2002 California Gas Report

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 3.8 million residential customers and 200,000 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, customers also utilize the PG&E system to meet their gas needs in southern California.

The forecast in this report covers the years 2002 through 2022. However, as a matter of convenience, the tabular data at the end of the section show only the years 2002 through 2007 and the years 2010, 2015, 2020 and 2022.

The northern California section of the report begins with the demand forecast, including a discussion of economic conditions, forecast methodology, and other factors affecting demand in various markets. 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.

GAS DEMAND REQUIREMENTS

OVERVIEW

PG&E's 2002 California Gas Report average year demand forecast projects total on-system demand growing at an annual average rate of 1.8 percent between 2002 and 2022. This overall growth rate is a combination of 0.9 percent annual growth in the core market and 2.4 percent annual growth in the noncore market. By comparison, the 2000 California Gas Report estimated an annual average growth rate of 1.4 percent per year, based on growth of 1.6 percent per year for the core market and 1.3 percent per year for the noncore market.[1]

Decreases in the estimated rate of growth in the core market are due to incorporation of more recent historic usage, economic, and demographic data; more recent forecasts of economic and demographic drivers; and re-specification of the econometric models used to forecast core demand. Increases in the projected rate of growth in the noncore market are largely due to changes in the electric generation gas consumption portion of that market.

In the 2002 CGR, gas demand by electric generators (EG) is estimated to decrease slightly from 2002 through 2004, and then increase at over four percent per year through 2022. The estimated EG demand for 2002 is 30 percent lower than actual demand in 2001, when a drought in the western states caused gas-fired generators to increase output to make up for reduced hydroelectric generation.

The slight decrease in EG gas demand during 2003 and 2004 stems from displacement of gas-fired steam-turbine power plants by new, more efficient gas-fired combined cycle plants. After 2004, EG gas demand on PG&E escalates due to the assumptions that (1) electricity demand increases, (2) few non-gas power plants are built, and (3) gas-fired plants are built near electricity demand centers, rather than near natural gas supply basins or interstate pipelines.

The third assumption is less certain than the first two. Gas pipelines are generally cheaper to build and operate than electric transmission lines. Under some proposals to the Federal Energy Regulatory Commission (FERC), however, generators would not bear the cost of new or upgraded electric transmission lines. If that becomes policy, generators will tend to minimize their own costs, not overall costs, by building near gas supply basins or interstate pipelines rather than electric demand centers as envisioned in this report.

In the 2002 CGR, demand in the industrial sector portion of the noncore market is estimated to be virtually flat, as compared to the 2000 CGR where growth in this sector was projected to be 1.3 percent.[2] Industrial gas customers are primarily large manufacturing firms. The California manufacturing sector has been in recession for well over a year (gas demand from this sector fell by nearly 20 percent in 2001), but is projected to begin a recovery in the third quarter of 2002. That recovery, coupled with

[1] The period used for calculating the 2000 CGR growth rates is 2000-2020. The 2000 CGR did not include the 2021-2022 period in the forecast horizon.
[2] As stated in note 1 above, the 2000 CGR growth rates are calculated over the period 2000-2020.

a return to more modest gas prices which occurred in the second half of 2001, are expected to boost demand for this sector in the near-term. However, long-term growth is expected to be slightly negative as the state continues its transition to a more services-oriented economy.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed from econometric models. Forecasts for other sectors (electric generation, NGV, wholesale) are developed from market information. While variation in short-term gas use depends mainly on prevailing weather conditions, longer-term trends in gas demand are driven primarily by underlying economic, demographic, and technological changes, such as growth in population and employment; changes in prevailing prices; and changes in the efficiency profiles of residential and commercial buildings and the appliances within them.

MARKET SENSITIVITY

The average-year gas demand forecast presented here is a reasonable projection for an uncertain future. However, point forecasts 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 forecasts of gas demand under assumed high demand and low demand conditions. The assumptions for these scenarios are described below.

