2012 California Gas Report

Prepared by the California Gas and Electric Utilities

July 2012

2012 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

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2012 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2012 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 details on the 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, Southwest Gas Corporation, 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 by customer class. Separate sets of 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 address shown in the Reserve Your Subscription section at the end of this report.

2012 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

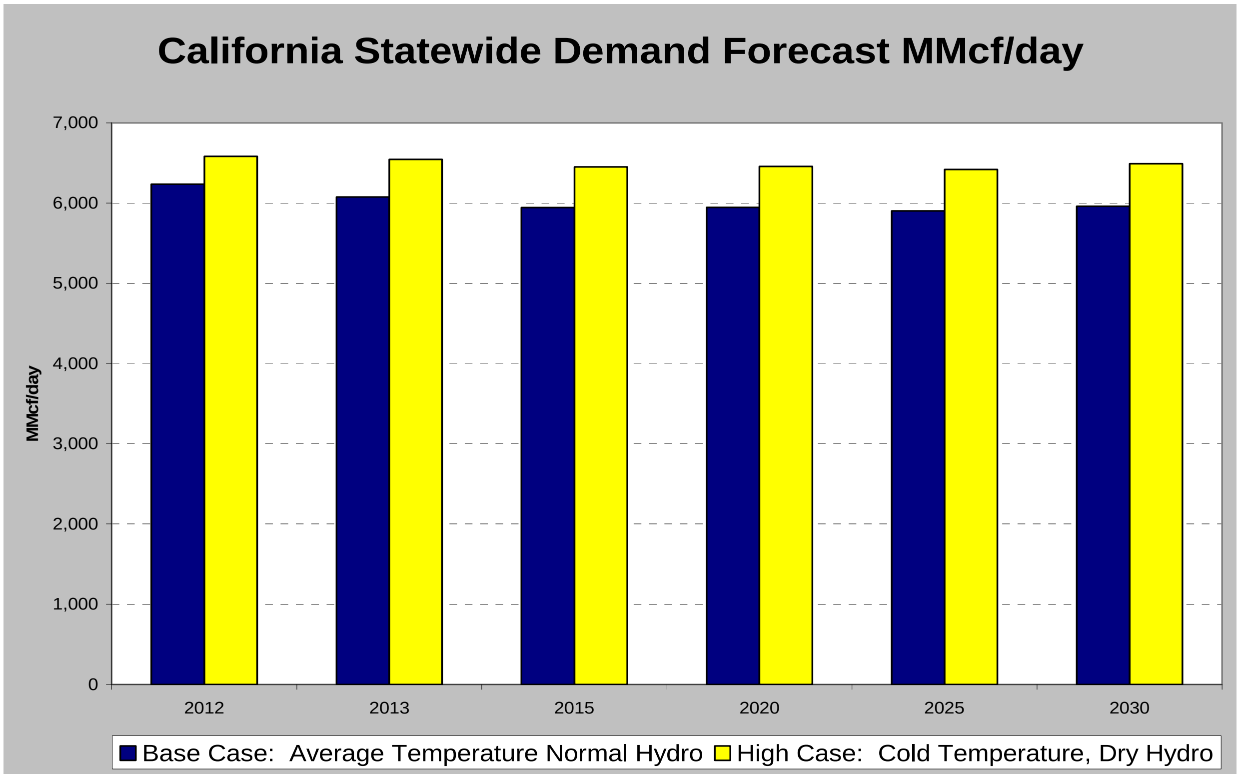
EXECUTIVE SUMMARY

DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to decrease at a modest rate of just -0.25 percent per year from 2012 to 2030. This forecast decline is a combination of annual growth in Natural Gas Vehicles (NGV), Enhanced Oil Recovery (EOR), and Wholesale markets which was offset by declines in all other market segments: residential; commercial; electric generation; and, industrial markets.

Residential gas demand is expected to decrease at an annual average rate of -0.08 percent. Demand in the core commercial and core industrial markets are expected to decline at an annual rate of -0.3 percent; whereas demand in the noncore commercial and industrial sector is estimated to decline by -0.33 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 as well as backstopping electricity generated from intermittent renewable resources, 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, under normal hydro conditions, is expected to decline at a modest -0.3% per year for the next 18 years due to more efficient power plants, statewide efforts to minimize greenhouse gas (GHG) emissions through aggressive programs pursuing demand side reductions and the acquisition of preferred resources that produced little or no carbon emissions. Under a scenario of sustained dry hydro conditions, gas demand for electric generation is expected to essentially remain flat over the 18 year forecast period.



The graph above summarizes statewide demand under a base case scenario and a high case scenario. The base case refers to the 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 6,248 MMcf/d in 2012 decreasing to 5,975 MMcf/d by 2030, a decline of -0.25% per year.

In 2012, Northern California is projected to require an additional 8% of gas supply to meet demand for the high gas demand scenario; whereas Southern California is projected to require an additional 3.4% of supply to meet the demand under the high scenario condition. This spread between the regions is a consequence of Northern California having colder weather (more heating degree-days annually) and tending to rely more heavily on hydroelectric power than Southern California. The weather scenario for each year is an independent event and each event 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. Gas prices at the Southern California border reached levels nearly ten times greater than had been experienced in 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 electric needs met with renewable power by 2012, with additional renewable power then added to increase the renewable portion to 33% by 2020 and beyond.

The state's 2006 Global Warming Solutions Act, also known as Assembly Bill (AB) 32, has set aggressive targets for the state to reduce its overall GHG production. This law creates substantial uncertainty on 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 the measures to meet the GHG reduction goals.

The table on the following page approximates total gas savings based on the impact of renewables in addition to the impact of electric and gas energy efficiency goals on the 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

	2011	2012	2013	2014	2015	2020	2025	2030
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) (1)								
Electricity Demand (GWh)	252,267	254,751	257,600	260,559	263,433	279,446	297,956	317,431
33% Reneweables by 2020								
Renewable Electric Generation (GWh/Yr) (2)	42,192	50,950	51,520	56,541	61,380	92,217	98,325	104,752
Increase over 2005 Level (GWh/Yr) (3)	19,792	28,550	29,120	34,141	38,980	69,817	75,925	82,352
Gas Savings over 2005 Level (Bcf/Day)	120	173	177	207	237	424	461	500
Gas Savings over 2005 Level (Bcf/Yr)	0.329	0.475	0.484	0.568	0.648	1.161	1.262	1.369
Electric Energy Efficieny Goals (5)								
Electricity Savings over 2005 Level (GWh/Yr)	16,165	18,711	21,341	23,972	24,765	25,364	25,720	25,847
Gas Savings over 2005 Level (Bcf/Yr) (4)	98	114	129	145	150	154	156	157
Energy Efficiency Goal for Natural Gas Programs (5)								
Gas Savings over 2005 Level (Bcf/Yr)	2	3	3	4	4	5	6	6
Total Gas Savings (Bcf/Yr) (6)	221	290	310	357	391	583	622	662
Total Gas Savings (Bcf/day) (6)	0.604	0.794	0.848	0.977	1.072	1.597	1.705	1.814

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.

FUTURE GAS SYSTEM IMPACTS RESULTING FROM INCREASED RENEWABLE GENERATION, AND LOCALIZED OR DISTRIBUTED GENERATION RESOURCES

Since utility system operators must balance electrical demand with appropriate generation sources on a real-time basis, most system operators rely on "dispatchable" resources that can respond quickly to changes in demand. The challenge with renewable resources is that while they can provide energy, they are not always totally predictable nor are they often considered controllable resources.

In the future, the increase in renewable generation in the state will definitely reduce the total amount of natural gas usage, but it is also expected that the future increases in renewable electric generation will increase the daily and hourly load forecast error associated with operation of natural gas fueled electric generation system. California is currently on track to meet a 33% Renewable Portfolio Standard by 2020 which will almost double the amount of renewable generation in the next eight years from the levels of 2008. In addition, the Governor has indicated an interest in significantly increasing the amount of smaller (less than 20 megawatts) generation in the state primarily with renewable or efficient technology. All this renewable energy will displace some of the natural gas currently being used to generate electricity in California but the reduction will not be proportional to the amount of renewable generation energy due to the intermittent nature of this renewable generation. The intermittent nature of renewable generation is likely to cause the electric system to rely more heavily on natural gas fired electric generation for providing the ancillary services (load following, ramping, and quick starts) needed to balance the electric system in the short term until other technologies can mature.

It is expected that solar and wind generating units will provide the major percentage of the new renewable electric generation in the years ahead with much of the smaller incremental renewable power coming from solar photovoltaic (PV) installations because solar generation costs have declined rapidly in the past few years and solar has siting advantages especially in the urban areas. Due to this expansion of renewable resources there may be an increased need for rapid response generators which could be available to follow load and the intermittent nature of these new renewables.

The impact of renewable generation resources that will be added into the California generation resource mix is that the system is likely to experience increased gas demand volatility for the electric generators that will be asked to meet the ancillary service needs in the state. In many months of the year the variability of wind is significant and in months that have significant cloud formation, or overcast conditions, the solar PV units may also have increased generation variability. The uncertainty in day-ahead gas demands will likely cause increased gas system inventory fluctuations. The gas system will therefore need to be flexible enough to handle such fluctuations with minimal disturbance to the delivery of the gas to other entities.

As noted previously, many recent studies have indicated that wind resources do not totally displace fossil fuels on a one-for-one basis. Therefore, since gas fired generation is the marginal resource in most hours the amount of gas consumed for integrating more renewables will definitely increase. The magnitude of that increase is still being studied, but recent analysis by the CAISO has shown some measurable increases of the capacity factors of the combined cycle and peaking natural gas units are expected in the future. There will undoubtedly be higher daily fluctuations of gas usage in the future especially on days when clouds materialize that were not forecast so the gas system will need to be able to accommodate such operations.

There may also be challenges in integrating new renewable generating facilities into both local and regional transmission grids. [1] The electric transmission system was built largely on a utility-by-utility basis to transport power from large central power stations to load centers. In most cases, the electric power generating plants were located within the utility service territory, with adjunct capabilities to sell power "off grid" to neighboring utilities or transmission-only utilities. The transportation of large quantities of remotely-generated, small scale and intermittent power supplies across long distances was not anticipated during the original construction of these systems, nor was this scenario anticipated in the development of state and federal regulatory pricing schemes. Such a change in the delivery of electric power will also add variability to the entire electric market which will most likely increase the variability of electric system generation and may increase the daily, hourly, and real time forecast error of the gas delivery systems. Lastly, smaller generators placed on the distribution systems of utilities were never envisioned in the past years, especially of the magnitude now anticipated. This, in effect, will also increase the variability of conventional gas fired or fossil generation and will necessitate higher quality forecasting methods in the future to minimize the deviations in the gas delivery needs.

The challenge of incorporating intermittent resources into the utility system is currently being addressed in several ways. Currently utility planners are anticipating the use of increased cycling fossil plants, pumped hydroelectric facilities, price responsive demand reducing programs, and distributed generation at load centers to handle much of the variability in gas demand. In addition, advances in forecasting wind availability, for example, will be critical in the facilitation of higher penetrations of wind resources on the electric system while attempting to minimize the gas delivery volatility. If forecasting can be improved then less spinning reserves and other ancillary services will be required. Also, a broader interconnection to the regional grid may offset the intermittent nature of a resource and alleviate some of the operational obstacles to integration so emphasis on shorter scheduling time increments between electric control areas would be very beneficial. However in the short term, or next five years, there is still a need to have sufficient resources available, most likely fossil resources, to balance the grid at times of renewable intermittency.

[1] *Linking Alternative and Distributed Energy Production to Electric Grid* Draft 12/28/2006. Prepared for the United States Department of Agriculture by Booz Allen and Hamilton. This source information has been modified to reflect conditions in California.

NATURAL GAS PROJECTS: PROPOSALS AND COMPLETIONS

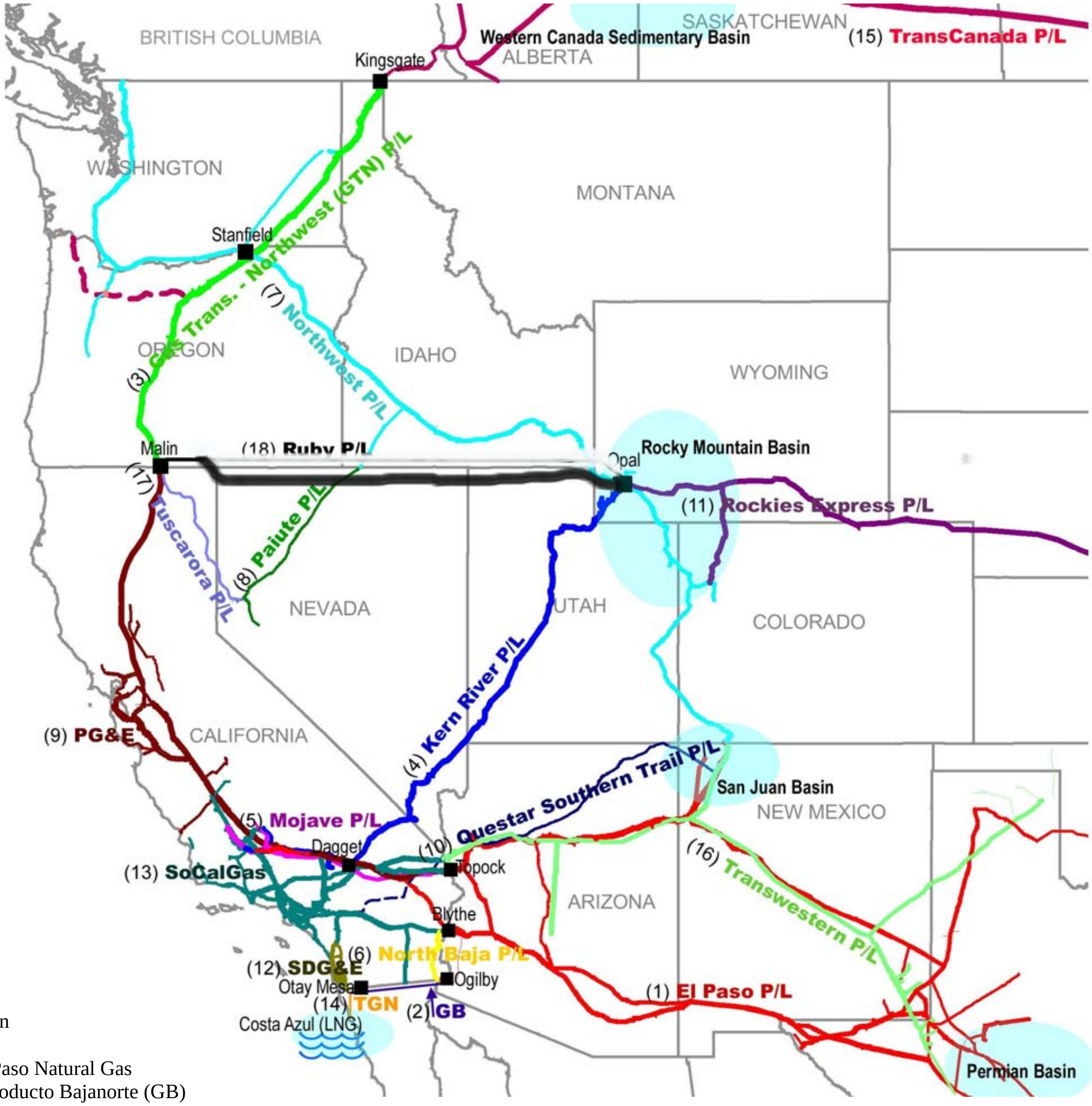
Over the past five years, California natural gas utilities, interstate pipelines, and in-state natural gas storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California 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.energyalmanac.ca.gov/naturalgas/index.html.

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 2010, the Ruby pipeline has come online bringing up to 1.5 Bcf/d of additional gas to California (via Malin) from the Rocky Mountains. The Energia Costa Azul LNG (liquefied Natural Gas) receiving terminal in Baja California provides yet another source of supply for California.

Additional pipeline capacity and open access have contributed to long-term supply availability and gas-on-gas competition for the California market. In addition to the new Ruby Pipeline, 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. Gasoducto 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 and Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express
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
18. Ruby Pipeline
19. Kern River Expansion

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 2012 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

	2012	2013	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	410	410	410	410	410	410
Out-of-State	4,670	4,574	4,505	4,564	4,518	4,546
Utility Total	5,080	4,984	4,915	4,974	4,928	4,956
Non-Utility Served Load (1)	1,347	1,282	1,222	1,166	1,142	1,173
Statewide Supply Sources Total	**6,427**	**6,267**	**6,136**	**6,140**	**6,070**	**6,129**
California's Requirements						
Utility						
Residential	1,189	1,180	1,166	1,166	1,161	1,173
Commercial	489	488	481	467	453	456
Natural Gas Vehicles	36	37	40	47	54	60
Industrial	923	919	917	894	877	874
Electric Generation (2)	1,917	1,825	1,775	1,863	1,867	1,870
Enhanced Oil Recovery Steaming	32	41	41	41	41	41
Wholesale/International+Exchange	237	237	238	239	244	250
Company Use and Unaccounted-for	79	78	77	78	77	78
Utility Total	4,901	4,805	4,736	4,795	4,774	4,802
Non-Utility						
Enhanced Oil Recovery Steaming	839	795	761	741	733	752
EOR Cogeneration/Industrial	132	125	116	105	102	106
Electric Generation	376	362	345	320	306	315
Non-Utility Served Load (1)	1,347	1,282	1,222	1,166	1,142	1,173
Statewide Requirements Total (3)	**6,248**	**6,088**	**5,957**	**5,961**	**5,916**	**5,975**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(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	2012	2013	2015	2020	2025	2030
Northern California						
California Sources (1)	100	100	100	100	100	100
Out-of-State	2,307	2,237	2,199	2,255	2,229	2,237
Northern California Total	2,407	2,337	2,299	2,355	2,329	2,337
Southern California						
California Sources (2)	310	310	310	310	310	310
Out-of-State	2,363	2,337	2,305	2,309	2,289	2,309
Southern California Total	2,673	2,647	2,615	2,619	2,599	2,619
Utility Total	5,080	4,984	4,915	4,974	4,928	4,956
Non-Utility Served Load (3)	1,347	1,282	1,222	1,166	1,142	1,173
Statewide Supply Sources Total	**6,427**	**6,267**	**6,136**	**6,140**	**6,070**	**6,129**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

STATEWIDE ANNUAL GAS REQUIREMENTS [1]
Average Temperature and Normal Hydro Year
MMcf/Day

	2012	**2013**	**2015**	**2020**	**2025**	**2030**
Utility						
Northern California						
Residential	551	548	544	547	543	546
Commercial - Core	228	228	228	228	226	226
Natural Gas Vehicles - Core	5	6	6	6	7	7
Natural Gas Vehicles - Noncore	1	1	1	1	1	2
Industrial - Noncore	487	487	493	489	493	498
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	122	122	122	122	122	122
Electric Generation [2]	775	709	671	725	725	725
Exchange (California)	1	1	1	1	1	1
Company Use and Unaccounted-for	47	46	45	46	46	46
Northern California Total [3]	2,228	2,158	2,120	2,176	2,175	2,183
Southern California						
Residential	638	632	623	620	618	628
Commercial - Core	213	214	211	206	203	207
Commercial - Noncore	47	46	43	33	24	23
Natural Gas Vehicles - Core	29	30	33	39	45	51
Industrial - Core	60	58	56	50	43	39
Industrial - Noncore	376	374	368	354	341	336
Wholesale	226	226	227	228	233	239
SDG&E+Vernon Electric Generation	208	190	191	183	187	191
Electric Generation [4]	812	804	790	833	833	832
Enhanced Oil Recovery Steaming	32	41	41	41	41	41
Company Use and Unaccounted-for	32	32	32	32	31	32
Southern California Total	2,673	2,647	2,615	2,619	2,599	2,619
Utility Total	4,901	4,805	4,736	4,795	4,774	4,802
Non-Utility Served Load [5]	1,347	1,282	1,222	1,166	1,142	1,173
Statewide Gas Requirements Total [6]	**6,248**	**6,088**	**5,957**	**5,961**	**5,916**	**5,975**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

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

	2012	**2013**	**2015**	**2020**	**2025**	**2030**
California's Supply Sources						
Utility						
California Sources	410	410	410	410	410	410
Out-of-State	4,953	4,955	4,910	4,987	4,955	4,993
Utility Total	5,363	5,365	5,320	5,397	5,365	5,403
Non-Utility Served Load (1)	1,411	1,372	1,322	1,253	1,224	1,258
Statewide Supply Sources Total	**6,774**	**6,737**	**6,642**	**6,650**	**6,589**	**6,661**
California's Requirements						
Utility						
Residential	1,268	1,259	1,249	1,258	1,263	1,282
Commercial	510	505	500	487	475	479
Natural Gas Vehicles	36	37	40	47	54	60
Industrial	925	921	919	896	880	876
Electric Generation (2)	2,078	2,086	2,055	2,150	2,154	2,158
Enhanced Oil Recovery Steaming	32	41	41	41	41	41
Wholesale/International+Exchange	251	252	253	254	259	266
Company Use and Unaccounted-for	84	85	84	86	85	87
Utility Total	5,184	5,186	5,141	5,218	5,211	5,249
Non-Utility						
Enhanced Oil Recovery Steaming	839	795	761	741	733	752
EOR Cogeneration/Industrial	132	125	116	105	102	106
Electric Generation	440	452	446	407	389	400
Non-Utility Served Load (1)	1,411	1,372	1,322	1,253	1,224	1,258
Statewide Requirements Total (3)	**6,595**	**6,558**	**6,463**	**6,471**	**6,435**	**6,507**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(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	**2012**	**2013**	**2015**	**2020**	**2025**	**2030**
Northern California						
California Sources [1]	100	100	100	100	100	100
Out-of-State	2,500	2,466	2,460	2,524	2,512	2,528
Northern California Total	2,600	2,566	2,560	2,624	2,612	2,628
Southern California						
California Sources [2]	310	310	310	310	310	310
Out-of-State	2,453	2,489	2,449	2,463	2,443	2,465
Southern California Total	2,763	2,799	2,759	2,773	2,753	2,775
Utility Total	5,363	5,365	5,320	5,397	5,365	5,403
Non-Utility Served Load [3]	1,411	1,372	1,322	1,253	1,224	1,258
Statewide Supply Sources Total	**6,774**	**6,737**	**6,642**	**6,650**	**6,589**	**6,661**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

STATEWIDE ANNUAL GAS REQUIREMENTS [1]
Cold Temperature and Dry Hydro Year
MMcf/Day

	2012	**2013**	**2015**	**2020**	**2025**	**2030**
Utility						
Northern California						
Residential	569	567	567	579	586	595
Commercial - Core	237	232	233	236	236	238
Natural Gas Vehicles - Core	5	6	6	6	7	7
Natural Gas Vehicles - Noncore	1	1	1	1	1	2
Industrial - Noncore	487	488	494	490	495	500
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	122	122	122	122	122	122
Electric Generation (2)	936	909	897	947	947	947
Exchange (California)	1	1	1	1	1	1
Company Use and Unaccounted-for	51	51	51	52	52	53
Northern California Total (3)	2,421	2,387	2,381	2,445	2,458	2,474
Southern California						
Residential	699	692	682	678	677	687
Commercial - Core	225	225	222	217	213	218
Commercial - Noncore	48	47	44	35	25	24
Natural Gas Vehicles - Core	29	30	33	39	45	51
Industrial - Core	61	59	57	51	44	40
Industrial - Noncore	376	374	368	354	341	336
Wholesale	241	241	242	243	248	255
SDG&E+Vernon Electric Generation	208	197	200	190	194	198
Electric Generation (4)	812	858	837	890	891	890
Enhanced Oil Recovery Steaming	32	41	41	41	41	41
Company Use and Unaccounted-for	33	34	33	34	33	34
Southern California Total	2,763	2,799	2,759	2,773	2,753	2,775
Utility Total	5,184	5,186	5,141	5,218	5,211	5,249
Non-Utility Served Load (5)	1,411	1,372	1,322	1,253	1,224	1,258
Statewide Gas Requirements Total (6)	**6,595**	**6,558**	**6,463**	**6,471**	**6,435**	**6,507**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern California 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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) 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 the composition of supplies from both out-of-state sources as well as California sources. The data are 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 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.

