial/Industrial	77	75	63	34	155	4	2	410
EG (3)	145	140	119	63	291	7	4	769
EOR	7	7	6	3	15	0	0	39
Wholesale/Resale/International (4)	7	227	88	43	18	3	8	394
Total	243	1,154	458	157	571	24	34	2,641
Pacific Gas and Electric Company (5)								
Core	0	202	60	571	5	0	0	838
Noncore Industrial/Wholesale/EG (6)	136	295	62	643	26	0	55	1,217
Total	136	497	122	1,214	31	0	55	2,055
Other Northern California								
Core (7)	0	0	0	0	0	0	12	12
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	469	21	0	0	820	23	0	1,333
TOTAL SUPPLIER	848	1,672	580	1,371	1,422	47	101	6,041

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes, unaccounted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN / PG&E	Kern River	Mojave (9)	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	53	21	36	15	2	7	139
Noncore Commercial/Industrial	0	136	53	0	0	0	0	189
Total	6	189	73	36	15	2	7	328

Includes new procedure to allocate SDG&E volumes in 2006.

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) Because many of Mojave's transport contracts expired in 2006, the pipeline's emphasis is now to transport natural gas from Daggett to Ehrenberg via El Paso's line 1903. As a result, its gas deliveries to points inside California have declined from previous years.

Recorded 2007 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
Southern California Gas Company								
Core (2)	-4	746	220	8	44	1	3	1,018
Noncore Commercial/Industrial	71	56	77	42	146	3	9	405
EG (3)	150	118	161	89	306	7	19	849
EOR	7	5	7	4	14	0	1	39
Wholesale/Resale/International (4)	8	183	149	33	19	1	13	406
Total	232	1,108	615	176	529	12	45	2,717
Pacific Gas and Electric Company (5)								
Core	0	152	119	545	9	0	0	825
Noncore Industrial/Wholesale/EG (6)	128	388	91	700	42	0	52	1,401
Total	128	540	210	1,244	51	0	52	2,226
Other Northern California								
Core (7)	0	0	0	0	0	0	12	12
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	465	25	0	0	1,049	14	0	1,552
TOTAL SUPPLIER	825	1,673	825	1,420	1,629	26	109	6,507

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes, unaccounted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	50	41	26	15	1	10	149
Noncore Commercial/Industrial	0	96	77	0	0	0	0	173
Total	6	146	118	26	15	1	10	322

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.
(10) Mojave's emphasis after 2006 is to transport natural gas from Daggett to Ehrenberg via El Paso's line 1903. In 2007, only 26 MMcf/d was delivered to California and 429 MMcf/d was transported to Arizona.

STATEWIDE RECORDED HIGHEST SENDOUT

The table below summarizes the highest sendout days by the state in the summer and winter periods from the last five years. Daily sendout from Southern California, Pacific Gas & Electric and from customers not served by these utilities were used to construct the following tables.

Estimated California Highest Winter Sendout (MMcf/d)

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total	Non-Utility (3)	State Total
2003	12/29/2003	2,987	3,844	6,831	1,254	8,085
2004	11/29/2004	3,369	4,364	7,732	1,044	8,777
2005	1/3/2005	3,570	3,942	7,512	1,217	8,729
2006	12/19/2006	3,547	4,242	7,789	1,315	9,104
2007	1/15/2007	3,906	4,685	8,591	1,700	10,291

Estimated California Highest Summer Sendout (MMcf/d)

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total	Non-Utility (3)	State Total
2003	7/21/2003	2,508	3,042	5,550	1,018	6,568
2004	7/21/2004	2,459	3,340	5,799	1,138	6,937
2005	7/21/2005	2,287	3,089	5,376	1,226	6,602
2006	7/24/2006	2,646	3,801	6,447	1,342	7,789
2007	8/29/2007	2,793	3,773	6,566	1,558	8,124

Notes:
(1) PG&E Piperanger.
(2) SoCalGas Envoy.
(3) Source: DOGGR, Monthly Oil and Gas Production and Injection Report, Lipmann Monthly Pipeline Reports. Nonutility Demand equals Kern/Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern/Mojave and California Production. Provided by the CEC.

2008 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 4.5 million residential customers and over 220,000 businesses in northern and central California. In addition to serving residential, commercial, and industrial markets, PG&E provides gas transportation and storage services to a variety of gas-fired electric generation plants in its service area. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers also utilize the PG&E system to meet their gas needs in southern California.

The northern California section of the report begins with an overview of the gas demand forecast followed by a discussion of the forecast methodology, economic conditions,, and other factors affecting demand in various markets, including the regulatory environment. Following the gas demand forecast are discussions of gas supply and pipeline capacity. Abnormal peak day demands and supply resources, as well as gas balances, are discussed at the end of this section.

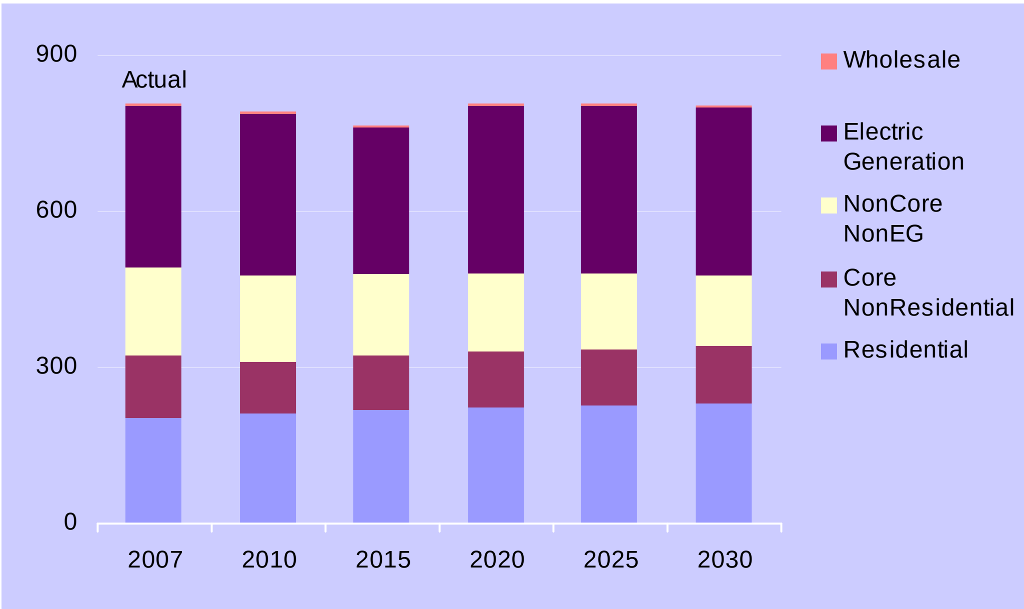
The forecast in this report covers the years 2008 through 2030. However, as a matter of convenience, the tabular data at the end of the section show only the years 2008 through 2013, and the years 2015, 2020, 2025, and 2030.

GAS DEMAND

OVERVIEW

PG&E's *2008 California Gas Report* (CGR) average year demand forecast projects total on-system demand growing at an annual average rate of 0.2 percent between 2008 and 2030. This overall growth rate is a combination of 0.5 percent annual growth in the core market and an annual decrease of 0.1 percent in the noncore market. By comparison, the 2006 CGR estimated an annual average growth rate of 1.3 percent per year, based on growth of 0.9 percent per year for the core market and 1.7 percent per year for the noncore market. [2]

Composition of PG&E Requirements (Bcf)
Average Demand Year



The projected rate of growth of the core market has decreased from the *2006 California Gas Report* primarily due to increased emphasis on Energy Efficiency and expected high gas prices. The forecast rate of growth of the noncore market has decreased significantly due to declines in projected load for the industrial sector. The decline is primarily due to expected high gas prices and California's continued shift away from manufacturing and processing.

In this CGR, total gas demand by electric generators and cogenerators in northern California is estimated to increase at a rate of about 0.6 percent per year from 2008 through 2030. This total gas demand includes gas demand by SMUD's

---

[2] The period used for calculating the 2008 CGR growth rates is from 2008 to 2030.

gas-fired power plants. It excludes gas delivered by third-party pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in central California

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed from econometric models. Forecasts for other sectors (NGV, wholesale) are developed from market information. Forecasts of gas demand by power plants are based on modeling of the electricity market in the Western Electricity Coordinating Council using the MarketBuilder model. While variation in short-term gas use depends mainly on prevailing weather conditions, longer-term trends in gas demand are driven primarily by changes in customer usage patterns influenced by underlying economic, demographic, and technological changes; such as: growth in population and employment; changes in prevailing prices; growth in electricity demand and in electric generation by renewables; and, changes in the efficiency profiles of residential and commercial buildings and the appliances within them.

MARKET SENSITIVITY

The average-year gas demand forecast presented here is a reasonable projection for an uncertain future. However, a point forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, appliance saturation, and efficiencies). In order to give some flavor of the possible variation in gas demand, PG&E has developed an alternative forecast of gas demand under assumed high demand conditions.

For the high-demand condition scenario, PG&E relied on a weather vintage approach. PG&E forecast total gas demand for 2009, assuming the demographic conditions and infrastructure likely to exist in 2009, but with the 2009 weather conditions set to match conditions that have an approximately 1-in-35 likelihood of occurrence. PG&E used the weather conditions from November 1976 through October 1977, as this time period was extremely dry in both northern California and the Pacific Northwest. In addition, the winter of 1976-1977 was colder than normal.

Temperature

Because space heating accounts for a high percentage of use, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's average-year forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past twenty years.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the average-year scenario and gas use will vary accordingly. PG&E's high demand forecast assumes that winter temperatures in the forecast horizon will be the same of those which prevailed during November 1976-October 1977.

Seasonal variations in temperature have relatively little effect on power plant gas demand and, consequently, PG&E's forecasts of power plant gas demand are based on average temperatures. (Each summer typically contains a few heat waves with temperatures 10º or 15º Fahrenheit above normal, which lead to peak electricity demands and drive up power plant gas demand; however, on a seasonal basis, temperatures seldom deviate more than 2º Fahrenheit from average.)

Hydro Conditions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50% above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in water year 2001 (October 2000 through September 2001). For the 2008 CGR's high demand scenario, as noted above, PG&E used the 1977 drought, which was more severe in both northern California and the Pacific Northwest than the 2001 drought.

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 1.0 percent annually from 2008 to 2030. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies and high gas prices. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to plunge by more than 8 percent. After recovering somewhat in 2002 and 2003, temperature-adjusted gas use per household reverted to its long-term trend and fell by 1.4 percent and 1.1 percent in 2006 and 2007, respectively. Due to expected continuing upgrades in appliance and building efficiencies, PG&E forecasts residential demand to grow on average by 0.6 percent per year from 2008 to 2030, implying an average decrease in gas use per household of almost 0.4 percent per year.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by less than 0.7 percent per year from 2008 to 2030. The 2000-2001 noncore to core migration wave has caused this class to be less temperature sensitive than it had previously been and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to remain flat over the forecast horizon. Over the next 20 years, sales for this sector are expected to grow by the rate at which the customer base is forecast to increase.

Industrial

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of increasing gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 and has remained fairly flat since that point in time due to high real natural gas prices and to continuing structural change in California's manufacturing sector. While the Industrial sector has the potential for high year to year variability, over the long term, industrial gas consumption is expected to slowly decline by about 0.5 percent annually over the next 20 years as northern California's economy continues its decades-long transformation from manufacturing and agriculture to services..

Electric Generation

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. Operations at most cogeneration plants are not strongly affected by prices in the wholesale electricity market because electricity is co-produced with some other product, usually steam, for an industrial process.

PG&E forecasts gas demand by power plants and market-sensitive cogenerators using the MarketBuilder model. MarketBuilder is an economic-equilibrium model that has been applied to various markets with geographically distributed supplies and demands, such as the North American natural gas market. PG&E uses MarketBuilder to simulate the electricity market in the Western Electricity Coordinating Council, which encompasses the electric systems from Denver to the Pacific Coast, and from northern Mexico to British Columbia and Alberta.

PG&E's forecast for 2008-2030 uses the base-case electricity demand forecast from the CEC's *2007 Integrated Energy Policy Report*. For areas outside California, PG&E used many assumptions from the reference case prepared by the Planning Working Group of the Seams Steering Group—Western Interconnection. The Planning Working Group consists of personnel from various state agencies and electric transmission organizations in the WECC.

SMUD EG

The Sacramento Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the United States, and SMUD provides electric service to over 575,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants, a gas-fired combined-cycle plant and a peaking turbine with a total capacity of approximately 1,000 MW. The peak gas load of these units is approximately 158 MMCF/d, and the average load is 117 MMCF/d.

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 representing about 87 MMCF/d of capacity.

EG Carbon Legislation/AB 32

During the forecast horizon covered by this 2008 California Gas Report there are many uncertainties which may significantly impact the future trajectory of natural gas demand. It is unclear at this time what the ultimate effect on natural gas demand from California's landmark AB32-GHG (Green House Gas) reduction goals will be. On the one hand, more aggressive energy efficiency programs and/or increased RPS targets could significantly reduce the need for natural gas use for the purpose of residential and commercial space and water heating and for electric generation significantly. In contrast, significant reductions in GHG emissions in the State could be achieved through greater electrification of motors used in commercial and industrial applications and/or increased penetration of electric and natural gas vehicles in residential and commercial markets. These reductions in GHG could result in increased consumption of natural gas in the state. PG&E's recent experience with its innovative agricultural internal combustion engine conversion incentive (AG-ICE) is a good example of how GHG reductions can be achieved through electrification of commercial engines. In this particular case, PG&E offered incentives to convert motors used in agricultural irrigation systems which were burning diesel, gasoline, butane or propane to electric engines. The purpose of the program was to address issues related to deteriorating air quality in the

North Valley and Central Valley areas. The program was an enormous success with nearly 2,000 engines being converted in the past 3-years.

For its part PG&E intends to continue to minimize GHG emissions levels by aggressively pursing both demand side reductions and acquisition of preferred resources, which produce little or no carbon emissions. It is important to note that PG&E has virtually no baseload or intermittent resource additions in its current long term plans which are carbon-based. However, for resource adequacy and load following purposes, PG&E expects that natural gas fired generation will provide the bulk of this service for the foreseeable future.

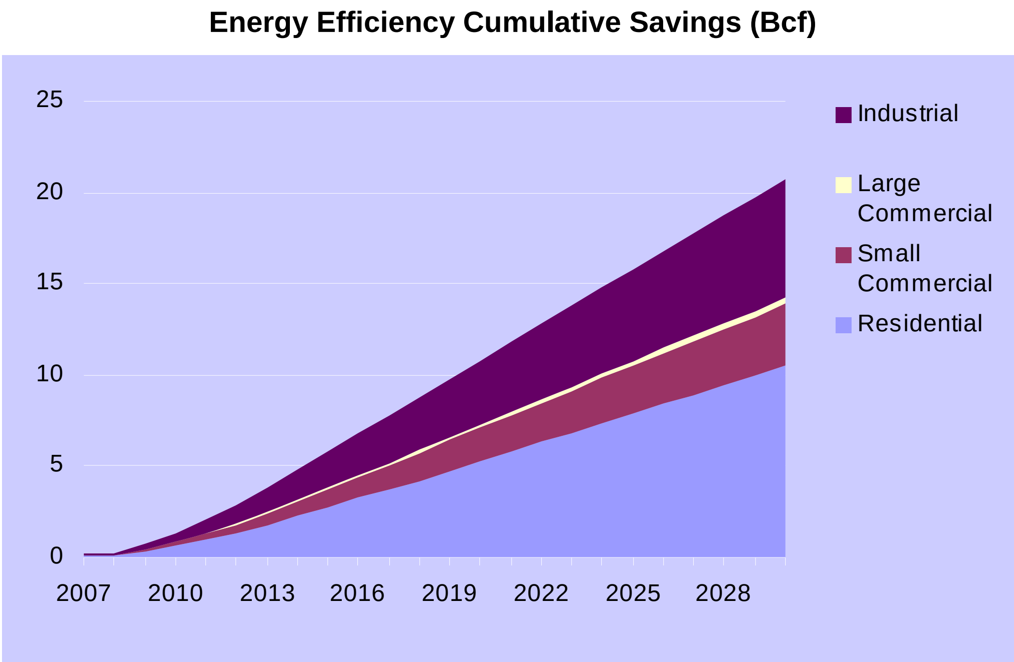
ENERGY EFFICIENCY PROGRAMS

PG&E engages in a number of energy efficiency and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. PG&E administers over 85 distinct energy efficiency programs, including services that help customers evaluate their energy efficiency options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as weatherization.

Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the gas and electric Energy Efficiency programs.

The cumulative net energy efficiency load impact forecast for selected years is provided in the table below. The net load impact includes all Energy Efficiency programs that Pacific Gas and Electric Company (PG&E) has forecasted to implement in the years 2008 through 2030. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.

Details of PG&E's' 2006-2008 Energy Efficiency program portfolio are contained in PG&E's' Advice Letter 2704-G, 2786-E, which was submitted on February 17, 2006.


Energy Efficiency Cumulative Savings (Bcf)
25
20
15
10
5
0
2007
2010
2013
2016
2019
2022
2025
2028
Industrial
Large Commercial
Small Commercial
Residential

GAS SUPPLY, CAPACITY AND STORAGE

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990's. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Almost all of PG&E's noncore customers buy all or most of their gas supply needs directly from the market. They use PG&E's transportation and storage services to meet their gas supply needs.

GAS SUPPLY

California-Sourced Gas

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2007, PG&E's customers obtained on average 128 MMcf/day of California source-gas.

U. S. Southwest Gas

PG&E's customers have access to three major U.S. Southwest gas producing basins--Permian, San Juan, and Anadarko--via the El Paso, Southern Trails, and Transwestern pipeline systems.

PG&E's customers can purchase gas in the basins and transport it to California via interstate pipelines. Customers can also purchase gas supplies at the California-Arizona border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity..

Canadian Gas

PG&E's customers can purchase Canadian gas from various suppliers in western Canada (British Columbia and Alberta) and transport it to California primarily through the Gas Transmission Northwest Pipeline. Customers can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon.

Storage

In addition to storage services offered by PG&E, Wild Goose Storage, Inc. and Lodi Gas Storage, LLC provide storage services from the Wild Goose and Lodi facilities, respectively.

INTERSTATE PIPELINE CAPACITY

As a result of pipeline expansion and new projects, California utilities and end-users benefit from improved access to supply basins and enhanced gas-on-gas and pipeline-to-pipeline competition. Interstate pipelines serving northern and central California include the El Paso, Mojave, Transwestern, Gas Transmission Northwest, Southern Trails, and Kern River pipelines. These pipelines provide northern and central California with access to gas producing regions in the U. S. Southwest and Rocky Mountain areas, and in western Canada.

U.S. Southwest and Rocky Mountains

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,073 MMcf/day.

Canada

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest at Malin, Oregon. The Redwood Path has a firm capacity of 2,021 MMcf/day.

NEW GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

PG&E anticipates that sufficient new supplies will be available from a variety of sources at market-competitive prices to meet existing and projected market demands in its service area. The new supplies could be delivered through a variety of sources, including new interstate pipeline facilities and expansion of PG&E's existing transmission facilities, or PG&E's or others' storage facilities.

In the near term (2008-2015), new sources of gas supply will be from Liquefied Natural Gas (LNG) imports, the Rocky Mountain supply basin and Biogas.

LNG Imports

Liquefied Natural Gas (LNG) imports will provide a new supply source whether directly connected to the PG&E system, or delivered across other systems to PG&E. The presence of LNG supplies in the West and Gulf Coast areas will increase supply and at a minimum make other supplies more available to western markets. Supplies of LNG can be expected to have a favorable impact on gas prices in that they, worst case, can be expected to dampen price increases, and best case, produce lower prices than currently exist.

The first LNG re-gasification project completed is Sempra LNG's Costa Azul project, on Mexico's Baja Peninsula. Deliveries from the project began in May 2008, and future deliveries will likely move both directly into southern California, as well as on to interstate pipelines that can access northern California. The facility will also serve markets in Mexico. The initial capacity of this project is 1.0 Bcf/d and could be expanded in the future. Other projects along both the Mexican coast and the U.S. west coast are in various stages of preliminary development but have not received permits to begin construction. It is possible that one or more of these other projects will move to completion and begin deliveries but probably not until 2012 at the earliest.

Rocky Mountains

Another new source of gas supplies that could serve the northern California market would be from the Rocky Mountains, which is one of the natural gas supply areas in North America that is growing. El Paso Natural Gas has announced the 1.2 Bcf/d Ruby Pipeline project, which would connect the Rocky Mountain supply basin at Opal with Malin, Oregon. This project would provide a source of supply to offset declines of supply from the Western Canadian Sedimentary Basin in Canada. This project could be on-line in 2011.

There are other proposed projects that would bring supplies from the Rockies to California and the Pacific Northwest. Gas Transmission Northwest and Williams Company have proposed the Sunstone Pipeline Project, which would parallel Williams' existing Northwest Pipeline to Stanfield, where it would interconnect with the Gas Transmission Northwest Pipeline to flow gas to Malin. Williams has indicated that this project could go into service in 2011. Spectra Energy has also proposed the Bronco Pipeline, which would follow a route similar to Ruby. If this project moves forward it could become operational in 2011. It is unlikely that both Ruby and Spectra pipelines will be constructed.

Biogas

Energy from animal waste continues to be one of the most innovative ways PG&E is realizing its renewable energy goals. PG&E is partnering with California dairies to provide biomethane from dairy manure to its customers through California's natural gas pipelines. This cutting-edge initiative will provide renewable energy and produce important climate benefits by preventing methane from escaping to the atmosphere.