Temperature

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

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the average-year scenario and gas use will vary accordingly. PG&E's low demand forecast assumes that winter temperatures in the forecast horizon will be two standard deviations above the twenty-year average. Conversely, the high demand forecast assumes that winter temperatures in the forecast horizon will be two standard deviations below the twenty-year average. Seasonal variations in temperature have relatively little effect on power plant gas demand and, consequently, PG&E's forecasts of yearly power plant gas demand in the 2002 CGR are based on average temperatures

Hydro Conditions

The 2002 CGR includes a dry-hydro case in response to concerns raised by the drought in water year 2001 (October 2000 through September 2001). EG gas demand during that water year increased almost 200 MMcf/day over the roughly average water year 2000. In California, water year 2001 was dry in both the Sacramento and San

Joaquin River basins. The Pacific Northwest, which typically generates five times as much hydroelectric energy as California, was extremely dry. By some measures, water year 2001 it was the second driest in the western U.S. since 1929. For this CGR, PG&E selected a less extreme case, namely water year 1994. Water year 1994 represents a roughly 1 in 10 to 1 in 20 dry hydro year in the western states.[3]

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 1.2 percent annually from 2002 to 2022. However, gas use per household has been falling 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 fall by close to 10 percent. Gas use per household is expected to partially recover in 2002, as prices have returned to more moderate levels. However, in 2003 and beyond, residential use per household is expected to revert to its long-term trend due to continuing upgrades in appliance and building efficiencies. As a result, PG&E forecasts residential demand to grow at 0.8 percent per year from 2002 to 2022, implying an average decrease in use per household of nearly 0.4 percent per year.

Commercial

The 2000-2001 run-up in gas prices (as well as a flagging economy) depressed sales to the commercial market, but also fostered a certain amount of noncore to core migration that overall increased temperature-adjusted commercial sales by about 3 percent. Because some of these customers did not migrate until mid to late 2001, their sales were not fully reflected in 2001 commercial throughput. As a result, 2002 commercial sales are expected to be more than five percent above those of a year earlier. Over the next 20 years, sales for this sector are expected to grow about one percent per year.

Natural Gas Vehicles

Growing concern over air quality in California is focusing public attention on vehicles that emit less harmful exhaust. PG&E has a program to educate customers of the merits of including natural gas vehicles (NGVs) in their fleets. Both the National Energy Policy Act and the California Air Resources Board's low emission vehicle regulations should continue to increase this market.

Additionally, the U.S. Congress recently passed energy legislation that includes significant tax incentives for alternative fueled vehicles and infrastructure, including NGVs. If signed into law, this new legislation will create new demand for these vehicles. Under current law, NGVs are expected to account for approximately 5 MMcf/day of demand by year 2004, increasing to 10 MMcf/day by the year 2022.

[3] To rank early Water Years against more recent ones, one must estimate hydroelectric generation for each year given that historical year's runoff and current dams and fishery rules. The uncertainty of this estimation makes it difficult to specify a precise probability of exceedance for Water Year 1994.

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 soaring gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. In the near-term, requirements for this sector are expected in rise as demand responds to a return to more moderate gas prices and the northern California manufacturing sector begins to recover. However, industrial gas consumption is expected to slowly decline by about 0.20 percent annually over the next 20 years as California's manufacturing sector continues to gradually shrink.

Electric Generation

The Western electricity crisis of 2000-2001 increased attention on the demand for natural gas by EG plants. Annual EG gas demand on the PG&E system peaked in 2001 as a result of slow construction of power plants and severe drought. New, more efficient power plants that are operational or near completion, and the return to near-average hydroelectric conditions, are reducing EG gas demand in 2002. PG&E's forecast shows EG gas demand falling below the 2002 level in 2003 and 2004, followed by growth over 4 percent per year through 2022. This forecast is critically dependent on the assumption that most new generation will be gas fired and that new generation will be built near electric demand centers. Although this forecast is plausible, alternative assumptions (discussed in the risk section) may produce significantly different forecasts.