Recorded 2008 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)	-39	730	228	14	84	1	-21	998
Noncore Commercial/Industrial	73	103	70	19	121	6	8	400
EG (3)	166	233	158	44	275	13	17	907
EOR	7	10	7	2	12	1	1	39
Wholesale/Resale/International (4)	1	192	198	11	21	0	-2	422
Total	209	1,268	661	90	514	21	3	2,766
Pacific Gas and Electric Company (5)								
Core	0	219	136	502	1	0	0	858
Noncore Industrial/Wholesale/EG (6)	135	433	131	623	23	0	43	1,387
Total	135	652	267	1,125	23	0	43	2,245
Other Northern California								
Core (7)	0	0	0	0	0	0	14	14
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	445	28	0	0	840	19	0	1,332
TOTAL SUPPLIER	789	1,948	928	1,215	1,377	40	60	6,357

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	1	73	38	9	17	0	-2	136
Noncore Commercial/Industrial	0	80	118	0	0	0	0	198
Total	1	152	157	9	17	0	-2	334

(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 2008, Line 1903 transported 449 MMcf/d to Arizona.

Recorded 2009 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 + UAF (2)	98	590	187	20	69	0	19	983
Noncore Commercial/Industrial	35	123	48	31	135	9	5	386
EG (3)	73	259	101	65	284	20	10	811
EOR	3	11	4	3	12	1	0	35
Wholesale/Resale/International (4)	7	191	155	30	17	1	12	412
Total	216	1,174	495	148	518	30	46	2,627
Pacific Gas and Electric Company (5)								
Core	0	219	136	486	0	0	0	842
Noncore Industrial/Wholesale/EG (6)	135	358	175	623	46	0	0	1,337
Total	135	577	311	1,110	46	0	0	2,179
Other Northern California								
Core (7)	0	0	0	0	0	0	13	13
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	386	27	0	0	909	19	0	1,341
TOTAL SUPPLIER	737	1,778	806	1,258	1,473	49	59	6,160

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.

(2) Includes NGV volumes

(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	45	36	23	14	0	9	133
Noncore Commercial/Industrial	0.058	105	85	0	0	0	0	191
Total	6	150	122	23	14	0	9	324

(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.

Recorded 2010 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 + UAF (2)	181	504	212	30	91	0	-10	1,008
Noncore Commercial/Industrial	5	154	41	28	130	9	14	420
EG (3)	10	323	87	58	273	19	29	768
EOR	0	14	4	3	12	1	1	30
Wholesale/Resale/International (4)	7	191	155	30	17	1	12	412
Total	203	1,186	499	149	524	29	46	2,638
Pacific Gas and Electric Company (5)								
Core	0	219	136	486	0	0	0	842
Noncore Industrial/Wholesale/EG (6)	135	358	175	623	46	0	0	1,337
Total	135	577	311	1,110	46	0	0	2,179
Other Northern California								
Core (7)	0	0	0	0	0	0	13	13
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	386	27	0	0	909	19	0	1,341
TOTAL SUPPLIER	724	1,790	810	1,259	1,479	48	59	6,171

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(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	45	36	23	14	0	9	133
Noncore Commercial/Industrial	0.058	105	85	0	0	0	0	191
Total	6	150	122	23	14	0	9	324

(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.

Recorded 2011 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
Southern California Gas Company									
Core + UAF (2)	195	442	257	33	138	0	-25	0	1,040
Noncore Commercial/Industrial	-18	157	24	25	203	14	20	0	423
EG (3)	-31	270	41	44	349	25	34	0	726
EOR	-1	10	2	2	13	1	1	0	27
Wholesale/Resale/International (4)	30	116	97	21	124	0	9	0	407
Total	175	996	420	125	828	40	40	0	2,623
Pacific Gas and Electric Company (5)									
Core	0	166	120	501	6	0	0	37	831
Noncore Industrial/Wholesale/EG (6)	108	132	116	563	118	0	6	281	1,323
Total	108	298	236	1,064	124	0	6	318	2,154
Other Northern California									
Core (7)	24	0	0	0	0	0	13	37	74
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	391	12	0	0	1,045	23	0	0	1,471
TOTAL SUPPLIER	698	1,306	656	1,189	1,997	63	59	355	6,322

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(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)	RUBY	Total
San Diego Gas & Electric Company									
Core	25	59	34	4	19	0	-3	0	138
Noncore Commercial/Industrial	-1	32	42	12	79	0	10	0	174
Total	23	91	76	17	98	0	7	0	312
SouthWest Gas									
Core	24	0	0	0	0	0	13.00	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.17	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

(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.

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 Gas Company, Pacific Gas & Electric and from customers not served by these utilities were used to construct the following tables.

Estimated California Highest Summer Sendout (MMcf/d (5))

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2007	08/29/2007	2,751	3,686	6,438	1,558	7,996
2008	09/04/2008	2,467	3,153	5,620	1,358	6,978
2009	09/02/2009	2,592	3,235	5,827	1,369	7,196
2010	08/25/2010	2,700	3,504	6,204	1,153	7,357
2011	04/08/2011	2,164	3,313	5,477	1,322	6,799

Estimated California Highest Winter Sendout (MMcf/d (5))

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2007	01/15/2007	3,848	4,577	8,425	1,700	10,126
2008	12/17/2008	4,070	4,910	8,980	1,403	10,382
2009	12/08/2009	4,157	4,505	8,662	1,327	9,989
2010	11/29/2010	3,426	4,356	7,782	1,151	8,932
2011	12/12/2011	2,842	4,152	6,994	1,501	8,495

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 SoCalGas peak day supply from Kern/Mojave and California Production. Provided by the CEC.
(4) PG&E and SoCalGas sendouts are reported for the day on which the Utility Total sendout is the maximum for the respective season each year. Winter season months are Jan, Feb, Mar, Nov and Dec; while Summer season months are Apr, May, Jun, Jul, Aug, Sep and Oct..
(5) For 2007-2010, PG&E and SoCalGas data are originally in energy units (MDth) and are converted to volumetric units (MMcf) by 1.0150 Dth/Mcf for PG&E and, 1.0235 Dth/Mcf for SoCalGas. For 2011, PG&E’s data were reported in volumetric units; SoCalGas’ data were converted from energy units using 1.0209 Dth/Mcf.

2012 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 4.3 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.

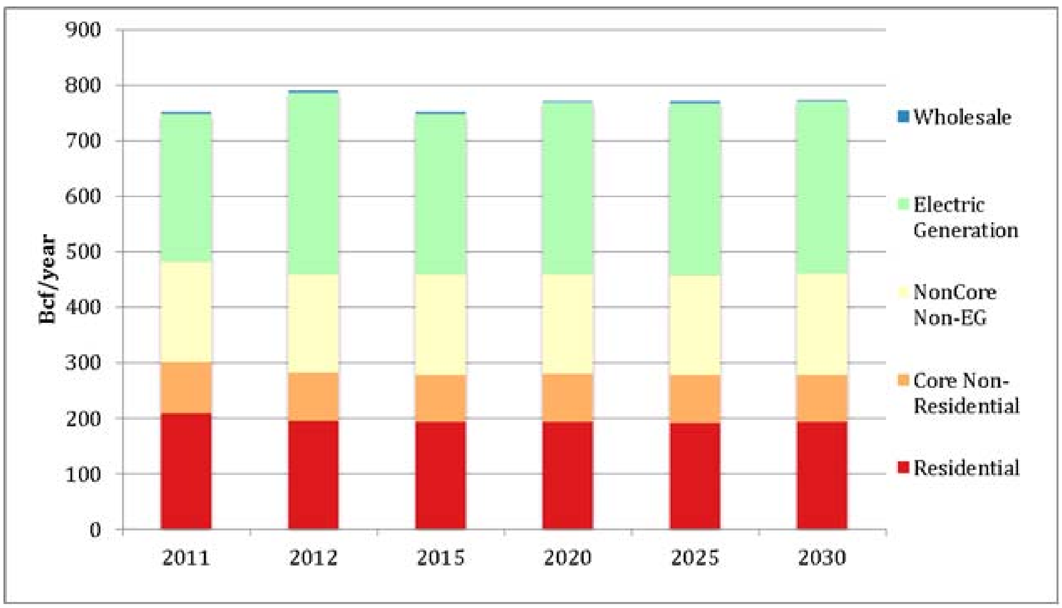
The forecast in this report covers the years 2012 through 2030. However, as a matter of convenience, the tabular data at the end of the section show only the years 2012 through 2014, and the years 2015, 2020, 2025, and 2030.

GAS DEMAND

OVERVIEW

PG&E's *2012 California Gas Report (CGR)* average-year demand forecast projects total on-system demand to decline at an annual average rate of 0.2 percent between 2012 and 2030. This is due to the combination of a 0.1 percent annual decline in the core market and an annual decline of 0.2 percent in the noncore market. By comparison, the 2010 CGR estimated an annual average growth rate of 0.3 percent per year, based on growth of 0.3 percent per year for both the core and the noncore markets.

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



The projected rate of growth of the core market has decreased from the *2010 California Gas Report* primarily due to increased emphasis on energy efficiency, slower growth in the customer base, and the incorporation of climate change where a warmer climate is assumed in the forecast horizon.

The forecast rate of growth of the noncore market has decreased due to a decrease in the forecast of electric load, an increase in assumed renewable energy generation in northern California, and a decrease in assumed gas-fired power plants in northern California. In this CGR, total gas demand by electric generators and cogenerators in northern California for average hydrological conditions is estimated to increase at a rate of about 0.1 percent per year from 2013 through 2030 (the forecast for 2012 includes actual demand for the first quarter, which was affected by dry hydrological conditions in the Northwest and California and the extended outage of the San Onofre Nuclear Generating Station. This total gas demand excludes gas delivered by nonutility 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. In addition, increasing quantities of renewable energy generation are expected to increase the need for load following and ancillary services such as regulation. These ancillary services are likely to be provided by gas-fired power plants, thus, affecting gas demand to some extent. PG&E's 2012 CGR forecast, however, does not capture this impact.

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; changes in the efficiency profiles of residential and commercial buildings and the appliances within them; and, the response to climate change.

FORECAST SCENARIOS

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 by considering the year with cold temperature and dry hydro conditions. Assuming the demographic conditions and infrastructure likely to exist in each forecast year, PG&E forecasts total gas demand with the weather conditions set to match the conditions that have an approximately 1-in-35 likelihood of occurrence. PG&E used the weather conditions from November 1976 through October 1977, as the winter of 1976-1977 was colder than normal, and this time period was extremely dry in both northern California and the Pacific Northwest.

Temperature Assumptions

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. In previous CGRs, PG&E's average-year demand forecast assumed that temperatures in the forecast period would be equivalent to the average of observed temperatures during the past twenty years. PG&E is now building into its forecast an assumption of climate change. The climate change scenario is developed from work done at the National Center for Atmospheric Research (Boulder, Colorado) and downscaled to the PG&E service area. Although the near term temperatures of this scenario differ little from long term averages, the years beyond 2015 begin to show the effects of a warming climate. For example, in 2015, total December/January heating degree days are only 2 percent below the 20 year average. By 2025, however, the impact is significant, with the difference at 10 percent.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the climate change 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 as those that 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 for average and high demand are both based on average temperatures. (Each summer typically contains a few heat waves with temperatures 10^{o} or 15^{o} 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 2^{o} 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 year 2001 (October 2000 through September 2001). For the 2012 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 0.8 percent annually from 2012 to 2030. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. 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, despite slight upticks in 2009 and 2011 due to cold winters, has fallen on average 2 percent per year since 2004. Due to expected continuing upgrades in appliance and building efficiencies, as well as warming temperatures, PG&E forecasts total residential demand to decline on average by 0.1 percent per year from 2012 to 2030, implying an average decrease in gas use per household of 1.0 percent per year.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by 0.3 percent per year from 2012 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 decline slightly over the forecast horizon, negating any sales increase due to the slow growth in customers. Over the next 18 years, sales for this sector are expected to decline 0.1 percent per year.

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 but has seen slow growth in the recent past due to very low natural gas prices and increased capacity at local refineries, though these effects have been tempered by the 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 grow slowly at 0.1 percent annually over the next 18 years.

Electric Generation

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to the retirement of existing power plants with once-through cooling; the timing, location, and type of new generation, particularly renewable-energy facilities; construction of new electric transmission lines; and the impact of greenhouse gas legislation and regulations on both generation and load. Because of these uncertainties, the forecast is held constant at 2020 levels for 2025 and 2030.

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. In this CGR, PG&E has assumed additions of new onsite and export (demand- and supply-side) combined heat and power plants through 2020. Operations at most cogeneration plants are not strongly affected by prices in the wholesale electricity market because electricity is generated 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 model 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 2012–2030 uses the mid-case electricity demand forecast from the CEC's 2011 *Integrated Energy Policy Report.* The forecast assumes that renewable energy generation will provide 20% of the state's retail sales by 2014 and 33% by 2020. PG&E assumed that gas-fired plants that employ once-through cooling will retire by the compliance date set by the State Water Resources Control Board (with some exceptions where the plant owner has proposed a different date), generally replaced by new gas-fired plants with comparable capacities.

SMUD Electric Generation

The Sacramento Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the United States, and 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/day, and the average load is about 122 MMcf/day.

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/day of capacity.

GREENHOUSE GAS LEGISLATION / AB32

During the forecast horizon covered by this CGR, there are many uncertainties that may significantly impact the future trajectory of natural gas demand. It is unclear at this time what the ultimate effect on natural gas demand will be from California's landmark California Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB32). On the one hand, more aggressive energy efficiency programs and/or increased targets for renewable electricity supplies could significantly reduce the use of natural gas by residential and commercial customers and power plants. On the other hand, increased penetration of electric and natural gas vehicles could reduce gasoline use and overall greenhouse gas (GHG) emissions, but increase consumption of natural gas.

PG&E will continue to minimize GHG emissions by aggressively pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

RENEWABLE ELECTRIC GENERATION

PG&E expects the future increase in renewable electric generation to increase the daily and hourly deviations between forecast and actual generation from natural gas fueled electric resources. The intermittent nature of some renewable generation (e.g., wind or solar power) is likely to cause the electric system to rely more heavily on natural gas fired electric generation to cover forecast deviations and intra-day and intra-hour variability of intermittent generation. This will, in turn, result in higher daily forecast errors for gas and increased gas system inventory fluctuations

ENERGY EFFICIENCY PROGRAMS

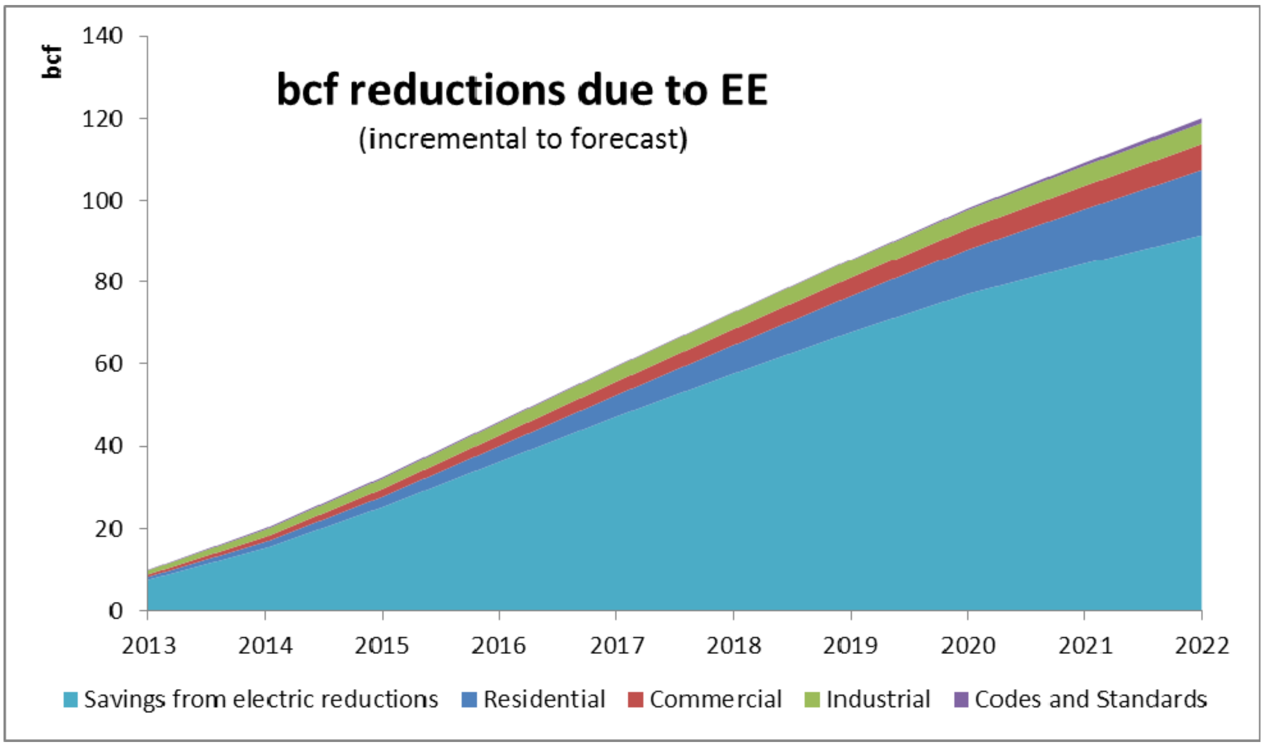
PG&E engages in a number of energy efficiency and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. PG&E administers many energy efficiency programs, including services that help customers evaluate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

Conservation and energy efficiency load impacts are shown as positive numbers. They are measured at the meter and include any interactive effects that may result from efficiency improvements of electric end uses; for instance, increased natural gas heating load that could result from efficiency improvements in lighting and appliances. These figures also include any reductions in natural gas demand for generation that may occur due to lower electric demand; see "savings from electric reductions" in the graph below.

The cumulative energy efficiency load impact forecast for selected years is provided in Figure 1 below. The load impact in Figure 1 includes all Energy Efficiency savings that CPUC/Energy Division has forecast to be available in the years 2012 through 2022. Savings for these efforts are based on the report "Analysis To Update Energy Efficiency Potential, Goals, And Targets For 2013 And Beyond," which was conducted by Navigant Consulting and was published March 30, 2012.

Details of PG&E's' 2013-2014 Energy Efficiency program portfolio are currently under development. Details of the 2010-12 Energy Efficiency Portfolio can be found in CPUC decision 09-09-047.

Figure 1: Bcf reductions due to EE (incremental to forecast)



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.

Overall, most of the gas supplies that serve PG&E customers are sourced from out of state with only a small portion originating in California. This is due to the increasing gas demand in California over the years and the limited amount of native California supply available.

GAS SUPPLY

California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2011, PG&E's customers obtained on average 108 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 producing basins and transport it to California via inter-state pipelines. They can also purchase gas 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 gas from various suppliers in western Canada (British Columbia and Alberta) and transport it to California primarily through the Gas Transmission Northwest Pipeline. Likewise, they 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, the Ruby Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon. The Ruby Pipeline came online in July 2011 and brings up to 1.5 Bcf/day of Rocky Mountain gas to Malin, Oregon. With Ruby pipeline, the share of Canadian gas to PG&E's system has been reduced.

Storage

In addition to storage services offered by PG&E, there are four other storage providers in northern California -- Wild Goose Storage, Inc., Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. There are additional proposed storage projects that have the potential to expand the northern California gas storage capacity in the 2012 to 2014 period.

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, Paiute Pipeline Company, Ruby (online since July 2011), 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 1,009 MMcf/day.

Canada and Rocky Mountains

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 1,989 MMcf/day.

GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

PG&E anticipates that sufficient 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 (2012-2015), new sources of gas supply to northern California will be from the Rocky Mountain supply basin. In addition, the growth of gas production in the Midcontinent and Eastern shale plays (e.g., Barnett in northeast Texas, Marcellus in Pennsylvania) have had the effect of pushing larger volumes of Rockies, San Juan and Permian supplies to California, as those supplies are crowded out of markets to the east.

LNG Imports/Exports

Liquefied Natural Gas (LNG) imports are not expected to be a significant supply source in the near term whether directly connected to the PG&E system, or delivered across other systems to PG&E. The recent success in developing relatively low cost domestic shale gas supplies has largely eliminated the need for LNG imports. There are several proposed LNG projects utilizing existing U.S. import terminals to export LNG to the world market. In addition, there are proposed export projects with new LNG terminals in western Canada or the U.S. that would compete for gas supplies available to northern California.

Rocky Mountains

A new path for gas supplies that serve the northern California market is on the Ruby pipeline from the Rocky Mountains, which is a growing natural gas supply area in North America. In July 2011, El Paso Natural Gas Corp (recently purchased by Kinder Morgan, Inc) completed the 1.5 Bcf/day Ruby Pipeline project, which connects the Rocky Mountain supply basin at Opal with Malin, Oregon. This project provides a source of supply to offset declines of supply.

North American Supply Development

The most promising development in the North American gas supply picture in the past several years has been the rapid development of various shale gas resources through horizontal drilling combined with hydraulic fracturing. While the initial developments were concentrated in the U.S. midcontinent, the large Marcellus play in the eastern U.S. has been ramping up, resulting in record U.S. gas production in 2011. Most industry forecasts now expect supply can increase to meet the most aggressive demand scenario in the future. Unconventional supply, which includes gas from tight sands, coal bed methane and shale formations, is currently at 60% of total production and will continue to grow, while many of the traditional supply basins have been declining in output for a number of years.

GAS STORAGE

There are several new natural gas storage projects in northern California that have significantly expanded total northern California gas storage capacity. These projects are in addition to the Lodi Gas Storage expansion, which added 12 Bcf of working gas capacity at the end of 2008.

PG&E co-developed a natural gas storage project with Gill Ranch Storage, LLC. This project, located in the central San Joaquin Valley west of Fresno, has about 20 Bcf of working gas along with about 650 MMcf/day of firm withdrawal. It utilizes depleted gas reservoirs. This storage project became operational in late 2010.

Wild Goose Storage, which currently has 29 Bcf of working gas capacity, filed for its Phase III expansion in April 2009. This expansion would bring the facility's capacity up to 50 Bcf and is expected to go online in late 2012.

The 10-Bcf Central Valley Gas Storage project, which is being developed by the Nicor Companies, completed its application in 2009. The CPUC approved the project in 2010, and the expected in-service date is mid-2012.

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 West Sacramento. The outcome of the CPUC approval process is unclear at this time, as there are three conflicting proposals for the final decision, one of which recommends denial.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Quality

Gas quality has received much less attention since 2010 due to the abundance of domestic gas supply which has diminished interest in LNG imports, as described in the previous chapter. Hence, the challenges associated with integrating LNG and traditional North American sources, each typically with different quality characteristics, do not require immediate resolution.

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 1,385.

Core Gas Aggregation Program

At present, Core Transport Agents (CTAs) serve approximately 13 percent of PG&E's core gas demand. PG&E recently began implementing the CTA Settlement Agreement, part of the Gas Accord V Settlement Agreement. The CTA Settlement Agreement modifies the practice by which PG&E offers a share of its pipeline and storage capacity holdings to CTAs to serve core customers. Implementation has resulted in numerous revisions to PG&E's Gas Schedule G-CT (Core Gas Aggregation Service) and to PG&E's CTA Service Agreement.