As the nation's largest dairy producer and largest energy consumer, renewable biomethane holds significant promise for PG&E, its customers, and the environment. It is also a step toward developing an important renewable energy source from California's vital agricultural sector.

In 2007, PG&E and Bioenergy Solutions began construction of a biomethane to pipeline injection project, which will deliver commercial-grade, renewable natural gas derived from animal waste. It is the first project in California and third nationwide to deliver pipeline-quality, renewable natural gas to a utility. The project will be completed and delivering gas in the first half of 2008. Several other projects from "cow power" developer Microgy will similarly deliver biomethane under contract to PG&E near the end of 2008.

PG&E has launched an initiative to seek emerging biomethanation technologies to convert California's extensive biomass resources into pipeline-quality natural gas that can be delivered for high-value uses, such as efficient, dispatchable power generation. In partnership with industry, PG&E will facilitate the development of a project that will demonstrate the technical and economic feasibility of emerging technologies for the production of significant quantities of clean renewable biomethane.

Frontier Gas Supplies

On the longer term horizon, 2015 and beyond, the best other possibility of new supply appears to be gas from near the Arctic Circle delivered through an Alaska Pipeline, or via a pipeline through Canada's McKenzie Delta in the Northwest Territory, or both. These pipelines could be capable of transporting several Bcf/d each to Canadian and U.S. markets, including those in California. Neither pipeline has received final approval and completion is likely to be about 10 years away.

Natural Gas Storage

There are also three new natural gas storage projects planned in northern California. PG&E is co-developing a natural gas storage project with Gill Ranch Storage, LLC. This project, located in the central San Joaquin Valley west of Fresno, would have about 20 Bcf of working gas along with about 650 MMcf/d of firm withdrawal. It would utilize depleted gas reservoirs in the Starkey formation. This storage project is expected to be operational in 2010.

Lodi Gas Storage will add an additional 12 Bcf of working gas storage capacity and will provide about an additional 100 MMcf/d of firm injection and 200 MMcf/d of firm withdrawal capacities. Lodi Gas Storage is projecting an in-service date of September 2008.

The 8 Bcf Sacramento Natural Gas Storage project is also in the development stage. This project would utilize the Florin Gas Field, which is a depleted natural gas reservoir in Sacramento. The project is currently in the permitting phase of development and the project owners have indicated that it could be operational sometime in 2009.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Quality

Gas quality has received much attention over the last several years, largely due to the predicted increase in receipts of LNG. The compositional quality of LNG can be an issue as LNG can differ significantly from traditional North American sources. Equipment that burns natural gas can generally tolerate a range of gas quality but there are practical and safety limits that need to be considered by receiving pipelines and local distribution companies. PG&E has historically used the heating value of the gas, expressed as BTU, as an indicator of gas interchangeability (the ability to substitute gas of one chemical composition for gas of another, different chemical composition). However, based on recent testing, the Wobbe Number is a better indicator of gas quality. The Wobbe Number reflects not only the BTU content but the specific gravity of the gas as well. Specific gravity is an indicator of the relative proportion of heavier versus lighter hydrocarbons. In its testing, PG&E tentatively concluded that it could accept gas supplies with a Wobbe Number as high as 1385.

FEDERAL REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines that serve the California market because these cases can impact the cost of gas delivered to our gas customers. These cases can also affect the services provided to our gas customers. PG&E is an active participant in the FERC cases on the pipelines where we hold firm capacity.

GTN Pipeline

In June 2006, GTN filed a general rate case application with FERC with a requested effective date of new rates of January 1, 2007. FERC approved the proposed rates subject to the outcome of hearings. Before hearings were held, however, GTN and the interveners reached a settlement that resolved all issues. FERC approved the Settlement on January 7, 2008. The settlement placed new rates into effect retroactive to January 1, 2007. The settled rates were about 25% higher than previous rates but less than the 71% increase GTN had filed with FERC. For example, the rate to transport gas from the U.S.-Canadian border to the California-Oregon border increased from $0.26/Dth to $0.33/Dth. The Settlement also resolved a number of other issues related to services and contract obligations. In particular, PG&E's existing capacity contract was subdivided into several smaller stand alone contracts.

Transwestern

In September 2006, Transwestern filed a general rate case application with FERC with a requested effective date of November 1, 2006. FERC approved the proposed rates subject to the outcome of hearings. Before hearings were held, however, Transwestern and the interveners reached a settlement that resolved all issues except certain gas quality matters. FERC approved the Settlement on April 27, 2007. The settlement placed new rates into effect retroactive to April 1, 2007. The settled rate to transport gas from the San Juan basin to the California-Arizona border remained unchanged at approximately $0.36/Dth. The Settlement also resolved various other issues including fuel recovery and credit standards. TW ultimately withdrew its gas quality proposals after discussion with interveners.

El Paso

El Paso plans to file a general rate case application with FERC in June 2008 with a proposed effective date of January 1, 2009. The existing three-year rate Settlement expires December 31, 2008. PG&E believes the new application will mainly focus on rates, with few service changes proposed and PG&E thinks that the interveners in the case are likely to focus on both rates and services. PG&E plans to be actively involved in this case and it seems possible, based on previous efforts, that a settlement can be reached prior to hearings.

ANORMAL PEAK DAY SUPPLY AND DEMAND

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of core demand under extremely adverse conditions. The design criteria for PG&E, as required under CPUC regulation, is a 27 degree Fahrenheit system-weighted mean temperature. This corresponds to a roughly 1 in 90 extreme temperature event. The APD core load demand forecast is estimated to be approximately 3.2 Bcf/day. The APD load forecast shown here excludes all noncore demand and, in particular, excludes all EG demand. PG&E estimates that total noncore demand during an APD event would be 1.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD forecast is developed using forecast models to estimate the relationship of daily core gas usage to daily weather conditions during several recent winters. This relationship is then used to simulate what the core load would be under the adverse weather conditions that occurred on December 21, 1990, the coldest day on record in PG&E's service area.

FORECAST OF APD SUPPLY AVAILABILITY

For APD planning purposes, supplies will flow under Core Procurement's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Supplies could also be purchased from noncore suppliers. Flowing supplies may come from Canada, the U.S. Southwest, the Rocky Mountain Region, SoCalGas, and California. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's and independent storage providers' underground storage facilities located within Northern and Central California.

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to approximately 95% of PG&E's core customers. Core aggregators provide procurement services for the balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as the cold weather front drops down from Canada with a two to three day lag before hitting PG&E's service territory. There is also impact on supply from the southwest. While prices can influence the availability of supply to our system, cold weather can affect producing wells in the basins which, in turn, can affect the total supply to our system and others.

When Core supplies are insufficient to meet core demand, PG&E can, divert gas from the noncore (including gas-fired electric generators) to meet Core demand. High Diversion and Emergency Flow Order noncompliance charges are expected to be sufficient to cause the noncore market to either reduce or cease its use of gas or switch to an alternate fuel. However, little, if any, alternate fuel burn capability exists today, so supply diversions from the noncore would necessitate that noncore customers (including EG) curtail operations. The implication for the future is that under supply shortfall conditions such as an APD, a significant portion of EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that in the near term, noncore demand (including gas fired electric generation) on an APD would be 1.5 Bcf/day. With the additions of the Wild Goose and Lodi storage facilities, more noncore demand will be satisfied in the event of an APD. The availability of supply for any given high demand event, such as an APD, is dependent on a wide range of factors including the availability of interstate flowing supplies and on system storage inventories.

Forecast of Core Gas Demand and Supply on an Abnormal Peak Day (APD)
MMcf/Day

	2008-09	2009-10	2010-11
ADP Core Demand	3,167	3,227	3,287
Firm Storage Withdrawal	1,104	1,104	1,104
Required Flowing Supply	2,063	2,123	2,183
Total APD Resources (to meet demands)	3,167	3,227	3,287

Notes:
(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD planning criterion: system temperature on APD is 27 degrees F. PG&E now uses a system composite temperature based on six weather sites and this results in a 27 degree APD temperature that is roughly equivalent to the 29 degree APD temperature used in previous reports.
(2) Includes supplies flowing under firm and as-available capacity, and capacity made available pursuant to supply diversion arrangements.
(3) Core Firm Storage Withdrawal capacity includes 49 MMcf/d contracted with an on-system independent storage provider.

The tables below provide peak day demand projections on PG&E's system for both winter and summer periods.

Winter Peak Day Demand (MMcf/Day)

Year	Core (1)	Non-Core Non-EG (1)	Electric Generation (2)	Total Demand	Storage *Withdrawal*	Required Flowing Supply
2008	1,478	474	727	2,680	-1,099	1,581
2009	1,797	452	749	2,998	-1,187	1,811
2010	1,821	448	817	3,086	-1,291	1,795
2011	1,833	447	819	3,099	-1,344	1,755
2012	1,852	447	736	3,035	-1,353	1,682
2013	1,861	444	736	3,041	-1,351	1,690
2014	1,868	441	717	3,025	-1,352	1,673
2015	1,875	434	707	3,016	-1,351	1,665

Notes:
(1) 1-in-35 peak temperature cold day event for PG&E.
(2) Daily average cold year winter demand

Summer Peak Day Demand (MMcf/Day)

Year	Core (1)	Non-Core Non-EG (1)	Electric Generation (2)	Total Demand	Storage *Injection*	Required Flowing Supply
2008	511	598	1,246	1,966	218	2,184
2009	518	584	1,196	1,964	170	2,134
2010	522	582	1,316	1,997	146	2,143
2011	526	580	1,269	2,022	108	2,130
2012	531	579	1,123	1,952	111	2,063
2013	534	574	1,137	1,944	109	2,053
2014	535	565	1,095	1,916	110	2,026
2015	536	558	1,113	1,907	110	2,017

Notes:
(1) Daily average summer demand.
(2) 1-in-35 dry hydro peak demand condition.

2008 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2003-2007
MMCF/DAY

LINE		2003	2004	2005	2006	2007	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
1	Core Purchases	0	0	0	0	0	1
2	Customer Gas Transport & Exchange	155	104	117	136	128	2
3	Total California Source Gas	155	104	117	136	128	3
	OUT-OF-STATE GAS						
	Core Net Purchases						
6	Rocky Mountain Gas	9	18	11	5	9	6
7	U.S. Southwest Gas	155	223	245	262	271	7
8	Canadian Gas	569	578	535	571	545	8
	Customer Gas Transport						
10	Rocky Mountain Gas	170	252	151	81	95	10
11	U.S. Southwest Gas	434	316	361	357	479	11
12	Canadian Gas	595	609	592	643	700	12
13	Total Out-of-State Gas	1,932	1,996	1,895	1,919	2,099	13
14	STORAGE WITHDRAWAL (2)	327	260	250	242	287	14
15	Total Gas Supply Taken	2,414	2,360	2,262	2,297	2,514	15
	GAS SENDOUT						
	CORE						
19	Residential	546	536	512	546	561	19
20	Commercial	244	235	233	233	233	20
21	NGV	5	3	4	4	4	21
22	Total Throughput-Core	795	774	749	783	798	22
	NONCORE						
24	Industrial	418	428	431	442	459	24
25	Electric Generation (1)	739	808	753	778	858	25
26	NGV	1	1	1	1	1	26
27	Total Throughput-Noncore	1,158	1,237	1,185	1,221	1,317	27
28	WHOLESALE	10	10	10	10	10	28
29	Total Throughput	1,963	2,021	1,944	2,014	2,126	29
30	CALIFORNIA EXCHANGE GAS	1	1	2	2	2	30
31	STORAGE GAS (2)	341	285	268	222	300	31
32	SHRINKAGE Company Use / Unaccounted for (3)	109	53	48	60	86	32
33	Total Gas Send Out (4)	2,414	2,360	2,262	2,298	2,514	33
	CURTAILMENT / ALTERNATIVE FUEL BURNS (5)						
36	Residential, Commercial, Industrial	0	0	0	0	0	36
37	Utility Electric Generation	0	0	0	0	0	37
38	TOTAL CURTAILMENT	0	0	0	0	0	38

NOTES:

(1) Electric generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, other non-utility generation and deliveries to power plants by third-party pipelines.
(2) Includes both PG&E and third party storage
(3) Shrinkage in the historical period may include effects due to PG&E's Billing System primarily associated with normalizing for serial billing of residential and small commercial customers.
(4) Total gas send-out excludes off-system transportation; off-system deliveries are subtracted from supply total.
(5) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2008-2012
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2008	2009	2010	2011	2012	LINE
GAS SUPPLY AVAILABLE							
1	California Source Gas	158	158	158	158	158	1
	Out of State Gas						
2	Baja Path(1)	1,073	1,073	1,073	1,073	1,073	2
3	Redwood Path(2)	2,021	2,021	2,021	2,021	2,021	3
4	Supplemental(3)	0	0	0	0	0	4
5	**Total Supplies Available**	3,252	3,252	3,252	3,252	3,252	5
GAS SUPPLY TAKEN							
6	California Source Gas	158	158	158	158	158	6
7	Out of State Gas (via existing facilities)	2,131	2,144	2,172	2,163	2,096	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2,289	2,302	2,330	2,321	2,254	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	**Total Throughput**	2,289	2,302	2,330	2,321	2,254	11
REQUIREMENTS FORECAST BY END USE							
	CORE						
12	Residential	552	572	577	582	588	12
13	Commercial	233	234	236	238	238	13
14	NGV	4	4	4	3	3	14
15	**Total Core**	789	810	817	823	830	15
	NONCORE						
16	Industrial	468	451	449	448	447	16
17	SMUD Electric Generation(4)	122	125	118	122	122	17
18	PG&E Electric Generation(5)	696	700	730	751	677	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,299	1,288	1,310	1,333	1,258	23
24	**Off-System Deliveries(6)**	163	163	163	125	125	24
	Shrinkage						
25	Company use and Unaccounted for	39	40	40	41	41	25
26	**TOTAL END USE**	2,289	2,302	2,330	2,321	2,254	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Tranmission Northwest pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation,and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.
(6) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2013-2030
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2013	2015	2020	2025	2030	LINE
GAS SUPPLY AVAILABLE							
1	California Source Gas	158	158	158	158	158	1
	Out of State Gas						
2	Baja Path[1]	1,073	1,073	1,073	1,073	1,073	2
3	Redwood Path[2]	2,021	2,021	2,021	2,021	2,021	3
4	Supplemental[3]	0	0	0	0	0	4
5	**Total Supplies Available**	3,252	3,252	3,252	3,252	3,252	5
GAS SUPPLY TAKEN							
6	California Source Gas	158	158	158	158	158	6
7	Out of State Gas (via existing facilities)	2,093	2,064	2,181	2,144	2,135	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2,251	2,222	2,339	2,302	2,293	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	**Total Throughput**	2,251	2,222	2,339	2,302	2,293	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	592	596	613	625	630	12
13	Commercial	239	239	238	238	238	13
14	NGV	4	5	8	13	18	14
15	**Total Core**	835	840	860	876	886	15
	Noncore						
16	Industrial	443	432	411	388	362	16
17	SMUD Electric Generation[4]	122	122	122	122	122	17
18	PG&E Electric Generation[5]	670	647	765	765	765	18
19	NGV	1	2	3	4	6	19
20	Wholesale	10	10	10	10	10	20
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,248	1,214	1,312	1,290	1,266	23
24	**Off-System Deliveries[6]**	125	125	125	90	90	24
	Shrinkage						
25	Company use and Unaccounted for	42	42	42	46	50	25
26	**TOTAL END USE**	2,251	2,222	2,339	2,302	2,293	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Tranmission Northwest pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation,and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.
(6) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2008-2012
MMCF/DAY
HIGH DEMAND YEAR

LINE		2008	2009	2010	2011	2012	LINE
GAS SUPPLY AVAILABLE							
1	California Source Gas	158	158	158	158	158	1
	Out of State Gas						
2	Baja Path[(1)]	1,073	1,073	1,073	1,073	1,073	2
3	Redwood Path[(2)]	2,021	2,021	2,021	2,021	2,021	3
4	Supplemental[(3)]	0	0	0	0	0	4
5	**Total Supplies Available**	3,252	3,252	3,252	3,252	3,252	5
GAS SUPPLY TAKEN							
6	California Source Gas	158	158	158	158	158	6
7	Out of State Gas (via existing facilities)	2,391	2,448	2,463	2,479	2,392	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2,549	2,606	2,621	2,637	2,550	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	**Total Throughput**	2,549	2,606	2,621	2,637	2,550	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	561	625	630	636	642	12
13	Commercial	240	253	255	257	258	13
14	NGV	4	4	4	3	3	14
15	**Total Core**	805	881	889	896	903	15
	Noncore						
16	Industrial	468	451	449	448	447	16
17	SMUD Electric Generation[(4)]	122	125	118	122	122	17
18	PG&E Electric Generation[(5)]	939	928	944	989	894	18
19	NGV	1	1	1	1	1	19
20	Wholesale	10	10	10	10	10	20
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,541	1,517	1,524	1,571	1,476	23
24	**Off-System Deliveries[(6)]**	163	163	163	125	125	24
	Shrinkage						
25	Company use and Unaccounted for	40	45	45	45	46	25
26	**TOTAL END USE**	2,549	2,606	2,621	2,637	2,550	26
27	System Curtailment	0	0	0	0	0	27

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Tranmission Northwest pipeline.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Forecast by SMUD.

(5) Electric generation includes cogeneration, PG&E-owned electric generation,and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.

(6) Deliveries to southern California.

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2013-2030
MMCF/DAY
HIGH DEMAND YEAR

LINE		2013	2015	2020	2025	2030	LINE
GAS SUPPLY AVAILABLE							
1	California Source Gas	158	158	158	158	158	1
	Out of State Gas						
2	Baja Path[(1)]	1,073	1,073	1,073	1,073	1,073	2
3	Redwood Path[(2)]	2,021	2,021	2,021	2,021	2,021	3
4	Supplemental[(3)]	0	0	0	0	0	4
5	**Total Supplies Available**	3,252	3,252	3,252	3,252	3,252	5
GAS SUPPLY TAKEN							
6	California Source Gas	158	158	158	158	158	6
7	Out of State Gas (via existing facilities)	2,394	2,370	2,495	2,459	2,450	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2,552	2,528	2,653	2,617	2,608	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	**Total Throughput**	2,552	2,528	2,653	2,617	2,608	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential	647	651	670	683	688	12
13	Commercial	258	259	257	257	258	13
14	NGV	4	5	8	13	18	14
15	**Total Core**	909	914	935	953	964	15
	Noncore						
16	Industrial	443	432	411	388	362	16
17	SMUD Electric Generation[(4)]	122	122	122	122	122	17
18	PG&E Electric Generation[(5)]	893	873	997	997	997	18
19	NGV	1	2	3	4	6	19
20	Wholesale	10	10	10	10	10	20
22	California Exchange Gas	1	1	1	1	1	22
23	**Total Noncore**	1,470	1,441	1,544	1,522	1,498	23
24	**Off-System Deliveries[(6)]**	125	125	125	90	90	24
	Shrinkage						
25	Company use and Unaccounted for	48	48	48	52	56	25
26	**TOTAL END USE**	2,552	2,528	2,653	2,617	2,608	26
27	System Curtailment	0	0	0	0	0	27

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Tranmission Northwest pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Forecast by SMUD.
(5) Electric generation includes cogeneration, PG&E-owned electric generation,and deliveries to power plants connected to the PG&E system by either PG&E or third party pipelines. It excludes deliveries by the Kern Mojave system.
(6) Deliveries to southern California.