Looking back, peak EG gas demand in 2001 followed a decade in which growth in electricity demand outpaced construction of new power plants. During the 1990s, electricity demand in the Western Electricity Coordinating Council (WECC)[4] grew from 72,000 average MW in 1989 to 90,000 aMW in 2000[5]. As demand grew by 18,000 aMW, electric generating capacity increased by about 9,000 aMW. In other words, construction of new, highly efficient power plants lagged behind demand growth. As a result, older power plants that burn relatively large amounts of natural gas to generate each MWh were kept in service. Those older plants were extensively used during the 2000-2001 drought.

A significant change is now occurring in electric generation. Through the 1980s and 1990s, most gas-fired power plants in the WECC were steam turbines. A very large number of combined-cycle plants (CCs) are now operating or are under construction. These more efficient CCs will displace many older steam turbines, causing a short-term decline in EG gas demand. These new CCs consume about 30 percent less natural gas per MWh generated.

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[4] The Western Electricity Coordinating Council, or WECC, covers an area consisting of the Western U.S. roughly from Colorado to the Pacific coast, plus Alberta, British Columbia, and northwestern Baja California. This area is electrically interconnected by a grid of high-voltage electric transmission lines, but has few electrical connections to areas farther east. Consequently it can be considered a separate market for electricity, isolated from the remainder of North America. The WECC was formed on April 18, 2002 by combining other agencies, notably the Western Systems Coordinating Council or WSCC.

[5] One aMW is an electricity demand that averages 1 MW over 1 year. Because there are 8760 hours per year (365*24), 1 aMW equals 8760 MWh.

Longer term, the forecasting picture is much less clear and is highly dependent on the following factors:

Electricity Demand: PG&E's EG gas forecast is derived from an electric demand forecast. That forecast projects electric demand growth for California and the WECC to average 1.7 percent per year from 2002 through 2022.[6] The growth in electric demand recorded from 1980 through 2000 was 2.6 percent per year. The California electric demand forecast used in this report is consistent with the "most likely" case scenario as shown in the California Energy Commission publication, *2002-2012 Electricity Outlook Report*, February 2002.

Type of new power plants: PG&E's forecast assumes that new power plants with low running costs, such as coal-fired plants and wind turbines, are brought on-line in amounts that offset any decline in production from existing low-cost power plants, such as coal-fired, nuclear and geothermal plants. PG&E's forecast further assumes that most increases in electricity demand after 2002 are met by construction of gas-fired combined-cycle plants.

Gas-fired CCs seem to be the first choice for new power plants throughout the United States. Extrapolation of current trends leads to very large EG gas demand nationwide, which might require shipping gas long distances (e.g., by pipeline from Alaska or Jamaica, or by tanker from other continents). At some point, the cost of shipping may drive up gas prices and encourage a shift to non-gas alternatives.

Location of new power plants: PG&E's forecast assumes that, starting in 2007, new CCs will be built in each region of the WECC in proportion to that region's growth in electricity demand. This is a key assumption, and it depends largely on the relative prices for electric and gas transmission.

PG&E's forecast assumes that power plant siting decisions will generally be based on lowest overall costs. Under this assumption, power plants will be built near electricity demand centers, because pipelines are cheaper to build and operate than electric transmission lines. However, in some proposals to the FERC, the investment cost of building or expanding electric transmission lines will be charged directly to end-use customers, or spread equally over all power plants regardless of location.[7] This type of pricing may cause remote siting of new power plants, reducing PG&E's EG gas deliveries below forecast levels.

Risks to the EG Forecast

In addition to the electric/gas transmission pricing issue discussed earlier, there are other market dynamics that could significantly affect the level of EG gas demand. For example, if fewer new CCs or coal-fired plants are built, steeper increases in EG gas demand will occur because if fewer new plants were built, the old and less efficient gas-fired steam turbine plants will pick up the slack.