FEDERAL REGULATORY MATTERS

PG&E actively participates in Federal Energy Regulatory Commission (FERC) ratemaking proceedings for interstate pipelines connected PG&E's system because these cases can impact the cost of gas delivered to our gas customers and the services provided. PG&E also participates in FERC proceedings of general interest to the extent they affect PG&E's operations and policies or natural gas market policies generally.

Ruby Pipeline

Ruby Pipeline, a subsidiary of El Paso Corporation, runs 675 miles from Opal, Wyoming to Malin, Oregon, and was placed into service in July 2011. Ruby is currently capable of transporting 1.5 Bcf/day to bring supplies of Rocky Mountain gas to the Northwest and to California. PG&E holds 375 MMcf/day of capacity on Ruby, which is the first carbon neutral pipeline in the United States.

El Paso

El Paso filed a rate case application (Docket RP10-1398) for revised rates and terms and conditions effective April 1, 2011. Under El Paso's proposal, basic firm transportation rates would rise by over 30%. FERC conducted hearings in late 2011 and a decision is expected sometime in 2012.

El Paso received approval to abandon two compressor stations in 2011 (CP10-510). It later filed with FERC to temporarily abandon a number of additional compressor units but the proposal was rejected (CP11-17). El Paso has since filed a new proposal (CP12-45) to abandon compressor facilities at six locations associated with El Paso's Northern Mainline and San Juan Triangle. PG&E and other California utilities have protested this application.

Kern River

Kern completed its Apex Expansion in 2011 which expanded mainline capacity by approximately 266 MMcf/day.

Transwestern

On September 21, 2011, Transwestern submitted a petition to the FERC for approval of a Stipulation and Agreement of Settlement (Settlement) between Transwestern and its shippers in lieu of its obligation to file a Natural Gas Act Section 4 general rate case (RP11-2576-000). FERC approved the Settlement October 31, 2011 which established new fuel rates effective April 1, 2012.

Gas Transmission Northwest

On August 12, 2011, Gas Transmission Northwest LLC (GTN) submitted to FERC a petition for approval of a Settlement Agreement between GTN and its shippers implementing changes to GTN's transportation rates and tariff provisions (RP11-2377-000). FERC approved the Settlement on November 30, 2011, with rates effective January 1, 2012.

FERC Notice of Inquiry Regarding Integration of Variable Energy Resources (Docket RM10-11)

FERC sought comments in April 2010 as to how to more effectively integrate renewable generation resources into the electric grid. While providing numerous comments from an electric perspective, PG&E also emphasized that electric system planners need to work closely with gas system planners to confirm that gas systems are sized appropriately and offer the necessary services to allow gas fired electric generation projects to respond to sudden changes in renewable project output. FERC has not taken any specific action in response to the comments.

FERC Request for Comments Regarding Gas-Electric Coordination (AD12-12)

Various FERC Commissioners have raised questions about whether there is sufficient coordination between gas and electric system operators regarding reliability. Concerns have arisen for several reasons: extreme weather events that can affect both the gas and electric grids; expectations of significant increases in gas fired electric generation nationwide (less so in PG&E's service territory since a significant number of gas fired generators have already exist); and the expanding prevalence of renewable generation portfolio requirements and the resulting need for non-renewable fuel sources, like natural gas, to support the grid when renewable generation is unavailable or reduced. Industry stakeholders were invited to submit comments by March 30, 2012, including identification of any impediments to closer coordination. PG&E responded that gas–electric coordination is best viewed on a regional basis due to the numerous differences in infrastructure and electric markets across the country. PG&E does not believe there are any compelling coordination issues in California since a high degree of coordination already exists between gas system operators and the (electric) California Independent System Operator. It is unknown what steps FERC will take in response to the comments but it is probable FERC will ultimately make some policy changes to further ensure reliability.

OTHER REGULATORY MATTERS

Hydraulic Fracturing

Hydraulic fracturing is not new (see www.fracfocus.org). It is the combination of hydraulic fracturing with horizontal drilling that has unlocked vast shale gas resources across North America. Given the rapid growth in shale drilling and the number of "fracked" wells, federal, state and local governments are focusing on better understanding the water and air quality impacts. In April 2012, the Environmental Protection Agency (EPA) issued its first federal regulation for natural gas wells that are hydraulically fractured to reduce volatile organic compounds and methane emissions. Also, the Department of Energy (DOE), the Department of the Interior, and the EPA announced that they will jointly develop a multi-agency program to study the key challenges associated with unconventional oil and gas production (April 2012). The program takes into consideration the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. The outcomes of these studies will support policy decisions at both the federal and state levels.

Gas Exports

Over the last five to ten years there has been a shift in focus in North America from the need to import LNG to the potential for LNG exports. As noted earlier, the boom in unconventional production drives this shift. While producers seek to arbitrage North American gas prices and international oil-linked prices, the federal government is assessing the cumulative impact of approving up to 14 Bcf/day of LNG exports. The FERC has approved a number of projects based on their individual merit, whereas the DOE is focused on how the cumulative impact of LNG exports would affect domestic prices and the general public interest. Pending a study to be released in summer 2012, the DOE will formulate policy to apply to the numerous applications pending.

Exports to Mexico have grown in recent years to 500 Bcf in 2011 and will continue to grow due to declining gas production and higher gas demand in Mexico.

Greenhouse Gas (GHG) Reporting and Allowances Purchases

In 2012 PG&E Gas Operations will report to the EPA GHG emissions in accordance with 40 CFR Part 98 in three primary categories: GHG emissions in 2011 resulting from combustion at six compressor stations where the annual emissions exceed 25,000 Metric Tons of CO_2 equivalent; the GHG emissions resulting from combustion of all customers except customers consuming more than 460,000 Mcf; and certain vented and fugitive emissions from the six compressor stations and the distribution system.

In 2012 PG&E Gas Operations reported to the California Air Resources Board (CARB) GHG emissions in the amount of 39.5 Million Metric Tons of CO_2 equivalent in three primary categories: GHG emissions resulting from combustion at six compressor stations where the annual emissions exceed 25,000 Metric Tons of CO_2 equivalent; the GHG emissions resulting from combustion of all customers; and certain vented and fugitive emissions from six compressor stations and the distribution system.

In 2012 PG&E expects that a total of seven compressor stations will emit more than 25,000 Metric Tons of CO_2 equivalent and in 2013 PG&E will begin purchasing greenhouse gas emissions allowances for those stations.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of demand under extremely adverse conditions. PG&E uses a 1-in-90 year cold temperature event as the design criterion. This corresponds to a 27 degree Fahrenheit system-weighted mean temperature across the PG&E gas system. PG&E core demand forecast corresponding to 27 degree F temperature is estimated to be approximately 3.1 Bcf/day. PG&E load forecast shown here excludes all noncore demand and, in particular, excludes all electric generation (EG) demand. PG&E estimates that total noncore demand during an APD event would be approximately 1.8 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD core forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

APD SUPPLY REQUIREMENT FORECAST

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 85 percent of PG&E's core gas usage. 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 an 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 EG, 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 those noncore customers, including EG, to 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 EG, on an APD would be approximately 1.8 Bcf/day. With the additions of the Wild Goose, Lodi, Gill Ranch, and Central Valley Gas 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 APD
MMcf/day

	2012-13	2013-14	2014-15
APD Core Demand (1)	3,077	3,074	3,071
Firm Storage Withdrawal (2)	1,101	1,077	1,049
Required Flowing Supply (3)	1,977	1,997	2,022
Total APD Resources	3,077	3,074	3,071

Notes:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. The APD core demand forecast is calculated for 27 degrees Fahrenheit system composite temperature, corresponding to a 1-in-90 year cold temperature event. PG&E uses a system composite temperature based on six weather sites. This results in a 27 degree APD temperature that is roughly equivalent to the 29 degree APD temperature used in earlier reports.

(2) Core Firm Storage Withdrawal capacity includes 98 MMcf/day contracted with an on-system independent storage provider.

(3) Includes supplies flowing under firm and as-available capacity, and capacity made available pursuant to supply diversion arrangements.

The tables below provide peak day demand projections on PG&E's system for both winter month (December) and summer month (August) periods under PG&E's high-demand scenario.

Winter Peak Day Demand
(MMcf/day)

Year	Core [1]	Non-Core Non-EG [2]	EG, including SMUD[3]	Total Demand
2012	2,891	473	1,024	4,388
2013	2,888	474	1,066	4,428
2014	2,885	479	1,081	4,445
2015	2,882	479	1,035	4,396
2016	2,879	469	935	4,283
2017	2,877	470	964	4,311

Notes:
(1) Core demand calculated for 30-degrees-Fahrenheit system-composite temperature, corresponding to a 1-in-35-year cold-temperature event.
(2) Average daily winter (December) demand.
(3) Average daily winter (December) demand under 1-in-35 dry hydro conditions.

Summer Peak Day Demand
(MMcf/day)

Year	Core[4]	Non-Core Non-EG[4]	EG, including SMUD[5]	Total Demand
2012	419	626	1,409	2,454
2013	417	626	1,388	2,431
2014	418	630	1,363	2,411
2015	419	633	1,326	2,378
2016	421	629	1,134	2,184
2017	421	626	1,136	2,183

Notes:
(4) Average daily summer (August) demand.
(5) Average daily summer (August) demand under 1-in-35 dry hydro conditions.

2012 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2007-2011
MMCF/DAY

LINE		2007	2008	2009	2010	2011	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
1	Core Purchases	0	0	0	0	0	1
2	Customer Gas Transport & Exchange	128	135	135	120	108	2
3	Total California Source Gas	128	135	135	120	108	3
	OUT-OF-STATE GAS						
	Core Net Purchases						
6	Rocky Mountain Gas	9	1	0	2	44	6
7	U.S. Southwest Gas	271	356	352	293	286	7
8	Canadian Gas	545	502	486	536	501	8
	Customer Gas Transport						
10	Rocky Mountain Gas	95	65	94	125	417	10
11	U.S. Southwest Gas	479	564	535	428	248	11
12	Canadian Gas	700	623	623	674	563	12
13	Total Out-of-State Gas	2,099	2,111	2,091	2,057	2,059	13
14	STORAGE WITHDRAWAL(2)	287	290	256	310	346	14
15	Total Gas Supply Taken	2,514	2,535	2,483	2,487	2,513	15
	GAS SENDOUT						
	CORE						
19	Residential	561	541	547	553	577	19
20	Commercial	233	237	217	220	244	20
21	NGV	4	5	5	5	5	21
22	Total Throughput-Core	798	783	769	779	826	22
	NONCORE						
24	Industrial	457	477	461	480	497	24
25	Electric Generation (1)	858	861	853	795	724	25
26	NGV	1	1	1	1	1	26
27	Total Throughput-Noncore	1,316	1,339	1,315	1,276	1,222	27
28	WHOLESALE	10	10	10	10	10	28
29	Total Throughput	2,125	2,132	2,094	2,064	2,058	29
30	CALIFORNIA EXCHANGE GAS	2	2	2	2	1	30
31	STORAGE INJECTION(2)	301	329	312	363	405	31
32	SHRINKAGE Company Use / Unaccounted for	86	72	76	58	49	32
33	Total Gas Send Out (3)	2,514	2,535	2,483	2,487	2,513	33
	TRANSPORTATION & EXCHANGE						
34	CORE — ALL END USES	56	69	87	101	118	34
35	NONCORE — INDUSTRIAL	457	477	461	480	497	35
36	ELECTRIC GENERATION	858	861	853	795	724	36
37	SUBTOTAL/RETAIL	1,370	1,407	1,402	1,376	1,339	37
38	WHOLESALE/INTERNATIONAL	10	10	10	10	10	38
39	TOTAL TRANSPORTATION AND EXCHANGE	1,381	1,417	1,412	1,385	1,349	39
40	CURTAILMENT/ALTERNATIVE FUEL BURNS						
41	Residential, Commercial, Industrial	0	0	0	0	0	40
42	Utility Electric Generation	0	0	0	0	0	41
43	TOTAL CURTAILMENT	0	0	0	0	0	42

NOTES:

(1) Electric generation includes SMUD, cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by other pipelines.
(2) Includes both PG&E and third party storage
(3) Total gas send-out excludes off-system transportation; off-system deliveries are subtracted from supply total.
(4) 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
FORECAST YEARS 2012-2014
MMCF/DAY

AVERAGE DEMAND YEAR

LINE			2012	2013	2014	LINE
FIRM CAPACITY AVAILABLE						
1	**California Source Gas**		100	100	100	1
	Out of State Gas					
2	Baja Path[(1)]		1009	1009	1009	2
3	Redwood Path[(2)]		1989	1989	1989	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	3.a
4	**Supplemental[(3)]**		0	0	0	4
5	**Total Supplies Available**		3139	3139	3139	5
GAS SUPPLY TAKEN						
6	**California Source Gas**		100	100	100	6
7	**Out of State Gas (via existing facilities)**		2307	2237	2222	7
8	**Supplemental**		0	0	0	8
9	**Total Supply Taken**		2407	2337	2322	9
10	**Net Underground Storage Withdrawal**		0	0	0	10
11	**Total Throughput**		2407	2337	2322	11
REQUIREMENTS FORECAST BY END USE						
	CORE					
12	Residential[(4)]		551	548	544	12
13	Commercial		228	228	227	13
14	NGV		5	6	6	14
15	**Total Core**		785	782	777	15
	NONCORE					
16	Industrial		487	487	490	16
17	SMUD Electric Generation[(5)]		122	122	122	17
18	PG&E Electric Generation[(6)]		775	709	696	18
19	NGV		1	1	1	19
20	Wholesale		10	10	10	20
21	California Exchange Gas		1	1	1	21
22	**Total Noncore**		1396	1331	1320	22
23	**Off-System Deliveries[(7)]**		179	179	179	23
	Shrinkage					
24	Company use and Unaccounted for		47	46	46	24
25	**TOTAL END USE**		2407	2337	2322	25
	TRANSPORTATION & EXCHANGE					
26	CORE	ALL END USES	120	124	123	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	487	487	490	27
28		ELECTRIC GENERATION	897	831	818	28
29		SUBTOTAL/RETAIL	1,504	1,442	1,431	29
30		WHOLESALE/INTERNATIONAL	10	10	10	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,514	2,895	2,871	31
32	System Curtailment		0	0	0	32

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 TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.

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

(4) Includes Southwest Gas direct service to its northern California service area.

(5) Forecast by SMUD.

ANNUAL GAS SUPPLY
FORECAST YEARS 2015-2030
MMCF/DAY

AVERAGE DEMAND YEAR

LINE			2015	2020	2025	2030	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		100	100	100	100	1
	Out of State Gas						
2	Baja Path[1]		1009	1009	1009	1009	2
3	Redwood Path[2]		1989	1989	1989	1989	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	3.a
4	**Supplemental[3]**		0	0	0	0	4
5	**Total Supplies Available**		3139	3139	3139	3139	5
GAS SUPPLY TAKEN							
6	**California Source Gas**		100	100	100	100	6
7	**Out of State Gas (via existing facilities)**		2199	2255	2229	2237	7
8	**Supplemental**		0	0	0	0	8
9	**Total Supply Taken**		2299	2355	2329	2337	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	10
11	**Total Throughput**		2299	2355	2329	2337	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential[4]		544	547	543	546	12
13	Commercial		228	228	226	226	13
14	NGV		6	6	7	7	14
15	**Total Core**		777	781	776	778	15
	Noncore						
16	Industrial		493	489	493	498	16
17	SMUD Electric Generation[5]		122	122	122	122	17
18	PG&E Electric Generation[6]		671	725	725	725	18
19	NGV		1	1	1	2	19
20	Wholesale		10	10	10	10	20
21	California Exchange Gas		1	1	1	1	21
22	**Total Noncore**		1298	1349	1353	1358	22
23	**Off-System Deliveries[7]**		179	179	154	154	23
	Shrinkage						
24	Company use and Unaccounted for		45	46	46	46	24
25	**TOTAL END USE**		2299	2355	2329	2337	25
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	122	121	121	122	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	493	489	493	498	27
28		ELECTRIC GENERATION	793	847	847	847	28
29		SUBTOTAL/RETAIL	1,408	1,457	1,461	1,467	29
30		WHOLESALE/INTERNATIONAL	10	10	10	10	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,418	1,467	1,471	1,477	31
32	System Curtailment		0	0	0	0	33

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 TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E

ANNUAL GAS SUPPLY
FORECAST YEARS 2012-2014
MMCF/DAY

HIGH DEMAND YEAR

LINE		2012	2013	2014	LINE
FIRM CAPACITY AVAILABLE					
1	**California Source Gas**	100	100	100	1
	Out of State Gas				
2	Baja Path[(1)]	1009	1009	1009	2
3	Redwood Path[(2)]	1989	1989	1989	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	3.a
4	**Supplemental**[(3)]	0	0	0	4
5	**Total Supplies Available**	3139	3139	3139	5
GAS SUPPLY TAKEN					
6	**California Source Gas**	100	100	100	6
7	**Out of State Gas (via existing facilities)**	2500	2466	2475	7
8	**Supplemental**	0	0	0	8
9	**Total Supply Taken**	2600	2566	2575	9
10	**Net Underground Storage Withdrawal**	0	0	0	10
11	**Total Throughput**	2600	2566	2575	11
REQUIREMENTS FORECAST BY END USE					
	Core				
12	Residential[(4)]	569	567	553	12
13	Commercial	237	232	232	13
14	NGV	5	6	6	14
15	**Total Core**	811	805	791	15
	Noncore				
16	Industrial	487	488	491	16
17	SMUD Electric Generation[(5)]	122	122	122	17
18	PG&E Electric Generation[(6)]	936	909	929	18
19	NGV	1	1	1	19
20	Wholesale	10	10	10	20
21	California Exchange Gas	1	1	1	21
22	**Total Noncore**	1558	1531	1554	22
23	**Off-System Deliveries**[(7)]	179	179	179	23
	Shrinkage				
24	Company use and Unaccounted for	51	51	51	24
25	**TOTAL END USE**	2600	2566	2575	25
	TRANSPORTATION & EXCHANGE				
26	CORE ALL END USES	119	125	125	26
27	NONCORE IAL/INDUSTRIAL	487	488	491	27
28	ELECTRIC GENERATION	1,058	1,031	1,051	28
29	SUBTOTAL/RETAIL	1,664	1,644	1,667	29
30	WHOLESALE/INTERNATIONAL	10	10	10	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,674	1,654	1,677	31
32	System Curtailment	0	0	0	32

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 TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.

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

(4) Includes Southwest Gas direct service to its northern California service area.

(5) Forecast by SMUD.

(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E

ANNUAL GAS SUPPLY
FORECAST YEARS 2015-2030
MMCF/DAY

HIGH DEMAND YEAR

LINE			2015	2020	2025	2030	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		100	100	100	100	1
	Out of State Gas						
2	Baja Path[1]		1009	1009	1009	1009	2
3	Redwood Path[2]		1989	1989	1989	1989	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	3.a
4	**Supplemental[3]**		0	0	0	0	4
5	**Total Supplies Available**		3139	3139	3139	3139	5
GAS SUPPLY TAKEN							
6	**California Source Gas**		100	100	100	100	6
7	**Out of State Gas (via existing facilities)**		2460	2524	2512	2528	7
8	**Supplemental**		0	0	0	0	8
9	**Total Supply Taken**		2560	2624	2612	2628	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	10
11	**Total Throughput**		2560	2624	2612	2628	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential[4]		567	579	586	595	12
13	Commercial		233	236	236	238	13
14	NGV		6	6	7	7	14
15	**Total Core**		806	821	830	840	15
	Noncore						
16	Industrial		494	490	495	500	16
17	SMUD Electric Generation[5]		122	122	122	122	17
18	PG&E Electric Generation[6]		897	947	947	947	18
19	NGV		1	1	1	2	19
20	Wholesale		10	10	10	10	20
21	California Exchange Gas		1	1	1	1	21
22	**Total Noncore**		1524	1572	1576	1582	22
23	**Off-System Deliveries[7]**		179	179	154	154	23
	Shrinkage						
24	Company use and Unaccounted for		51	52	52	53	24
25	**TOTAL END USE**		2560	2624	2612	2628	25
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	125	125	127	129	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	494	490	495	500	27
28		ELECTRIC GENERATION	1,019	1,069	1,069	1,069	28
29		SUBTOTAL/RETAIL	1,637	1,685	1,691	1,698	29
30		WHOLESALE/INTERNATIONAL	10	10	10	10	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,647	1,695	1,701	1,708	31
33	System Curtailment		0	0	0	0	33

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 TransCanada Gas Transmission Northwest pipeline and Ruby pipeline.

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

(4) Includes Southwest Gas direct service to its northern California service area.

(5) Forecast by SMUD.

2012 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 an 18-year natural gas demand and forecast period, from 2012 through 2030; only the consecutive years 2012 through 2014 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.

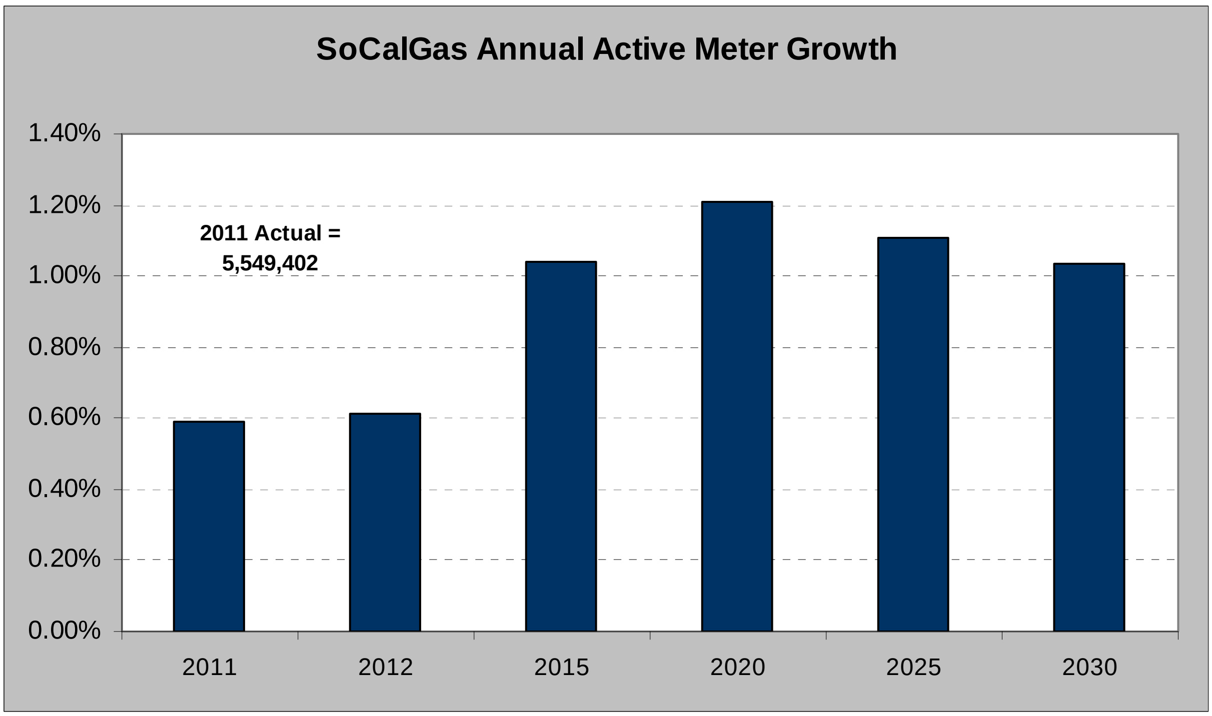
The Southern California section of the *2012 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, 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. As of mid-2012, Southern California's economy is slowly climbing out of its most severe slump since the 1930s. After peaking in 2007, SoCalGas area employment shrank by 1.6% in 2008, plummeted 6.3% in 2009, dropped a further 1.3% in 2010 then rose a meager 0.4% in 2011. Overall area jobs are expected to average 1.8% annual growth from 2011 through 2016. Local industrial employment (manufacturing and mining) will grow a more modest 1.0% per year from 2011 to 2016. Commercial jobs should grow by 1.9% per year during the same period. Construction employment should make a strong comeback--albeit from a drastically low current level, averaging over 8% annual growth from 2011 through 2016. Services and wholesale trade will also enjoy relatively robust job growth of about 2.5% per year during the same period—led by 3.8% annual growth in professional and business services.