2008 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

Southern California Gas Company (SoCalGas) is the principal distributor of natural gas in Southern California, providing retail and wholesale customers with transportation, exchange and storage services and also procurement services to most retail core customers. SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and electric generation (EG) customers in Southern California. San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation, the City of Long Beach Municipal Oil and Gas Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas also provides gas transportation service across its system to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico, S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 22-year natural gas demand forecast period, from 2008 through 2030; only the consecutive years 2008 through 2013 and the point years 2015, 2020, 2025, and 2030 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

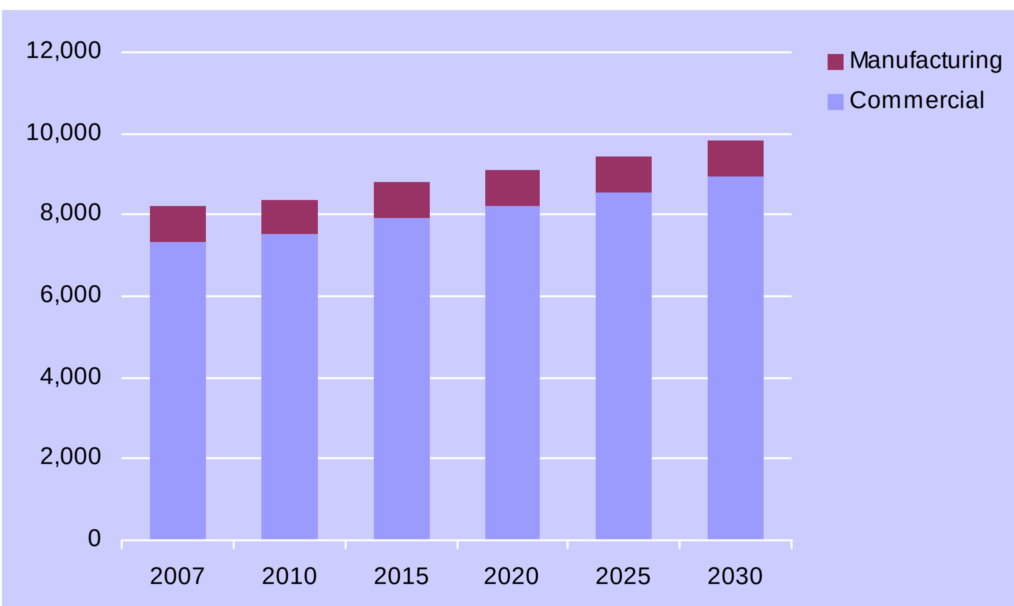
The Southern California section of the *2008 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The natural gas price forecast methodology used to develop the gas demand forecast is discussed followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

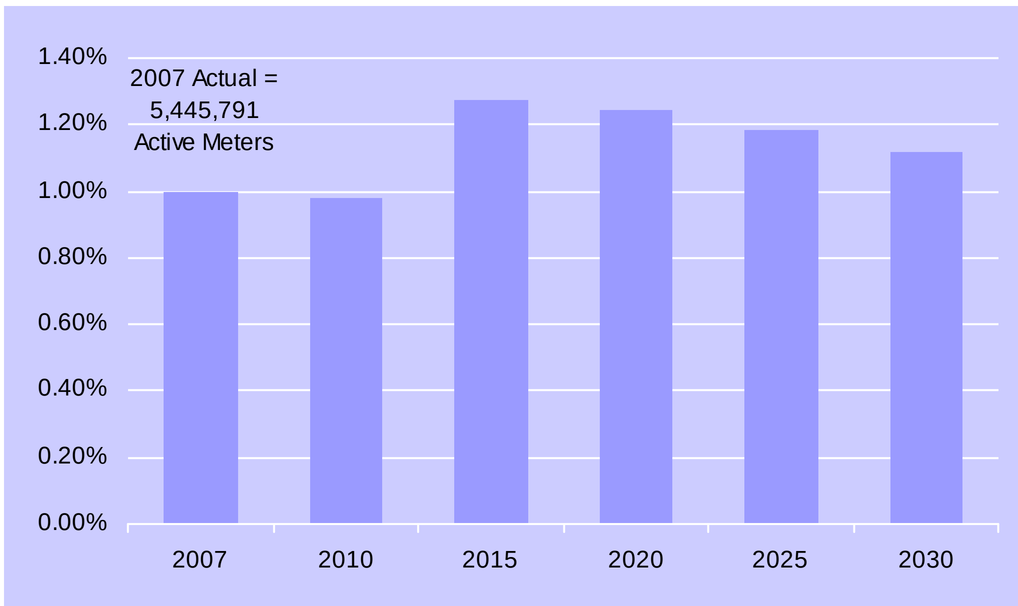
The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. After enjoying strong job growth above 2% in both 2005 and 2006, the SoCalGas area's 12-county economy began to slow in 2007 – hit by a worsening slump in the formerly high-flying housing market; total employment growth slowed to 0.4% in 2007. 2008 is expected to be the weakest year of the current economic slowdown, with jobs shrinking by 0.4% during the year before beginning to rebound in 2009 and 2010. Area jobs are expected to average modest 0.9% annual growth from 2007 through 2012. Local industrial employment (manufacturing and mining) will stay weak, with virtually no net growth from 2007 through 2012. Commercial employment should continue to fare relatively better, averaging decent 1.0% growth during those same five years. Construction will be the weakest area to 2012, averaging 1.5% annual job losses to 2012. Services will enjoy the strongest employment increases during the same period, growing an average of 1.3% per year—led by 2.6% annual growth in professional and business services.

Southern California Employment (Thousand Jobs)



In the longer term, service-area employment growth is expected to slow slightly as the area population's average age gradually increases--part of a national demographic trend of aging and retiring "baby boomers". From 2007 through 2030, total area job growth should average 0.8% to 0.9% per year. Area industrial jobs are forecasted to remain virtually flat through 2030; we expect the industrial share of total employment to fall from 10.5% in 2007 to 8.6% by 2030. Commercial job growth is expected to average 0.9% annually from 2007 through 2030.

SoCalGas Annual Meter Growth



In 2008 SoCalGas' service area is in the midst of a serious housing slump. Home builders are being buffeted both by their own new-home excess inventories and by low-priced existing-home foreclosure fallout from the former financing frenzy. As a result, new homes and corresponding new gas meter hookups are expected drop in 2008 to barely half their amounts of recent years. As the housing over-supply slowly clears and as prices drop back closer to more historically affordable levels, gradual home-building recovery should begin by 2010. Looking farther ahead, longer term meter growth will depend mostly on population trends in the service area. Area population is forecasted to average modest 0.9% to 1.0% annual growth from 2007 through 2030. As a result of this population growth, SoCalGas expects its active meters to increase an average of 1.1% annually during the same period.

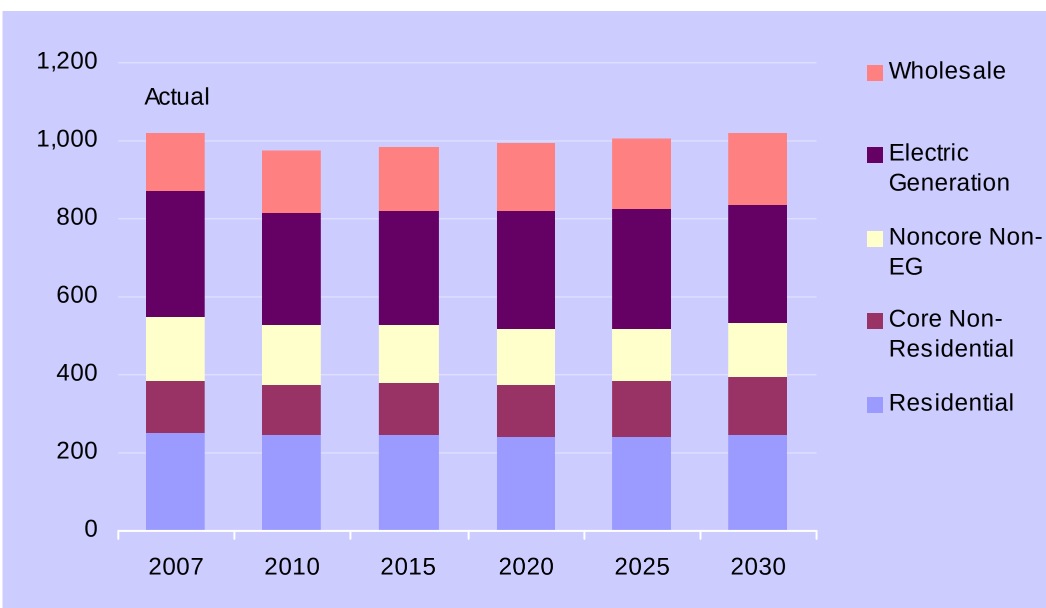
GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects gas demand for all its market sectors to grow at an annual average rate of just 0.02% from 2008 to 2030. Demand is expected be virtually flat for the next 22 years due to modest economics growth, CPUC-mandated DSM goal and renewable goal, decline in commercial and industrial demand, and continued increased use of non-utility pipeline systems by EOR customers. By comparison, the *2006 California Gas Report* projected an annual growth rate of 0.15% from 2006 to 2025. The difference between the two forecasts is caused by the slump in the housing market for the next few years, a reduced employment forecast, a higher gas price projection, and aggressive energy efficiency savings goals.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2007 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and for the 2008 to 2030 forecast period.

Composition of SoCalGas Requirements (Bcf)
Average Temperature and Normal Hydro Year



Notes:
(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, natural gas vehicles, company-use, and lost and unaccounted-for.
(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
(3) Retail electric generation includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, Southwest Gas and Ecogas.

From 2008 to 2030, residential demand, including wholesale residential service to SDG&E and the City of Long Beach, is expected to remain flat due to the seesawing effect of declining use per meter offsetting new meter growth. The retail core commercial and industrial markets are expected to show some modest customer gains due to the growing economy; however, very aggressive energy efficiency goals and associated programs are projected to reduce this load by 9% or 9 Bcf by 2030. Similarly, the retail non-core commercial/industrial markets are also expected to decline for the same reason as the core market. Utility gas demand for EOR steaming operations, which have declined since the Kern/Mojave pipeline began offering direct service to California customers in 1992, are expected to continue to decline as more utility service contracts expire. The non-core non-cogeneration load as a whole is expected to decline to 131 Bcf by 2030 from 155 Bcf in 2008. Lastly, gas demand in the electric generation (EG) market is expected to drop sharply in 2009 due to the expected departure of several of SoCalGas' long-term EOR cogeneration customers. Non-cogeneration EG is expected to remain relative flat due to the addition of more efficient power plants, the addition of new transmission lines, and renewable electricity goals. Total electric generation load, including cogeneration and non-cogeneration EG for a normal hydro year is expected to drop from 313 Bcf in 2008 to 298 Bcf in 2030, a cumulative decrease of 5%.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions – 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 in the residential and core commercial and industrial markets. The largest demand variations due to temperature occur in the month of December. Heating Degree Day (HDD) differences between the two conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is when the average temperature for the day drops 1 degree below 65° Fahrenheit. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a recurrence period of 35 years.

Hydro Condition

The non-cogen EG forecasts are prepared for two hydro conditions – average and dry. The dry hydro case refers to gas demand under a 1-in-10 hydro year.

MARKET SECTORS

Residential

Residential demand adjusted for temperature totaled 245 Bcf in 2007. The unadjusted residential demand for 2007 was 0.25% less than the temperature adjusted total for Southern California because of warmer than normal weather conditions exhibited throughout the year. The actual, observed cumulative Heating Degree Days for 2007 were approximately 0.80% less than the totals that characterize the average year weather design for SoCalGas.

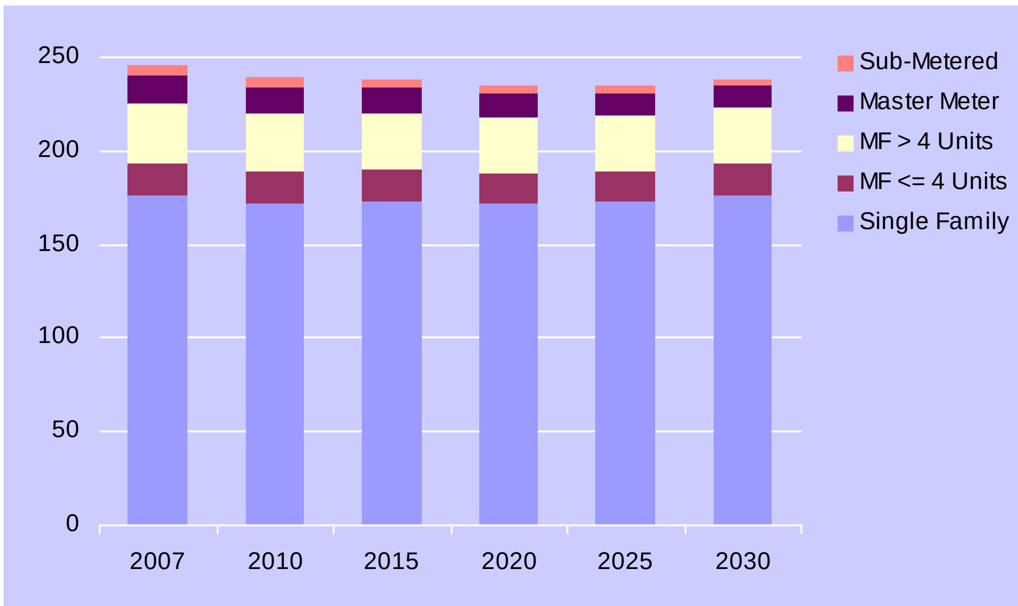
The total residential customer count for SoCalGas consists of five residential segment types. These are single family, small and large multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 5.23 million in 2007. This amount reflects a 53,326 meter increase relative to the 2006 total. The overall observed 2006-2007 residential meter growth was 1.03%.

During the forecast period covering 2008 through 2030, residential meters are estimated to increase at an average annual rate of 1.38%. Forecasted population growth in SoCalGas' service territory is expected to drive an increase in connected residential single family and multi-family customers. In contrast, master meter and sub-metered customers, which constitute only a small portion of the overall residential customer count, have been declining in recent years because existing master meters and sub-meters are being converted to individually-metered customers. Over the forecast period, the master meter and sub-metered customer counts are expected to decline by an average of 0.69% per year, or about 294 less active master meters and submeters per year. By the year 2030, the total residential meter count is expected to reach 6.86 million in aggregate.

Use per meter for all classes of residential customers is anticipated to decline due to the expected energy savings from tightened building and appliance standards and utility energy efficiency programs. In 2007, the single family and multi-family average annual use per meter were 515 therms and 312 therms, respectively. By 2030, the single and multi-family average use per meter is forecasted to decline to 436 and 239 therms, respectively. This change reflects a 15.34% overall decline in single family households' temperature-adjusted use per customer, or alternatively, an average annual decline in use per customer of 0.67%. For multi –family households, the overall decline in use per customer is expected to be 23.4%, or an average annual decline in use per customer of 1.02%. The expected decline in use per customer can be explained by the continued improvements in energy efficiency of appliances, tighter building shells and the cumulative impact of energy efficiency programs administered by the utilities.

The projected residential natural gas demand will be influenced primarily by residential meter growth, the forecasted declining use per customer, and the gradual attrition of submeter and master meter customers. The weather-adjusted residential demand forecast, on average, is expected to decline by 0.12% per year. In 2007, temperature adjusted residential demand was 245 Bcf. By the year 2030, residential demand is expected to decline to 239 Bcf. The difference reflects an average decrease of 0.3 Bcf per year. The graph below illustrates the projection

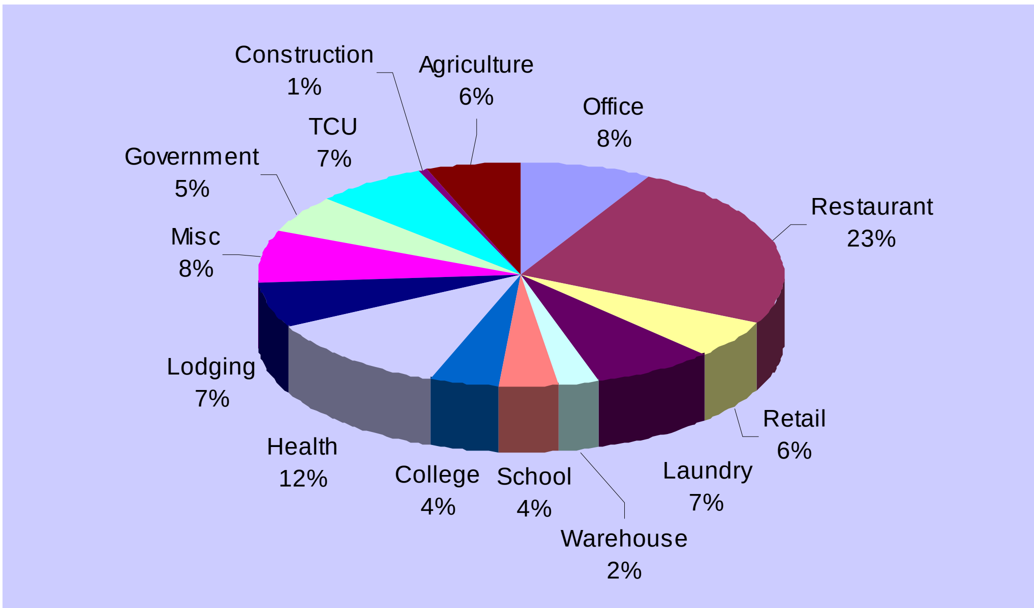
Annual Residential Demand Forecast (Bcf)



Commercial

The commercial market consists of 14 business types identified by the customer's North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 23% of the usage in 2007.

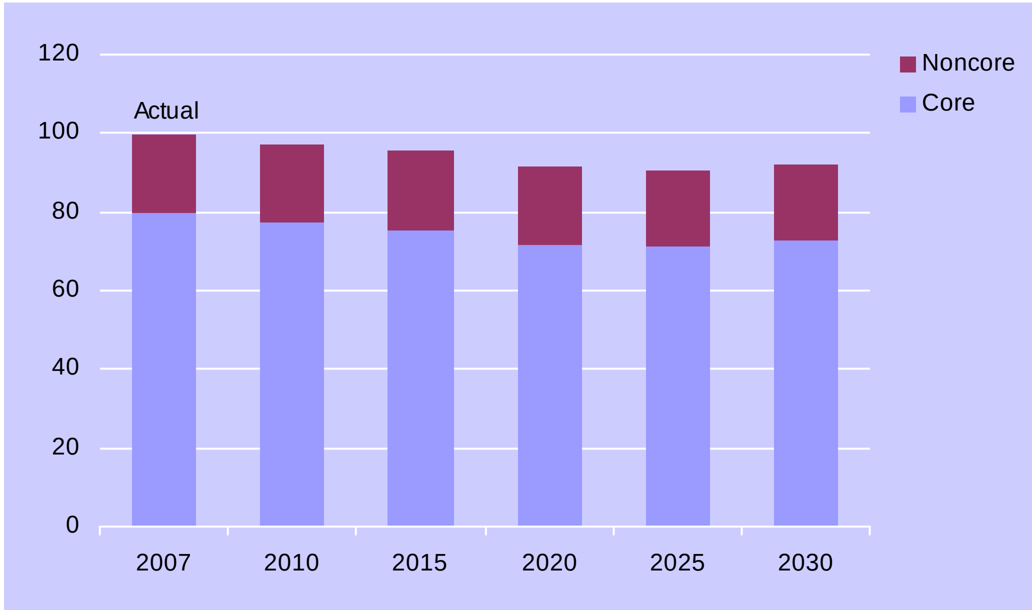
Commercial Gas Demand by Business Types



On a temperature-adjusted basis, core commercial market demand in 2007 totaled 82 Bcf, up about 2.7 Bcf, or 3.4%, from 2006. On average, the core commercial market demand is expected to decrease about 0.4% per year, over the next 23 years, to just below 75 Bcf in 2030. The decrease in gas usage is mainly the result of gas demand decreases expected from the impact of CPUC-authorized energy efficiency programs in this market.

The noncore commercial market has stabilized in the last two years after five consecutive years of losses due to the migration of non-core customers to core customer status. The migration has ceased and no additional movement is projected in this forecast. Noncore commercial demand in 2007 was 20 Bcf - unchanged from 2006 level. Last year, the large drop in office space demand in the defense industry is being offset by strong gain in the healthcare industry. The non-core commercial market is expected to show some modest growth by 2030. However, aggressive CPUC-authorized energy efficiency programs targeted at this market is expected to flatten demand to 20 Bcf by 2025. Even though the change is negligible, gas demand at some industries such as office, transportation, communications and utilities (TCU) are expected to grow faster than others such as retail, government and education.

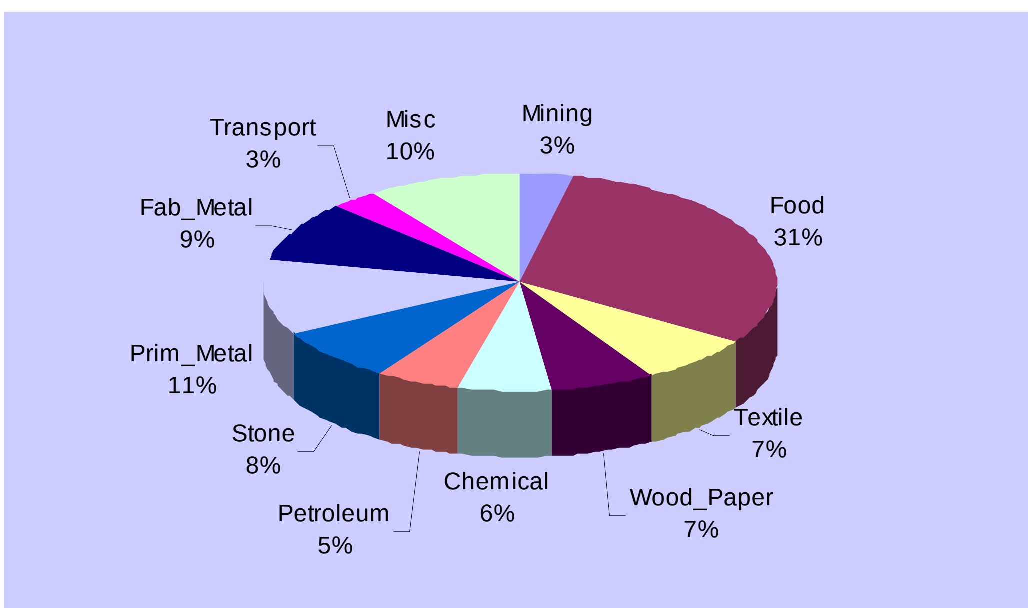
Annual Commercial Demand Forecast (Bcf)



Industrial

Industrial gas demand in 2007 by business types served by Southern California Gas is shown below. Strong gas demand for food processing has replaced gas demand lost in the textile, petroleum and wood/paper businesses. Food processing has grown from 25% of the industrial market in 2003 to 31% by 2007.