[6] Based on an agreement between the CGR Working Committee and the California Energy Commission

[7] Many proposals for electric transmission pricing include "congestion pricing", in which electricity prices are higher downstream of bottlenecks in the electric transmission grid. In theory, such pricing would incent siting of power plants downstream of bottlenecks. In practice, building a new power plant downstream of a bottleneck may reduce or even eliminate the congestion, and thereby weaken or eliminate the price difference that was supposed to be an incentive.

More efficient use of gas or a shift to non-gas technologies could lead to more moderate increases in EG gas demand than are forecast in the report. Wide-scale deployment of gas-fired fuel cells, for example, could reduce EG gas demand because they are 15 to 30 percent more efficient than CC plants. A greater reliance on non-gas alternatives such as new coal-fired power plants, wind turbines, and solar power could also reduce the growth in EG gas demand.

Moreover, conservation programs and market structures aimed at decreasing the growth in the demand for electricity could also significantly moderate the growth in EG gas demand.

SMUD EG

The Sacramento Municipal Utility District is the sixth largest municipal electric utility in the United States and provides electric service to over 500,000 customers within the greater Sacramento area. SMUD currently has 519 MW of gas fired electric generation capacity and is currently in the process of developing an additional 500 MW that is expected to be in service in 2005. SMUD owns approximately 3.6 percent of the PG&E's Backbone Line 300 and 5 percent of Line 401. SMUD also has the following long-term interstate capacity contracts: 10 MMcf/day on Transwestern, 31 MMcf/day of PG&E GT-NW and Transcanada Pipeline Ltd.'s BC and Alberta, and 20 MMcf/day of the Kern River expansion expected to be in service in May 2003. Further, SMUD has a five-year storage contract with the Wild Goose expansion project expected to be in service in 2003.

GAS SUPPLY SOURCES

California-Source Gas

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2001, PG&E's customers obtained on average 186 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 and Transwestern pipeline systems.

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

Canadian Gas

PG&E's customers can purchase Canadian gas from various suppliers in Canada and transport it to California primarily through PG&E GT-NW. Customers can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Pipeline and via the PG&E GT-NW Pipeline interconnect at Stanfield, Oregon. Rocky Mountain supplies increase diversity of gas supplies in northern and central California.

Storage

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

Supplemental Gas Supplies

Supplemental gas supplies are included in PG&E's forecast to meet customer's gas requirements and avoid curtailments.

PG&E anticipates that sufficient supplemental 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 supplemental supplies shown in this report 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.

GAS SUPPLY/PIPELINE CAPACITY

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly over the past few years. 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.

INTERSTATE GAS PIPELINE CAPACITY

In recent years, the natural gas pipeline industry has taken significant steps to expand the nation's already extensive pipeline network. These efforts have allowed California utilities and end-users 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, PG&E Gas Transmission - Northwest, 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

Total PG&E intrastate capacity connected to U.S. Southwest pipeline systems (Transwestern, El Paso, and Kern River) is limited to 1,140 MMcf/day, which is the maximum capacity of PG&E's Baja Path (Line 300). In developing the forecast of gas supply takes, PG&E has assumed continued annual supply availability of 1,140 MMcf/day from the U. S. Southwest for the entire forecast period.

Canada

PG&E's Redwood Path (Lines 400/401) is connected to PG&E GT-NW at Malin, Oregon. The Redwood Path has an average capacity of approximately 1,850 MMcf/day to serve both northern and southern California markets, although that will be increasing in late 2002 to about 2,050 MMcf/day.

PG&E has assumed seasonal supply availability of 1,800 MMcf/day in the winter and 1,900 MMcf/day in the summer for the forecast period of 2002 - 2022.

The actual capacity or supplies taken could differ from those shown above. Operational conditions could limit the capacity during certain times of the year. In addition, market conditions could reduce supplies taken by PG&E's customers.