In the longer term, SoCalGas service-area employment is expected to increase modestly as the area population's average age gradually increases--part of a national demographic trend of aging and retiring "baby boomers". From 2011 through 2030, total area job growth should average 1.1% per year. Area industrial jobs are forecasted to shrink an average of 0.2% per year through 2030; we expect the industrial share of total employment to fall from 9.5% in 2011 to 7.4% by 2030. Commercial jobs are expected to grow an average of 1.2% annually from 2011 through 2030.



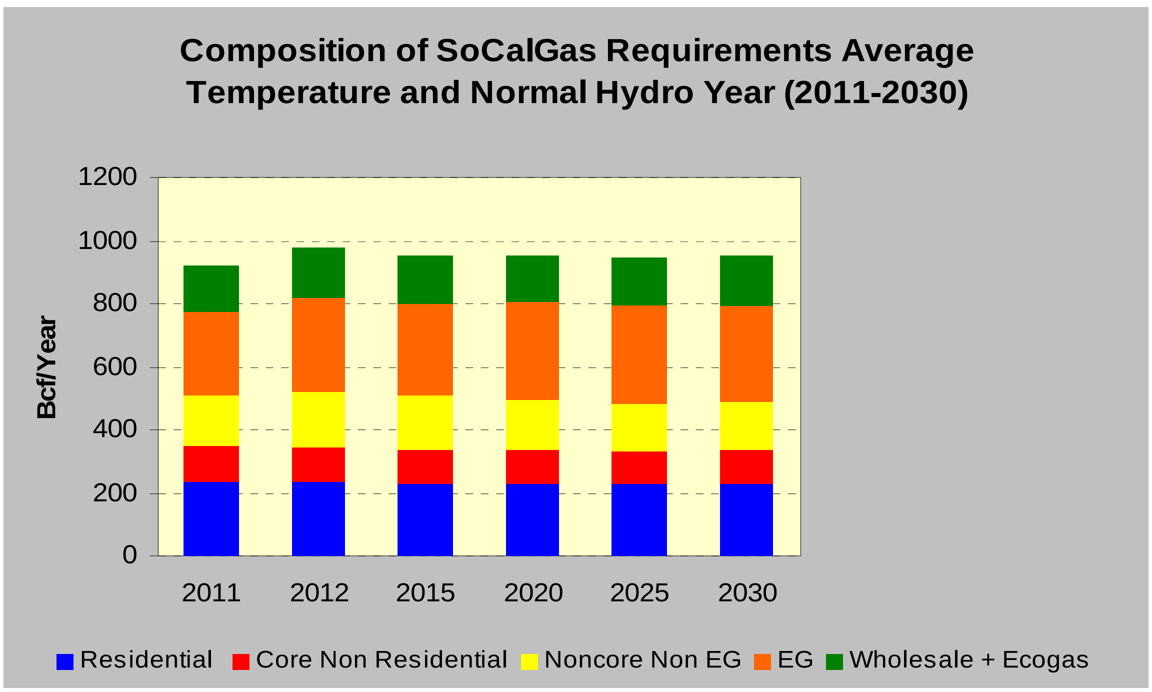
Since 2007, SoCalGas' service area has remained mired in a serious housing slump. Home building was depressed by a glut of existing-home short sales and foreclosures, restrictive credit conditions, and potential buyers' uncertainty in the job market. As a result, new gas meter hookups dropped drastically from a peak year of nearly 85,000 in 2006 to under 19,000 in 2011. On the positive side: 1) with so little recent new construction, there is now little remaining unsold new-home inventory in Southern California; 2) area home prices have dropped so far that they are now much more affordable relative to typical households' incomes; and 3) the area's population is still expected to grow about 0.8% per year to 2030, boosted partly by continuing foreign immigration. So, in coming years, as foreclosures clear and employment recovers, new housing and meter growth should eventually rebound. SoCalGas expects its active meters to increase an average of just over 1% annually from 2011 through 2030.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects total gas demand to grow at an annual rate of 0.12% from 2011 to 2030. Over the forecast period 2012-2030, demand is expected to exhibit annual decline (of 0.13%) from the level in 2012 due to modest economic growth, CPUC-mandated energy efficiency (EE)s and renewable electricity goals, decline in commercial and industrial demand, and continued increased use of non-utility pipeline systems by EOR customers and savings linked to advanced metering modules. By comparison, the *2010 California Gas Report* projected an annual decline in the growth rate of 0.21% from 2010 to 2030. The difference between the two forecasts is caused primarily by a higher gas price outlook in the 2010 report and by the recession which occurred from 2007-2009.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2011 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and for the 2012 to 2030 forecast period.



Notes:
(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, natural gas vehicles.
(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 2012 to 2030, residential demand is expected to decline from 234 Bcf to 229 Bcf. The decline is due to the seesawing effect of declining use per meter offsetting new meter growth. The core, non-residential markets are expected to decline from 111 Bcf in 2012 to 108

Bcf by 2030. The change reflects an annual decline rate of 0.15% over the forecast period. The noncore, non-EG markets are expected to decline from 175 Bcf in 2012 to 151 Bcf by 2030. The annual rate of decline is approximately 0.8% due to very aggressive energy efficiency goals and associated programs. Utility gas demand for EOR steaming operations, which has declined since the FERC-regulated Kern/Mojave interstate pipeline began offering direct service to California customers in 1992, is expected to be relatively flat over the forecast period now that all the long-term utility service contracts have expired. Total electric generation load, including cogeneration and non-cogeneration EG for a normal hydro year is expected to rise from 299 Bcf in 2012 to 305 Bcf in 2030, an increase of 0.11% per year.

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

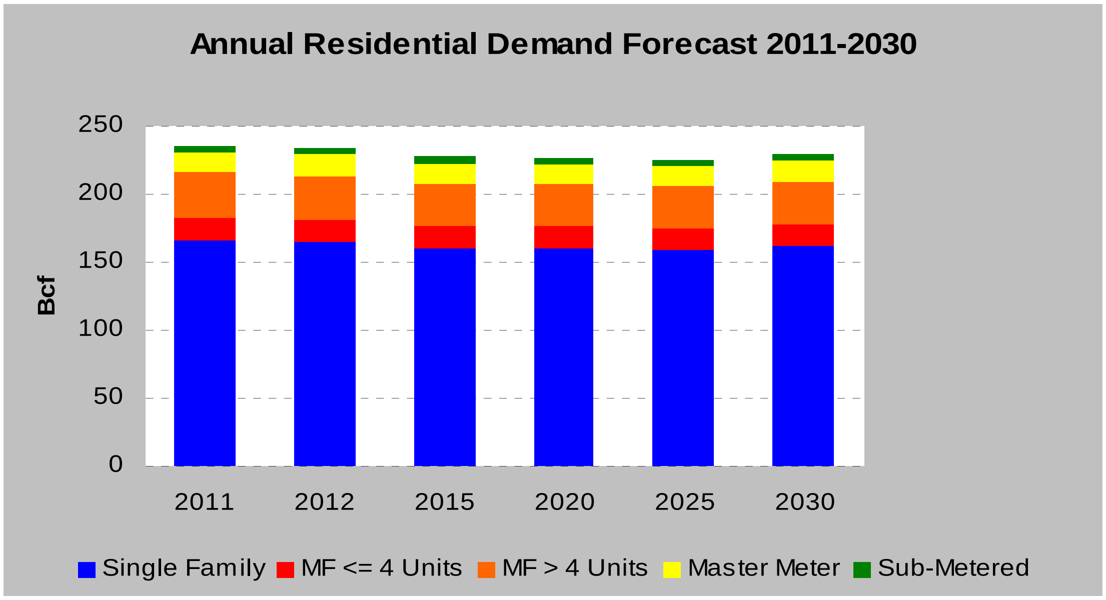
Residential

Residential demand adjusted for temperature totaled 236 Bcf in 2011. Residential usage declined 4 Bcf from 2010 to 2011. This decrease in gas demand results from a combination of continued decline in the residential use per meter, minor increases in marginal gas rates, the impact of savings from AMI project deployment starting in January 2013, and CPUC authorized energy efficiency program savings in this market.

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 were 5.34 million at the end of 2011. This amount reflects a 33,523 active meter increase between 2010 and 2011 at year end. The overall observed 2010-2011 residential meter growth was 0.63%. Just four years before, the observed meter growth had been 53,326 new meters between 2006 and 2007, which amounts to an annual growth rate of 1.03%. The decrease in active meter growth reflects the overall state of the economy in Southern California.

The *2010 California Gas Report* showed that the single family and multi family annual use per meter totaled 493 therms and 303 therms, respectively. The *2012 California Gas Report* shows the 2011 single family and multi family average annual use per meter has decreased to 469 therms and 294 therms, respectively. The decline of approximately 3 to 5% per year in use per meter from 2010-2011 for all classes of residential customers is expected to moderate as the economy expands but due to the expected energy savings resulting from tightened building and appliance standards and energy efficiency programs, demand per customer will continue to decline at an annul rate of -0.1% in the 2012-2030 forecast period. The expected decline in use per customer can further be explained by demand reductions anticipated as a result of the deployment of the Advanced Metering Infrastructure (AMI) system in the Southern California Area. With AMI, customers will have more timely information available about their daily gas use and thereby are expected to use gas more efficiently. Mass deployment of SoCalGas' AMI will begin in 2013. The deployment of SoCalGas' AMI will not only provide substantial operating efficiencies but will also generate long term conservation benefits.

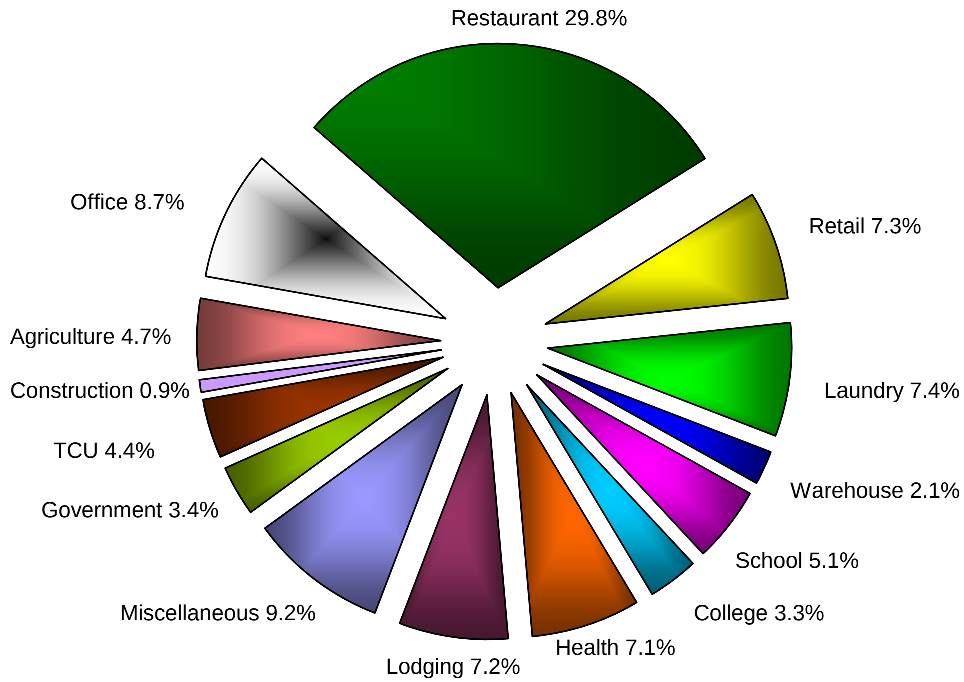
In summary, the projected residential natural gas demand will be influenced primarily by residential meter growth, moderated by the forecasted declining use per customer, and the gradual attrition of sub-meter and master meter customers to individual meter use. The weather-adjusted residential demand forecast, on average, is expected to decline by 0.16% per year. In 2011, temperature adjusted residential demand was 236 Bcf. In 2012, the load is expected to be 234 Bcf. By the year 2030, residential demand is expected to decline to 229 Bcf. The 5 Bcf decline in the residential load over this period is illustrated in the graph below.



Commercial

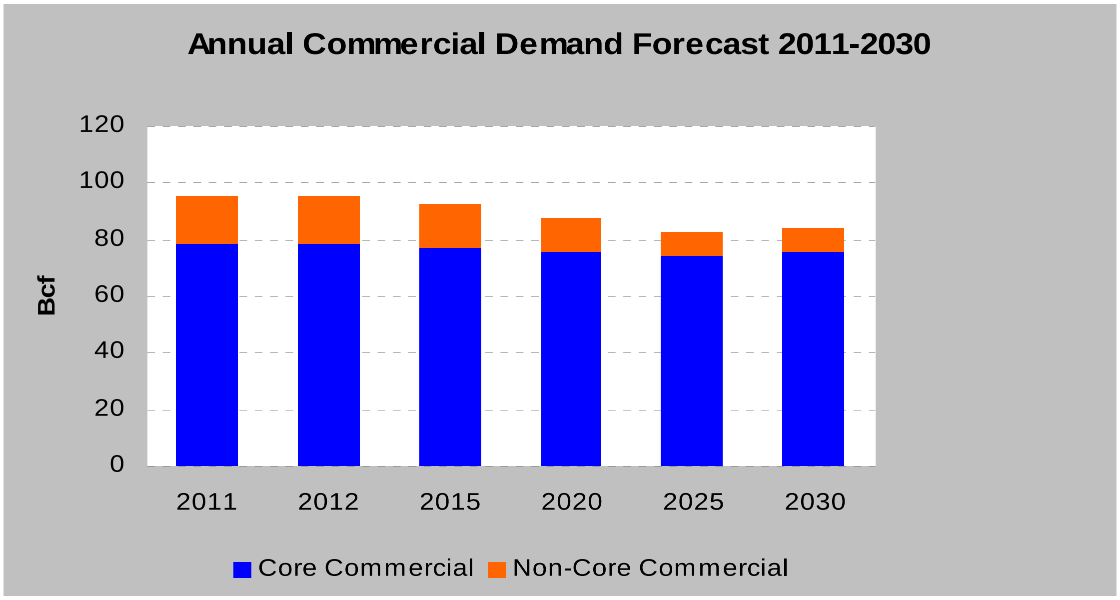
The commercial market consists of 14 business types identified by the customer's North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 29.8% of the usage in 2011.

Commercial Gas Demand by Business Types: Composition of Industry 2011



The core commercial market demand is expected to remain flat over the forecast period. On a temperature-adjusted basis, the core commercial market demand in 2011 totaled 78 Bcf. By the year 2030, the load is anticipated to be approximately 75 Bcf. The average annual rate of decline from 2011 to 2030 is forecasted at -0.21 percent. The slow growth in gas usage is mainly the result of the impact of CPUC-authorized energy efficiency programs in this market.

Noncore commercial demand in 2011 was 17.4 Bcf. The average annual rate of decline is expected to be approximately 3.9% between 2012 and 2030. The non-core commercial market is expected to show substantial attrition by 2030, when the load is expected to total 8.4 Bcf. Aggressive CPUC-authorized energy efficiency programs targeted at this market are expected to depress this segment of the noncore load along with costs of compliance with environmental regulation and migration of noncore commercial customers located in the City of Vernon from SoCalGas' retail service to service from the City of Vernon.



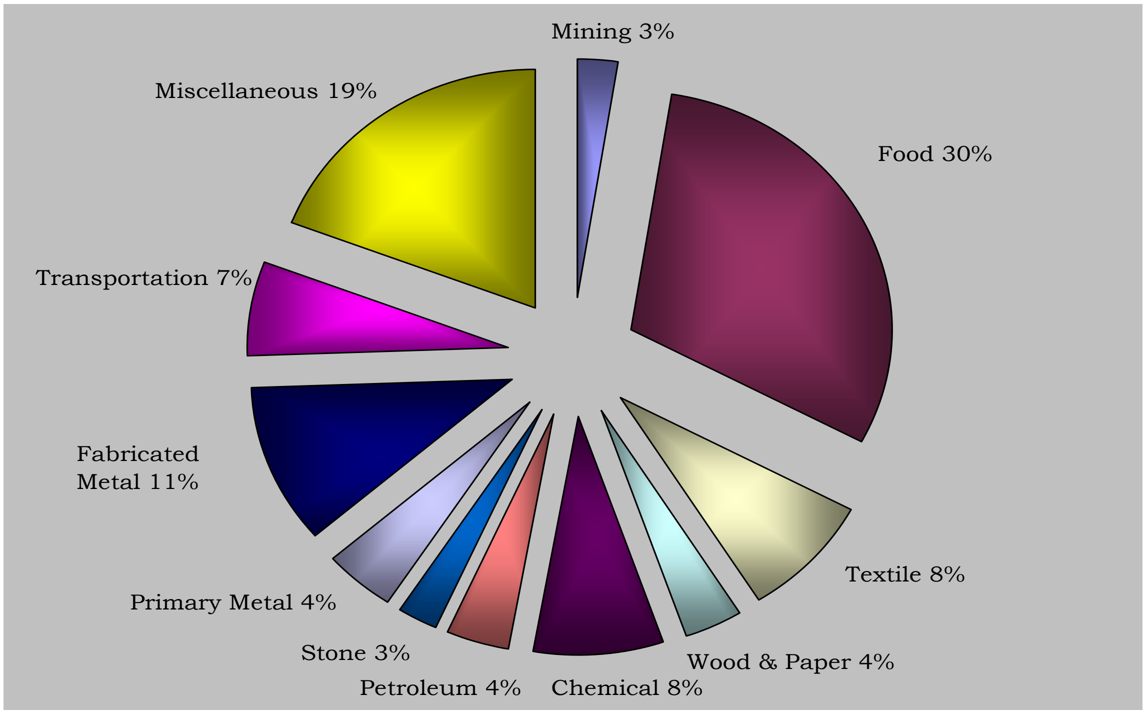
Industrial

Non-Refinery Industrial Demand

In 2011, temperature-adjusted core industrial demand was 22.4 Bcf, which is 0.3 Bcf slightly higher than 2010 deliveries. Core industrial market demand is projected to decrease by 2.2% per year from 21.9 Bcf in 2012 to 14.3 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, the impact of savings from AMI project deployment starting in January 2013, the municipalization of City of Vernon and CPUC authorized energy efficiency program savings in this market.

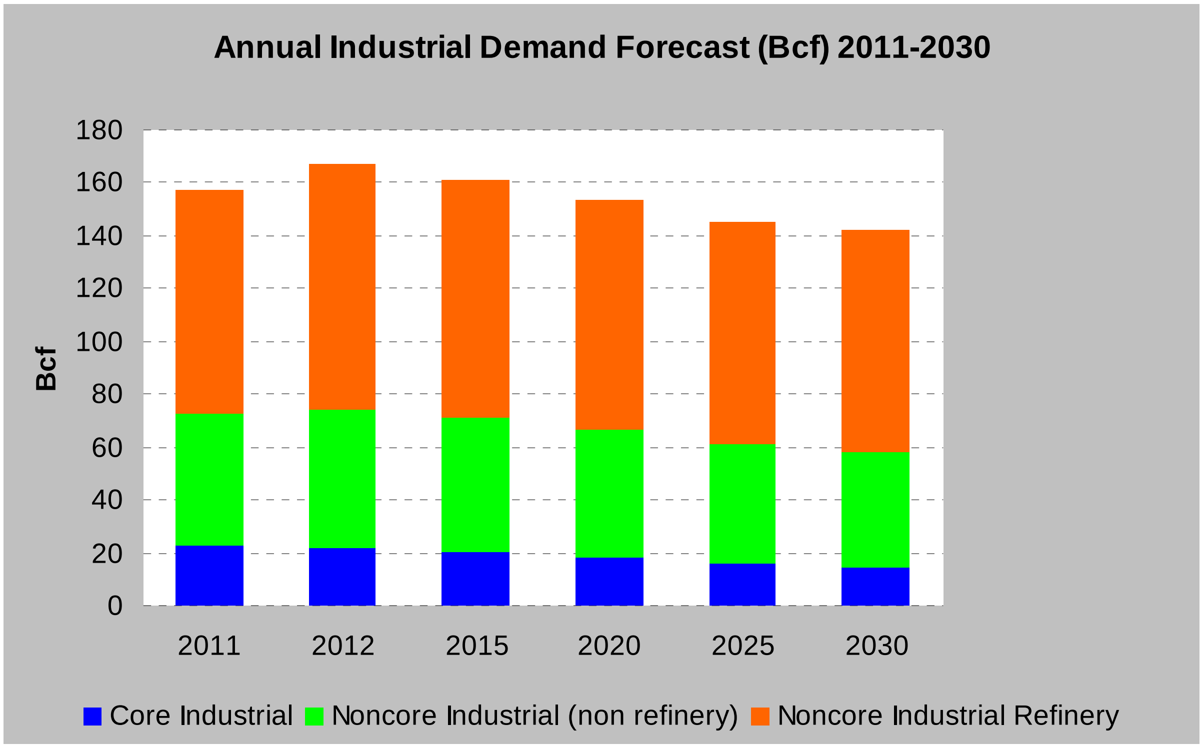
Industrial gas demand in 2011 by business types served by California is shown below.

Non-Refinery Industrial Gas Demand by Business Types
Composition of Core Industrial Activity (2011)



Overall, the retail noncore industrial (non-refinery) gas demand has shown persistent signs of weakness since 2006 due to competitive economic pressure to relocate out-of-state or to exit the line of business altogether. After 2007, the economic recession has led to further reductions in gas demand from this market segment with industrial demand dropping annually by 5%, 13.5%, and 14.3% from the 2006 level through 2009. Since 2009, this market has experienced annual growth of 10% and 5% respectively, for 2010 and 2011, indicating a recovery from the nation-wide economic recession which began in 2007.

Gas demand for the retail noncore industrial market as a whole is expected to decline at a rate of 0.9% annually over the 2012 to 2030 forecast period. Demand for 2011 was 50.4 Bcf and is projected to be just less than 44 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 and the expected implementation of regulations to aggressively reduce CO_2 emissions by effectively increasing the gas commodity price for many of these large industrial customers.



Refinery-Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Gas demand in 2011 was 84.5 Bcf and is expected to be 78.3 Bcf in 2030. Refinery industrial gas demand is forecast to decline about 0.5% per year over the 2012-2030 forecast period, from 85.4 Bcf in 2012. The decrease over the forecast period is primarily due to the estimated savings from Commission-authorized energy efficiency programs. The implementation of regulations to aggressively reduce CO_2 emissions effectively increases the commodity prices for both natural gas and butane for these large industrial customers; the expected price advantage of natural gas vs. butane over the forecast period only lessens the decline in gas consumption that would occur from energy efficiency impacts alone at refineries.