Non-Refinery Industrial Gas Demand by Business Types

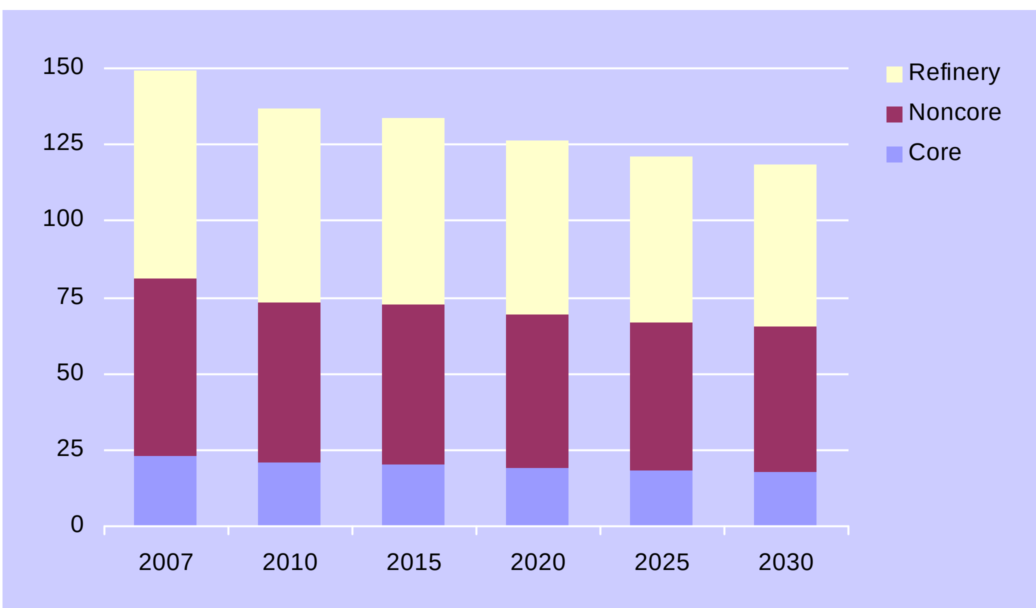


In 2007, temperature-adjusted core industrial demand was 23 Bcf which is 0.3 Bcf (1.3%) lower than 2006 deliveries. Core industrial market demand is projected to decrease by 0.8% per year from 22 Bcf in 2008 to 18 Bcf in 2030. This decrease in gas demand results from a combination of a slightly lower forecasted growth in industrial production, minor increases in marginal gas rates and the impact of CPUC-authorized energy efficiency programs savings in this market.

After several years of stable gas demand, the retail non-core industrial gas demand is finally showing signs of weakness due the closure of several large accounts in the container, gypsum and cheese manufacturing business. Furthermore, industrial demand in 2007 dropped 6.5% from 2006 level at all sectors, including mining, textile, pharmaceutical, wood/paper, stone, primary metals and fabricated metal manufacturing. The only bright spot is food processing, which has been showing a steady growth increase of 4% annually since 2003.

Gas demand for the retail non-core industrial market as a whole is expected to decline at a rate of 0.9% annually, from an actual of 60 Bcf in 2007 to a projected demand of 49 Bcf by 2030. The reduced demand is primarily due to the departure of customers within the City of Vernon to wholesale service by the City of Vernon, the Commission-authorized energy efficiency programs designed to reduce gas demand, the expected slowdown of economic activity mostly in the mining, textile and petroleum sectors, and lastly the gradual decline in energy intensity among all sectors. By 2030, the energy efficiency programs-induced demand reductions and the transition for wholesale service by the City of Vernon are expected to reduce non-core industrial load by 4.4 Bcf and 3.8 Bcf, respectively.

Annual Industrial Demand Forecast (Bcf)



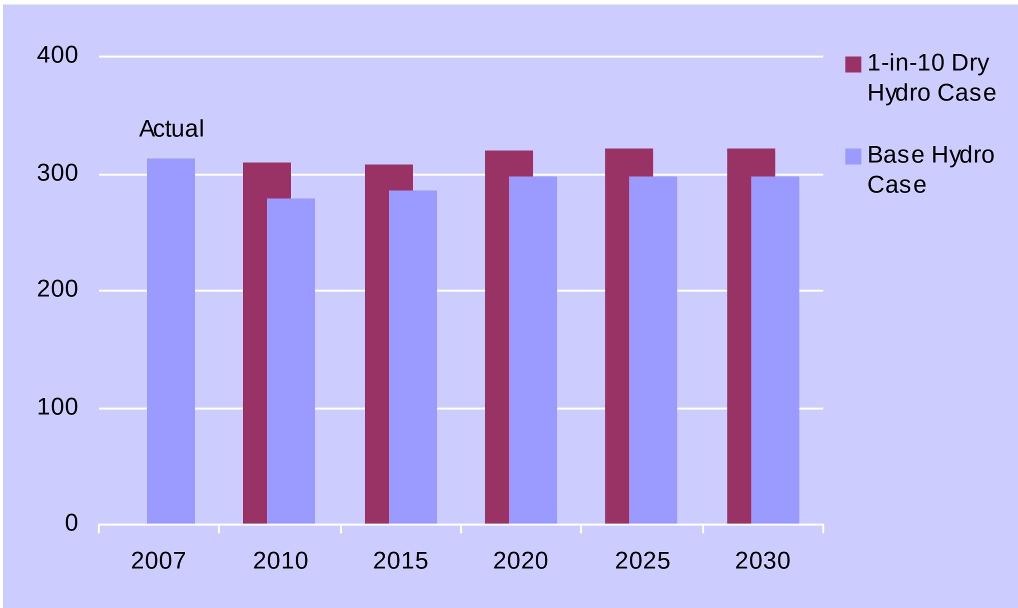
Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial gas demand is forecast to decline 0.9% per year, from 68 Bcf in 2007 to 53 Bcf in 2030. The majority of the decrease is due to the estimated savings from both Commission-authorized energy efficiency programs and other refinery process related energy efficient improvements that are not eligible for SoCalGas' Energy Efficiency programs. The reduction of refinery gas demand also reflects the effect of refiners' using alternate fuels such as butane during summer months when their cost of natural gas is forecasted to be less competitive than the cost of these alternate fuels.

Electric Generation

This sector includes the following markets: all commercial/industrial cogeneration; EOR-related cogeneration; and, non-cogeneration electric generation. It should be noted that the forecasts of EG-related load are subject to a higher degree of uncertainty due to the following: the continued operation of existing generation facilities; the timing and location of new generation facilities in the western United States; the regulatory and market decisions that impact the operation of existing cogeneration facilities; the timing and construction of new renewable resources; the construction of additional electric transmission lines, and future GHG regulations. The forecast is based on a power market simulation for the period 2008 to 2015 and thus reflects the anticipated dispatch of all of the EG resources in the SoCalGas service territory under base electricity demand and both the average and the low hydroelectric availability market conditions. The base case assumes that 20% of the state's energy needs are met with renewable power by 2012 and additional renewable power is added after 2012 to maintain the 20% level.

Due to the large uncertainty in the timing and type of generation plants that would be added after 2015, the 2020 value was developed by growing the 2015 usage by the same rate as electric energy growth, minus the part that would be met with renewable power. The forecast also assumes that new lower GHG generation sources will be developed and built in a large enough quantity to influence the demand for natural gas after 2020 and thus the EG forecast is held constant at 2020 levels for 2025 and 2030. The following graph shows total cogeneration and non-cogeneration EG forecasts for normal year and 1-in-10 dry hydro year.

SoCalGas Service Area Total Electric Generation Forecast (Bcf)



Industrial/Commercial/Cogeneration <20MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. In 2007, recorded gas deliveries to this market were 21 Bcf, or 1.2 Bcf higher than 2006 deliveries and 1 Bcf higher than 2005 deliveries. Projected demand in this market segment is separated into existing load and added load from expected participation in the CPUC-authorized Self-Generation Incentive Program (SGIP). The existing load is expected to grow at a modest rate tied to the gradual growth of business activity, whereas the added load is expected to grow at a faster rate due to SGIP. This forecast assumes funding for the SGIP would be extended to 2017. Overall, the cogeneration demand is projected to grow to 23 Bcf by the year 2030.

Industrial/Commercial Cogeneration >20 MW

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecast to remain relatively constant from 52 Bcf in 2008 to 53 Bcf in 2020. Although there is uncertainty in this sector as contracts come up for renewal, This forecast assumes that these facilities will continue to be cost – effective and thus will continue to operate at historical levels. This may change in the future which could therefore have a significant impact on the forecast. Furthermore, this sector could also be impacted by GHG regulations.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to decline 0.3% per year, from 18 Bcf in 2007 to 17 Bcf in 2030, mainly due to projected fuel switching in the summer months.

Enhanced Oil Recovery-Related Cogeneration

In 2007, recorded gas deliveries to the EOR-related cogeneration market were 22.6 Bcf, an increase of 5.7 Bcf due to higher usage by cogenerators under SoCaGas' long-term EOR transportation contracts. EOR-related cogeneration demand is expected to decrease slightly to 22.0 Bcf in 2008 and then to 6.6 Bcf in 2009 as several of SoCalGas' long-term EOR gas transportation contracts expire. Demand is forecast to level off in 2010 at 3.7 Bcf and remain at that level for the remainder of the forecast period.

Non-Cogeneration Electric Generation

For the non-cogeneration EG market, gas demand is forecast to remain relatively flat from 200 Bcf in 2008 to 202 Bcf in 2020. This forecast is the result of several factors. The transition from a dryer 2008 hydroelectric conditions to a normal hydroelectric conditions after 2008, the addition of more efficient power plants, the addition of new electric transmission lines, and renewable goals.

SoCalGas' forecast includes 3,700 MW of new thermal generating resources, both combined cycles and peaking units in its service area by the end of 2015. However, 600 MW of older plants were retired as a result of direct replacement. Throughout the entire planning period that was modeled, SoCalGas assumes that market participants will construct additional generation resources such that the Western Electricity Coordinating Council maintains a minimum planning reserve margin of 15%. For electricity demand within California, SoCalGas used the California Energy Commission's (CEC) *California Energy Demand 2008-2018, Staff Revised Forecast* (http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF.PDF) with the incremental 2009-2016 energy efficiency savings for IOUs as ordered by the California Public Utility Commission D.07-12-052. For electric end-use demand outside of California, SoCalGas used Ventyx's electric demand forecast.

Starting in 2008, renewable electricity generation was ramped up to meet 20% of the state's total electric energy distributed in 2012. The renewable-sourced energy generation in 2012 was estimated by taking 20% of the forecasted load from the CEC's California Energy Demand 2008-2018, Staff Revised Forecast. Additional renewable generation was then added in each year to keep the renewable power at 20% of electricity demand.

Due to the large uncertainty in the timing and type of generation plants that would be added after 2015, the 2020 value was developed by growing the 2015 usage by the same rate as electric energy growth, minus the part that would be met with renewable power. The forecast also assumes that new lower GHG generation sources have been developed and built in a large enough quantity to influence the demand for natural gas. However, the EG forecast is held constant at 2020 levels for 2025 and 2030, since this is the time frame where new technology will likely begin to impact overall EG demand. SoCalGas performed a dry hydro sensitivity gas demand forecast. This dry hydro forecast had more impact on the SoCalGas system in the earlier years than the later years. A 1-in-10 dry hydro year, as defined by the CEC, is expected to raise gas demand to 40 Bcf in 2009 before leveling off to 22 Bcf in 2015.

Uncertainties in achieving renewables goals and electric demand will affect the gas demand forecast for electricity generation. For sensitivity analyses of gas demand to EG demand and the renewables goal, SoCalGas uses the average Southern California natural gas plant heat rate of 8,300 Btu/KWh and an UAF factor of 1.0305 MMBtu/MCF of gas. SoCalGas expects that for each additional 1000 GWh of EG demand, gas demand would grow by 8 Bcf, assuming all the growth comes from Southern California gas-fired power plants. If the percentage of renewable energy increases by 1% in Southern California (approximately 1,800 GWh), EG gas demand would decrease by 14 Bcf, assuming all the decrease comes from Southern California gas-fired power plants.

Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2007 were 14.3 Bcf, a slight increase of 0.1 Bcf from 2006. SoCalGas' EOR steaming demand is expected to decrease to 12.5 Bcf in 2008 as SoCalGas' long-term EOR gas transportation contracts terminate in late 2008. From 2009 through the end of the forecast period, usage is expected to be approximately 10.2 Bcf. These figures include gas delivered to PG&E's EOR customers through inter-utility exchange. In 2007, 0.004 Bcf of gas was delivered to PG&E through such arrangements. No change in demand is expected in that market. The EOR-related cogeneration demand is discussed in the Electric Generation sector.

Crude oil prices are forecast to remain high over the forecast period which may result in some expansion of California EOR operations in some fields. However, this expansion is forecast to be offset by declining oil production in other fields as the fields are depleted. For gas supplies, oil producers will rely increasingly on interstate pipelines in California to supplant traditional supply sources, such as own source gas and SoCalGas' transportation system.

Wholesale and International

SoCalGas provides wholesale transportation service SDG&E, the City of Long Beach Electric and Gas Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon) and Ecogas. The wholesale load is expected to increase from 152 Bcf in 2008 to 176 Bcf in 2030.

San Diego Gas & Electric

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to increase at an average growth rate of 0.5% per year from 119 Bcf in 2008 to 133 Bcf in 2030. Refer to SDG&E's section for more information.

City of Long Beach

For the City of Long Beach, SoCalGas used the forecast prepared by Long Beach for this report. Long Beach's gas use is expected to increase from 10.9 Bcf in 2008 to 11.2 Bcf in 2030. Long Beach's local deliveries are expected to decline from about 2.1 Bcf in 2008 to 0.6 Bcf in 2030. SoCalGas' transportation to Long Beach is expected increase from 8.8 Bcf in 2008 to 10.6 Bcf in 2030. Refer to City of Long Beach Municipal Gas & Oil Department for more information.

Southwest Gas

The demand forecast for Southwest Gas is based on a long-term demand forecast prepared by Southwest Gas. In 2008, SoCalGas will serve approximately 7.1 Bcf directly, with another 2.8 Bcf being served by PG&E under exchange arrangements with SoCalGas. The load is expected to grow by 1.7% per year from 9.9 Bcf in 2008 to approximately 15.2 Bcf in 2030.

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June, 2005. The forecasted throughput starts at 9 Bcf in 2008 and increases to 12 Bcf by 2030. Vernon's commercial and industrial load is based on recorded 2006 and 2007 usage for commercial and industrial customers already served by Vernon plus those additional customers that are expected to request retail service from Vernon. The throughput forecast for the EG customers is based on a power market simulation.

Ecogas Mexico, S. De R.L. De C.V (Ecogas)

SoCalGas used the forecast prepared by Ecogas, Mexicali, for this report. Mexicali's use is expected to stay steady at 5.3 Bcf/year.

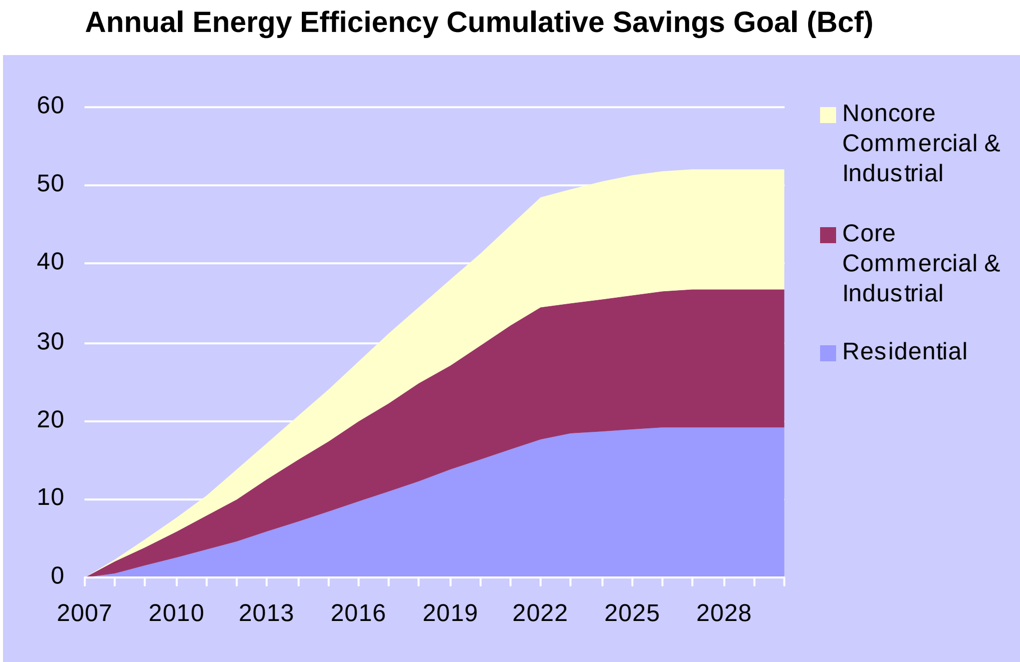
Natural Gas Vehicles (NGV)

The NGV market is forecast to continue to grow due to federal, state and local incentives and regulations related to the purchase and operation of alternate fuel vehicles coupled with rapidly increasing cost of petroleum (gasoline and diesel). At the end of 2007, there were 216 compressed natural gas (CNG) fueling stations serving approximately 20,000 vehicles that consumed 8.6 Bcf of natural gas during the year. SoCalGas remains optimistic about the NGV market's growth, forecasting an increase in demand from 8.6 Bcf in 2007 to 18.0 Bcf in 2015 and 41.4 Bcf in 2030. The growth is being propelled by the private and public sectors, with customer support from SoCalGas' Clean Transportation program.

ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is shown in the graph below. The net load impact includes all Energy Efficiency programs that SoCalGas and SDG&E have forecasted to be implemented starting from the years 2008 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.



Savings reported are for measures installed under SoCalGas' Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SoCalGas' Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SoCalGas' 2006-2008 Energy Efficiency program portfolio are contained in SoCalGas' Advice Letter 3588 which was submitted on February 1, 2006 and became effective March 3, 2006. SoCalGas is expected to submit its proposed 2009-2011 Energy Efficiency program on June 23, 2008.

Notes:
(1) Energy Efficiency load impacts include 2003-2004 program savings, but do not include pre-2003 program savings.
(2) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(3) SoCalGas does not include "soft" impacts, e.g., energy management services type measures.
(4) The assumed average measure life is 15 years.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

Southern California Gas and San Diego Gas & Electric receive gas supplies from several sedimentary basins in the western United States and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountain, Western Canada, and local California supplies. Recorded 2003 through 2007 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

California Gas

Gas supply available to SoCalGas from California sources (state onshore plus state/federal offshore supplies) was 232 MMcf/day in 2007.

Southwestern U.S. Gas

Traditional Southwestern U.S. sources of natural gas, especially from the San Juan Basin, will continue to supply most of Southern California's natural gas demand. This gas is delivered via the El Paso Natural Gas Company and Transwestern Pipeline Company pipelines. The San Juan Basin's conventionally produced gas supplies have peaked in 1999 and has been declining at annual rate of -1.4%. Permian Basin's gas also provides an additional source of supply into California.

Rocky Mountain Gas

Rocky Mountain supply presents a viable alternative to traditional Southwestern U.S. gas sources for Southern California. This gas is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Production from the Rocky Mountain region in 2007 has doubled since 2000 due to the successful applications of new technology to drill for coal-bed methane gas. For the first time, the annual average production rate has exceeded 10 Bcf/d in 2007. In recent years, Rocky Mountain gas has increasingly flowed to Midwestern and Pacific Northwest markets.

Canadian Gas

SoCalGas anticipates that the role of Canadian gas in meeting Southern California's demand during the forecast period will decline. New pipeline capacity out of western Canada to the U.S. Midwest and eastern United States are likely to move Canadian gas away from California. Increased gas deliveries from the Rockies and Permian Basin to California are expected to replace these supplies.

Liquefied Natural Gas (LNG)

With the completion of the Costa Azul LNG terminal in Baja California, Mexico in May 2008, LNG is expected to be an important supply source to California. As for the other gasification facilities currently under the planning and permitting stage, it is uncertain as to how many other re-gasification facilities will actually be built and where they will be located on the West Coast of North America.

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day is theoretically is over 7,275 MMcf/day based on the Federal Energy Regulatory Commission (FERC) Certificate Capacity or SoCalGas estimated physical capacity of upstream pipelines. These pipeline systems provide access to several large supply basins, located in: New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and LNG.

Upstream Capacity to Southern California

Pipeline	Upstream Capacity (MMcf/d)
El Paso at Blythe	1,410
El Paso at Topock	540
Transwestern at Needles	1,150
PG&E at Kern River	650 (1)
Southern Trails at Needles	80
Kern/Mojave at Wheeler Ridge	885
Kern at Kramer Junction	500
Occidental at Wheeler Ridge	150
California Production	310
TGN at Otay Mesa	400
North Baja at Blythe	1,200
Total Potential Supplies	7,275

(1) Estimate of physical capacity.

FIRM RECEIPT CAPACITY

SoCalGas/SDG&E currently has firm receipts capacity at the following locations for its core customers to access supply from interstate pipelines.

SoCalGas/SDG&E Current Firm Receipt Capacity

Transmission Zone	Total Transmission Zone Firm Access (MMcf/d)	Specific Point of Access (1) (Limitations)(2) (MMcf/d)
Southern	1,210	EPN Ehrenberg (1,200) TGN Otay Mesa (400) NBP Blythe (1,200)
Northern	1,590	EPN Topock (540) TW North Needles (800) QST North Needles (120) KR Kramer Junction (500)
Wheeler Ridge	765	KR/MP Wheeler Ridge (765) PG&E Kern River Station (520) OEHI Gosford (150)
Line 85	160	California Supply
Coastal	150	California Supply
Other	N/A	California Supply
Total	3,875	

(1) Pipelines

EPN: El Paso Natural Gas Pipeline
TGN: Transportadora de Gas Natural de Baja California
NBP: North Baja Pipeline
TW: Transwestern Pipeline
MP: Mojave Pipeline
QST: Questar Southern Trails Pipeline
KR: Kern River Pipeline
PG&E: Pacific Gas and Electric
OEHI: Occidental of Elk Hills

(2) Transmission Zone Contract Limitations:

Southern Zone:

- In total EPN Ehrenberg and NBP Blythe cannot exceed 1,210 MMcfd.
- In total EPN Ehrenberg, NBP Blythe and TGN Otay Mesa cannot exceed 1,210 MMcfd.