ABNORMAL PEAK DAY SUPPLY AND DEMAND

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of *core demand* under extremely adverse conditions. The design criteria for PG&E, as required under CPUC regulation, is a 29 degree Fahrenheit system-weighted mean temperature. This corresponds to a roughly 1 in 90 extreme temperature event. The APD load forecast shown here excludes all noncore demand and, in particular, excludes all EG demand. PG&E estimates that total noncore demand during an APD event would be 1.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD forecast is developed using statistical tools to estimate the relationship of daily core gas usage to daily weather conditions during several recent winters. This relationship is then used to simulate what the core load would be under the adverse weather conditions that occurred on December 11, 1932, the coldest day on record in PG&E's service area.

FORECAST OF APD SUPPLY AVAILABILITY

For APD planning purposes, supplies will flow under core's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's underground storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek. Flowing supplies may be from Canada, U.S. Southwest, Rocky Mountain Region, SoCalGas, and California-source gas. Supplies could also be purchased from noncore customers once gas enters the PG&E system. PG&E Gas Procurement Department is responsible for managing the flowing supplies to PG&E's core customers in the event of an APD occurrence. Core aggregators serving core transport customers on PG&E's system have the obligation to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

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

Under APD conditions, PG&E can, if necessary, divert gas from the noncore (including gas fired electric generators) to meet core demand. Diversion of noncore supply in lieu of expanding firm core supplies has been the basis for infrastructure system planning for years, based on the assumption that the noncore market would either shut down their use of gas or switch to an alternate fuel. However, little, if any, alternate fuel burn capability exists today, so supply diversions from the noncore would necessitate that noncore customers (including EG) shut down operations. The implication for the future is that under APD conditions a significant portion of the EG

customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that in the near term, noncore demand (including gas fired electric generation) on an APD would be 1.5 Bcf/day. With the recent additions of the Wild Goose and Lodi storage facilities, more noncore demand will be satisfied in the event of an APD. However, looking to the future, if gas fired electric generation grows as forecasted, supplemental supplies will eventually be needed if the goal is to serve the core load and most, if not all, noncore load. These supplemental supplies could be in the form of additional storage facilities or incremental pipeline capacity.

PACIFIC GAS AND ELECTRIC COMPANY
Forecast of Core Gas Demand and Supply on an Abnormal Peak Day (APD)
MMcf/Day

	2002-2003	2003-2004	20042005	2005-2006	2006-2007
APD Core Demand[1]	3,152	3,168	3,203	3,234	3,266
Firm Storage Withdrawal	1,006	1,006	1,006	1,006	1,006
Required Flowing Supplies[2]	2,146	2,162	2,197	2,228	2,260
Total APD Resources (to meet demands)	3,152	3,168	3,204	3,237	3,272

NOTES:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD planning criterion: system temperature on APD is 29 degrees F.

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

GAS BALANCES

OVERVIEW

Although available gas supplies exceed requirements on an average basis, on particularly cold winter days heightened demand could require the use of gas from underground storage. The balances listed in this report represent one possible combination of demand and supply necessary to deliver incremental supplies. They are not intended to reflect actual choices by customers, or an outcome sought or preferred by PG&E.

SEQUENCING

Sequencing describes the order in which gas supplies are purchased in accordance with PG&E's gas purchase policy and operational considerations. The gas balances presented in this report are based on sequencing assumptions consistent with these guidelines.

BALANCE RESULTS

The gas balances show full service to all customers under an average year for the forecast period. Beginning in 2010, supplemental supplies of 100 MMcf/day and increasing to 150 MMcf/day by 2015 and 500 MMcf/day by 2022 are assumed to be available to the PG&E system for all three temperature-year cases. No curtailments occur in any of the temperature cases.