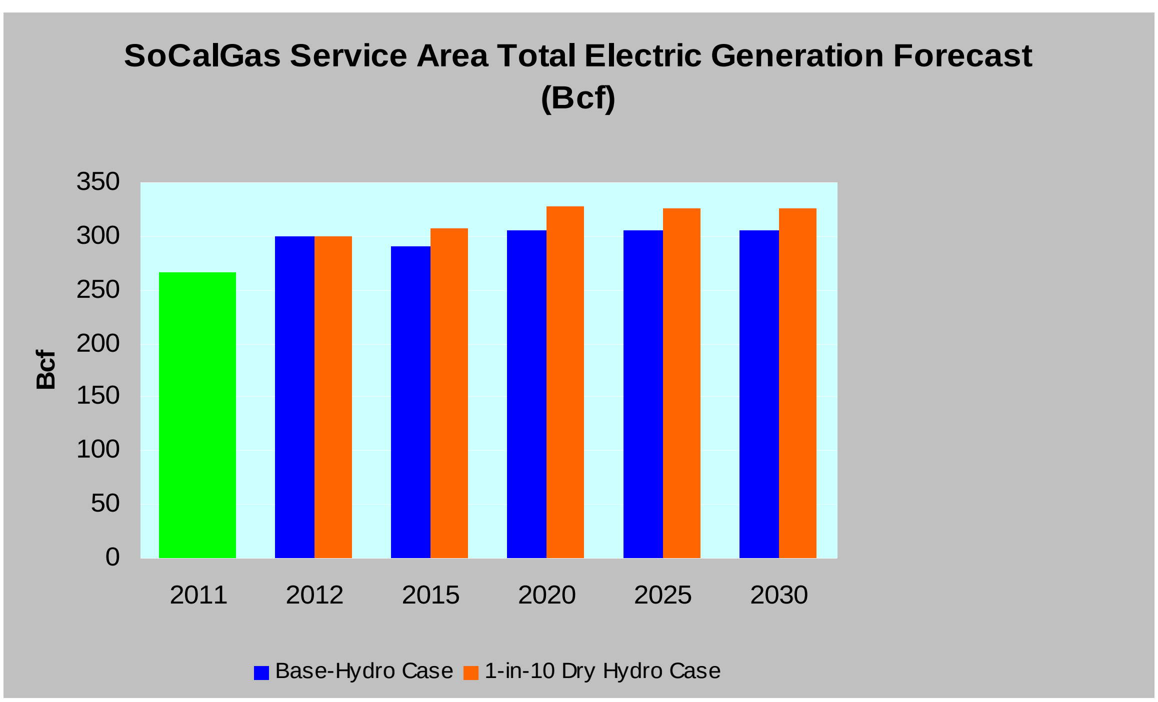
Electric Generation

This sector includes the following markets: all commercial/industrial cogeneration; EOR-related cogeneration; and, non-cogeneration electric generation. It should be noted that the forecast of electric generation (EG) load is subject to a higher degree of uncertainty due to the underlying key assumptions including, but not limited to: the continued operation of existing generation facilities and the potential shutdown of units from the state's new once-through-cooling (OTC) regulation; the timing and location of new generation facilities in the rest of California and the western United States; the regulatory and market decisions that impact the operation of existing cogeneration facilities; the location, timing and construction of new renewable resources; the construction of additional electric transmission lines, and the implementation of the Cap and Trade greenhouse gas (GHG) program. The forecast uses a power market simulation for the period 2012 to 2020 and reflects the anticipated dispatch of all EG resources in the SoCalGas service territory using a base electricity demand scenario under both average and low hydroelectric availability market conditions. The base case assumes that 33% of the state's energy needs are met with renewable power by 2020, and additional renewable power is added after 2020 to maintain the 33% level.

Due to the large uncertainty in the timing and type of generating plants that could be added after 2020, the EG forecast is held constant at 2020 levels for 2025 and 2030. During that time there is the potential for development and construction of new, lower GHG, generation sources in sufficient quantity to create downward pressure on the demand for natural gas after 2020; however, electrification of other sectors such as transportation could create counteracting upward pressure on electricity demand and associated gas demand.

For electricity demand within California, SoCalGas relies on the California Energy Commission's (CEC) Revised California Energy Demand Forecast 2012-2022, dated February 2012. Since this demand forecast does not include any uncommitted energy efficiency starting in the year 2013, SoCaGas reduced the forecast by the Projected Incremental Uncommitted Electric Savings. SoCalGas relies on Ventyx's electric demand forecast for the remainder of the Western Electricity Coordinating Council (WECC) area.

This EG gas demand forecast also assumes the State will implement a Cap and Trade GHG program beginning in 2013 and further assumes GHG compliance costs are based on those specified in CPUC Resolution E-4298, dated December 17, 2009. These costs are included in the dispatch costs for all fossil-fueled power plants within California and in the surcharge costs on all energy imported into California.



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. Customers in this market segment install their own electric generation equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). In 2008, recorded gas deliveries to this market were 18.7 Bcf. By 2011, the small cogeneration load totaled 20.9 Bcf, which represents an 11.8% increase over the 2008 level. Overall, cogeneration demand is projected to decline modestly from 20.5 Bcf in 2012 to 18.4 Bcf by the year 2030. From 2012 through 2030, small cogeneration load is anticipated to decline at an annual average rate of 0.61%. A key factor in stimulating this gas decline is the expected implementation of regulations to aggressively reduce CO_2 emissions by effectively increasing the gas commodity price for many of the larger small cogeneration customers

Industrial/Commercial Cogeneration >20 MW

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecast to remain relatively constant at 51 Bcf from 2012 through 2020. Although there is uncertainty in this sector as contracts come up for renewal, this forecast assumes that the existing facilities will continue to be cost–effective and thus will continue to operate at historical levels. Changes to this assumption in the future could have a significant impact on the forecast.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration consumed 21.3 Bcf in 2011 and is forecast to increase 0.6% per year, from 22.8 Bcf in 2012 to 25.6 Bcf in 2030. This increased gas demand is attributed to expected gas consumption from planned additional cogeneration equipment for this customer segment.

Enhanced Oil Recovery-Related Cogeneration

In 2011, recorded gas deliveries to the EOR-related cogeneration market were 4.1 Bcf, approximately the same as for 2010. EOR-related cogeneration demand is forecast to increase to 6.6 Bcf in 2012 and then level off in 2013 at 4.8 Bcf for the remainder of the forecast period. These fluctuations are due to temporary changes in operations for some of the EOR-related cogeneration customers.

Non-Cogeneration Electric Generation

For the non-cogeneration EG market, gas demand is forecast to slightly increase from 195 Bcf in 2012 to 202 Bcf in 2020. The growth is expected to be influenced by several major factors, including for example: the addition of more efficient power plants, the addition of new electric transmission lines, and the growth of renewable resources in Southern California.

SoCalGas' forecast includes the addition of approximately 3,100 MW of new combined cycle and peaking thermal generating resources in its service area by 2020. However, the forecast also assumes 2,500 MW of older plants are retired as a result of direct replacement. Throughout the entire forecast period, SoCalGas assumes that market participants will construct additional generation resources such that the WECC maintains a minimum planning reserve margin of 15%.

Starting in 2012, the forecast ramps up renewable electricity generation to meet 33% of the state's total electric energy consumption by 2020. The forecast estimates renewable-sourced energy generation in 2020 by taking 33% of CEC's forecasted electricity sales load. The forecast shows that close to 60% of the incremental renewable power needed to meet the state's 33% target will be physically located in Southern California by 2020. This puts more downward pressure on SoCalGas' EG gas demand forecast.

Due to the large uncertainty in the timing and type of generating plants that could be added after 2020, SoCalGas holds the EG forecast constant at 2020 levels for 2025 and 2030. In addition, SoCalGas performed a dry hydro sensitivity gas demand forecast, which indicated that under 1-in-10 dry hydro conditions, gas demand increases on average by 23 Bcf each year over the forecast period.

Uncertainty in electricity demand and California's achievement of renewables goals also affect the electric generation gas demand forecast. Using the average Southern California natural gas plant heat rate of 8,300 Btu/KWh and 1.0273 MMBtu/MCF to convert natural gas volumes to energy, SoCalGas performed a sensitivity analysis for natural gas demand from changes to electric demand and renewable goals. The results suggest that for each additional 1,000 GWh of electric demand, gas demand grows by 8 Bcf, assuming all the growth comes from Southern California gas-fired power plants. In addition, if the percentage of renewable energy increases by 1% in Southern California (approximately 1,500 GWh), the forecasted EG gas demand decreases by 12 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 2011 were 9.8 Bcf, essentially no change from 2010. SoCalGas' EOR steaming demand is expected to increase to 11.1 Bcf in 2012 and to 14.5 Bcf in 2013 as current EOR customers expand their operations and new customers come on line. Demand is forecast to level off at 14.5 Bcf from 2014 through the end of the forecast period. These figures include gas delivered to PG&E's EOR customers through inter-utility exchange. In 2011, less than 0.01 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 section.

Crude oil prices are forecast to remain high over the forecast period which may result in even more 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 Gas and Oil Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon) and Ecogas Mexico, L. de R.L. de C.V. The wholesale load is expected to decrease from 159 Bcf in 2012 to 157 Bcf in 2030.

San Diego Gas & Electric

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.3% per year from 125 Bcf in 2012 to 119 Bcf in 2030. Refer to SDG&E's section for more information.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach Municipal Gas & Oil Department. Long Beach's gas use is expected to remain fairly constant increasing from 9.4 Bcf in 2012 to 9.9 Bcf by 2030. Long Beach's locally supplied deliveries are expected to decline from 0.4 Bcf in 2012 to 0.3 Bcf by 2030. SoCalGas' transportation to Long Beach is expected to increase gradually from 9.0 Bcf in 2012 to 9.6 Bcf by 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 2012, SoCalGas expects to serve approximately 6.4 Bcf directly, with another 2.9 Bcf being served by PG&E under exchange arrangements with SoCalGas. The total load is expected to grow from 9.3 Bcf in 2012 to approximately 12 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. Since 2005, there has also been a gradual increase of Commercial/Industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 8.1 Bcf in 2012 and increases to 9.1 Bcf by 2016, after which the demand remains relatively flat through 2030. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon. The throughput forecast for Vernon's municipal 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 gradually increase from approximately 6.8 Bcf/year in 2012 to 7.2 Bcf/year by 2030.

Natural Gas Vehicles (NGV)

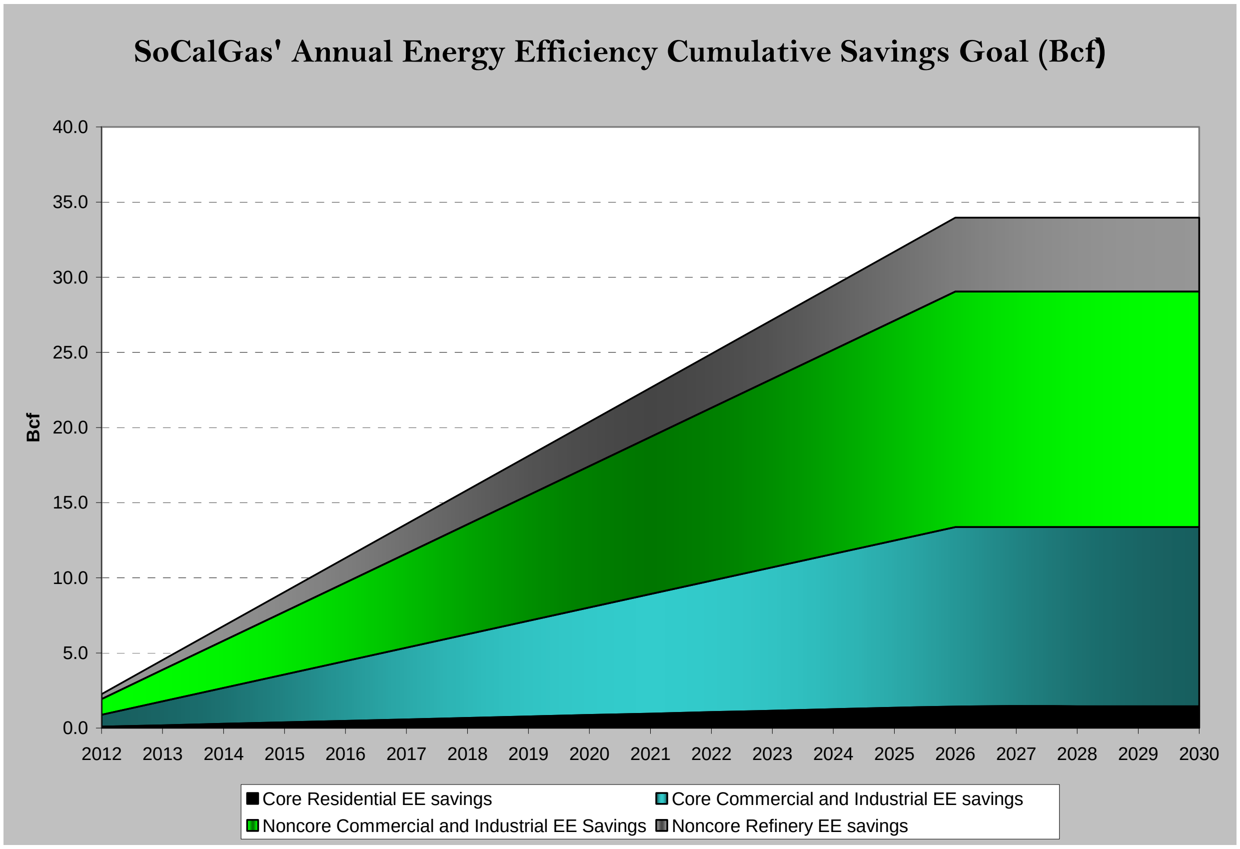
The NGV market is expected to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, the increasing cost of petroleum (gasoline and diesel), and a 10 year low in natural gas prices, due to a significantly higher availability of natural gas. At the end of 2011, there were 256 compressed natural gas (CNG) fueling stations delivering 10.1 Bcf of natural gas during the year. SoCalGas remains optimistic about the NGV market's growth, forecasting an increase in demand from 10.1 Bcf in 2011 to 14.2 Bcf in 2020 and 19.0 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 has forecasted to be implemented beginning in year 2010 and occurring through year 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060 and updated by the following decision, D.09-05-037, D.09-09-047 and D. 12-05-015.

Annual Energy Efficiency Cumulative Savings Goal (Bcf)



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' Energy Efficiency program portfolio are contained in D.04-09-060 and updated by the following decision, D.09-05-037, D.09-09-047 and D. 12-05-015.

(1) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(2) SoCalGas does not include "soft" impacts, e.g., energy management services type measures.
(3) The assumed average measure life is 15 years.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

Southern California Gas Company and San Diego Gas & Electric Company 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 2007 through 2011 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 was 175 MMcf/day in 2011.

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 have been declining at an annual rate of 1.4%. The 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 2011 has doubled since 2000 due to the successful applications of new technology to drill for coal-bed methane gas. 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 and LNG exports to Asia 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.

Biogas

Biogas is a mixture of methane and carbon dioxide produced by the bacterial degradation of organic matter. Biogas is a byproduct produced from processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition under sub-stoichiometric conditions. These processes are applied to biodegradable biomass materials, such as, but not limited to, livestock manure, wastewater sewage, food waste, and green waste.

Biogas is a renewable energy source, and once conditioned/upgraded to specific gas quality specifications[1], it can be injected into the natural gas pipeline system or used onsite or offsite to generate power from internal combustion engines, fuel cells, turbines, and also used as a fuel source for natural gas vehicles. Currently, there are instances where biogas is being vented naturally or flared to the atmosphere. Venting and flaring wastes this valuable renewable resource and fails to support the state in achieving its emission reduction targets set forth by Assembly Bill ("AB") 32 and the Renewables Portfolio Standard (RPS) goals as processed renewable natural gas injected into a common carrier natural gas pipeline system can ultimately count toward satisfying AB 32 and RPS goals.[2]

SDG&E and SoCalGas continue to work with the City of Escondido to verify the conditioning/upgrading treatment of the biogas produced at the Hale Avenue Regional Reclamation Facility (HARRF) Wastewater Treatment Plant is able to continuously meet SoCal Gas' pipeline gas quality (Tariff Rule 30) standards. This biogas treatment research collaboration further demonstrates the technology as a new source of renewable energy.

On April 25, 2012, SoCalGas filed an Application (A.12-04-024) with the CPUC to establish a new tariff to offer a Biogas Conditioning/Upgrading Services Tariff[3] in response to customer inquiries and requests. The proposed service is designed to meet the current and future needs of biogas producers seeking to upgrade their biogas for beneficial uses such as pipeline injection, onsite power generation, or compressed natural gas vehicle refueling stations. There is growing interest regarding biogas production potential in SoCalGas' service territory from the following activities: landfill diversion of organic waste material, wastewater treatment, concentrated animal feeding operations, and food/green waste processing.

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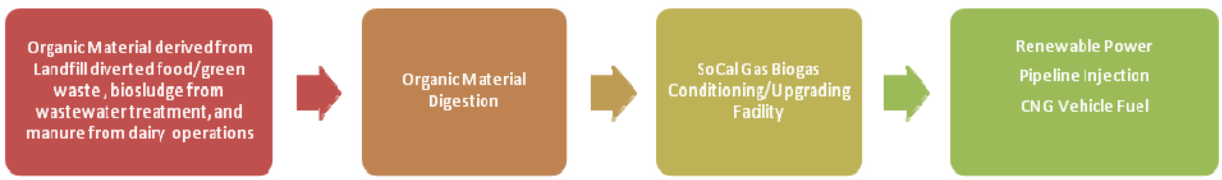
[1] SoCal Gas' Tariff Rule 30 (http://socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

[2] On March 28, 2012, the California Energy Commission voted to suspend provisions for the consumption of biomethane as eligible for RPS and will limit the use of biomethane as pre-certified power plants until resolution of the suspension. SoCalGas is hopeful this will be addressed this legislative session which ends August 31, 2012, and allow in-state biomethane to be eligible for RPS credit.

[3] http://socalgas.com/regulatory/A1204024.shtml

Under the proposed tariff, when a customer contacts SoCalGas and expresses interest in the Biogas/Conditioning Upgrading Services Tariff, SoCalGas will conduct a feasibility analysis to determine the technical and economic feasibility of the design, installation, operation and maintenance of the gas conditioning equipment. Pending the outcome of the feasibility analysis, and for those customers who elect to proceed with the tariff service, SoCalGas will design, install, own, operate, and maintain the biogas conditioning/upgrading facility on or adjacent to the tariff service customer's premises and charge the tariff service customer the fully allocated cost of providing the service under a long term (10 to 15 year) service agreement. SoCalGas' role will be to process the tariff service customer's biogas and condition it to the gas quality level(s) contractually specified by the tariff service customer in the service agreement, and as outlined in the process flow diagram below.



Liquefied Natural Gas (LNG)

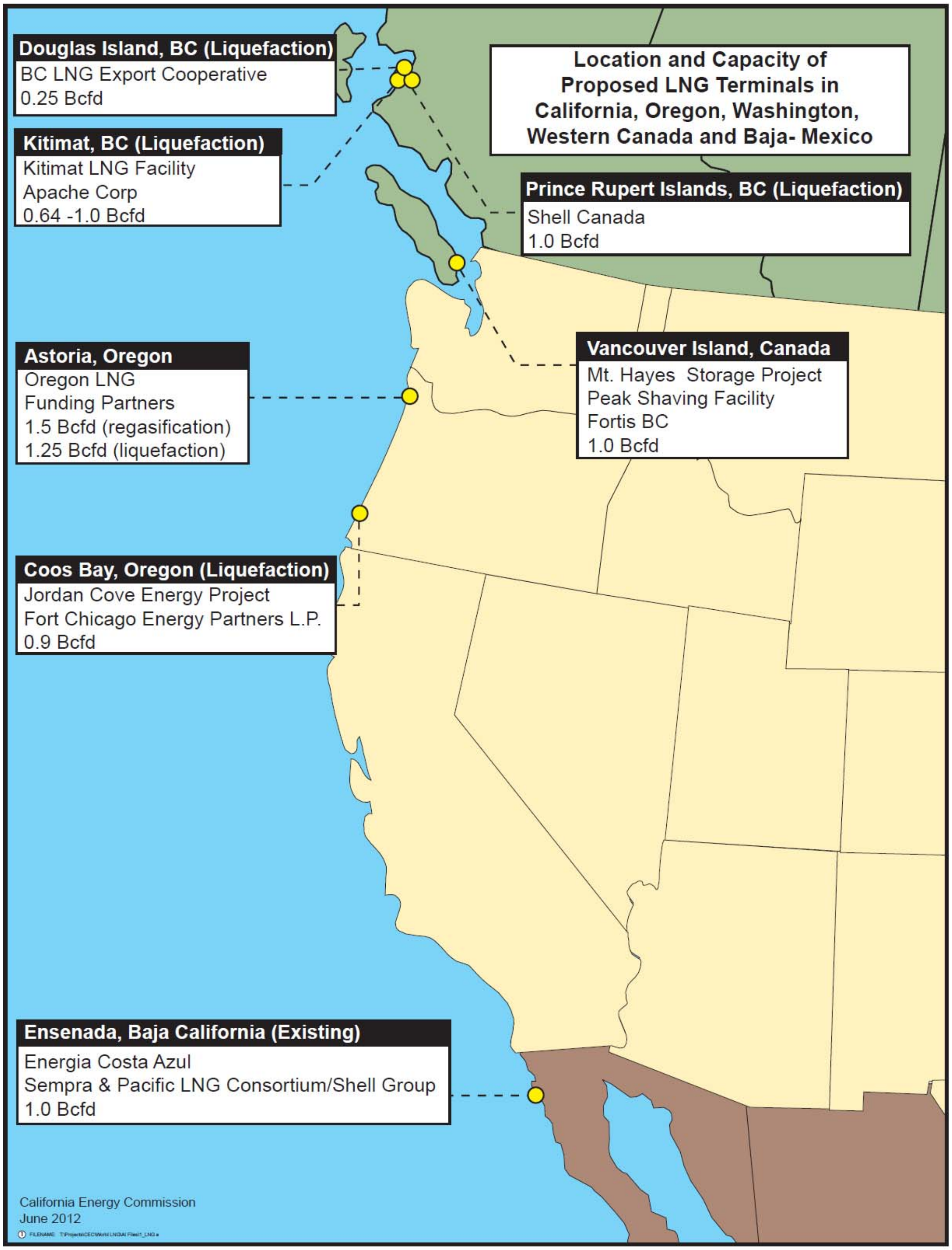
With the completion of the Costa Azul LNG terminal in Baja California, Mexico, in May 2008, LNG was expected to be an important supply source to California. However with increasing shale-based gas supplies available in the U.S., LNG sourced gas is not expected to play a large role in California's gas supply picture. 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. Instead, with the low domestic price of natural gas, several companies are now proposing to export U.S.-sourced LNG supplies to Asia and other parts of the world instead of importing LNG supplies for regasification in the United States. The map on the following page shows the locations of these supply sources.

Instead, U.S. companies are now proposing to develop U.S.-sourced LNG liquefaction facilities in the U.S. Gulf, East and West coasts for LNG exports. EIA reports that over 13.7 Bcf/day of liquefaction facilities are being proposed over the next few years. It is uncertain, at this time, how much U.S.-sourced LNG the U.S. Government will allow to be exported. Currently, four companies have received export licenses totaling 6.5 Bcf/day to countries with which the U.S. has Free Trade Agreements (FTA). One company has received DOE approval for exports to non-FTA countries. The other three companies are also seeking government approval to export LNG to non-FTA countries.

In addition to the Costa Azul terminal in Mexico, a few other LNG terminal projects had been proposed on the West Coast that could have resulted in additional LNG-derived supplies being delivered to California but these projects have since been abandoned. The Jordan Cove LNG project in Coos Bay, Oregon is now considering turning the site into an LNG liquefaction and export facility. The Kitimat, British Columbia, LNG re-gasification facility has now been turned into an LNG liquefaction and export facility with exports heading to Korea. It is too early at this pint to estimate expected exports that could result 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 2012-2030 forecast period presented in the 2012 California Gas Report. Should these LNG export facilities be completed and exports begin, they may trigger higher gas prices in the western U.S. and California.