Northern Zone:

- In total TW at Topock and EPN at Topock cannot exceed 540 MMcfd.
- In total TW at North Needles and QST at North Needles cannot exceed 800 MMcfd.
- In total TW at North Needles, TW Topock, EPN Topock, QST North Needles and KR Kramer Junction cannot exceed 1,590 MMcfd.

Wheeler Ridge Zone:

- In total PG&E at Kern River Station and OEHI at Gosford cannot exceed 520 MMcfd.
- In total PG&E Kern River Station, OEHI Gosford, and KR/MP Wheeler Ridge cannot exceed 765 MMcfd.

In 2007 SoCalGas purchased a 45-mile segment of pipeline from Questar which allows for pressure betterment in the Twentynine Palms area. The pipeline also provides additional capacity that allows SoCalGas to continue to maintain full delivery into the area under peak load conditions.

STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand. SoCalGas owns and operates four underground storage facilities located at Aliso Canyon, Honor Rancho, Goleta and Playa Del Rey. These facilities play a vital role in balancing the region's energy supply and demand.

Of SoCalGas' total 131.1 billion cubic feet (Bcf) of storage capacity, 79 Bcf is allocated to our Core residential, small industrial and commercial customers. About 5 Bcf of space is used for system balancing. The remaining capacity is available to other customers.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Market OIR

R.04-01-025 was issued in January 2004 and focused on the time period from 2006 to 2016 and sought to address a broad range of supply issues to increase demand reduction efforts, ensure sufficient interstate pipeline capacity to serve California, maximize the utilization and benefits of storage facilities, and enable access of imported liquefied natural gas (LNG) supplies. Each of the California natural gas public utilities where respondents to R.04-01-025, which was bifurcated into two phases; Phase 1 to address proposals regarding interstate capacity, and Phase 2 to address infrastructure adequacy.

Firm Access Rights and Off System Delivery

D.04-09-022 ordered SoCalGas to file a separate application to address its proposal for firm rights. In A.04-12-004, SoCalGas again put forth its proposal for a system of firm rights on the SoCalGas system and also to integrate the two gas transmission systems on an economic basis. The Commission subsequently bifurcated A.04-12-004 into two phases; Phase 1 would address system integration issues with regard to the SoCalGas and SDG&E systems and Phase 2 would address the firm access rights and off-system delivery issues.

SoCalGas' system integration proposal sought to combine the transmission-related costs of SDG&E and SoCalGas so that customers of each utility share in the transmission costs of both utilities. These integrated transmission rates would allow customers of SDG&E and SoCalGas to obtain gas at that rate from any existing or new receipt point on the SDG&E and SoCalGas systems. In April 2006, the Commission issued D.06-04-033 approving SoCalGas and SDG&E's system integration proposals.

The second phase of A.04-12-004 was initiated following the Commission's issuance of D.06-04-033 to address firm rights and off system deliveries. The Commission issued decision in Phase II. The decision addresses the issues concerning a system of firm access rights for SDG&E and SoCalGas. Other issues addressed were SDG&E and SoCalGas proposals for an off-system delivery service to PG&E Company and for a gas pooling service, and whether SoCalGas peaking rate tariff should be retained.

SoCalGas, SDG&E, and SoCal Edison Settlement

A final decision was issued in the "Omnibus" proceeding December 7, 2007 granting, in part, and denying, in part, the joint application of SoCalGas and SDG&E, and SCE filed on August 28, 2006. The application sought Commission approval to implement a range of revisions to the natural gas operations and service offerings of SoCalGas and SDG&E, relating to core operations, unbundled storage, and provisions for expansion of storage capacities, among other things. The proposal was an "integrated package" intended to implement provisions of two settlement agreements. The Edison Settlement is intended to resolve all issues between Edison and the Sempra Utilities in Investigation I.02-11-040 and I.03-02-033, and provides that Edison withdraw all claims in those proceedings. Many issues were deferred to the BCAP proceeding including the treatment of revenues associated with SoCalGas' unbundled storage program; the maximum rates for unbundled storage services; and certain concerns raised by the City of Long Beach and Southwest Gas Corporation regarding storage rate parity with the core customers of SDG&E and SoCalGas.

Biennial Cost Allocation Proceeding (BCAP)

SoCalGas and SDG&E filed their BCAP, A. 08-02-001, on February 4, 2008. The Prehearing Conference was held on April 3, 2008. The proceeding deals with issues deferred from the Omnibus proceeding as well as to update throughput forecasts, cost allocation, and rates by customer class. The BCAP has been bifurcated into two phases. Phase I will deal with core storage capacity allocation, the allocation of revenues between shareholders and customers of the unbundled Transactions Based Storage (TBS) program and cost ceilings on inventory, injection, and withdrawal services. Phase II will include the customer demand forecasts, Unaccounted For Gas (UAF) allocation by customer class, cost allocation of base margin and non-margin costs by customer class, and a new Transmission Level Service (TLS) closing the regulatory gap between CPUC- and FERC-regulated pipeline systems.

Other Ongoing Regulatory Issues

In the LNG OIR, R.07-11-001, the Commission established the OIR to examine issues relating to whether and how the largest California utilities should enter into procurement contracts for natural gas from liquefied natural gas ("LNG") suppliers on the West Coast. This rule making proceeding is currently in progress.

In Decision D. 07-06-013 the Commission provided for the issuance of an order instituting rulemaking (OIR) to review the gas utilities' incentive mechanisms by no later than December 2007. The Commission modified the decision to delay the OIR's issuance date to June 2008, in order to avoid scheduling conflicts with SoCalGas' BCAP.

FEDERAL REGULATORY MATTERS

SoCalGas participates in FERC proceedings relative to interstate capacity serving California because these cases can affect the cost of gas delivered to customers. SoCalGas holds contracts for interstate transportation capacity on El Paso, Kern River, GTN and Transwestern pipelines.

El Paso Natural Gas Company plans to file a rate case in June 2008 with proposed rates effective January 1, 2009. The current three-year settlement expires December 31, 2008. SoCalGas plans to intervene and participate actively in the upcoming rate case, with a focus on rates and services.

Kern River filed its rate case in November 2004. In this highly contentious case, rate design, particularly Kern's levelized methodology, and return on equity (ROE) are two of the most controversial issues. In a recent opinion issued on April 17, 2008, the FERC approved Kern's levelized rate design methodology and re-opened the case to only consider the inclusion of Master Limited Partnerships in the proxy group used for determining Kern's ROE. A decision on this aspect of the case is expected by year end 2008. Concomitantly, BP Energy and Calpine Corporation, who oppose the FERC's rulings in this case, have submitted the FERC rulings for review in the U.S. Circuit Court of Appeals.

Transwestern filed a rate case on September 29, 2006. Key issues in this case were the proposed fuel and reservation rate increases and gas quality standards. Shippers filed a settlement agreement on February 1, 2007 that resolved all issues except for gas quality standards for Wobbe and Btu content. FERC approved the uncontested settlement on June 26, 2007. On February 29, 2008, Transwestern submitted a request to FERC to withdraw its revised tariff sheets proposing Wobbe and Btu quality specifications and defer the issue to the next rate case. This request was accepted by FERC on April 14, 2008. The Settlement has a 5-year term.

Another proceeding of note is the North Baja Pipeline (NBP) expansion. On February 7, 2006, TransCanada filed an application for a two-phase expansion of its North Baja Pipeline. The project proposed to import up to 2.7 Bcf/day of Liquified Natural Gas (LNG) supply from terminals in Baja California. The project links to a corresponding expansion of the Gasoducto Bajanorte line in Mexico. North Baja connects with the SoCalGas' system at the Blythe Meter Station site. Phase I of the project went into service April 2008; the anticipated in-service date for Phase II is June 2010.

GREENHOUSE GAS ISSUES

National Policy

National greenhouse gas (GHG) policy is currently under development and will likely evolve along two paths, through federal Environmental Protection Agency (EPA) rulemaking and Congress. EPA is preparing to develop GHG regulations within the framework of the Clean Air Act, as soon as it makes a finding that GHG emissions are an endangerment to human health. This is expected later this year. In parallel, there are a number of different bills proposed in the Senate and the House intending to establish a new national GHG emission reduction program. In general, the programs will all be designed to reduce national GHG emissions, and the electric utility sector will bear much of the reduction requirements in a number of the bills.

Restriction on New Conventional Coal Generation

Many bills would prohibit new coal-fired generation unless it includes carbon sequestration. Since carbon sequestration technology is not yet proven, in the near term, new generation will likely be dependent upon natural gas. Even absent a prohibition on coal generation without sequestration, the prospect of future carbon regulation can be expected to stifle coal investments, at least until the specific form of that regulation is known. Therefore as California's electricity demand increases, California as well as the rest of the country will likely become more dependent upon new natural gas generation to meet needs that cannot be met through renewable resources. This increase in national demand for natural gas, combined with future anticipated reductions in available North American natural gas supplies, may tighten supplies to California.

Reduction in GHG Emissions from the Electric Sector

Many national legislative proposals would establish a national cap on GHG emissions that declines over time. Since existing conventional coal power plants have higher emissions than their natural gas-fired counterparts, there will be pressure to reduce the use of these older coal plants and increase the construction and use of natural gas-fired and renewable plants. Absent corresponding decreases in national demand for natural gas-fired generation (through enhanced energy efficiency requirements and other measures such as a national RPS) this will increase national demand for natural gas.

Under a GHG cap & trade program, GHG emission allowances could be allocated on a fuel-neutral basis based upon MW output. This maximizes incentives for high emitters to reduce their emissions while properly recognizing prior actions that have reduced GHG emissions. It also maximizes the incentives for zero emitting resources to enter the market, because they would have the opportunity to sell allowances when they enter as a result of their extremely low emission profile. In short, such a structure maximizes incentives to use the most efficient and lowest GHG-emitting electric generation technologies.

Motor Vehicle Emission Reductions

National GHG policy-makers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Some legislative proposals consider reducing the use of all fossil fuels, without recognizing the fact that natural gas use may need to actually increase, at least in the near term, to meet the needs of a cleaner national transportation fleet.

California Policy

California is in the process of implementing a broad portfolio of policies and regulations aimed at reducing greenhouse gas (GHG) emissions. This process is a collaborative effort underway at the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the California Air Resources Board (ARB). ARB however is statutorily empowered with rendering the final decision on the GHG regulatory framework and compliance. Policies under consideration include both programmatic measures and market-based mechanisms to reduce GHG emissions.

Emission Performance Standard

On January 25, 2007, the CPUC adopted an interim GHG Emission Performance Standard (EPS) pursuant to SB 1368. This is a facility-based emission standard requiring that all new long-term commitments for base-load generation to serve California consumers be built with power plants that have emissions no greater than a combined cycle gas turbine plant – 1,100 pounds of CO_2 (carbon dioxide) per megawatt-hour. New long-term contracts covered under the EPS standard include new plant investments, new or renewal contracts with a term of five years or more or major investments by the utility in its existing base-load power plants. These emission-based standards may be revisited once an emission cap is operational in California pursuant to AB 32.

The EPS effectively eliminates the ability for California LSEs to procure electricity from coal resources, thereby increasing the need for new renewable generation and natural gas-fired generation resources (for baseload generation and to address the reliability needs associated with increased reliance on intermittent renewable generation resources).

Low Carbon Fuel Standards

On January 18, 2007, Governor Schwarzenegger signed an Executive Order establishing the low carbon fuel standard (LCFS). LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. It is recognized that 40 percent of California's GHG emissions are attributable to the transportation sector and 96 percent of the state's transportation needs require petroleum-based fuels. The LCFS requires fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, a declining standard for GHG emissions measured in CO2-equivalent gram per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for both natural gas and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet, which will increasingly utilize electricity and natural gas in the future.

CPUC/CEC Interim Recommendations on Point of Regulation

On March 13, the CPUC approved interim recommendations to the Air Resources Board on a number of policies and requirements for GHG emissions reductions from the electricity and natural gas sectors. These recommendations, which resulted in collaboration and joint decisions by the CPUC and CEC, may be adopted as part of the ARB scoping plan for its further work in implementing AB 32, which requires that statewide GHG emissions be reduced to 1990 levels by 2020. The CPUC and CEC recommend that ARB adopt a mix of direct mandatory/regulatory requirements and a cap-and-trade system (C&T) for the energy sectors, but also recommends that the natural gas sector not be included in a cap and trade system at this time. It was recommended that for now reductions in the natural gas sector should come exclusively from mandatory measures (primarily energy efficiency programs).

The referenced "natural gas sector" in the interim decision, does not include sources likely to be directly regulated by the ARB - large point sources using natural gas and electricity generation fueled by natural gas. Specifically, the "natural gas sector" would exclude all natural gas used for electric generation including all natural gas used by cogeneration facilities (including the thermal use of the co-generator). The "natural gas sector" would also exclude all utility deliveries to wholesale customers, to avoid double counting. For distribution operations of utilities, it would include only the natural gas combustion not covered directly by ARB as large point sources and fugitive emissions associated with the distribution and transmission systems. For interstate pipelines, it would include the combustion of all customers served directly by the interstate pipeline that are not large point sources, all interstate pipeline natural gas combustion in the state of California not covered as large point sources, and all fugitive emissions within the state of California. The natural gas consumption and fugitive emissions of independent natural gas storage facilities would be included if they are not covered directly by ARB as large point sources. All stationary combustion sources emitting > 25,000 MT CO_2/year would be regulated by ARB as large point sources.

It has not been determined if residential and small industrial natural gas customers will be included in a C&T program. Although a programmatic approach to reducing emissions from remaining emitters in this sector plus the development of offsets in this sector could be used for compliance in the capped sector. Allowing firms in this sector to be a source of offsets effectively provides incentives for these smaller customers to find low GHG reductions and connects this sector with the capped sector. Natural gas combustion in utility operations, interstate pipelines, and independent storage producers may be excluded in a C&T system. These kinds of emissions are not easily subject to measurement or verification. Fugitive emissions, including from pipelines, storage facilities, and compressor stations are not easily subject to accurate measurement or verification and are therefore better addressed through programs aimed at best practices in managing leaks and other methane emissions. Natural gas used as a feedstock may also be excluded from the natural gas sector.

Programmatic Emission Reduction Measures

The Commissions and ARB are considering a variety of non-market based measures to reduce GHG emissions. Some of these programs include, the California Energy Efficiency Green Building Standards, which include both residential and commercial new and retrofit, the Green State Buildings Executive Order, CPUC's adopted goal of "zero net energy" for all new residential construction by 2020 and a similar goal for commercial buildings by 2030, potential Combined Heat and Power and Distributed Generation portfolio standards or feed-in tariffs, and increasing the renewable portfolio standard to 33%. Energy Efficiency and renewables are considered fundamental to emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas fired CTs.

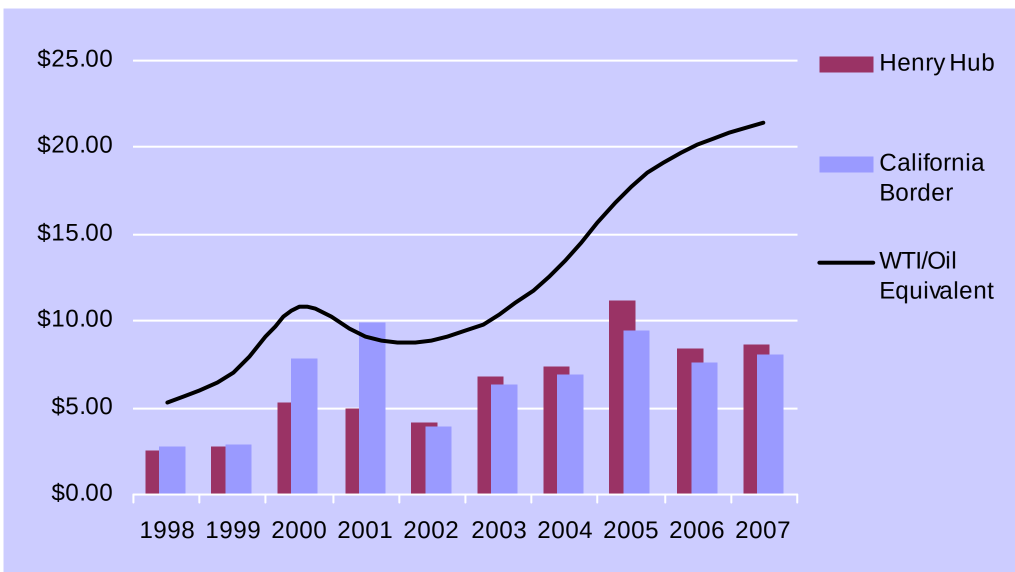
A decision adopting final CPUC and CEC recommendations to the ARB, which would include treatment of the natural gas sector under AB 32, is scheduled for September 2008. The CPUC and CEC's recommendations are limited to the electricity and natural gas sectors. The first indication on policy direction by ARB, which will describe the regulatory framework in which California will reduce GHG emission levels to 1990 by 2020, including whether a multi-sector C&T system will be implemented, the sectors to be included in the C&T system, and the emission cap for each sector will not be available until ARB releases their draft Scoping Plan in June 2008. ARB is scheduled to adopt its final Scoping Plan by November 2008. The final Scoping Plan is to be adopted and in effect by January 1, 2009. By 2012 GHG reduction measures are enforceable. The Scoping Plan will be updated by ARB every five years.

GAS PRICE FORECAST

MARKET CONDITION

The upward pressure on natural gas prices in 2007 and beyond is due to a combination of unprecedented oil price increases, strong growth in natural gas consumption, particularly in the electric generation sector, and higher exploration and production costs. Yearly average natural gas prices in 2007 have risen more than 230 percent over the last 10 years; however, the price of natural gas is still trading at a discount to crude oil as indicated by the price of West Texas Intermediate (WTI) crude oil as shown in the chart below.

Recorded Annual Natural Gas and Oil Equivalent Prices in Constant 2007 Dollars/MMBtu



Current North American production from conventional supplies has been declining, particularly at the Western Canadian Sedimentary Basin and offshore production in the Gulf of Mexico. However, with advance technology in horizontal drilling, proven reserves from unconventional resources has been soaring due to the unlocking of trapped gas from shale, tight sands and coal bed methane in the Mid Continent and Rockies. The new technology is successful at finding trapped gas that was not economical before, but is economic at the current substantially higher prices. The aggressive expansion in the production of shale gas in the Mid Continent and continuing growing production of coal bed methane in the Rockies is expected to relieve some of the price pressure in the next few years

With world-wide LNG prices at nearly twice the current price at Henry Hub, LNG imports in the short-term are expected to be limited with no direct impact on domestic supply or price. In the long-run however, more LNG will be available when the new generation of liquefaction trains are reliably operated; although world-wide demand will most likely dictate the amount of LNG supplies delivered to North America.

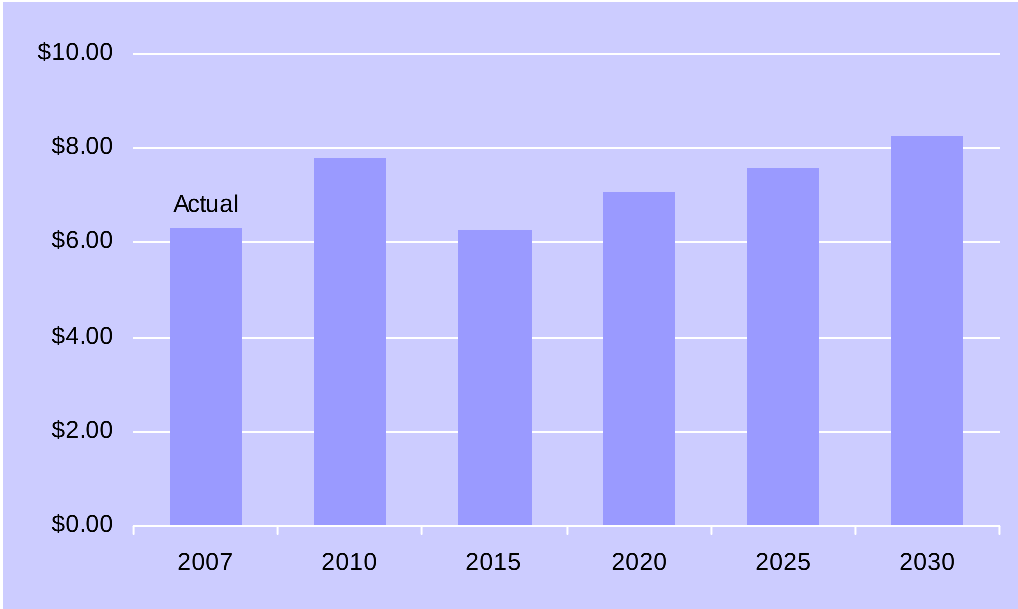
Therefore, industry experts prognosticate that gas prices can be expected to remain relatively high and volatile during the forecast period due to the high production costs, growing global demand for LNG and increasing demand for clean natural gas for electric power generation. This expectation is corroborated by the New York Mercantile Exchange's (NYMEX) natural gas futures prices and by industry experts' opinions in the public and private sectors.