2002 California Gas Report

PACIFIC GAS AND ELECTRIC COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 1997-2001
MMCF/DAY

LINE		1997	1998	1999	2000	2001	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
	Core Purchases	29	13	8	12	29	
	Customer Gas Transport & Exchange	118	134	143	151	157	
	Total California Source Gas	147	147	151	163	186	
	OUT-OF-STATE GAS						
	Core Purchases						
	Rocky Mountain Gas	4	44	62	28	6	
	U.S. Southwest Gas	140	205	210	209	204	
	Canadian Gas	565	595	595	604	574	
	Customer Gas Transport						
	Rocky Mountain Gas	71	53	48	24	78	
	U.S. Southwest Gas	319	310	286	374	644	
	Canadian Gas	681	815	875	939	864	
	Total Out-of-State Gas	1,780	2,022	2,076	2,178	2,370	
12	STORAGE WITHDRAWAL	113	107	60	92	94	12
13	Total Gas Supply Taken	2,040	2,276	2,287	2,433	2,650	13
	GAS SENDOUT						
	CORE						
15	Residential	528	618	644	581	543	15
16	Commercial	208	224	232	218	244	16
17	NGV	1	1	1	2	2	17
18	Total Throughput-Core	737	843	877	801	789	18
	NONCORE						
19	Industrial	588	514	473	537	420	19
20	Electric Generation [2]	566	688	703	941	1100	20
21	EOR	4	1	0	0	1	21
22	NGV	1	1	1	1	1	22
23	Wholesale/Resale	10	12	12	11	11	23
24	Total Throughput-Noncore	1169	1216	1189	1490	1533	24
25	Total Throughput	1906	2059	2066	2291	2322	25
33	CALIFORNIA EXCHANGE GAS	12	14	0	0	0	33
34	STORAGE GAS[3]	74	146	63	40	252	34
35	SHRINKAGE Company Use / Unaccounted for	48	57	158	102	76	35
36	Total Gas Send Out [4]	2,040	2,276	2,287	2,433	2,650	36
	CURTAILMENT / ALTERNATIVE FUEL BURNS[5]						
37	Residential, Commercial, Industrial and EO	0	1	0	0	0	37
38	Utility Electric Generation	0	0	0	0	0	38
39	TOTAL CURTAILMENT	0	1	0	0	0	39

NOTES:

(1) Also includes Wholesale/Resale and non-utility generation.

(2) Electric generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Includes both PG&E and third party storage

(4) Total gas send-out excludes off-system transportation.

(5 UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available[4]	2949	2949	2949	2949	2949	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	192	196	204	212	220	12
13	Customer Transport	119	71	77	148	186	13
14	*Total U.S. Southwest Gas*	311	267	281	360	406	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1051	999	1010	1052	1064	16
17	*Total Canadian Gas*	1651	1599	1610	1652	1664	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	1962	1866	1891	2012	2070	21
22	Subtotal (all pipeline)	2112	2016	2041	2162	2220	22
23	Storage Injection	172	175	174	174	175	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	2650	2557	2581	2702	2761	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	563	565	570	576	581	1
2	Commercial	233	235	238	240	243	2
3	NGV	2	3	3	3	4	3
4	Total Core	798	803	811	819	828	4
	NONCORE						
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	65	67	54	88	124	6
7	PG&E Electric Generation[2]	746	640	669	747	761	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1273	1174	1190	1301	1351	13
	SHRINKAGE						
14	Company use and Unaccounted for	32	31	31	32	33	14
15	TOTAL END USE SERVED BY UTILITY[3]	2103	2008	2032	2152	2212	15
16	Storage Injection (Includes Wild Goose)	172	175	174	174	175	16
17	Subtotal - including injection	2275	2183	2206	2326	2387	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2641	2549	2572	2692	2753	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	0	1	64	136	4
5	*Total out of state gas*	2799	2799	2800	2863	2935	5
6	Total supplies Available[4]	2949	2949	2950	3013	3085	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3316	3379	3451	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	228	251	288	321	332	12
13	Customer Transport	229	386	582	719	730	13
14	*Total U.S. Southwest Gas*	457	637	870	1040	1062	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1078	1083	1083	1084	1084	16
17	*Total Canadian Gas*	1678	1683	1683	1684	1684	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	0	1	64	136	19
20	*Total Supplement*	0	0	1	64	136	20
21	Total out of state	2135	2320	2554	2788	2882	21
22	Subtotal (all pipeline)	2285	2470	2704	2938	3032	22
23	Storage Injection	175	174	174	174	174	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	2826	3010	3244	3478	3572	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	587	605	632	656	665	1
2	Commercial	245	251	261	270	273	2
3	NGV	4	5	6	7	8	3
4	Total Core	836	861	899	933	946	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	125	186	185	185	185	6
7	PG&E Electric Generation[2]	815	915	1113	1317	1400	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas[3]	0	10	10	10	10	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1405	1575	1766	1962	2042	13
	SHRINKAGE						
14	Company use and Unaccounted for	34	36	40	43	44	14
15	TOTAL END USE SERVED BY UTILITY[4]	2275	2472	2705	2938	3032	15
16	Storage Injection (Includes Wild Goose)	175	174	174	174	174	16
17	Subtotal - including injection	2450	2646	2879	3112	3206	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2816	3012	3245	3478	3572	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.