Attached is a map from the California Energy Commission highlighting all of the proposed LNG projects on the West Coast as of mid June 2012. At this point, aside from the Energia Costa Azul facility, each of these projects is still awaiting necessary government approvals in order to begin construction. Additional information on these projects is available at www.energy.ca.gov/naturalgas/ .

Proposed West Coast LNG Terminals



LNG PROJECT	LOCATION	AVERAGE PRODUCTION CAPACITY (BCF/D)	STATUS AS OF JUNE 2012
BC LNG (LIQUEFACTION)	BC, CANADA	0.25/DAY	ON MARCH 8, 2011, BC LNG EXPORT CO-OPERATIVE LLC FILED AN APPLICATION WITH CANADA'S NATIONAL ENERGY BOARD FOR A NATURAL GAS EXPORT LICENSE.
PRINCE RUPERT ISLAND, SHELL CANADA	BC, CANADA	1.0/DAY	APPLICATION NOT YET SUBMITTED
OREGON LNG (LIQUEFACTION AND REGASIFICATION)	OREGON	1.5 /DAY (REGASIFICATION) 1.25 /DAY (LIQUEFACTION)	IN APRIL OF 2012, OREGON LNG NOTIFIED FERC OF PLANS TO MODIFY THE APPLICATION TO INCLUDE LIQUEFACTION CAPACITY.
JORDAN COVE ENERGY (LIQUEFACTION)	OREGON	1.0 /DAY	ON FEBRUARY 29, 2012, JORDAN COVE NOTIFIED FERC THAT IT NO LONGER INTENDS TO BUILD AN IMPORT FACILITY AND SUBMITTED A PREFILING TO BUILD AN EXPORT FACILITY ON APRIL 16, 2012, FERC VACATED THE ORDER AUTHORIZING THE CONSTRUCTION OF AN LNG IMPORT TERMINAL..
PORT OF KITIMAT (LIQUEFACTION)	CANADA	0.64 / DAY	IN 2010, APACHE ACQUIRED A CONTROLING 51% STAKE IN KITIMAT WITH GALVESTON LNG RETAINING 49%. ALSO IN 2010, KITIMAT SIGNED AN MOU WITH MAJOR JAPANESE FIRM AFTER MOU WITH MITSUBISHI EXPIRED. IN MARCH 2011, THE OWNERSHIP SHIFTS SO THAT 40% APACHE CORP; 30% EOG RESOURCES CANADA; 30% ENCANA CORP. KINDER MORGAN LNG IS THE OPERATOR. IN 2011, HAISLA NATION AND LNG PARTNERS OF HOUSTON JOINED TO PROPOSE AN LNG EXPORT FACILITY JUST NORTH OF KITIMAT. THE PROJECT RECEIVED A 20 YEAR EXPORT LICENSE APPROVAL BY THE NATIONAL ENERGY BOARD ON OCTOBER 4, 2011. THE PROJECT IS EXPECTED TO MOVE ABOUT 0.7 BCF/D AND IS SCHEDULED TO COME ONLINE IN 2013.

MT. HAYES STORAGE PROJECT (EXISTING)	CANADA	1/DAY (NOTE: THIS IS A PEAK SHAVING FACILITY, NOT AN IMPORT FACILITY)	TERASEN FIRST APPLIED IN 2004 FOR PERMISSION TO BUILD THE FACILITY. IN 2008, THE COMPANY RECEIVED FINAL APPROVAL.
ENERGIA COSTA AZUL LNG (EXISTING REGASIFICATION)	MEXICO	1/DAY	IN 2008, THE FIRST CARGO FROM SAKHALIN 2 SET SAIL. GAZPROM AND ROYAL DUTCH SHELL OFFICIALLY REACHED AN AGREEMENT THAT WOULD SEND LNG FROM SAKHALIN 2 TO ENERGIA COSTA AZUL. IN 2009, ENERGIA COSTA AZUL RECEIVED 1.45 BCF FROM TANGGUH 1. IN 2010, COSTA AZUL WAS SUPPOSED TO START RECEIVING STANDARD CARGOES OF 3 BCF EVERY 12 DAYS. ALSO IN 2010, THE FIRST LNG CARGO FROM THE NEW PERU LNG PLANT ARRIVED. IN 2010, THERE WAS AN ATTEMPT TO SUSPEND OPERATIONS OVER A LAND DISPUTE BUT THE MEXICAN COURT REVOKED THE ORDER TO SUSPEND THE SEMPRA TERMINAL PERMIT.

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day theoretically is over 6,515 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	1,210
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	750
Occidental at Wheeler Ridge	150
California Production	310
TGN at Otay Mesa	400
North Baja at Blythe	600
Total Potential Supplies	6,725

(1) Estimate of physical capacity.

FIRM RECEIPT CAPACITY

SoCalGas/SDG&E currently has firm receipt 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 (1,210) TGN Otay Mesa (400) NBP Blythe (600)
Northern	1,590	EPN Topock (540) TW North Needles (800) QST North Needles (120) KR Kramer Junction (550)
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 City of 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 135.1 billion cubic feet (Bcf) of storage capacity, 82 Bcf is allocated to our Core residential, small industrial and commercial customers. About 4 Bcf of space is used for system balancing. The remaining capacity is available to other customers.

REGULATORY ENVIRONMENT

State Regulatory Matters

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 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 a 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 filed application A.08-06-006 in June 2008 to expand the existing off-system delivery authority to all receipt points. SoCalGas requested approval to: provide interruptible and firm off-system services at all receipt points; charge a discountable interruptible off-system delivery rate; charge a firm off-system delivery rate that fully recovers the costs of new facilities plus a discountable interruptible off-system delivery; roll-in the firm off-system facility costs into those of the overall transmission system if appropriate, and resolve shipper imbalances. A final decision was issued March 2011 which authorized off-system delivery service.

SoCalGas filed application A.010-03-028 in March 2009 to assess how the Firm Access Rights (FAR) system is working and whether any changes or modifications are needed ("FAR update"). SoCalGas requested: minor changes to the open season process; change of the "FAR" name to the more appropriate and descriptive "Backbone Transportation Service," increase firm capacity at the Kramer Junction receipt point by 50 MMcfd to 550 MMcfd, authorization of a fully-unbundled cost-based rate design and in-kind treatment of transmission fuel. A final decision was issued April 2011 which adopted operational modifications unanimously recommended by the participating parties to further reduce scheduling uncertainty and improve operation of the FAR system, including changes designed to improve the performance of the FAR system during periods when access to the SDG&E/SoCalGas gas transmission system is constrained.

TRIENNIAL COST ALLOCATION PROCEEDING (TCAP)

SoCalGas and SDG&E filed their TCAP, A.11-11-002 in November 2011. The application updated throughput forecasts, cost allocation, and rates by customer class for 2013 through 2015, in addition to addressing issues related to the prior settlement agreements adopted in SoCalGas and SDG&E's previous cost allocation proceeding. A February 2012 Ruling has subsequently bifurcated the TCAP into two phases; Phase I will address the Pipeline Safety Enhancement Plans (PSEP) originally filed by SoCalGas and SDG&E in Commission Rulemaking R.11-02-019. SoCalGas and SDG&E's PSEP seeks funding for safety enhancement projects for the years 2012 through 2015.

Phase 2 of the TCAP will address cost allocation including all issues raised by SoCalGas and SDG&E in their original TCAP application (A.11-11-002) to allocate the cost of service to various customer classes to recover the cost of service from the respective rate base. In addition, Phase 2 will include the costs of the PSEP addressed in Phase 1. A Phase 1 decision is expected in the first quarter of 2013 and a Phase 2 decision is expected in mid-2013.

PIPELINE SAFETY

On February 24, 2011, the CPUC approved an Order Instituting Rulemaking (OIR) to develop and adopt new regulations on pipeline safety. Through the new OIR, the Commission will develop and adopt safety regulations that address topics such as construction standards, shut-off valves, maintenance requirements, records management and retention, ratemaking, and penalty provisions.

On June 9, 2011, the CPUC issued a decision requiring that the utilities file a plan to pressure test or replace transmission pipelines that have not been pressure tested. SoCalGas/SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011. The comprehensive plan covers all of the utilities' approximately 4,000 miles of transmission lines (3,750 miles for SoCalGas and 250 miles for SDG&E) and would be implemented in two phases. Phase 1: focuses on populated areas of SoCalGas' and SDG&E's service territories and, if approved, would be implemented over a 10-year period, from 2012 to 2022. Phase 2: will cover unpopulated areas of SoCalGas' and SDG&E's service territories and will be filed with the CPUC at a later date.

The Utilities' Pipeline Safety Enhancement Plan was transferred for consideration from the Pipeline Safety Rulemaking to the Utilities' Triennial Cost Allocation Proceeding.
A decision by the CPUC on our plan is expected in 2013.

FEDERAL REGULATORY MATTERS

SoCalGas and SDG&E participate in FERC proceedings involving interstate natural gas pipelines serving California that can affect the cost of gas delivered to their customers. SoCalGas holds contracts for interstate transportation capacity on the El Paso, Kern River, Transwestern, and GTN pipelines. SoCalGas and SDG&E also participate in FERC proceedings involving the natural gas industry generally as those proceedings may impact their operations and policies.

El Paso

El Paso's rates have been the subject of extensive litigation at FERC in recent years. El Paso filed its third general rate case in five years in September 2010. The 2010 rate case proceeded to a hearing on all issues in 2011, and decisions are expected in 2012. El Paso's 2008 rate case proceeded to a hearing on reserved issues in 2010, and a FERC decision was issued in May 2012 that resolved issues favorably to California consumers concerning El Paso's acquisition cost of California pipeline facilities and El Paso's 1996 Settlement rate cap provisions. El Paso's 2005 rate case was concluded by a decision of the U.S. Court of Appeals for the D.C. Circuit issued in January 2012, affirming FERC's approval of the settlement of that case over the objection of a non-settling party. Additionally, a complaint case challenging El Paso's postage stamp fuel rate design was filed in 2010, and an Initial Decision was issued in September 2011 that upholds the postage stamp fuel rate as argued by the California utilities and the CPUC jointly.

In January 2012 El Paso filed an application to abandon certain compression facilities used to transport San Juan Basin gas supplies to interconnects with the SoCalGas and PG&E systems. Protests to the application are pending at FERC, including a protest filed jointly by SoCalGas, SDG&E, PG&E, and the CPUC.

The El Paso pipeline assets were acquired by Kinder Morgan in a transaction that closed in May 2012.

Kern River

Litigation at FERC of Kern River's 2004 general rate case will conclude in 2012 with the issuance of a final rehearing order. In a series of orders FERC has held Kern River to its original 1992 levelized rate design, resulting in reduced rates for eligible shippers which extend for periods up to 15 years.

Transwestern

Under the settlement of its 2006 rate case Transwestern was required to file a new general rate case in 2011. The 2011 case was settled in advance of filing, with the major issue being the fuel rate for San Juan Basin gas supplies. Under the settlement, the fuel rate for San Juan Basin gas supplies delivered to California will decrease annually from 2012-2014.

Gas Transmission Northwest (GTN)

In December 2011 FERC approved a rate case settlement between GTN and its customers. Under the settlement, transportation rates for Canadian gas supplies delivered to California will be reduced for the three-year term of 2012-2014.

Coordination Between Gas and Electric Markets

In February 2012 FERC opened a proceeding to receive comments concerning potential revisions to coordinate scheduling protocols and emergency response measures between gas and electricity markets. The proceeding may lead to a rulemaking docket involving regional and national issues.

GREENHOUSE GAS ISSUES

National Policy

National greenhouse gas (GHG) policy is currently under development. 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.

Restriction on New Conventional Coal Generation

In March 2012 EPA proposed the first Clean Air Act standards for carbon pollution. The proposed standards apply only to new facilities and can be met by a range of power generation facilities burning fossil fuels, including natural gas or coal with technologies to reduce carbon emissions. Since carbon sequestration technology is not yet proven, in the near term, new generation will likely be dependent upon natural gas. 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 the electricity demand that cannot be met through renewable resources.

Motor Vehicle Emissions 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. Under

EPA's Mandatory Reporting of Greenhouse Gases rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of carbon dioxide, nitrous oxide, and methane from their products.

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 developing and implementing the final regulations on GHG regulatory framework and compliance. Approved policies include both programmatic measures and market-based mechanisms to reduce GHG emissions.

Global Warming Solutions Act of 2006

California enacted the Global Warming Solutions Act, also known as AB 32, to help avoid potential climate change-related damage to the economy, public health and the environment. The legislation requires the state to reduce GHG emissions to 1990 levels by 2020 and directs the California Air Resources Board (CARB) to develop policies and programs to achieve this goal. ARB adopted its final Scoping Plan in 2009, which includes new and existing emissions reduction measures including a low-carbon fuel standard, energy efficiency and conservation measures, a renewable portfolio standard (RPS) for electricity generation and a market-based emissions cap-and-trade program.

Low Carbon Fuel Standard

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 CO_2 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.

Cap and Trade Program

The AB 32 Cap and Trade Program was approved by the Office of Administrative Law in December 2011. The Regulation became effective January 1, 2012. The GHG emissions cap declines by about 2% per year in the initial period and then by about 3% a year through 2020. The 2020 cap is about 15% below 2012 levels. Approximately 85% of the GHG emissions in California are covered under the cap. Industrial sources and the electricity sector start out with free allocations of emissions allowances. The reminder of the allowances will be sold at auctions, which will be held on a quarterly basis beginning in November 2012.

The first compliance period is scheduled to begin January 1, 2013 for electricity, including imports, and large industrial facilities with CO_2 emissions equal to or greater than 25,000 metric tons per year. The second compliance period is 2015-2017 and includes distributors of transportation fuels, natural gas, and other fuels. The third compliance period, which includes all covered sectors, is 2018-2020.

In 2013, several of SoCalGas' and one of SDG&E's compressor stations will have a compliance obligation under the Cap and Trade Program and SoCalGas and SDG&E will have to purchase emissions allowances to cover their GHG emissions

In 2015, SoCalGas' and SDG&E's small and medium-sized customers (fewer than 25,000 tons CO_2/yr or 4.7 million therms/yr) will be part of the AB 32 Cap and Trade Program. CARB allocated free allowances to Electric utilities to help offset the cost of AB 32 programs for customers. CARB plans to decide whether or not to allocate free allowances to gas utilities on behalf of their customers in 2013. If CARB decides not to give gas utilities free allowances, then an emissions allowance has to be purchased from CARB or in the secondary market for every ton of CO_2 emitted by customers in this group. CARB estimates that allowance prices will be between $10-$70 per metric ton.

Due to uncertainties about whether or not natural gas will be allocated free allowances by CARB, it is unclear if natural gas demand will be affected by the program.

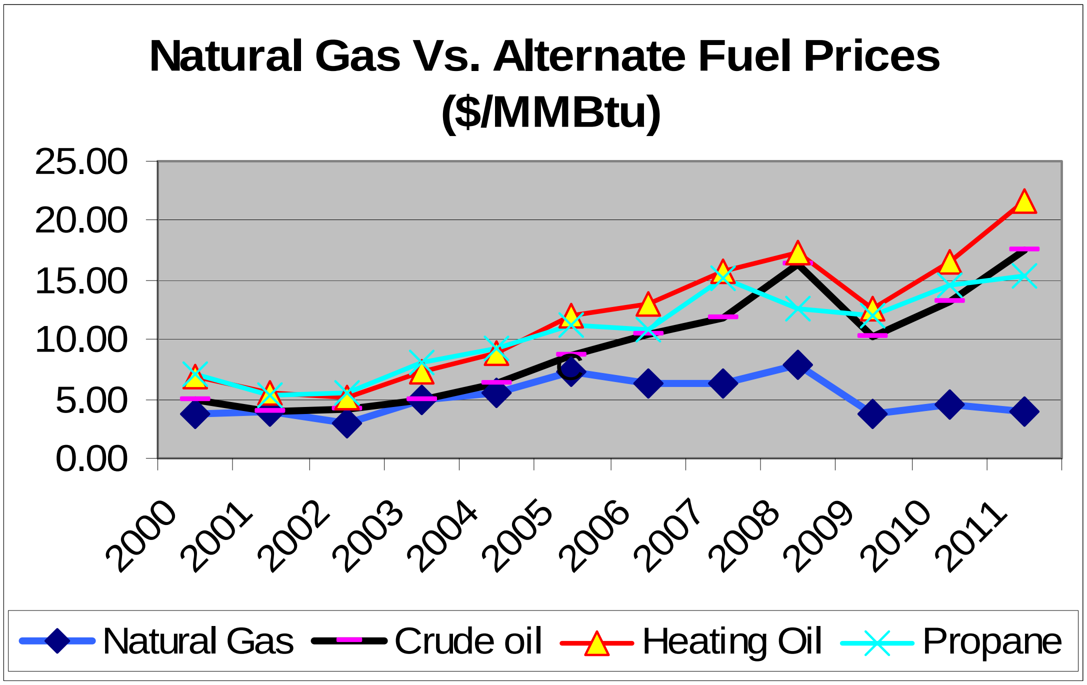
Programmatic Emission Reduction Measures

The CEC, CPUC and CARB are considering or have approved 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, the 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 electric renewables portfolio standard to 33%. Energy Efficiency and renewables are considered fundamental to GHG 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 combustion turbines.

GAS PRICE FORECAST

MARKET CONDITION

Natural gas prices during the 2012 CGR period are forecast to increase due to a combination of oil price increases and strong growth in natural gas consumption, particularly in the electric generation sector. The price of natural gas is currently trading at an unprecedented discount to crude oil and oil-derived products as shown in the chart below but over the longer term oil and gas prices should start to converge.



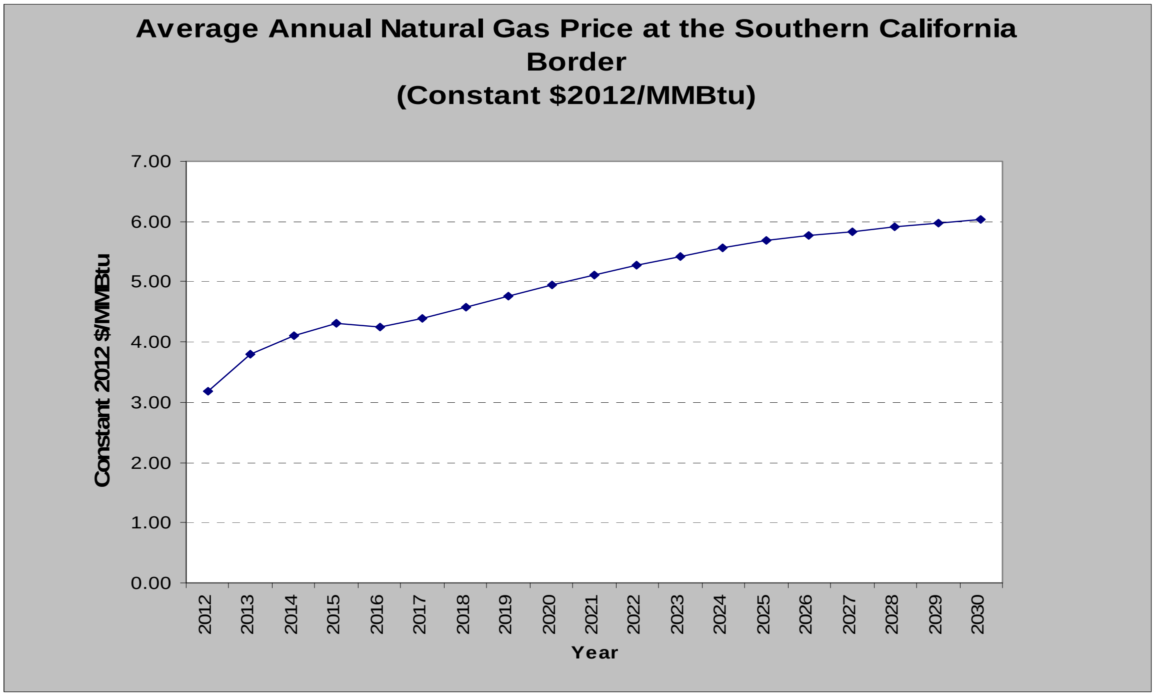
Current North American production from conventional supplies has been declining, particularly at the Western Canadian Sedimentary Basin and offshore production in the Gulf of Mexico. However, with advanced technology in horizontal drilling, proven reserves from unconventional resources have been soaring due to the unlocking of trapped gas from shale, tight sands and coal bed methane in the Mid-Continent, Rockies and eastern U.S. The new technology is successful at finding trapped gas that was not economical before but is now economic due to technological breakthroughs that have reduced development costs substantially. The aggressive expansion in the production of shale gas in the Mid-Continent, eastern U.S. and Canada and continuing growing production of coal bed methane in the Rockies is expected to moderate some of the price pressure in the next few years although reductions in conventional sources and possible exports of U.S. sourced LNG could offset that price moderation to some degree.

With world-wide LNG prices still higher than the current price at Henry Hub, LNG imports in the short-term are expected to be limited with only a minor impact on domestic supply or price. LNG however is expected to moderate winter gas price increases as LNG will be withdrawn from storage during peak demand periods. LNG deliveries into the U.S. Southwest from the Energia Costa Azul LNG receiving terminal in Baja California, Mexico, have occurred in limited quantities to date. In the long-run, 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. Although some LNG imports are expected to continue in the forecast period, U.S. sourced LNG exports are also likely and will reduce natural gas supply availability in the U.S.

Therefore, industry experts now forecast that gas supplies can be expected to be more plentiful and less volatile during the forecast period. Increased shale gas production and increased LNG liquefaction supplies combined with a mild worldwide economic recovery are expected to moderate prices in the medium term. However, increasing demand for clean natural gas for electric power generation, Natural Gas Vehicles fuel, and substitution of gas for coal in electric power production to meet GHG reduction goals will continue to put upward pressure on prices in the longer term.

DEVELOPMENT OF THE FORECAST

The base 2012 CGR Gas Price Forecast (2012 CGR GPF) used to develop the gas demand forecasts was prepared using the average of NYMEX natural gas futures prices in March 2012 and the long-term forecasts from 2012 to 2030 of the California Energy Commission (CEC), the Energy Information Administration (EIA) and private sources that relied on fundamentals-based models. Natural gas prices are expected to average out at $3.30/MMbtu in 2012 and increase by about 3.3 percent per year through 2030. This growth rate is higher than expected because the current natural gas prices are uncharacteristically low due to a 1-in-80-year 2011-2012 warm winter in the U.S. East.



It is important to recognize that natural gas prices have recently been much lower than in the past, but no price forecast can be expected to account for all uncertainties. SoCalGas and the participants of the *2012 CGR* do not warrant the accuracy of the gas price projection. In no event shall SoCalGas or the participants of the *2012 CGR* be liable for the use or reliance of the natural gas price forecast.

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 38.9 degrees Fahrenheit for SoCalGas' service area and 41.3 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 are approved to hold (per CPUC D.08-12-020 on Dec. 4, 2008 at p. 12) to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers. 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
2012	3,036	393	3,429	2,225	1,204
2013	3,003	391	3,394	2,225	1,169
2014	2,980	390	3,370	2,225	1,145
2015	2,964	388	3,352	2,225	1,127
2016	2,956	388	3,343	2,225	1,118
2017	2,954	387	3,341	2,225	1,116
2018	2,957	386	3,344	2,225	1,119

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 amount was approved by the CPUC for SoCalGas and SDG&E to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers in CPUC D.08-12-020 on 12/4/2008 at p. 12.