DEVELOPMENT OF THE FORECAST

The base 2008 CGR Gas Price Forecast (2008 CGR GPF) used to develop the gas demand forecasts was prepared generally consistent with the methodology described in D.05-12-042 for the Renewables Portfolio Standard 2005 Market Price Referent. The 23-year 2008 CGR GPF is comprised of forecasts for three time frames, each utilizing a different method. The three-year short-term forecast from 2008 to 2010 was derived from the last 22-trading days of the NYMEX natural gas futures prices in March 2008. The long-term forecast from 2013 to 2030 was averaged using three forecasts from the California Energy Commission (CEC), the Energy Information Administration (EIA) and private sources that relied on fundamentals-based models, and the intermediate-term forecast from 2011 to 2013 was a straight blend between the short-term and long-term forecasts. Natural gas prices are expected to bottom out at $6.00/Dth in constant 2007 dollars in 2014 before showing real price increases as demand catches up with supply after 2014.

It is important to recognize that natural gas prices have been much more volatile than in the past, and no price forecast can be expected to account for all uncertainties. SoCalGas and the participants of the 2008 CGR do not warrant the accuracy of the gas price projection. In no event shall SoCalGas or the participants of the 2008 CGR be liable for the use or reliant of the natural gas price forecast.

Project Annual Weighted Average Cost of Gas
in Constant 2007 Dollars/MMBtu



PEAK DAY DEMAND AND DELIVERABILITY

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. The extreme peak day design criteria is defined as a 1-in-35 likelihood event for each utility's service area. This criteria correlates to a system average temperature of 38.8 degrees Fahrenheit for SoCalGas' service area and 41.8 degrees Fahrenheit for SDG&E's service area.

Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The firm storage withdrawal amount of 2,225 MMCF/day is the value SoCalGas and SDG&E have recommended to hold to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers in their 2009 BCAP (Phase I) prepared direct testimony. Firm withdrawal plus firm pipeline supplies must be sufficient to meet peak day operating requirements. The following table provides an illustration of how storage and flowing supplies can meet the growth in forecasted retail core peak day demand for a summer peak and a winter peak.

Retail Core Peak Day Demand and Supply Requirements (MMcf/Day)

Year	SoCalGas Retail Core Demand (1)	SDG&E Retail Core Demand (2)	Total Demand	Firm Storage Withdrawal (3)	Required Flowing Supply
2009	3,084	420	3,504	2,225	1,279
2010	3,083	425	3,509	2,225	1,284
2011	3,079	430	3,510	2,225	1,285
2012	3,085	434	3,520	2,225	1,295
2013	3,089	439	3,528	2,225	1,303
2014	3,091	444	3,535	2,225	1,310
2015	3,080	449	3,529	2,225	1,304

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) This is the amount SoCalGas and SDG&E have recommended to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers in their 2009 BCAP (Phase I) prepared direct testimony.

The tables below provide system-wide peak day demand projections on SoCalGas' system for both winter (December month) and summer (August month) periods.

Winter Peak Day Demand (MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2009	3,084	1,017	1,201	5,302
2010	3,083	1,022	1,057	5,162
2011	3,079	1,025	1,103	5,207
2012	3,085	1,030	1,088	5,203
2013	3,089	1,034	1,070	5,192
2014	3,091	1,039	1,136	5,267
2015	3,080	1,040	1,119	5,239

Notes:
(3) 1-in-35 peak temperature cold day SoCalGas core.
(4) 1-in-10 peak temperature cold day for Hdd-sensitive load. Includes SoCalGas non-core and wholesale non-EG.
(5) UEG/EWG Base Hydro + all other EG.

Summer Peak Day Demand (MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2009	614	545	2,266	3,424
2010	618	543	2,171	3,332
2011	621	542	2,179	3,341
2012	624	542	2,122	3,288
2013	626	542	2,062	3,230
2014	628	541	2,363	3,532
2015	628	537	1,941	3,106

Notes:
(1) Average daily summer (August) demand SoCalGas core.
(2) Average daily summer (August) demand. (Includes SoCalGas retail and wholesale load).
(3) Peak day summer (August) load under 1-in-10 dry hydro conditions.

2008 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2003 TO 2007

Line			2003	2004	2005	2006	2007	Line
	GAS SUPPLY TAKEN							
1	California Source Gas		241	291	274	242	232	1
	Out-of-State Gas							
2	Pacific Interstate Companies		0	0	0	0	0	2
3	Other Out-of-State		2,378	2,429	2,220	2,386	2,462	3
4	Total Out-of-State Gas		2,378	2,429	2,220	2,386	2,462	4
5	TOTAL SUPPLY TAKEN		2,619	2,720	2,494	2,628	2,694	5
6	Net Underground Storage Withdrawal		-11	-22	-11	13	23	6
7	**TOTAL THROUGHPUT (1)(2)**		2,608	2,698	2,483	2,641	2,717	7
	DELIVERIES BY END-USE (3)							
8	Core	Residential	666	699	660	678	673	8
9		Commercial	200	215	211	215	224	9
10		Industrial	57	63	65	65	65	10
11		NGV	15	17	20	21	23	11
12		Subtotal	938	994	956	979	985	12
13	Noncore	Commercial	62	60	60	63	60	13
14		Industrial	349	356	344	347	345	14
15		EOR Steaming	42	35	34	39	39	15
16		Electric Generation	789	781	676	769	849	16
17		Subtotal	1,242	1,232	1,114	1,218	1,293	17
18	Wholesale/International		377	427	393	394	406	18
19	Co. Use & LUAF		51	45	20	50	33	19
20	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,608	2,698	2,483	2,641	2,717	20
	TRANSPORTATION AND EXCHANGE							
21	Core	All End Uses	10	7	7	11	14	21
22	Noncore	Commercial/Industrial	403	414	404	410	405	22
23		EOR Steaming	42	35	34	39	39	23
24		Electric Generation	788	781	676	769	849	24
25		Subtotal-Retail	1,243	1,236	1,121	1,229	1,307	25
26	Wholesale/International		377	427	393	394	406	26
27	**TOTAL TRANSPORTATION & EXCHANGE**		1,620	1,663	1,514	1,623	1,713	27
	CURTAILMENT (RETAIL & WHOLESALE)							
28		Core	0	0	0	0	0	28
29		Noncore	0	0	0	0	0	29
30		TOTAL - Curtailment	0	0	0	0	0	30
31	**REFUSAL**		0	0	0	0	0	31
	NOTES:							
	(1) Exclude own-source gas supply of procurement by Edison and City of Long Beach.		4	6	2	1	4	

(2) Deliveries by end-use includes sales, transportation, and exchange volumes.
(3) Data includes effect of prior period adjustments.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2008 THRU 2012

AVERAGE TEMPERATURE YEAR

LINE			2008	2009	2010	2011	2012	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	8
9	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	9
	GAS SUPPLY TAKEN							
10	California Source Gas		310	310	310	310	310	10
11	Out-of-State		2,384	2,297	2,286	2,274	2,275	11
12	TOTAL SUPPLY TAKEN		2,694	2,607	2,596	2,584	2,585	12
13	Net Underground Storage Withdrawal		0	0	0	0	0	13
14	TOTAL THROUGHPUT 1/		2,694	2,607	2,596	2,584	2,585	14
	REQUIREMENTS FORECAST BY END-USE 2/							
15	CORE 3/	Residential	661	656	655	653	652	15
16		Commercial	217	217	217	216	215	16
17		Industrial	59	57	57	57	57	17
18		NGV	25	29	32	36	39	18
19		Subtotal-CORE	963	958	961	963	964	19
20	NONCORE	Commercial	54	54	55	55	55	20
21		Industrial	334	322	320	318	317	21
22		EOR Steaming	35	28	28	28	29	22
23		Electric Generation (EG)	854	794	763	779	780	23
24		Subtotal-NONCORE	1,278	1,199	1,166	1,179	1,179	24
25	WHOLESALE &	Core	171	169	170	171	172	25
26	INTERNATIONAL	Noncore Excl. EG	46	50	50	50	50	26
27		Electric Generation (EG)	200	196	214	186	185	27
28		Subtotal-WHOLESALE & INTL.	417	415	434	407	407	28
29		Co. Use & LUAF	37	35	35	35	35	29
30	SYSTEM TOTAL THROUGHPUT 1/		2,694	2,607	2,596	2,584	2,585	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	13	13	13	13	13	31
32	NONCORE	Commercial/Industrial	388	376	374	372	371	32
33		EOR Steaming	35	28	28	28	29	33
34		Electric Generation (EG)	854	794	763	779	780	34
35		Subtotal-RETAIL	1,291	1,212	1,179	1,192	1,192	35
	WHOLESALE &							
36	INTERNATIONAL	All End Uses	417	415	434	407	407	36
37	TOTAL TRANSPORTATION & EXCHANGE		1,707	1,627	1,613	1,600	1,600	37
	CURTAILMENT (RETAIL & WHOLESALE)							
38		Core	0	0	0	0	0	38
39		Noncore	0	0	0	0	0	39
40		TOTAL - Curtailment	0	0	0	0	0	40

NOTES:

	2008	2009	2010	2011	2012
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	6	10	10	9	9

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2008	2009	2010	2011	2012
3/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	979	974	977	979	980

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2013 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2013	2015	2020	2025	2030	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	8
9	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	9
	GAS SUPPLY TAKEN							
10	California Source Gas		310	310	310	310	310	10
11	Out-of-State		2,298	2,314	2,329	2,355	2,399	11
12	TOTAL SUPPLY TAKEN		2,608	2,624	2,639	2,665	2,709	12
13	Net Underground Storage Withdrawal		0	0	0	0	0	13
14	TOTAL THROUGHPUT [1/]		2,608	2,624	2,639	2,665	2,709	14
	REQUIREMENTS FORECAST BY END-USE [2/]							
15	CORE [3/]	Residential	655	654	642	644	654	15
16		Commercial	215	212	202	200	204	16
17		Industrial	57	56	53	50	49	17
18		NGV	42	47	64	86	108	18
19		Subtotal-CORE	969	969	960	980	1,014	19
20	NONCORE	Commercial	55	55	53	53	54	20
21		Industrial	316	311	293	283	278	21
22		EOR Steaming	28	28	29	28	28	22
23		Electric Generation (EG)	775	782	811	815	816	23
24		Subtotal-NONCORE	1,174	1,176	1,186	1,179	1,176	24
25	WHOLESALE &	Core	173	176	182	193	203	25
26	INTERNATIONAL	Noncore Excl. EG	50	50	50	50	50	26
27		Electric Generation (EG)	207	217	225	227	229	27
28		Subtotal-WHOLESALE & INTL.	430	443	457	470	482	28
29		Co. Use & LUAF	35	36	36	36	37	29
30	SYSTEM TOTAL THROUGHPUT [1/]		2,608	2,624	2,639	2,665	2,709	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	13	13	12	12	12	31
32	NONCORE	Commercial/Industrial	371	366	347	336	332	32
33		EOR Steaming	28	28	29	28	28	33
34		Electric Generation (EG)	775	782	811	815	816	34
35		Subtotal-RETAIL	1,187	1,189	1,199	1,191	1,188	35
36	WHOLESALE & INTERNATIONAL	All End Uses	430	443	457	470	482	36
37	TOTAL TRANSPORTATION & EXCHANGE		1,618	1,632	1,655	1,661	1,670	37
	CURTAILMENT (RETAIL & WHOLESALE)							
38		Core	0	0	0	0	0	38
39		Noncore	0	0	0	0	0	39
40		TOTAL - Curtailment	0	0	0	0	0	40

NOTES:

	2013	2015	2020	2025	2030
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	8	7	5	3	2
2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.					
3/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	985	985	976	998	1,033

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2008 THRU 2012

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2008	2009	2010	2011	2012	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	8
9	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	9
	GAS SUPPLY TAKEN							
10	California Source Gas		310	310	310	310	310	10
11	Out-of-State		2,047	2,073	2,015	2,041	2,033	11
12	TOTAL SUPPLY TAKEN		2,357	2,383	2,325	2,351	2,343	12
13	Net Underground Storage Withdrawal		0	0	0	0	0	13
14	TOTAL THROUGHPUT [1/]		2,357	2,383	2,325	2,351	2,343	14
	REQUIREMENTS FORECAST BY END-USE [2/]							
15	CORE [3/]	Residential	725	719	718	716	715	15
16		Commercial	229	229	229	228	227	16
17		Industrial	60	58	58	58	58	17
18		NGV	25	29	32	36	39	18
19		Subtotal-CORE	1,040	1,034	1,037	1,039	1,039	19
20	NONCORE	Commercial	56	56	56	56	56	20
21		Industrial	334	322	320	318	317	21
22		EOR Steaming	35	28	28	28	29	22
23		Electric Generation (EG)	854	905	846	872	864	23
24		Subtotal-NONCORE	1,279	1,311	1,250	1,275	1,266	24
25	WHOLESALE &	Core	186	186	186	188	188	25
26	INTERNATIONAL	Noncore Excl. EG	46	50	50	50	50	26
27		Electric Generation (EG)	200	207	230	199	195	27
28		Subtotal-WHOLESALE & INTL.	432	442	466	437	433	28
29		Co. Use & LUAF	38	38	38	38	38	29
30	SYSTEM TOTAL THROUGHPUT [1/]		2,357	2,383	2,325	2,351	2,343	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	14	14	14	14	14	31
32	NONCORE	Commercial/Industrial	390	378	376	374	373	32
33		EOR Steaming	35	28	28	28	29	33
34		Electric Generation (EG)	854	905	846	872	864	34
35		Subtotal-RETAIL	1,293	1,325	1,264	1,288	1,280	35
36	WHOLESALE & INTERNATIONAL	All End Uses	432	442	466	437	433	36
37	TOTAL TRANSPORTATION & EXCHANGE		1,725	1,767	1,730	1,726	1,713	37
	CURTAILMENT (RETAIL & WHOLESALE)							
38		Core	0	0	0	0	0	38
39		Noncore	0	0	0	0	0	39
40		TOTAL - Curtailment	0	0	0	0	0	40

NOTES:

	2008	2009	2010	2011	2012
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	6	10	10	9	9

2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

	2008	2009	2010	2011	2012
3/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,057	1,052	1,054	1,056	1,057

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2013 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2013	2015	2020	2025	2030	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		310	310	310	310	310	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Kern-Mojave (Kramer Junction)		200	200	200	200	200	7
8	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	8
9	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	9
	GAS SUPPLY TAKEN							
10	California Source Gas		310	310	310	310	310	10
11	Out-of-State		2,489	2,486	2,503	2,531	2,576	11
12	TOTAL SUPPLY TAKEN		2,799	2,796	2,813	2,841	2,886	12
13	Net Underground Storage Withdrawal		0	0	0	0	0	13
14	TOTAL THROUGHPUT [1/]		2,799	2,796	2,813	2,841	2,886	14
	REQUIREMENTS FORECAST BY END-USE [2/]							
15	CORE [3/]	Residential	718	717	704	706	717	15
16		Commercial	227	224	212	211	215	16
17		Industrial	58	57	54	51	50	17
18		NGV	42	47	64	86	108	18
19		Subtotal-CORE	1,045	1,044	1,034	1,054	1,089	19
20	NONCORE	Commercial	56	56	55	55	56	20
21		Industrial	316	311	293	283	278	21
22		EOR Steaming	28	28	29	28	28	22
23		Electric Generation (EG)	853	843	875	879	880	23
24		Subtotal-NONCORE	1,254	1,239	1,252	1,245	1,242	24
25	WHOLESALE &	Core	190	192	198	210	221	25
26	INTERNATIONAL	Noncore Excl. EG	50	50	50	50	50	26
27		Electric Generation (EG)	222	232	241	243	245	27
28		Subtotal-WHOLESALE & INTL.	463	475	489	503	516	28
29		Co. Use & LUAF	38	38	38	39	39	29
30	SYSTEM TOTAL THROUGHPUT [1/]		2,799	2,796	2,813	2,841	2,886	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	14	14	13	13	13	31
32	NONCORE	Commercial/Industrial	373	367	348	338	333	32
33		EOR Steaming	28	28	29	28	28	33
34		Electric Generation (EG)	853	843	875	879	880	34
35		Subtotal-RETAIL	1,268	1,253	1,265	1,258	1,255	35
	WHOLESALE &							
36	INTERNATIONAL	All End Uses	463	475	489	503	516	36
37	TOTAL TRANSPORTATION & EXCHANGE		1,731	1,728	1,754	1,761	1,771	37
	CURTAILMENT (RETAIL & WHOLESALE)							
38		Core	0	0	0	0	0	38
39		Noncore	0	0	0	0	0	39
40		TOTAL - Curtailment	0	0	0	0	0	40

NOTES:

	2013	2015	2020	2025	2030
1/ Excludes own-source gas supply of gas procurement by the City of Long Beach	8	7	5	3	2
2/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.					
3/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,062	1,062	1,052	1,073	1,109

2008 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT

CITY OF LONG BEACH MUNICIPAL GAS & OIL DEPARTMENT

The annual gas supply and requirements for the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2003 through 2030. Long Beach prepared all forecasted requirements with the assistance of SoCalGas in the preparation of core demand forecast.

Serving approximately 145,000 customers, Long Beach is the largest California municipal gas utility and the fifth largest municipal gas utility in the United States. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's customer load profile is 50 percent residential and 50 percent commercial/industrial.

As a municipal utility, Long Beach's rates and policies are established by the City Council, which acts as the regulatory authority. The City Charter requires the gas utility to establish its rates comparable to the rates charged by surrounding gas utilities for similar types of service.

Long Beach receives a small amount of its gas supply directly into its pipeline system from local production fields that are located within Long Beach's service territory, as well as offshore. Previous to 2002, Long Beach received one third of its gas supply through local production. The majority of Long Beach supplies are purchased at the California border, primarily from the Southwestern United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

2008 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2003 THRU 2007

LINE		2003	2004	2005	2006	2007	LINE
	GAS SUPPLY AVAILABLE						
	California Source Gas						
1	Regular Purchases						1
2	Received for Exchange/Transport						2
3	Total California Source Gas						3
4	Purchases from Other Utilities						4
	Out-of-State Gas						
5	Pacific Interstate Companies						5
6	Additional Core Supplies						6
7	Incremental Supplies						7
8	Out-of-State Transport						8
9	Total Out-of-State Gas						9
10	Subtotal						10
11	Underground Storage Withdrawal						11
12	GAS SUPPLY AVAILABLE						12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	11	10	4	1	4	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	11	10	4	1	4	15
16	Purchases from Other Utilities	0	0	0	0	0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0	0	0	0	0	17
18	Additional Core Supplies	0	0	0	0	0	18
19	Incremental Supplies	21	21	29	30	26	19
20	Out-of-State Transport	0	0	0	0	0	20
21	Total Out-of-State Gas	21	21	29	30	26	21
22	Subtotal	32	31	33	31	31	22
23	Underground Storage Withdrawal	0	0	0	0	0	23
24	TOTAL Gas Supply Taken & Transported	32	31	33	31	31	24

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2003 THRU 2007

LINE			2003	2004	2005	2006	2007	LINE
	ACTUAL DELIVERIES BY END-USE							
1	CORE	Residential	17	16	16	15	15	1
2	CORE/NONCORE	Commercial	7	7	7	7	7	2
3	CORE/NONCORE	Industrial	7	6	7	7	7	3
4		Subtotal	31	29	30	28	29	4
5	NON CORE	Non-EOR Cogeneration	0.1	0.2	3	1.2	1	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	0	0	0	0	0	7
8		Subtotal	0.1	0.2	3	1.2	1	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal-WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	1	0.5	0.0	0.9	0.1	13
14		Subtotal-END USE	32	30	33	31	30	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL-THROUGHPUT		32	30	33	31	30	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	N/A	N/A	N/A	N/A	N/A	18
19		Non-EOR Cogeneration	N/A	N/A	N/A	N/A	N/A	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	21	21	29	30	26	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		21	21	29	30	26	24
	ACTUAL CURTAILMENT							
25		Residential	0	0	0	0	0	25
26		Commercial/Industrial	0	0	0	0	0	26
27		Non-EOR Cogeneration	0	0	0	0	0	27
28		EOR Cogen. & Steaming	0	0	0	0	0	28
29		Electric Utilites	0	0	0	0	0	29
30		Wholesale	0	0	0	0	0	30
31		TOTAL- Curtailment	0	0	0	0	0	31
32	REFUSAL		0	0	0	0	0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2008 THRU 2012

AVERAGE TEMPERATURE YEAR

LINE			2008	2009	2010	2011	2012	LINE
	CAPACITY AVAILABLE							
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		6	10	10	9	9	4
5	Out-of-State Gas		24	20	20	21	21	5
6	TOTAL SUPPLY TAKEN		30	30	30	30	30	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		30	30	30	30	30	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	15	15	15	15	15	9
10		Commercial	6	6	6	6	6	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	21	21	21	21	21	12
13	NONCORE	Industrial	8	8	8	8	8	13
14		Non-EOR Cogeneration	1	1	1	1	1	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	9	9	9	9	9	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		30	30	30	30	30	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	17	12	12	13	14	22
23	NONCORE	Industrial	8	8	8	8	8	23
24		Non-EOR Cogeneration	1	1	1	1	1	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	9	9	9	9	9	27
28	TOTAL TRANSPORTATION		26	21	21	22	23	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2013 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2013	2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE							
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		8	7	5	3	2	4
5	Out-of-State Gas		22	23	26	28	29	5
6	TOTAL SUPPLY TAKEN		30	30	31	31	31	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		30	30	31	31	31	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	15	15	15	15	16	9
10		Commercial	6	6	6	6	6	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	21	21	21	21	21	12
13	NONCORE	Industrial	8	8	8	8	8	13
14		Non-EOR Cogeneration	1	1	1	1	1	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	9	9	9	9	9	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		30	30	30	30	30	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	14	16	18	20	21	22
23	NONCORE	Industrial	8	8	8	8	8	23
24		Non-EOR Cogeneration	1	1	1	1	1	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	9	9	9	9	9	27
28	TOTAL TRANSPORTATION		23	25	27	29	30	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

2008 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

San Diego Gas & Electric Company (SDG&E) is a combined gas and electric distribution utility serving more than three million people in San Diego and southern portions of Orange counties. SDG&E delivers natural gas to over 835,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2007 were approximately 118 billion cubic feet (Bcf), which is an average of over 322 million cubic feet per day (MMcf/day).