(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
LOW DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available[4]	2949	2949	2949	2949	2949	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	117	121	127	135	142	12
13	Customer Transport	126	76	85	153	193	13
14	*Total U.S. Southwest Gas*	243	197	212	288	335	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1042	991	1000	1044	1055	16
17	*Total Canadian Gas*	1642	1591	1600	1644	1655	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	1885	1788	1812	1932	1990	21
22	Subtotal (all pipeline)	2035	1938	1962	2082	2140	22
23	Storage Injection	172	174	175	175	175	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	2573	2478	2503	2623	2681	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
LOW DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	507	509	513	518	524	1
2	Commercial	213	216	218	220	222	2
3	NGV	2	3	3	3	4	3
4	Total Core	722	728	734	741	750	4
	NONCORE						
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	65	67	54	88	124	6
7	PG&E Electric Generation[2]	746	640	669	747	761	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1273	1174	1190	1301	1351	13
	SHRINKAGE						
14	Company use and Unaccounted for	30	29	29	30	31	14
15	TOTAL END USE SERVED BY UTILITY[3]	2025	1931	1953	2072	2132	15
16	Storage Injection (Includes Wild Goose)	172	174	175	175	175	16
17	Subtotal - including injection	2197	2105	2128	2247	2307	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2563	2471	2494	2613	2673	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
LOW DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	0	1	34	77	4
5	*Total out of state gas*	2799	2799	2800	2833	2876	5
6	Total supplies Available[4]	2949	2949	2950	2983	3026	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3316	3349	3392	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	149	170	206	235	246	12
13	Customer Transport	233	384	579	746	785	13
14	*Total U.S. Southwest Gas*	382	554	785	981	1031	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1072	1083	1083	1084	1084	16
17	*Total Canadian Gas*	1672	1683	1683	1684	1684	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	0	1	34	77	19
20	*Total Supplement*	0	0	1	34	77	20
21	Total out of state	2054	2237	2469	2699	2792	21
22	Subtotal (all pipeline)	2204	2387	2619	2849	2942	22
23	Storage Injection	176	174	174	174	174	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	2746	2927	3159	3389	3482	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
LOW DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	529	545	569	591	599	1
2	Commercial	224	230	241	249	252	2
3	NGV	4	5	6	7	8	3
4	Total Core	757	780	816	847	859	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	125	186	185	185	185	6
7	PG&E Electric Generation[2]	815	915	1113	1317	1400	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas[3]	0	10	10	10	10	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1405	1575	1766	1962	2042	13
	SHRINKAGE						
14	Company use and Unaccounted for	32	33	37	40	42	14
15	TOTAL END USE SERVED BY UTILITY[4]	2194	2388	2619	2849	2943	15
16	Storage Injection (Includes Wild Goose)	176	174	174	174	174	16
17	Subtotal - including injection	2370	2562	2793	3023	3117	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2736	2928	3159	3389	3483	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.