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
2012	3,036	982	960	4,978
2013	3,003	985	1,004	4,992
2014	2,980	982	972	4,934
2015	2,964	978	967	4,908
2016	2,956	975	1,031	4,961
2017	2,954	971	1,064	4,988
2018	2,957	967	1,098	5,022

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core.
(2) 1-in-10 peak temperature cold day for Hdd-sensitive load. Includes SoCalGas non-core and wholesale non-EG.
(3) UEG/EWG Base Hydro + all other EG.

Summer Peak Day Demand (MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2012	600	619	1,718	2,937
2013	597	622	1,916	3,135
2014	591	618	1,808	3,017
2015	588	614	1,817	3,019
2016	587	610	1,876	3,073
2017	587	605	1,878	3,071
2018	588	600	1,881	3,069

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.

2012 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY

RECORDED YEARS 2007 TO 2011

Line	CAPACITY AVAILABLE		2007	2008	2009	2010	2011
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		232	209	216	203	175
	Out-of-State Gas						
11	Other Out-of-State		2,462	2,585	2,397	2,445	2,452
12	Total Out-of-State Gas		2,462	2,585	2,397	2,445	2,452
13	TOTAL SUPPLY TAKEN		2,694	2,794	2,613	2,648	2,627
14	Net Underground Storage Withdrawal		23	(28)	8	(10)	(4)
15	TOTAL THROUGHPUT (1)(2)		2,717	2,766	2,621	2,638	2,623
	DELIVERIES BY END-USE (3)						
16	Core	Residential	673	659	645	673	696
17		Commercial	224	211	210	216	217
18		Industrial	65	64	59	61	61
19		NGV	23	25	26	27	28
20		Subtotal	985	959	940	977	1,002
21	Noncore	Commercial	60	59	56	59	60
22		Industrial	345	341	324	361	363
23		EOR Steaming	39	39	35	30	27
24		Electric Generation	849	907	811	768	726
25		Subtotal	1,293	1,346	1,226	1,218	1,176
26	Wholesale/International		406	422	412	412	407
27	Co. Use & LUAF		33	39	43	31	38
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,717	2,766	2,621	2,638	2,623
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	14	17	20	25	29
30	Noncore	Commercial/Industrial	405	400	380	420	423
31		EOR Steaming	39	39	35	30	27
32		Electric Generation	849	907	811	768	726
33		Subtotal-Retail	1,307	1,363	1,246	1,243	1,205
34	Wholesale/International		406	422	412	412	407
35	TOTAL TRANSPORTATION & EXCHANGE		1,713	1,785	1,658	1,655	1,612
	CURTAILMENT (RETAIL & WHOLESALE)						
36		Core					
37		Noncore (4)					
38		TOTAL - Curtailment					
39	REFUSAL						
40		Total BTU Factor (Dth/Mcf)	1.0305	1.0299	1.0273	1.0235	1.0209
	NOTES:						
	(1) Exclude own-source gas supply of procurement by Edison and City of Long Beach.		4	4	2	2	1

(2) Deliveries by end-use includes sales, transportation, and exchange volumes.
(3) Data includes effect of prior period adjustments.
(4) Total 175 mmcf curtailment were reported in 2011.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2012 THRU 2014

AVERAGE TEMPERATURE YEAR

LINE			2012	2013	2014	LINE
	CAPACITY AVAILABLE					
1	California Line 85 Zone (California Producers)		160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	2
	Out-of-State Gas					
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	7
	GAS SUPPLY TAKEN					
8	California Source Gas		310	310	310	8
9	Out-of-State		2,363	2,337	2,306	9
10	TOTAL SUPPLY TAKEN		2,673	2,647	2,616	10
11	Net Underground Storage Withdrawal		0	0	0	11
12	TOTAL THROUGHPUT 4/		2,673	2,647	2,616	12
	REQUIREMENTS FORECAST BY END-USE 5/					
13	CORE 6/	Residential	638	632	627	13
14		Commercial	213	214	212	14
15		Industrial	60	58	56	15
16		NGV	29	30	31	16
17		Subtotal-CORE	940	934	927	17
18	NONCORE	Commercial	47	46	45	18
19		Industrial	376	374	372	19
20		EOR Steaming	32	41	41	20
21		Electric Generation (EG)	812	804	784	21
22		Subtotal-NONCORE	1,267	1,266	1,241	22
23	WHOLESALE &	Core	183	184	184	23
24	INTERNATIONAL	Noncore Excl. EG	42	43	43	24
25		Electric Generation (EG)	208	190	190	25
26		Subtotal-WHOLESALE & INTL.	434	416	416	26
27		Co. Use & LUAF	32	32	32	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,673	2,647	2,616	28
	TRANSPORTATION AND EXCHANGE					
29	CORE	All End Uses	28	28	28	29
30	NONCORE	Commercial/Industrial	424	420	416	30
31		EOR Steaming	32	41	41	31
32		Electric Generation (EG)	812	804	784	32
33		Subtotal-RETAIL	1,295	1,294	1,269	33
	WHOLESALE &					
34	INTERNATIONAL	All End Uses	434	416	416	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,729	1,710	1,685	35
	CURTAILMENT (RETAIL & WHOLESALE)					
36		Core	0	0	0	36
37		Noncore	0	0	0	37
38		TOTAL - Curtailment	0	0	0	38

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2012	2013	2014
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1	1	1

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

	2012	2013	2014
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	931	925	918

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE						
1	California Line 85 Zone (California Producers)		160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	2
	Out-of-State Gas						
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN						
8	California Source Gas		310	310	310	310	8
9	Out-of-State		2,305	2,309	2,289	2,309	9
10	TOTAL SUPPLY TAKEN		2,615	2,619	2,599	2,619	10
11	Net Underground Storage Withdrawal		0	0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,615	2,619	2,599	2,619	12
	REQUIREMENTS FORECAST BY END-USE [5/]						
13	CORE [6/]	Residential	623	620	618	628	13
14		Commercial	211	206	203	207	14
15		Industrial	56	50	43	39	15
16		NGV	33	39	45	51	16
17		Subtotal-CORE	922	915	909	925	17
18	NONCORE	Commercial	43	33	24	23	18
19		Industrial	368	354	341	336	19
20		EOR Steaming	41	41	41	41	20
21		Electric Generation (EG)	790	833	833	832	21
22		Subtotal-NONCORE	1,242	1,261	1,239	1,233	22
23	WHOLESALE &	Core	184	183	187	193	23
24	INTERNATIONAL	Noncore Excl. EG	44	45	46	46	24
25		Electric Generation (EG)	191	183	187	191	25
26		Subtotal-WHOLESALE & INTL.	419	411	420	430	26
27		Co. Use & LUAF	32	32	31	32	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,615	2,619	2,599	2,619	28
	TRANSPORTATION AND EXCHANGE						
29	CORE	All End Uses	28	27	26	27	29
30	NONCORE	Commercial/Industrial	411	388	365	359	30
31		EOR Steaming	41	41	41	41	31
32		Electric Generation (EG)	790	833	833	832	32
33		Subtotal-RETAIL	1,270	1,288	1,265	1,259	33
	WHOLESALE &						
34	INTERNATIONAL	All End Uses	419	411	420	430	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,689	1,699	1,685	1,689	35
	CURTAILMENT (RETAIL & WHOLESALE)						
36		Core	0	0	0	0	36
37		Noncore	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2015	2020	2025	2030
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1	1	1	1
5/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.				
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	913	906	901	917

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2012 THRU 2014

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2012	2013	2014	LINE
	CAPACITY AVAILABLE					
1	California Line 85 Zone (California Producers)		160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	2
	Out-of-State Gas					
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	7
	GAS SUPPLY TAKEN					
8	California Source Gas		160	160	160	8
9	Out-of-State		2,603	2,639	2,606	9
10	TOTAL SUPPLY TAKEN		2,763	2,799	2,766	10
11	Net Underground Storage Withdrawal		0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,763	2,799	2,766	12
	REQUIREMENTS FORECAST BY END-USE [5/]					
13	CORE [6/]	Residential	699	692	686	13
14		Commercial	225	225	223	14
15		Industrial	61	59	58	15
16		NGV	29	30	31	16
17		Subtotal-CORE	1,014	1,006	999	17
18	NONCORE	Commercial	48	47	46	18
19		Industrial	376	374	372	19
20		EOR Steaming	32	41	41	20
21		Electric Generation (EG)	812	858	837	21
22		Subtotal-NONCORE	1,268	1,320	1,295	22
23	WHOLESALE &	Core	198	198	198	23
24	INTERNATIONAL	Noncore Excl. EG	42	43	43	24
25		Electric Generation (EG)	208	197	197	25
26		Subtotal-WHOLESALE & INTL.	448	438	439	26
27		Co. Use & LUAF	33	34	33	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,763	2,799	2,766	28
	TRANSPORTATION AND EXCHANGE					
29	CORE	All End Uses	30	30	29	29
30	NONCORE	Commercial/Industrial	425	421	417	30
31		EOR Steaming	32	41	41	31
32		Electric Generation (EG)	812	858	837	32
33		Subtotal-RETAIL	1,298	1,350	1,325	33
	WHOLESALE &					
34	INTERNATIONAL	All End Uses	448	438	439	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,747	1,788	1,764	35
	CURTAILMENT (RETAIL & WHOLESALE)					
36		Core	0	0	0	36
37		Noncore	0	0	0	37
38		TOTAL - Curtailment	0	0	0	38

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2012	2013	2014
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1	1	1
5/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.			
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,004	997	990

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE						
1	California Line 85 Zone (California Producers)		160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	2
	Out-of-State Gas						
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN						
8	California Source Gas		310	310	310	310	8
9	Out-of-State		2,449	2,463	2,443	2,465	9
10	TOTAL SUPPLY TAKEN		2,759	2,773	2,753	2,775	10
11	Net Underground Storage Withdrawal		0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,759	2,773	2,753	2,775	12
	REQUIREMENTS FORECAST BY END-USE 5/						
13	CORE 6/	Residential	682	678	677	687	13
14		Commercial	222	217	213	218	14
15		Industrial	57	51	44	40	15
16		NGV	33	39	45	51	16
17		Subtotal-CORE	994	986	979	996	17
18	NONCORE	Commercial	44	35	25	24	18
19		Industrial	368	354	341	336	19
20		EOR Steaming	41	41	41	41	20
21		Electric Generation (EG)	837	890	891	890	21
22		Subtotal-NONCORE	1,290	1,320	1,298	1,292	22
23	WHOLESALE &	Core	198	198	202	208	23
24	INTERNATIONAL	Noncore Excl. EG	44	45	46	46	24
25		Electric Generation (EG)	200	190	194	198	25
26		Subtotal-WHOLESALE & INTL.	442	433	442	453	26
27		Co. Use & LUAF	33	34	33	34	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,759	2,773	2,753	2,775	28
	TRANSPORTATION AND EXCHANGE						
29	CORE	All End Uses	29	29	28	28	29
30	NONCORE	Commercial/Industrial	412	389	366	360	30
31		EOR Steaming	41	41	41	41	31
32		Electric Generation (EG)	837	890	891	890	32
33		Subtotal-RETAIL	1,320	1,349	1,326	1,320	33
	WHOLESALE &						
34	INTERNATIONAL	All End Uses	442	433	442	453	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,762	1,782	1,768	1,773	35
	CURTAILMENT (RETAIL & WHOLESALE)						
36		Core	0	0	0	0	36
37		Noncore	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	38

NOTES:
1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2015	2020	2025	2030
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1	1	1	1

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

	2015	2020	2025	2030
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	985	977	972	988

2012 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 forecast requirements prepared by the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2007 through 2030.

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 59 percent residential and 41 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. Currently, Long Beach receives approximately 5 percent of its gas supply from 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.

2012 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2007 THRU 2011

LINE	GAS SUPPLY AVAILABLE	2007	2008	2009	2010	2011	LINE
	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	4	4	2	2	1	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	4	4	2	2	1	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	26	23	23	24	25	19
20	Out-of-State Transport	0	0	0	0	0	20
21	Total Out-of-State Gas	26	23	23	24	24.96	21
22	Subtotal	31	27	25	26	26	22
23	Underground Storage Withdrawal	0	0	0	0	0	23
24	TOTAL Gas Supply Taken & Transported	31	27	25	26	26	24

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2007 THRU 2011

LINE	ACTUAL DELIVERIES BY END-USE		2007	2008	2009	2010	2011	LINE
1	CORE	Residential	15	14	14	15	15	1
2	CORE/NONCORE	Commercial	7	7	6	6	6	2
3	CORE/NONCORE	Industrial	7	5	4	4	3	3
4		Subtotal	29	26	24	24	24	4
5	NON CORE	Non-EOR Cogeneration	1	1	0	1	1	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	0	0	0	0	0	7
8		Subtotal	1	1	0	1	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	0.1	0.7	0.5	0.4	0.6	13
14		Subtotal-END USE	30	27	25	26	26	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL-THROUGHPUT		30	27	25	26	26	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	26	23	23	24	25	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		26	23	23	24	25	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.

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2012 THRU 2015

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2012	2013	2014	2015	LINE
1	California Source Gas						1
2	Out-of-State Gas						2
3	TOTAL CAPACITY AVAILABLE						3
	GAS SUPPLY TAKEN						
4	California Source Gas		1	1	1	1	4
5	Out-of-State Gas		25	25	25	25	5
6	TOTAL SUPPLY TAKEN		26	26	26	26	6
7	Net Underground Storage Withdrawal		0	0	0	0	7
8	TOTAL THROUGHPUT (1)		25.9	25.9	25.9	26.0	8
	REQUIREMENTS FORECAST BY END-USE (1)						
9	CORE	Residential	15	15	15	15	9
10		Commercial	6	6	6	6	10
11		NGV	0.3	0.3	0.3	0.3	11
12		Subtotal-CORE	21	21	21	21	12
13	NONCORE	Industrial	4	4	4	4	13
14		Non-EOR Cogeneration	1	1	1	1	14
15		EOR	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	16
17		NGV	0	0	0	0	17
18		Subtotal-NONCORE	5	5	5	5	18
19		Co. Use & LUAF	0.2	0.2	0.2	0.2	19
20	SYSTEM TOTAL THROUGHPUT (1)		26	26	26	26	20
21	SYSTEM CURTAILMENT		0	0	0	0	21
	TRANSPORTATION						
22	CORE	All End Uses	21	21	21	21	22
23	NONCORE	Industrial	4	4	4	4	23
24		Non-EOR Cogeneration	1	1	1	1	24
25		EOR	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	26
27		Subtotal NONCORE	5	5	5	5	27
28	TOTAL TRANSPORTATION		25.4	25.7	25.7	25.8	28

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2020	2025	2030	LINE
1	California Source Gas					1
2	Out-of-State Gas					2
3	TOTAL CAPACITY AVAILABLE					3
	GAS SUPPLY TAKEN					
4	California Source Gas		1	1.00	1.00	4
5	Out-of-State Gas		26	26	26	5
6	TOTAL SUPPLY TAKEN		27	27	27	6
7	Net Underground Storage Withdrawal		0	0	0	7
8	TOTAL THROUGHPUT (1)		27	26.88	27.24	8
	REQUIREMENTS FORECAST BY END-USE (1)					
9	CORE	Residential	15	15	16	9
10		Commercial	6	6	6	10
11		NGV	0	0	0	11
12		Subtotal-CORE	21	21	22	12
13	NONCORE	Industrial	4	4	4	13
14		Non-EOR Cogeneration	1	1	1	14
15		EOR	0	0	0	15
16		Utility Electric Generation	0	0	0	16
17		NGV	0	0	0	17
18		Subtotal-NONCORE	5	5	5	18
19		Co. Use & LUAF	0	0	0	19
20	SYSTEM TOTAL THROUGHPUT (1)		26	26	26	20
21	SYSTEM CURTAILMENT		0	0	0	21
	TRANSPORTATION					
22	CORE	All End Uses	22	22	22	22
23	NONCORE	Industrial	4	4	4	23
24		Non-EOR Cogeneration	1	1	1	24
25		EOR	0	0	0	25
26		Utility Electric Generation	0	0	0	26
27		Subtotal NONCORE	5	5	5	27
28	TOTAL TRANSPORTATION		26	27	27	28

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

2012 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 the southern portions of Orange counties. SDG&E delivered natural gas to 852,135 customers in San Diego County in 2011, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2011 were approximately 112 billion cubic feet (Bcf), which is an average of over 307 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

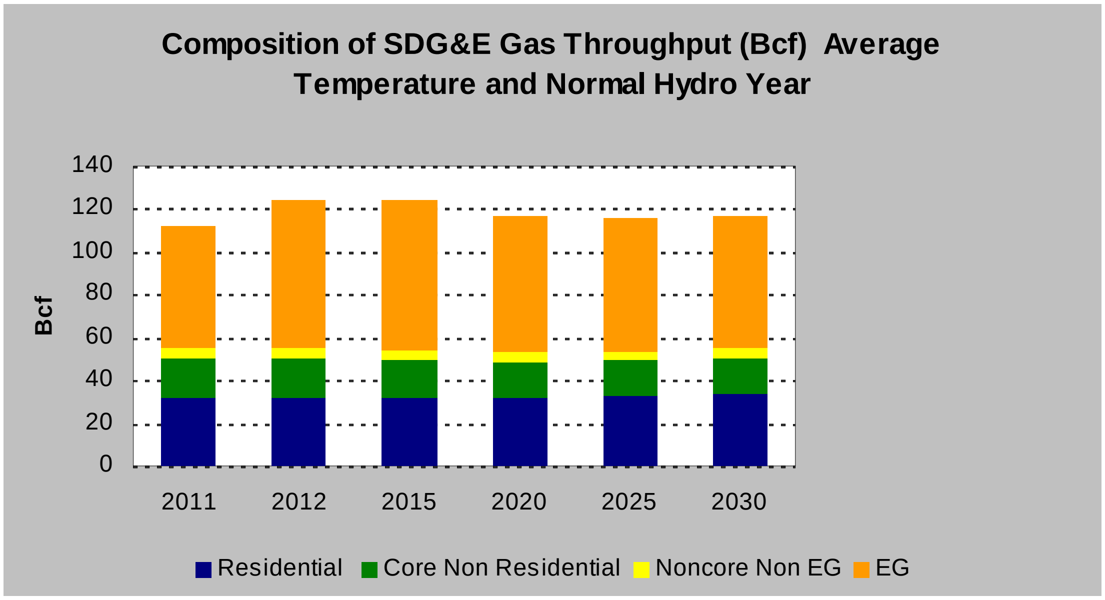
OVERVIEW

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.

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 remain virtually flat between 2011 and 2030. The total load, including EG, is expected to decline from a total of 124 Bcf in 2012 to 116 Bcf by 2030. 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.

ECONOMICS AND DEMOGRAPHICS

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 1.5% annually from 2011 to 2030; the subset of industrial (mining and manufacturing) jobs is projected to remain virtually flat over the same period. From 2011 to 2030, the county's inflation-adjusted Gross Product is expected to average 3.1% annual growth, which is faster than the 2.3% average annual growth seen from 2001 to 2011. (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 2011 through 2030.



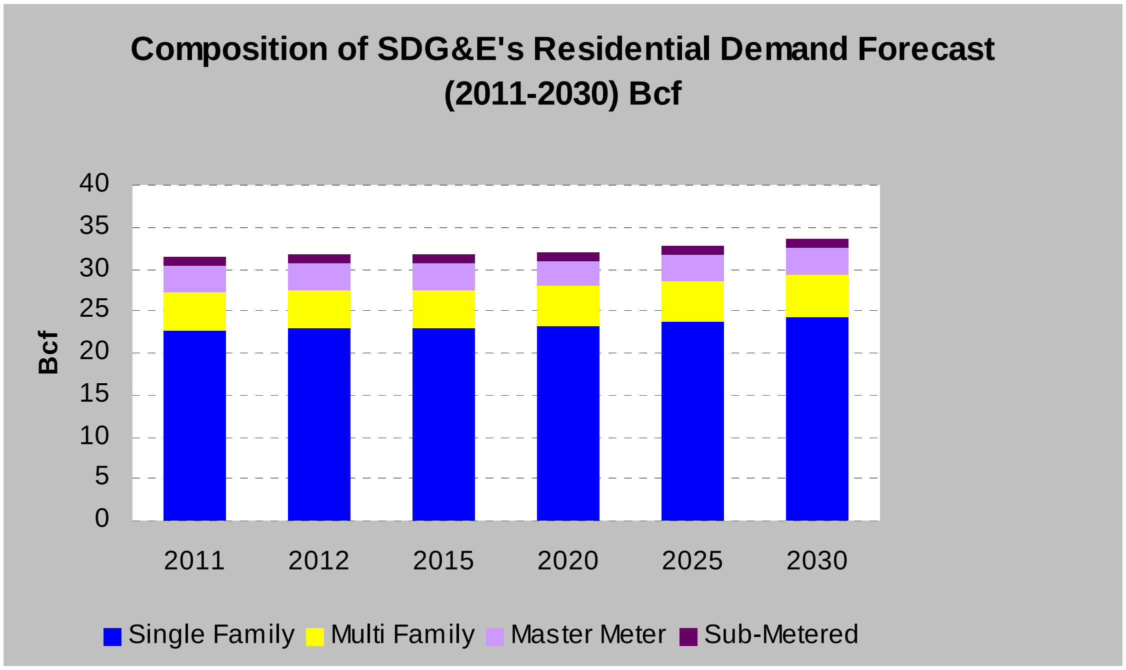
MARKET SECTORS

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 821,874 in 2011. This total reflects a 4,868 meter increase relative to the 2010 total. The overall observed 2010-2011 residential meter growth was 0.6%.

Residential demand adjusted for average temperature conditions totaled 31 Bcf in 2011. By the year 2030, the residential demand is expected to reach 34 Bcf. The change reflects a 0.5% annual compound growth rate.