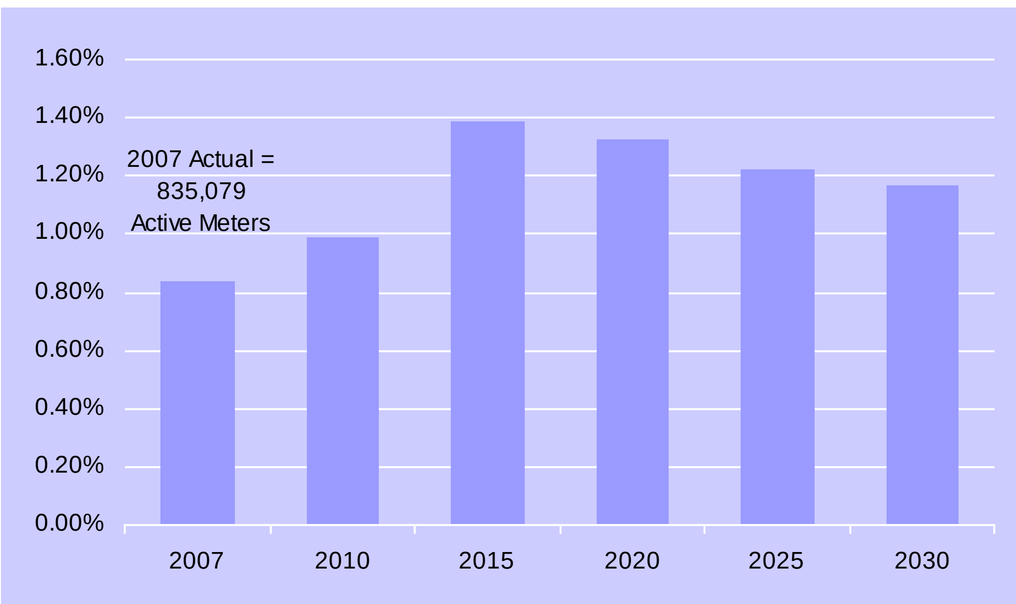
The Gas Supply, Capacity, and Storage section for SDG&E has been moved to SoCalGas' due to the integration of gas procurement and system integration functions into one combined SDG&E/SoCalGas system per D. 07-12-019 (natural gas operations and service offerings) and D. 06-12-031 (system integration.)

GAS DEMAND

OVERVIEW

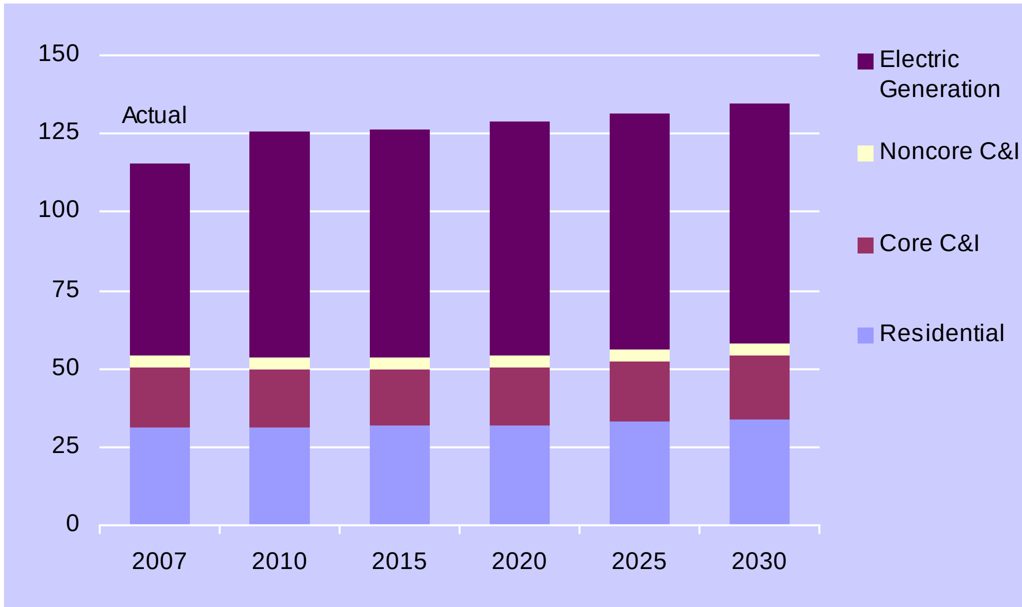
SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above. San Diego County's total employment is forecasted to grow an average of 1.1% annually from 2007 to 2030; the subset of industrial (mining and manufacturing) jobs is projected to remain virtually flat over the same period. From 2007 to 2030, the county's inflation-adjusted Gross Product is expected to average decent 2.8% annual growth, slightly slower than the 3.3% average annual growth seen from 2000 to 2007. (Gross Product is the local equivalent of national Gross Domestic Product, a measure of the total economic output of the area economy.) The number of SDG&E gas meters is expected to increase an average of 1.2% annually from 2007 through 2030.

SDG&E Annual Meter Growth



This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Non-EG gas demand is projected to increase by 11% between 2006 and 2025. Assumptions for SDG&E's gas transport requirements for EG are included as part of the wholesale market sector description for Southern California Gas Company.

Composition of SDG&E Gas Throughput (Bcf)
Average Temperature and Normal Hydro Year



MARKET SECTORS

Residential

The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 805,013 in 2007. This total reflects a 6,761 meter increase relative to the 2006 total. The overall observed 2006-2007 residential meter growth was 0.85%.

From 2007 through 2030, average residential meters are forecasted to grow at an annual rate of 1.46%. By the year 2030, the residential meters are expected to exceed 1.07 million meters.

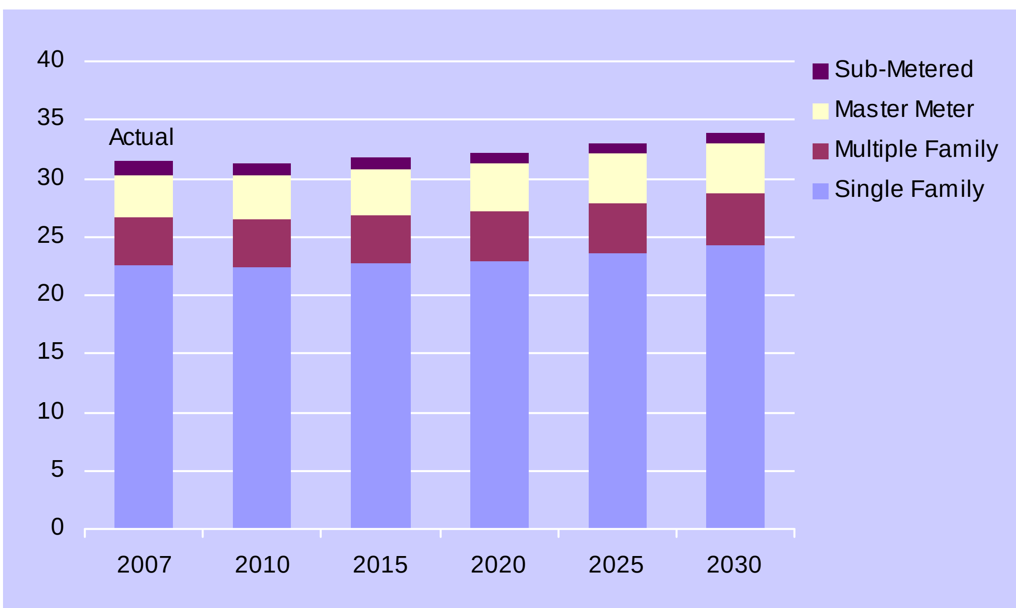
Residential demand adjusted for average temperature conditions totaled 31.4 Bcf in 2007. The unadjusted residential gas demand was 32.5 Bcf which is 3% higher than the temperature-adjusted demand due to cooler than normal weather conditions in the San Diego area. The difference is explained by 7.8% more observed Heating Degree Days (HDD) in 2007 from relative to average year weather conditions.

Use per meter for all classes of residential customers is anticipated to decline due to the expected energy savings from tightened building and appliance standards and CPUC-authorized energy efficiency programs. During the forecast period, the weather normalized annual average use per residential customer is expected to fall from 399 therms per customer in 2007 to 321 therms in 2030. The change reflects a 0.85% annual decline in use per customer.

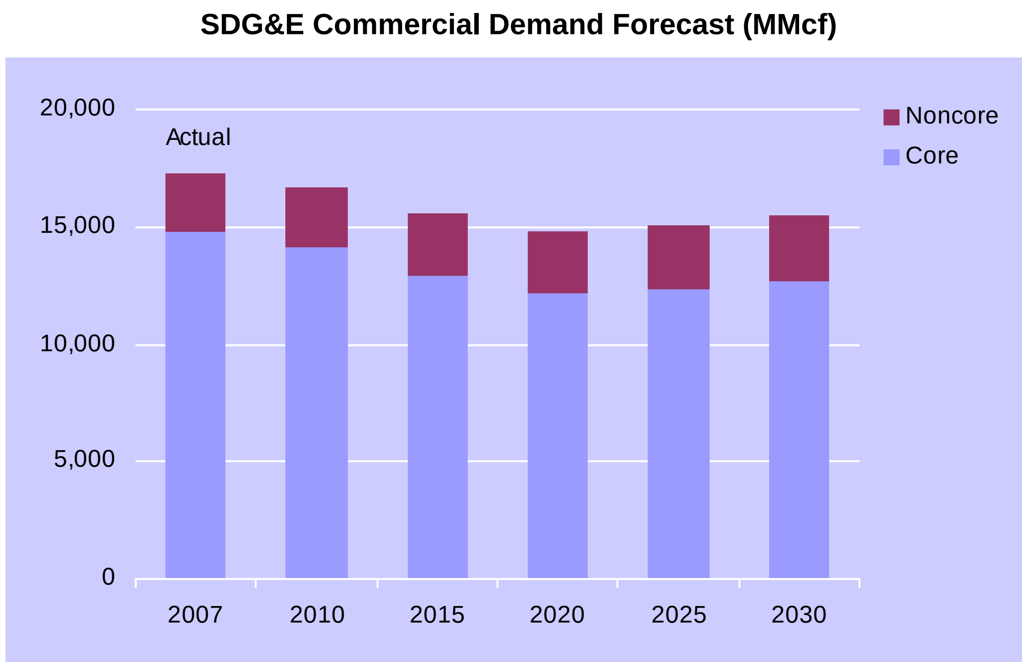
In 2007, residential demand was 31 Bcf and is expected to increase to 34 Bcf by 2030. The difference reflects an average annual increase of 0.10 Bcf per year.

The projected residential natural gas demand will be influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in the building shell design, appliance efficiency and CPUC-authorized EE programs.

SDG&E Residential Demand Forecast (Bcf)



Commercial



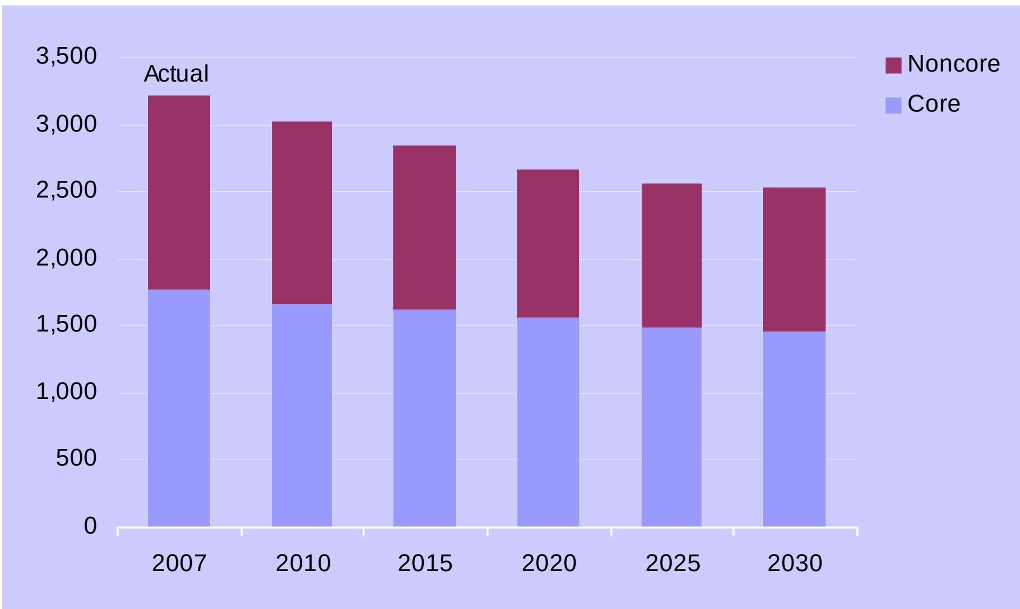
On a temperature-adjusted basis, the core commercial market demand in 2007 totaled just above 15 Bcf. From 2009 to 2012, the commercial meter growth is expected to contract. By the year 2030, the SDGE core commercial load is expected to decline to 12.9 Bcf, a reduction of approximately 2.1 Bcf. This change reflects an annual average reduction in commercial load of approximately 0.63% per year. The modest annual load reduction that is anticipated over the forecast period can be attributed to CPUC-mandated energy efficiency programs. The effect of the CPUC-authorized energy efficiency programs is expected to reduce core commercial gas demand through the year 2020. Thereafter, the core commercial gas demand is expected to increase very modestly by about 0.4% per year.

The non-core commercial load in 2007 was 2.5 Bcf – a drop of 22% from 2006 demand of 3.2 Bcf. However, this drop is due to the operational decision of a few customers who used natural gas for cogeneration instead of commercial application, and not expected to cause significant impact to the overall market. Over the next 22 years, gas demand in this market is projected show some modest gain, mostly driven by increased economic activity and employment in the service sector, but moderated by CPUC-mandated energy efficiency program. The non-core commercial load is projected to grow to 2.8 BCF by 2030, or an average annual increase of just 0.5%.

Industrial

In 2007, temperature-adjusted core industrial demand was 1.8 Bcf. Core industrial market demand is projected to decrease at an average rate of 0.7% per year from 1.7 Bcf in 2008 to 1.5 Bcf in 2030. This result is due to slightly lower forecasted growth in industrial production and the impact of CPUC-authorized energy-efficiency programs savings in the industrial sector.

SDG&E Industrial Demand Forecast (MMcf)

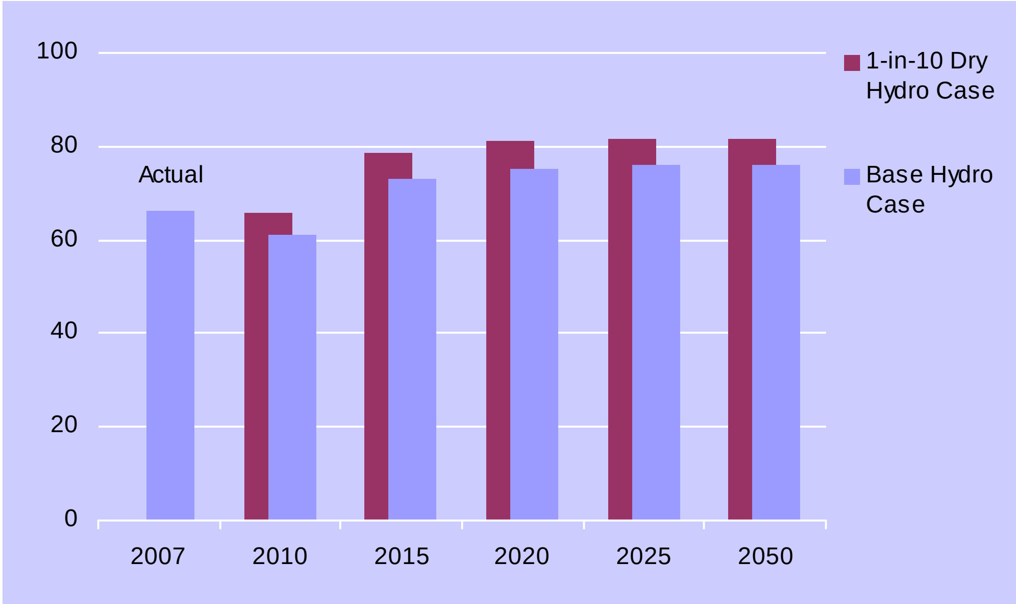


The non-core industrial load in 2007 was 1.5 Bcf and is expected to decline at an average rate of -1.3% per year, to 1.1 Bcf by 2030. CPUC-mandated energy efficiency programs targeted at this market more than offset any modest gains by increased economic activity and employment in the manufacturing sector. By 2030, energy efficiency savings is expected to reduce noncore industrial load 0.4 Bcf.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, is expected to increase at an annual average rate of 0.7 percent from 66 Bcf in 2008 to 76 Bcf in 2030. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

SDG&E Service Area Total Electric Generation Forecast (Bcf)



Cogeneration

Small EG load from self-generation increase 22 percent from 16.0 Bcf in 2006 to 19.5 Bcf in 2007. This large increase is due to the temporary switching of loads from commercial/industrial applications to cogeneration. Several very large cogeneration customers have the option of switching to optimize operations and this large increase simply offsets the drop in the commercial/industrial load last year. Small EG load is expected to grow from 19 Bcf in 2008 to 22 Bcf in 2030, or an averaging increase of 0.5 % per year. This growth is driven by employment activities in the region.

Non-Cogeneration Electric Generation

The forecast of the large EG loads in SDG&E's service area is based on the power market simulation as noted in the SoCalGas' Electric Generation chapter for "Non-Cogeneration EG" demand. This forecast includes 1,300 MW of new thermal generating resources, both combined cycles and peaking units in its service area by the end of 2015. However, approximately 1,000 MW were retired or replaced during the same time period. EG demand is forecasted to increase from 47 Bcf in 2008 to 54 Bcf in 2020 due to the addition of a new power plants. However, there is a dip in 2011 when the additional transmission capacity is added to the load pocket, thus reducing the need for local generation to be run for reliability. The EG demand rebounded back to 54 Bcf by 2020 with the addition of new capacity in 2013. The EG forecast is held constant at 2020 levels for 2025 and 2030 as previously explained.

SDG&E performed a 1-in-10 year dry hydro sensitivity forecast. Due to the displacement of generation by off-system resources, the impact of significant hydro conditions had little impact on SDG&E's EG gas demand. A dry hydro year, as defined by the CEC, increased SDG&E's EG demand on average for the forecast period by 5 Bcf per year. For additional information on EG assumption, such as renewable generation, greenhouse gas and sensitivity to electric demand and renewables goal, refer to the Non-Cogeneration Electric Generation in the Southern California section.

Natural Gas Vehicles (NGV)

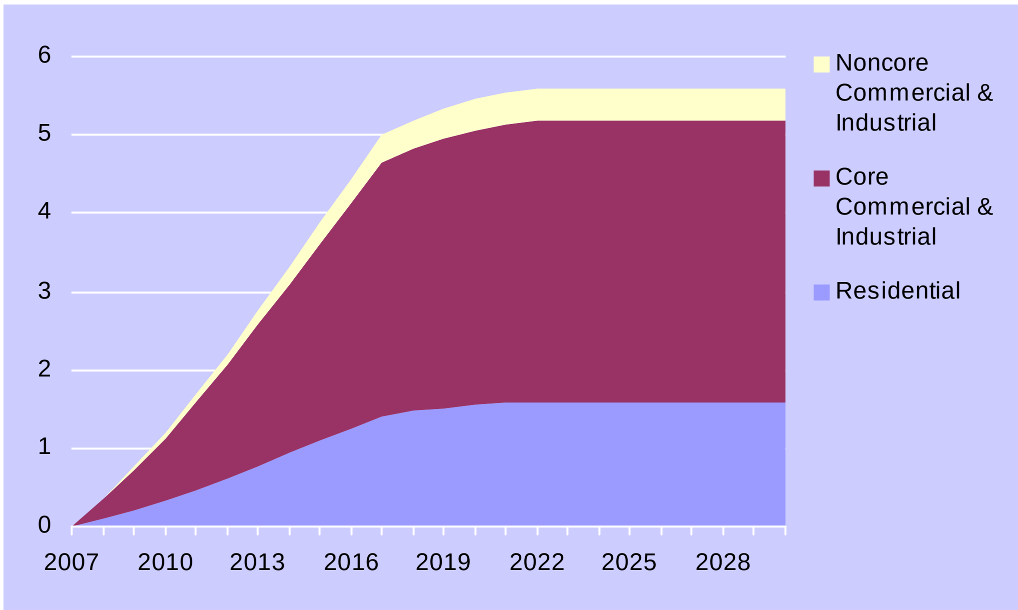
The NGV market is forecast to continue to grow due to federal, state and local incentives and regulations related to the purchase and operation of alternate fuel vehicles coupled with rapidly increasing cost of petroleum (gasoline and diesel). At the end of 2007, there were 33 compressed natural gas (CNG) fueling stations serving approximately 2,000 vehicles that consumed 1.3 Bcf of natural gas during the year. SDG&E expects the NGV market to continue to experience moderate growth, since transit fleets account for most of the demand and are close to fleet saturation levels.