(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
HIGH DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available[4]	2949	2949	2949	2949	2949	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	277	283	290	299	308	12
13	Customer Transport	222	296	223	329	416	13
14	*Total U.S. Southwest Gas*	499	579	513	628	724	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1081	1082	1080	1081	1083	16
17	*Total Canadian Gas*	1681	1682	1680	1681	1683	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	2180	2261	2193	2309	2407	21
22	Subtotal (all pipeline)	2330	2411	2343	2459	2557	22
23	Storage Injection	174	174	174	176	174	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	2870	2951	2883	3001	3097	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
HIGH DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	627	630	635	641	648	1
2	Commercial	255	257	261	263	266	2
3	NGV	2	3	3	3	4	3
4	Total Core	884	890	899	907	918	4
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	69	74	60	97	137	6
7	PG&E Electric Generation[2]	765	941	882	943	990	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1296	1482	1409	1506	1593	13
14	Company use and Unaccounted for	35	36	35	36	37	14
15		2215	2408	2343	2449	2548	15
16	Storage Injection (Includes Wild Goose)	174	174	174	176	174	16
17	Subtotal - including injection	2389	2582	2517	2625	2722	17
18	Pipeline Bypass[4]	366	366	366	366	366	18
19	Total Requirements	2755	2948	2883	2991	3088	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
HIGH DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
GAS SUPPLY AVAILABLE							
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas[1]	1115	1115	1115	1115	1115	2
3	Canadian Gas[2]	1684	1684	1684	1684	1684	3
4	Supplemental[3]	0	40	157	370	468	4
5	*Total out of state gas*	2799	2839	2956	3169	3267	5
6	Total supplies Available[4]	2949	2989	3106	3319	3417	6
7	Pipeline Bypass[5]	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3355	3472	3685	3783	8
GAS SUPPLY TAKEN							
	California Source Gas						
9	PG&E Purchases[6]	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases[6]	317	344	382	418	430	12
13	Customer Transport	467	600	681	677	667	13
14	*Total U.S. Southwest Gas*	784	944	1063	1095	1097	14
	Canadian Gas						
15	PG&E Purchases[6]	600	600	600	600	600	15
16	Customer Transport	1083	1084	1084	1084	1084	16
17	*Total Canadian Gas*	1683	1684	1684	1684	1684	17
	Supplemental						
18	PG&E Purchases[6]	0	0	0	0	0	18
19	Customer Transport	0	40	157	370	468	19
20	*Total Supplement*	0	40	157	370	468	20
21	Total out of state	2467	2668	2904	3149	3249	21
22	Subtotal (all pipeline)	2617	2818	3054	3299	3399	22
23	Storage Injection	175	174	179	174	174	23
24	Pipeline Bypass[5]	366	366	366	366	366	24
25	*Total Throughput*	3158	3358	3599	3839	3939	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

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

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
HIGH DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	654	674	704	731	741	1
2	Commercial	268	275	283	293	296	2
3	NGV	4	5	6	7	8	3
4	Total Core	926	954	993	1031	1045	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	137	210	200	200	200	6
7	PG&E Electric Generation[2]	1039	1140	1349	1561	1648	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas	0	10	10	10	10	11
12	California Exchange Gas[3]	1	1	1	1	1	12
13	Subtotal Noncore	1641	1824	2017	2221	2305	13
	SHRINKAGE						
14	Company use and Unaccounted for	38	40	44	47	49	14
15	TOTAL END USE SERVED BY UTILITY[4]	2605	2818	3054	3299	3399	15
16	Storage Injection (Includes Wild Goose)	175	174	179	174	174	16
17	Subtotal - including injection	2780	2992	3233	3473	3573	17
18	Pipeline Bypass[4]	366	366	366	366	366	18
19	Total Requirements	3146	3358	3599	3839	3939	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.

(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.