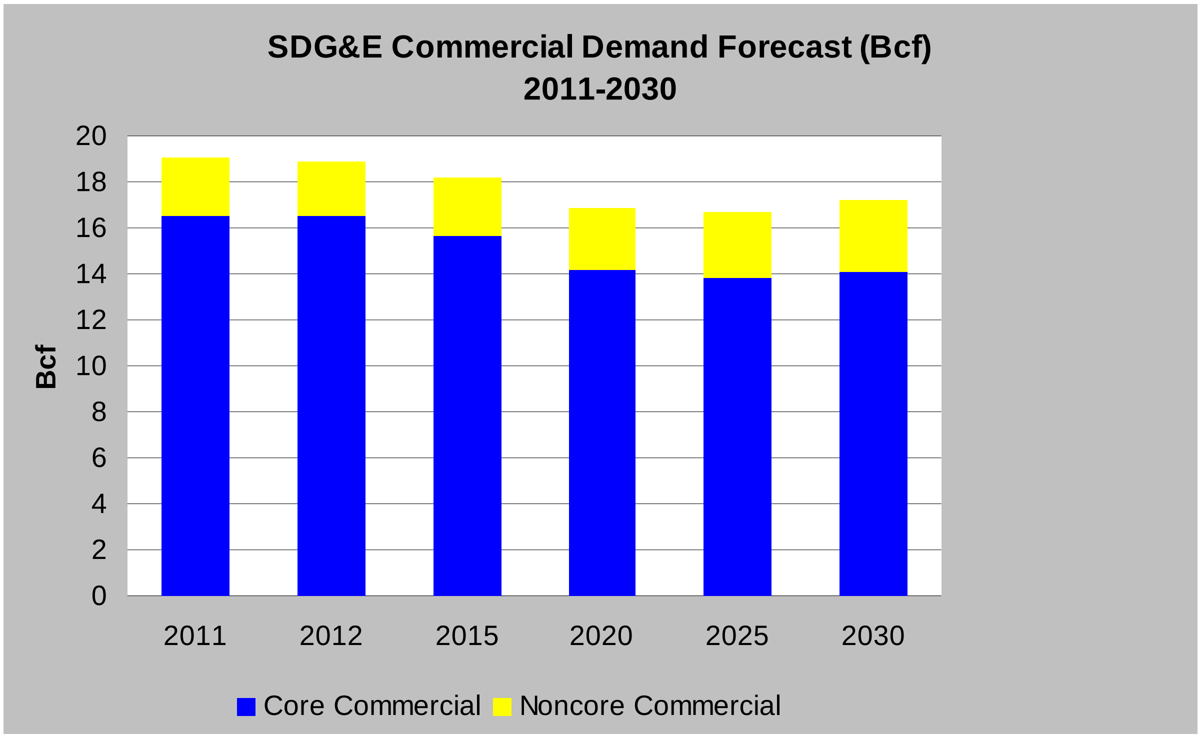
The projected residential natural gas demand will be influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in the building shell design, appliance efficiency and CPUC-authorized EE programs plus the additional efficiency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



Commercial

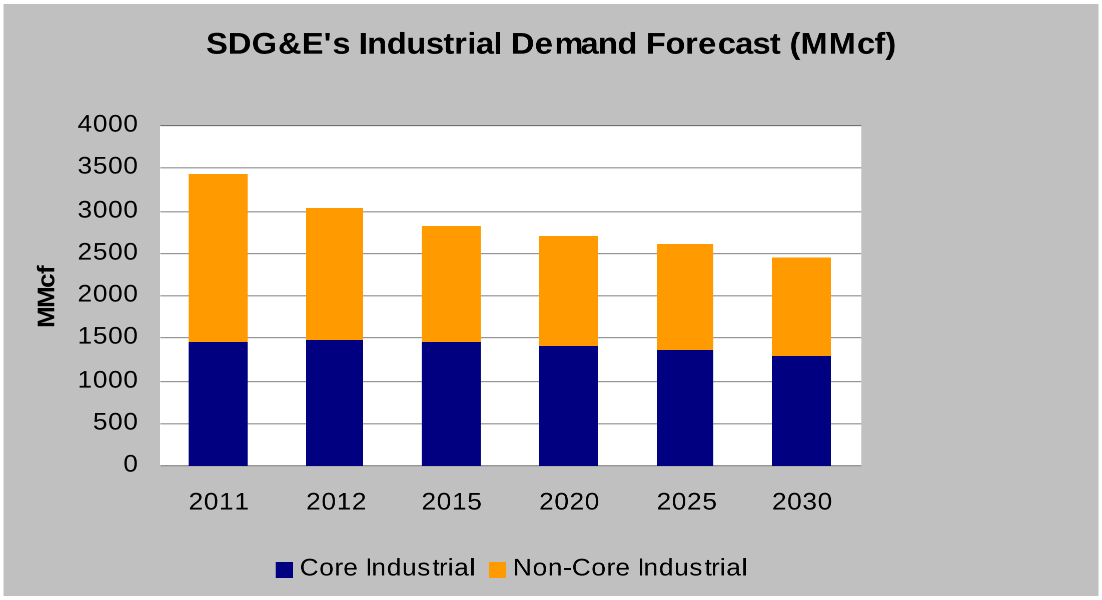
On a temperature-adjusted basis, the core commercial market demand in 2011 totaled 17 Bcf. By the year 2030, the SDG&E core commercial load is expected to decline to 14 Bcf. This change reflects an annual average reduction in commercial load by approximately 1.0%. The annual load reduction that is anticipated 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.

SDG&E's non-core commercial load was 2.5 Bcf in 2011. Over the forecast period, gas demand in this market is projected to show moderate growth mostly driven by increased economic activity and employment. The non-core commercial load is projected to grow to 3.1 Bcf by 2030. The anticipated annual growth rate over the forecast period is 1.2%.



Industrial

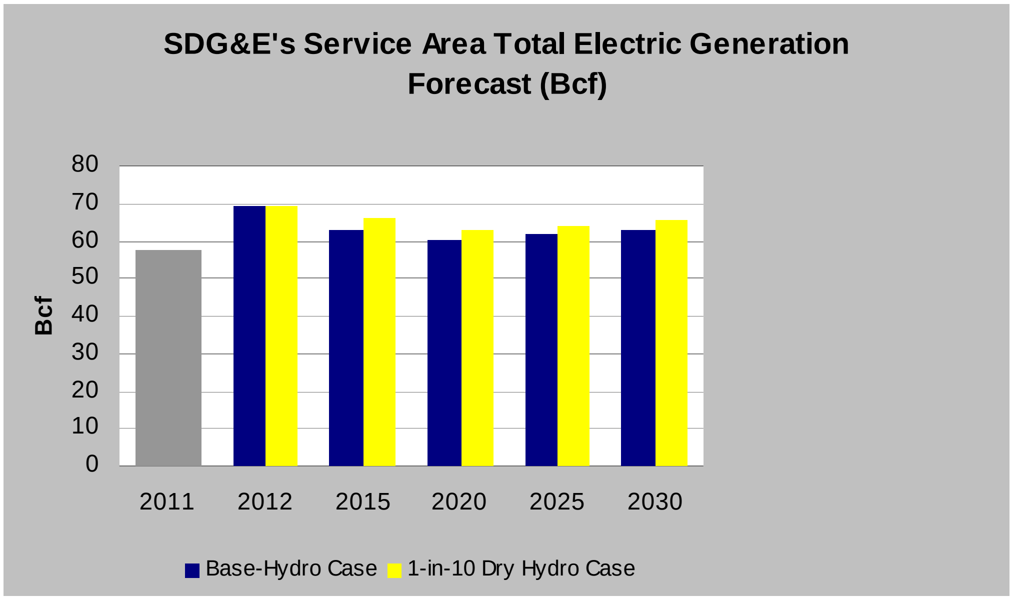
In 2011, temperature-adjusted core industrial demand was 1.5 Bcf. The core industrial market demand is projected to decrease at an average rate of 1% per year from 1.5 Bcf in 2012 to 1.3 Bcf in 2030. This result is due to slightly lower forecasted growth in industrial production and the impact of CPUC-authorized energy-efficiency programs savings in the industrial sector.



The non-core industrial load was 2.0 BCF in 2011 and it is expected to decline at an annual average rate of 2.8%. By 2030, the non-core industrial load is expected to reach 1.2 Bcf. The CPUC-mandated energy efficiency savings more than offset any modest gains from industrial economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, is expected to decrease at an annual average rate of 0.56 percent from 70 Bcf in 2009 to 62 Bcf in 2030. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.



Cogeneration

Small EG load from self-generation totaled 16.7 Bcf in 2011. By 2030, small EG load is expected to grow to 24.3 Bcf. The average annual growth rate of this market is expected to be 2% over the forecast period.

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 SoCalGas' Electric Generation chapter for "Non-Cogeneration EG" demand. This forecast includes approximately 450 MW of new thermal peaking generating resources in its service area by 2020. However, it also assumes that approximately 1,150 MW of the existing plants are retired during the same time period. EG demand is forecasted to decrease from 50 Bcf in 2012 to 39 Bcf in 2020 due to the addition of a new electric transmission line by summer 2012 and the attainment of the 33% state-wide renewable goal by 2020. The Sunrise Powerlink, which is currently under construction by SDG&E, would increase the import capability from the Imperial Valley into the SDG&E service area by about 1,000 MW. 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 the hydro generation by other off-system resources, the impact of significant hydro conditions had minor impact on SDG&E's EG gas demand. A dry hydro year increased SDG&E's EG demand on average for the forecast period by approximately 3 Bcf per year. For additional information on EG assumptions, such as renewable generation, greenhouse gas adders and sensitivity to electric demand and attainment of renewables' goals, refer to the Non-Cogeneration Electric Generation in the SoCalGas Electric Generation chapter.

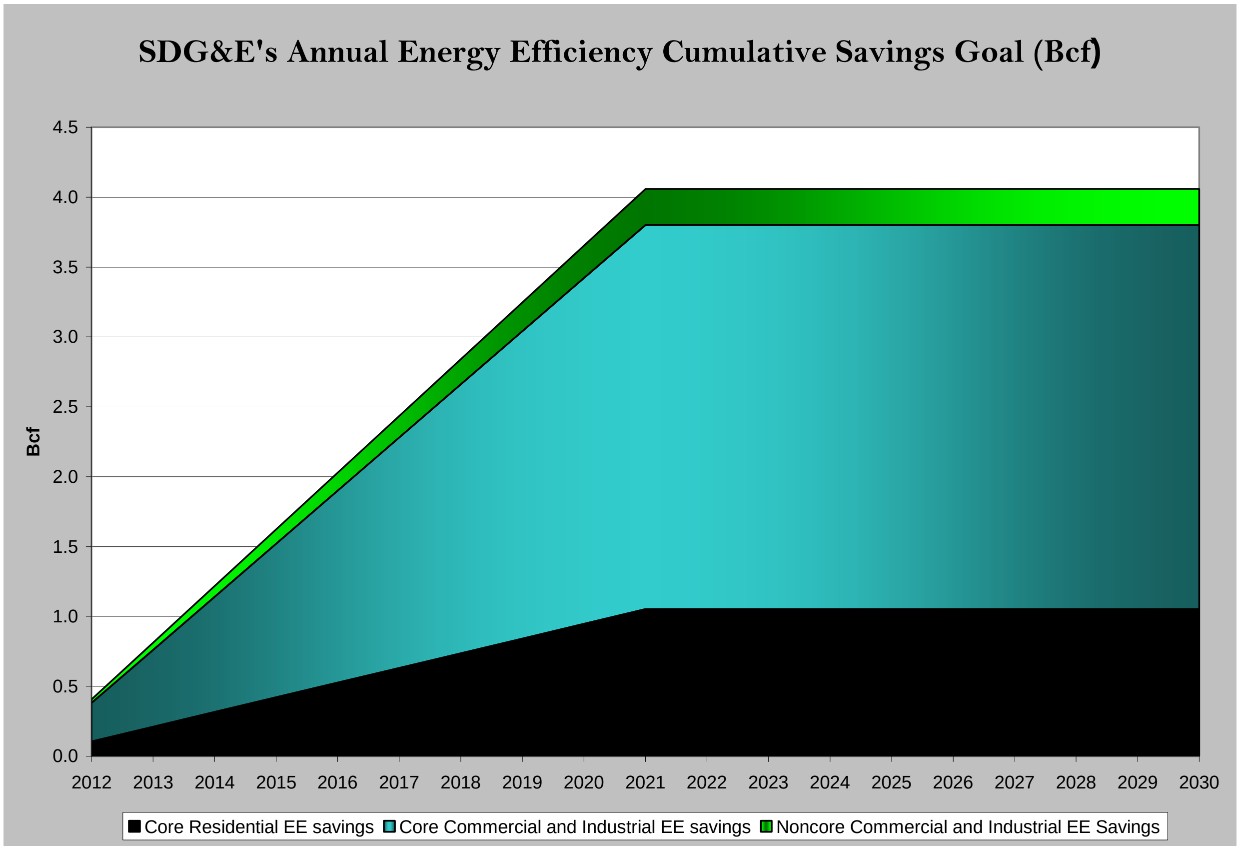
Natural Gas Vehicles (NGV)

The NGV market is forecast to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, the increasing cost of petroleum (gasoline and diesel), and a 10-year low in natural gas prices, as a result of significantly greater abundance of natural gas reserves. At the end of 2011, there were 31 compressed natural gas (CNG) fueling stations delivering 1.11 Bcf of natural gas during the year. SDG&E expects the NGV market to continue to experience slow growth, since transit fleets account for most of the demand and are very close to fleet saturation levels. The growth of the SDG&E market is also impacted by its market size and fleets, which are fairly small in the SDG&E service area. The economics of NGV stations is largely dependent on the amount of fuel usage, which is related to the fleet size.

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 SDG&E has forecasted to be implemented beginning in year 2010 and occurring through year 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060 and updated by the following decision, D.09-05-037, D.09-09-047 and D. 12-05-015.



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.

The cumulative net Energy Efficiency load impact forecast for selected years is provided in the graph above. The net load impact includes all Energy Efficiency programs that SDG&E has forecasted to implement starting from the years 2010 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.09-09-047 and updated by the following decision, D.09-05-037, D.09-09-047 and D. 12-05-015.

Notes:
(1) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(2) SDG&E does not include "soft" impacts, e.g., energy management services type measures.
(3) 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.

2012 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

San Diego Gas And Electric Company

Annual Gas Supply and Sendout (MMcf/Day)
Recorded Years 2007-2011

LINE			2007	2008	2009	2010	2011
	Actual Deliveries by End-Use						
1	**CORE**	Residential	89	149	82	85	88
2		Commercial	46	62	45	46	47
3		Industrial	0	0	0	0	0
4		NGV	2.6	2.8	2.8	2.7	2.9
5	*Subtotal -*	*CORE*	138	214	130	133	138
6	**NONCORE**	Commercial	0	0	0	0	0
7		Industrial	9	13	11	12	12
8		Non-EOR Cogen/EG	101	136	115	98	69
9		Electric Utilities	63	24	64	81	87
10	*Subtotal -*	*NONCORE*	173	173	191	191	169
11	**WHOLESALE**	All End Uses	0	0	0	0	0
12	*Subtotal -*	*Co Use & LUAF*	11	6	3	6	5
13	**SYSTEM TOTAL THROUGHPUT**		322	393	324	330	312
	Actual Transport & Exchange						
14	**CORE**	Residential	0	0	0	0	0
15		Commercial	4	8	8	10	10
16	**NONCORE**	Industrial	9	12	11	12	12
17		Non-EOR Cogen/EG	100	136	115	98	69
18		Electric Utilities	63	24	64	81	87
19	*Subtotal -*	*RETAIL*	176	180	199	201	179
20	**WHOLESALE**	All End Uses	0	0	0	0	0
21	**TOTAL TRANSPORT & EXCHANGE**		176	180	199	201	179
	Storage						
22		*Storage Injection*	15	0	0	0	0
23		*Storage Withdrawal*	15	74	0	0	0
	Actual Curtailment						
24		Residential	0	0	0	0	0
25		Com/Indl & Cogen	0	0	0	0	0
26		Electric Generation	0	0	0	0	0
27	**TOTAL CURTAILMENT**		0	0	0	0	0
28	**REFUSAL**		0	0	0	0	0
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.022	1.023	1.020	1.019	1.018

San Diego Gas And Electric Company

Annual Gas Supply Taken (MMcf/Day)
Recorded Years 2007-2011

LINE		2007	2008	2009	2010	2011
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					

	Gas Supply Taken	2007	2008	2009	2010	2011
	California Source Gas					
11	Regular Purchases	9	17	0	0	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	9	17	0	0	0
14	**Purchases from Other Utilities**	0	0	0	0	0
	Out-of-State Gas					
15	Pacific Interstate Companies	0	0	0	0	0
16	Additional Core Supplies	0	0	0	0	0
17	Supplemental Supplies-Utility	136	196	125	130	132
18	Out-of-State Transport-Others	176	180	199	201	179
19	**Total Out-of-State Gas**	313	376	324	330	312
20	**TOTAL Gas Supply Taken & Transported**	322	393	324	330	312

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2012 THRU 2014

AVERAGE TEMPERATURE YEAR

LINE			2012	2013	2014	LINE
	CAPACITY AVAILABLE [1/ & 2/]					
1	California Source Gas		0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	3
	GAS SUPPLY TAKEN					
4	California Source Gas		0	0	0	4
5	Southern Zone of SoCalGas		345	327	326	5
6	TOTAL SUPPLY TAKEN		345	327	326	6
7	Net Underground Storage Withdrawal		0	0	0	7
8	TOTAL THROUGHPUT		345	327	326	8
	REQUIREMENTS FORECAST BY END-USE [3/]					
9	CORE [4/]	Residential	87	87	87	9
10		Commercial	45	45	44	10
11		Industrial	4	4	4	11
12		NGV	3	3	3	12
13		Subtotal-CORE	139	139	138	13
14	NONCORE	Commercial	6	7	7	14
15		Industrial	4	4	4	15
16		Electric Generation (EG)	191	173	173	16
17		Subtotal-NONCORE	201	184	184	17
18		Co. Use & LUAF	5	4	4	18
19	SYSTEM TOTAL THROUGHPUT		345	327	326	19
	TRANSPORTATION AND EXCHANGE					
20	CORE	All End Uses	9	9	9	20
21	NONCORE	Commercial/Industrial	11	10	10	21
22		Electric Generation (EG)	191	173	173	22
23	TOTAL TRANSPORTATION & EXCHANGE		211	192	192	23
	CURTAILMENT					
24		Core	0	0	0	24
25		Noncore	0	0	0	25
26		TOTAL - Curtailment	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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: 131 131 130

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE [1/ & 2/]						
1	California Source Gas		0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	3
	GAS SUPPLY TAKEN						
4	California Source Gas		0	0	0	0	4
5	Out-of-State		326	315	322	331	5
6	TOTAL SUPPLY TAKEN		326	315	322	331	6
7	Net Underground Storage Withdrawal		0	0	0	0	7
8	TOTAL THROUGHPUT		326	315	322	331	8
	REQUIREMENTS FORECAST BY END-USE [3/]						
9	CORE [4/]	Residential	87	88	91	93	9
10		Commercial	43	39	38	39	10
11		Industrial	4	4	4	4	11
12		NGV	3	3	4	4	12
13		Subtotal-CORE	137	134	137	140	13
14	NONCORE	Commercial	7	7	8	9	14
15		Industrial	4	4	3	3	15
16		Electric Generation (EG)	174	166	170	174	16
17		Subtotal-NONCORE	185	177	181	186	17
18		Co. Use & LUAF	4	4	4	5	18
19	SYSTEM TOTAL THROUGHPUT		326	315	322	331	19
	TRANSPORTATION AND EXCHANGE						
20	CORE	All End Uses	9	8	8	9	20
21	NONCORE	Commercial/Industrial	11	11	11	12	21
22		Electric Generation (EG)	174	166	170	174	22
23	TOTAL TRANSPORTATION & EXCHANGE		194	185	189	195	23
	CURTAILMENT						
24		Core	0	0	0	0	24
25		Noncore	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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:

	2015	2020	2025	2030
transportation (CAT) in MDth/d	129	127	130	132

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2012 THRU 2014

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2012	2013	2014	LINE
	CAPACITY AVAILABLE [1/ & 2/]					
1	California Source Gas		0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	3
	GAS SUPPLY TAKEN					
4	California Source Gas		0	0	0	4
5	Out-of-State		356	347	346	5
6	TOTAL SUPPLY TAKEN		356	347	346	6
7	Net Underground Storage Withdrawal		0	0	0	7
8	TOTAL THROUGHPUT		356	347	346	8
	REQUIREMENTS FORECAST BY END-USE [3/]					
9	CORE [4/]	Residential	96	97	97	9
10		Commercial	47	47	46	10
11		Industrial	4	4	4	11
12		NGV	3	3	3	12
13		Subtotal-CORE	150	151	150	13
14	NONCORE	Commercial	6	7	7	14
15		Industrial	4	4	4	15
16		Electric Generation (EG)	191	180	180	16
17		Subtotal-NONCORE	201	191	191	17
18		Co. Use & LUAF	5	5	5	18
19	SYSTEM TOTAL THROUGHPUT		356	347	346	19
	TRANSPORTATION AND EXCHANGE					
20	CORE	All End Uses	9	9	9	20
21	NONCORE	Commercial/Industrial	11	10	10	21
22		Electric Generation (EG)	191	180	180	22
23	TOTAL TRANSPORTATION & EXCHANGE		211	199	199	23
	CURTAILMENT					
24		Core	0	0	0	24
25		Noncore	0	0	0	25
26		TOTAL - Curtailment	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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:

	2012	2013	2014
transportation (CAT) in MDth/d:	142	143	142

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE 1/ & 2/						
1	California Source Gas		0	0	0	0	1
2	Southern Zone of SoCalGas 1/		607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	3
	GAS SUPPLY TAKEN						
4	California Source Gas		0	0	0	0	4
5	Out-of-State		348	335	341	350	5
6	TOTAL SUPPLY TAKEN		348	335	341	350	6
7	Net Underground Storage Withdrawal		0	0	0	0	7
8	TOTAL THROUGHPUT		348	335	341	350	8
	REQUIREMENTS FORECAST BY END-USE 3/						
9	CORE 4/	Residential	97	98	100	103	9
10		Commercial	45	41	40	41	10
11		Industrial	4	4	4	4	11
12		NGV	3	3	4	4	12
13		Subtotal-CORE	149	146	148	152	13
14	NONCORE	Commercial	7	7	8	9	14
15		Industrial	4	4	3	3	15
16		Electric Generation (EG)	183	173	177	181	16
17		Subtotal-NONCORE	194	184	188	193	17
18		Co. Use & LUAF	5	5	5	5	18
19	SYSTEM TOTAL THROUGHPUT		348	335	341	350	19
	TRANSPORTATION AND EXCHANGE						
20	CORE	All End Uses	9	9	9	9	20
21	NONCORE	Commercial/Industrial	11	11	11	12	21
22		Electric Generation (EG)	183	173	177	181	22
23	TOTAL TRANSPORTATION & EXCHANGE		203	193	197	202	23
	CURTAILMENT						
24		Core	0	0	0	0	24
25		Noncore	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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: 141 138 140 145

2012 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 Mercantile 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.

Heating Value

Number of BTU's liberated by the complete combustion at constant pressure of one cubic foot of natural gas at a base temperature of sixty degrees Fahrenheit (60°F) and a pressure base of fourteen and seventy-three hundredths (14.73) psia, with air at the same temperature and pressure as the natural gas, after the products of combustion are cooled to the initial temperature of natural gas, and after the water vapor of the combustion is condensed to the liquid state. The heating value of the natural gas shall be corrected for the water vapor content of the natural gas being delivered except that, if such content is seven (7) pounds or less per one million cubic feet, the natural gas shall be considered dry.

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.

Load Following

A utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and for keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utilities customers.

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 60° 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.

PSEP

Pipeline Safety Enhancement Plan.

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.

Wobbe
The Wobbe number of a fuel gas is found by dividing the high heating value of the gas in BTU per standard cubic feet (scf) by the square root of a specific gravity with respect to air. The higher a gases' Wobbe number, the greater the heating value of the quality of gas that will flow through a hole of a given size in a given amount of time.

2012 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission as 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 has been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Herbert Emmrich(Chairperson) – SoCalGas/SDG&E
- Rose-Marie Payan-SoCalGas/SDG&E
- Robert Anderson – SoCalGas/SDG&E
- Jeff Huang – SoCalGas /SDG&E
- Phil Stadler– SDG&E
- Zeynep Yucel-PG&E
- Eric Hsu-PG&E
- Mark Minick - SCE
- David Sanchez- City of Long Beach Gas and Oil
- Paul Deaver- CEC
- Ruben Tavares - CEC
- Angela Tanghetti – CEC
- William Wood – CEC

Observers

- Richard Myers– CPUC Energy Division
- Ruben Tavares– CEC

RESERVE YOUR SUBSCRIPTION

2013 CALIFORNIA GAS REPORT – SUPPLEMENT

Southern California Gas Company
2013 CGR Reservation Form
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249

or

Fax: (213) 244-4957
Email: Herb Emmrich
HEmmrich@semprautilities.com

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Company Name: ______________________________________

C/O: ____

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Phone: (____) ______________ Fax: (____) ____________

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

RESERVE YOUR SUBSCRIPTION

2013 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2013 CGR Reservation Form
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177

or

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Email: Zeynep Yucel
ZTY1@pge.com

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C/O: ______________________________

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

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