ENERGY EFFICIENCY PROGRAMS

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage while still maintaining a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is provided in the graph in the next page. The net load impact includes all Energy Efficiency programs that SDG&E has forecasted to implement starting from the years 2008 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.

Energy Efficiency Cumulative Savings Goal (Bcf)



Savings reported are for measures installed under SDG&E's Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SDG&E's Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SDG&E's' 2006-2008 Energy Efficiency program portfolio are contained in SDG&E's' Advice Letter 1769-E/1591-G, which was submitted on February 1, 2006 and became effective March 3, 2006. SDG&E is expected to submit its proposed 2009-2011 Energy Efficiency program on June 23, 2008.

Notes:
(1) Energy Efficiency load impacts include 2003-2004 program savings, but do not include pre-2003 program savings.
(2) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(3) SDG&E does not include "soft" impacts, e.g., energy management services type measures.
(4) The assumed average measure life is 10 years.

GAS SUPPLY

Beginning April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined SoCalGas/SDG&E portfolio per Decision 07-12-019 December 6, 2007. Refer to the Gas Supply, Capacity and Storage section in the Southern California area for more information.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio with a total firm storage withdrawal capacity designed to serve the utilities' combined retail core peak-day gas demand. Please see the corresponding discussion of "Peak Day Demand and Deliverability" under the SoCalGas portion of this report for an illustration of how storage and flowing supplies can meet the growth in forecasted load for the combined (SoCalGas plus SDG&E) retail core peak day demand.

2008 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2003-2007

LINE			2003	2004	2005	2006	2007	LINE
	GAS SUPPLY TAKEN							
	California Source Gas							
1		Regular Purchases	3	5	6	6	7	1
2		Received for Exchange/Transport	0	0	0	0	0	2
3	Total California Source Gas		3	5	6	6	7	3
4	Purchases from Other Utilities		0	0	0	0	0	4
	Out-of-State Gas							
5		Pacific Interstate Companies	0	0	0	0	0	5
6		Additional Core Supplies	0	0	0	0	0	6
7		Supplemental Supplies-Utility	133	145	143	131	139	7
8		Out-of-State Transport-Others	182	213	174	191	176	8
9	Total Out-of-State Gas		314	358	317	322	316	9
10	TOTAL Gas Supply Taken & Transported		317	363	323	328	322	10
	ACTUAL DELIVERIES BY END-USE							
11	CORE	Residential	87	92	86	86	89	11
12		Commercial	47	48	48	48	49	12
13		Industrial	0	0	0	0	0	13
14	*Subtotal -*	*CORE*	134	140	134	133	138	14
15	NONCORE	Commercial	0	0	0	0	0	15
16		Industrial	10	10	10	12	9	16
17		Non-EOR Cogen/EG	172	203	163	131	101	17
18		Electric Utilities	0	0	0	47	63	18
19	*Subtotal -*	*NONCORE*	183	213	174	189	173	19
20	WHOLESALI	All End Uses	0	0	0	0	0	20
21	*Subtotal -*	*Co Use & LUAF*	1	10	15	5	11	21
22	System Total Throughput		317	363	323	328	322	22
	ACTUAL TRANSPORTATION AND EXCHANGE							
23	CORE	Residential	0	0	0	0	0	23
24		Commercial	2	2	2	3	4	24
25	NONCORE	Industrial	9	9	9	11	9	25
26		Non-EOR Cogen/EG	171	202	162	130	100	26
27		Electric Utilities	0	0	0	47	63	27
28	*Subtotal -*	*RETAIL*	182	213	174	191	176	28
29	WHOLESALI	All End Uses	0	0	0	0	0	29
30	Total Transportation and Exchange		182	213	174	191	176	30
	STORAGE							
31		Storage Injection	20	21	12	13	15	31
32		Storage Withdrawal	18	10	21	8	15	32
	ACTUAL CURTAILMENT							
33		Com/Indl & Cogen	0	0	0	0	0	33
34		Electric Generation	0	0	0	0	0	34
35	Total Curtailment		0	0	0	0	0	35
36	**REFUSAL**		0	0	0	0	0	36

NOTE: Actual deliveries by end-use includes sales and transportation volumes

MMbtu/Mcf:	1.012	1.012	1.015	1.017	1.022

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2008 THRU 2012

AVERAGE TEMPERATURE YEAR

LINE			2008	2009	2010	2011	2012	LINE
	FIRM CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		330	326	345	317	316	10
11	TOTAL SUPPLY TAKEN		330	326	345	317	316	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		330	326	345	317	316	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE 4/	Residential	86	86	86	86	86	14
15		Commercial	40	39	39	38	38	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	4	5	5	17
18		Subtotal-CORE	134	133	134	134	134	18
19	NONCORE	Commercial	7	7	7	7	7	19
20		Industrial	4	4	4	4	4	20
21		Electric Generation (EG)	181	178	196	168	167	21
22		Subtotal-NONCORE	192	189	207	179	178	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		330	326	345	317	316	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	4	3	3	3	3	25
26	NONCORE	Commercial/Industrial	10	11	11	11	11	26
27		Electric Generation (EG)	181	178	196	168	167	27
28	TOTAL TRANSPORTATION & EXCHANGE		195	192	210	182	181	28
	CURTAILMENT							
29		Core	0	0	0	0	0	29
30		Noncore	0	0	0	0	0	30
31		TOTAL - Curtailment	0	0	0	0	0	31

NOTES:
1/ Firm capacity under contract by SDG&E in 2008.
2/ For 2009 and after, assume capacity at same levels for 2008.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 133 (2008), 133 (2009), 134 (2010), 134 (2011), 134 (2012)

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2013 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2013	2015	2020	2025	2030	LINE
	FIRM CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		337	345	353	360	369	10
11	TOTAL SUPPLY TAKEN		337	345	353	360	369	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		337	345	353	360	369	13
	REQUIREMENTS FORECAST BY END-USE [3/]							
14	CORE [4/]	Residential	87	87	88	90	93	14
15		Commercial	37	35	33	34	35	15
16		Industrial	5	4	4	4	4	16
17		NGV	5	6	8	10	13	17
18		Subtotal-CORE	134	132	133	138	145	18
19	NONCORE	Commercial	7	7	7	7	8	19
20		Industrial	4	3	3	3	3	20
21		Electric Generation (EG)	188	199	206	208	209	21
22		Subtotal-NONCORE	199	209	216	218	220	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		337	345	353	360	369	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	3	3	3	3	3	25
26	NONCORE	Commercial/Industrial	11	11	10	10	11	26
27		Electric Generation (EG)	188	199	206	208	209	27
28	TOTAL TRANSPORTATION & EXCHANGE		202	213	219	221	223	28
	CURTAILMENT							
29		Core	0	0	0	0	0	29
30		Noncore	0	0	0	0	0	30
31		TOTAL - Curtailment	0	0	0	0	0	31

NOTES:
1/ Firm capacity under contract by SDG&E in 2008.
2/ For 2009 and after, assume capacity at same levels for 2008.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 134 132 133 138 145

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2008 THRU 2012

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2008	2009	2010	2011	2012	LINE
	FIRM CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		343	349	373	343	339	10
11	TOTAL SUPPLY TAKEN		343	349	373	343	339	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		343	349	373	343	339	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE 4/	Residential	97	97	97	98	98	14
15		Commercial	42	41	41	40	40	15
16		Industrial	5	5	5	5	5	16
17		NGV	3	3	4	5	5	17
18		Subtotal-CORE	147	146	147	148	148	18
19	NONCORE	Commercial	7	7	7	7	7	19
20		Industrial	4	4	4	4	4	20
21		Electric Generation (EG)	181	188	211	180	176	21
22		Subtotal-NONCORE	192	199	222	191	187	22
23		Co. Use & LUAF	4	4	4	4	4	23
24	SYSTEM TOTAL THROUGHPUT		343	349	373	343	339	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	4	4	4	4	4	25
26	NONCORE	Commercial/Industrial	10	11	11	11	11	26
27		Electric Generation (EG)	181	188	211	180	176	27
28	TOTAL TRANSPORTATION & EXCHANGE		195	203	226	195	191	28
	CURTAILMENT							
29		Core	0	0	0	0	0	29
30		Noncore	0	0	0	0	0	30
31		TOTAL - Curtailment	0	0	0	0	0	31

NOTES:
1/ Firm capacity under contract by SDG&E in 2008.
2/ For 2009 and after, assume capacity at same levels for 2008.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 146 (2008), 145 (2009), 146 (2010), 147 (2011), 147 (2012)

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2013 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2013	2015	2020	2025	2030	LINE
	FIRM CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2	El Paso Natural Gas Co.		50	50	50	50	50	2
3	Transwestern Pipeline Co.		33	33	33	33	33	3
4	Kern/Mojave		7	7	7	7	7	4
5	PGT/PG&E		51	51	51	51	51	5
6	Other		0	0	0	0	0	6
7	Total Out-of-State Gas		141	141	141	141	141	7
8	TOTAL FIRM CAPACITY AVAILABLE		141	141	141	141	141	8
	GAS SUPPLY TAKEN							
9	California Source Gas		0	0	0	0	0	9
10	Out-of-State		366	375	382	390	400	10
11	TOTAL SUPPLY TAKEN		366	375	382	390	400	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT		366	375	382	390	400	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE 4/	Residential	99	99	100	103	105	14
15		Commercial	39	38	35	36	37	15
16		Industrial	5	5	4	4	4	16
17		NGV	5	6	8	10	13	17
18		Subtotal-CORE	148	148	147	153	159	18
19	NONCORE	Commercial	7	7	7	7	8	19
20		Industrial	4	3	3	3	3	20
21		Electric Generation (EG)	203	213	221	223	225	21
22		Subtotal-NONCORE	214	223	231	233	236	22
23		Co. Use & LUAF	4	4	4	4	5	23
24	SYSTEM TOTAL THROUGHPUT		366	375	382	390	400	24
	TRANSPORTATION AND EXCHANGE							
25	CORE	All End Uses	4	3	3	3	3	25
26	NONCORE	Commercial/Industrial	11	11	10	10	11	26
27		Electric Generation (EG)	203	213	221	223	225	27
28	TOTAL TRANSPORTATION & EXCHANGE		218	227	234	236	239	28
	CURTAILMENT							
29		Core	0	0	0	0	0	29
30		Noncore	0	0	0	0	0	30
31		TOTAL - Curtailment	0	0	0	0	0	31

NOTES:
1/ Firm capacity under contract by SDG&E in 2008.
2/ For 2009 and after, assume capacity at same levels for 2008.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 147 148 147 153 159

2008 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature year
Long-term average recorded temperature.

BTU (British Thermal Unit)
Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water one degree Fahrenheit. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

California-Source Gas
1. Regular Purchases – All gas received or forecast from California producers, excluding exchange volumes. Also referred to as Local Deliveries.
2. Received for Exchange/Transport – All gas received or forecast from California producers for exchange, payback, or transport.

CEC
California Energy Commission.

CNG (Compressed Natural Gas)
Fuel for natural gas vehicles, typically natural gas compressed to 3000 pounds per square inch.

Cogeneration
Simultaneous production of electricity and thermal energy from the same fuel source. Also used to designate a separate class of gas customers.

Cold Temperature Year
Cold design-temperature conditions based on long-term recorded weather data.

Commercial (SoCalGas & SDG&E)
Category of gas customers whose establishments consist of services, manufacturing nondurable goods, dwellings not classified as residential, and farming (agricultural).

Commercial (PG&E)

Non-residential gas customers not engaged in electric generation, enhanced oil recovery, or gas resale activities with usage less than 20,800 therms per month.

Company Use

Gas used by utilities for operational purposes, such as fuel for line compression and injection into storage.

Conversion Factor (Natural Gas)

- 1 CF (Cubic Feet) = Approx. 1,000 BTUs
- 1 CCF = 100 CF = Approximately 1 Therm
- 1 Therm = 100,000 BTUs = Approximately 100 CF = 0.1 MCF
- 10 Therms = 1 Dth (dekatherm) = Approximately 1 MCF
- 1 MCF = 1,000 CF = Approximately 10 Therms = 1 MMBTU
- 1 MMCF = 1 million cubic feet = Approximately 1 MDth (1 thousand dekatherm)
- 1 BCF = 1 billion CF = Approximately 1 million MMBTU

Conversion Factor (Petroleum Products)

Approximate heat content of petroleum products (Million BTU per Barrel)

- Crude Oil 5.800
- Residual Fuel Oil 6.287
- Distillate Fuel Oil 5.825
- Petroleum Coke 6.024
- Butane 4.360
- Propane 3.836
- Pentane Plus 4.620
- Motor Gasoline 5.253

Conversion Factor (LNG)

Approximate LNG liquid conversion factor for one therm (High-Heat Value)

- Pounds 4.2020
- Gallons 1.1660
- Cubic Feet 0.1570
- Barrels 0.0280
- Cubic Meters 0.0044
- Metric Tonnes 0.0019

Core Aggregator

Individuals or entities arranging natural gas commodity procurement activities on behalf of core customers. Also, sometimes known as an Energy Service Provider (ESP), a Core Transport Agent (CTA), or a Retail Service Provider (RSP).

Core customers (SoCalGas & SDG&E)

All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

Core Customer (PG&E)

All customers with average usage less than 20,800 therms per month.

Core Subscription

Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

CPUC

California Public Utilities Commission.

Cubic Foot of Gas

Volume of natural gas, which, at a temperature of 60º F and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

Curtailment

Temporary suspension, partial or complete, of gas deliveries to a customer or customers.

EG

Electric generation (including cogeneration) by a utility, customer, or independent power producer.

Energy Service Provider (ESP)

Individuals or entities engaged in providing retail energy services on behalf of customers. ESP's may provide commodity procurement, but could also provide other services, e.g., metering and billing.

Enhanced Oil Recovery (EOR)

Injection of steam into oil-holding geologic zones to increase ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

Exchange

Delivery of gas by one party to another and the delivery of an equivalent quantity by the second party to the first. Such transactions usually involve different points of delivery and may or may not be concurrent.

Exempt Wholesale Generators (EWG)

A category of customers consuming gas for the purpose of generating electric power.

FERC

Federal Energy Regulatory Commission.

Futures (Gas)

Unit of natural gas futures contract trades in units of 10,000 million British thermal units (mmBtu) at the New York Merchantile Exchange (NYMEX). The price is based on delivery at Henry Hub in Louisiana.

Gas Accord

The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005.

Key features of the Gas Accord structure include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; and establishing transmission and storage rates.

Gas Sendout

That portion of the available gas supply that is delivered to gas customers for consumption, plus shrinkage.

GHG

Greenhouse gases are the gases present in the atmosphere which reduce the loss of heat into space and therefore contribute to global temperatures through the greenhouse effect. The most the most abundant greenhouse gases are, in order of relative abundance are water vapor, carbon dioxide, methane, nitrous oxide, ozone and CFCs.

Heating Degree Day (HDD)

A heating degree day is accumulated for every degree Fahrenheit the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65ºF; PG&E 60ºF). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50ºF average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Industrial (SoCalGas & SDG&E)

Category of gas customers who are engaged in mining and in manufacturing durable goods.

Industrial (PG&E)

Non-residential customers not engaged in electric generation, enhanced oil recovery, or gas resale activities using more than 20,800 therms per month.

LDC

Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)

Natural gas that has been super cooled to -260° F (-162° C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

MMBTU

Million British Thermal Units. One MMBTU is equals to 10 therms or one dekatherm.

MCF

The volume of natural gas which occupies 1,000 cubic feet when such gas is at a temperature of 60º Fahrenheit and at a standard pressure of approximately 15 pounds per square inch.

MMCF/DAY

Million cubic feet of gas per day.

NGV (Natural Gas Vehicle)

Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

Noncore Customers

Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

Non-Utility Served Load

The volume of gas delivered directly to customers by an interstate or intrastate pipeline or other independent source instead of the local distribution company.

Off-System Sales

Gas sales to customers outside the utility's service area.

Out-Of-State Gas

Gas from sources outside the state of California.

Priority of Service (SoCalGas & SDG&E)

In the event of a curtailment situation, utilities curtail gas usage to customers based on the following end-use priorities:

1. Firm Service – All noncore customers served through firm intrastate transmission service, including core subscription service.
2. Interruptible – All noncore customers served through interruptible intrastate transmission service, including inter-utility deliveries.

Priority of Service (PG&E)

In the event of a curtailment situation, PG&E curtails gas usage to customers based on the following end-use priorities:

1. Core Residential
2. Non-residential Core
3. Noncore using firm backbone service (including UEG)
4. Noncore using as-available backbone service (including UEG)
5. Market Center Services

PSIA

Pounds per square inch absolute. Equal to gauge pressure plus local atmospheric pressure.

Purchase from Other Utilities

Gas purchased from other utilities in California.

Requirements

Total potential demand for gas, including that served by transportation, assuming the availability of unlimited supplies at reasonable cost.

Resale

Gas customers who are either another utility or a municipal entity that, in turn, resells gas to end-use customers.

Residential

A category of gas customers whose dwellings are single-family units, multi-family units, mobile homes or other similar living facilities.

Short-Term Supplies

Gas purchased usually involving 30-day, short-term contract or spot gas supplies.

Spot Purchases

Short-term purchases of gas typically not under contract and generally categorized as surplus or best efforts.

Storage Banking

The direct use of local distribution company gas storage facilities by customers or other entities to store self-procured commodity gas supplies.

Storage Injection

Volume of natural gas injected into underground storage facilities.

Storage Withdrawal

Volume of natural gas taken from underground storage facilities.

Supplemental Supplies

A utility's best estimate for additional gas supplies that may be realized, from unspecified sources, during the forecast period.

System Capacity or Normal System Capacity (Operational Definition)

The physical limitation of the system (pipelines and storage) to deliver or flow gas to end-users.

System Utilization or Nominal System Capacity (Operational Definition)

The use of system capacity or nominal system capacity at less then 100 percent utilization.

Take-or-Pay

A term used to describe a contract agreement to pay for a product (natural gas) whether or not the product is delivered.

Tariff

All rate schedules, sample forms, rentals, charges, and rules approved by regulatory agencies for used by the utility.

TCF

Trillion cubic feet of gas.

Therm

A unit of energy measurement, nominally 100,000 BTUs.

Total Gas Supply Available

Total quantity of gas estimated to be available to meet gas requirements.

Total Gas Supply Taken

Total quantity of gas taken from all sources to meet gas requirements.

Total Throughput

Total gas volumes passing through the system including sales, company use, storage, transportation and exchange.

Transportation Gas

Non-utility-owned gas transported for another party under contractual agreement.

UEG

Utility electric generation.

Unaccounted-For

Gas received into the system but unaccounted for due to measurement, temperature, pressure, or accounting discrepancies.

Unbundling

The separation of natural gas utility services into its separate service components such as gas procurement, transportation, and storage with distinct rates for each service.

WACOG

Weighted average cost of gas.

Wholesale

A category of customer, either a utility or municipal entity, that resells gas.

2008 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission has respondents in the preparation of the California Gas Report.

- Pacific Gas and Electric Company
- San Diego Gas and Electric Company
- Southern California Gas Company

The following utilities also cooperated in the preparation of the report.

- City of Long Beach Municipal Gas and Oil Department
- Sacramento Municipal Utilities District
- Southern California Edison Company
- Southwest Gas Corporation
- ECOGAS Mexico, S. de R.L. de C.V

A statewide committee have been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Loan Nguyen (Chairperson) – SoCalGas/SDG&E
- Robert Anderson – SoCalGas/SDG&E
- Richard Aslin – PG&E
- Jamie Cattanach – Southwest Gas
- Herb Emmrich – SoCalGas/SDG&E
- Ma Paulina Flores – City of Long Beach
- Glen Holland – SDG&E
- Jeff Huang – SoCalGas /SDG&E
- Lynn Marshall - CEC
- Mark Minick - SCE
- Ruben Tavares - CEC
- Angela Tanghetti – CEC
- Kate Tiedeman - PG&E
- Debra Warady - SMUD
- William Wood - CEC

Observers

- Wendy al-Mukdad – CPUC Energy Division
- Bill Wood – CEC

Reserve Your Subscription

2009 California Gas Report – Supplement

Southern California Gas Company
2009 CGR Reservation Form
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249

or

Fax: (213) 244-3201
Email: Dean Kinports
DAKinports@semprautilities.com

- ❑ Send me a 2009 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ____

C/O: ____

Address: ____

City: ____________________ State: _______________ Zip: __________

Phone: (_____) __________________ Fax: (_____) ________________

Also, please visit our website at: www.socalgas.com
www.sdge.com

RESERVE YOUR SUBSCRIPTION

2009 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2009 CGR Reservation Form
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177

or

Fax: (415) 973-6272
Email: Kate Tiedeman
KMTc@pge.com

- ❑ Send me a 2009 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ______________________________

C/O: ______________________________

Address: ______________________________

City: ________________ State: ____________ Zip: ________

Phone: (_____) ______________ Fax: (_____) ____________

Also, please visit our website at: www.pge.com

Front cover: Photo of Cosumnes power plant from www.smud.org


Printed on recycled paper