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2004  
California  
Gas  
Report

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***NORTHERN CALIFORNIA***

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## **INTRODUCTION**

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 3.8 million residential customers and 214,000 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 2004 through 2025. However, as a matter of convenience, the tabular data at the end of the section show only the years 2004 through 2008 and the years 2010, 2013, 2016, 2020, and 2025.

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 2004 California Gas Report (CGR) average year demand forecast projects total on-system demand growing at an annual average rate of 1.3 percent between 2004 and 2025. This overall growth rate is a combination of 0.9 percent annual growth in the core market and 1.6 percent annual growth in the noncore market. By comparison, the 2002 CGR estimated an annual average growth rate of 1.8 percent per year, based on growth of 0.9 percent per year for the core market and 2.4 percent per year for the noncore market.<sup>1</sup>

The projected rate of growth of the core market has not changed. Decreases 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 which projected annual average growth has fallen from 3.4 percent in the 2002 CGR to 2.5 percent in the current CGR. Due to the incorporation of more recent historic usage data and updated natural gas price forecasts, industrial gas demand is now estimated to decline at a 0.4 average annual rate, whereas that decrease was projected to be on average 0.2 percent in the 2002 CGR.

In the 2004 CGR, total gas demand by electric generators and cogenerators in Northern California is estimated to increase at a rate of about 2.5% per year from 2005 through 2025. This total gas demand includes gas demand by SMUD's gas-fired power plants but does not include gas delivered to power plants in PG&E's service area through third-party pipelines.

### **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 underlying economic, demographic, and technological changes, such as growth in population and employment; changes in prevailing prices; growth in electricity demand and in electric generation by renewables; and changes in the efficiency profiles of residential and commercial buildings and the appliances within them.

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<sup>1</sup> The period used for calculating the 2002 CGR growth rates is 2002-2022. The 2002 CGR did not include the 2023-2025 period in the forecast horizon.

## **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 an alternative forecast of gas demand under assumed high demand conditions. The assumptions for this alternative scenario 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 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 2004 CGR are based on average temperatures. (Each summer typically contains a few short heat waves with temperatures 10 or 15 degF above normal, which drive up power plant gas demand; however, on a seasonal basis, temperatures seldom deviate more than 2 degF from average.)

### ***Hydro Conditions***

In contrast to temperature deviations, annual runoff for hydroelectric plants has varied by 50% above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in water year 2001 (October 2000 through September 2001). Total gas demand for electric generation during that water year increased about 200 MMcf/day over the roughly average water year 2000. For the 2004 CGR's high demand scenario, PG&E presents a case that approximates a 1-in-10 dry hydro year. The resulting dry-year increase in gas demand is 165 MDth/d. This increase is lower than that seen from 2000 to 2001 because new, more efficient power plants have largely replaced the steam-turbine power plants that ramped up in 2001.

### MARKET SECTORS

#### *Residential*

Households in the PG&E service area are forecast to grow 1.2 percent annually from 2004 to 2025. 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. Gas use per household recovered very slightly in 2002 as prices returned to more moderate levels, and rose again in 2003 as customers continued to relax their recently-adopted conservation behavior. However, in 2004 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 on average at 0.9 percent per year from 2004 to 2025, implying an average decrease in gas use per household of nearly 0.3 percent per year.

#### *Commercial*

The number of commercial customers in the PG&E service area is projected to grow on average by a little less than 1 percent per year from 2004 to 2025. The recent (2000-2001) noncore to core migration wave has caused this class to be less temperature sensitive than it had previously been and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to remain flat over the forecast horizon. Over the next 20 years, sales for this sector are expected to grow by the rate at which the customer base is forecast to increase.

#### *Industrial*

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of soaring gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 and is expected to drop by somewhat over 1 percent in 2004 due to both continuing high real natural gas prices and to continuing structural problems in California's manufacturing sector. Industrial gas consumption is expected to slowly decline by about 0.4 percent annually over the next 20 years as California's manufacturing sector continues to gradually shrink.

#### *Electric Generation*

PG&E forecasts gas demand for most cogenerators by trending from historical data. Most cogenerators are not strongly affected by conditions in the electricity market because electricity is co-produced with some other product, usually steam, for an industrial process.

PG&E forecasts gas demand by power plants and market-sensitive cogenerators using the MarketBuilder model. MarketBuilder is an economic-equilibrium model that has been applied to various markets with geographically distributed supplies and

demands, such as the North American natural gas market. PG&E uses MarketBuilder to simulate the electricity market in the Western Electricity Coordinating Council, which encompasses the electric systems from Denver to the Pacific Coast, and from northern Mexico to British Columbia and Alberta.

PG&E's forecast for 2005 is that filed at the California Public Utilities Commission on March 19, 2004 in Application 04-03-021. PG&E's forecasts for 2006 and 2007 are those that will be filed at the CPUC in an upcoming Biennial Cost Allocation Proceeding (BCAP).

PG&E's forecast for 2008-2025 is based largely on CEC assumptions. For the electricity demand forecast, PG&E used the Low Demand case from the CEC's 2003 Integrated Energy Policy Report. The forecast is shown in Table 12 of the CEC document [http://www.energy.ca.gov/reports/2003-08-08\\_100-03-002.PDF](http://www.energy.ca.gov/reports/2003-08-08_100-03-002.PDF). The published forecast extends through 2013, but the CEC staff provided it through 2025. For 2008-2025, PG&E also used CEC assumptions on construction of new power plants, including general location, fuel, and efficiency.

In general, the CEC assumptions reflect aggressive pursuit of energy efficiency and development of renewable generation technologies, in keeping with recent policies at both the state government and regulatory levels. The CEC also assumes that the next generation of gas-fired power plants will be more efficient, with heat rates of 6,800 Btu/kWh for combined-cycle plants and 8,900 Btu/kWh for gas turbines. These assumptions reduce the growth rate of total gas demand by electric generators and cogenerators from 3.5% per year in the 2002 CGR to about 2.5% in the 2004 CGR.

### **SMUD EG**

The Sacramento Municipal Utility District is the sixth largest community owned municipal utility in the United States and it provides electric service to over 550,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants and a peaking turbine with a total capacity of approximately 500 MW. The peak gas load is approximately 100,000 Dth/d and the average load is typically about 60,000 Dth/d. SMUD is currently constructing a new 500 MW gas fired plant, which is scheduled to be online by September 2005.

SMUD owns and operates its own local pipeline, which connects the three cogen plants to PG&E's backbone system near Winters, Ca. This 51-mile pipeline is being extended 26 miles to serve the new Cosumnes plant. SMUD also owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401. SMUD also has 32 MDth/d of capacity on TransCanada's pipeline system from Calgary to Malin, 20 MDth/d on Transwestern from San Juan (Ignacio) to Topock, and 20 MDth/d on Kern River from Opal to Daggett. SMUD also purchased an interest in some gas reserves in the San Juan Basin to meet its gas requirements.

## **GAS SUPPLY SOURCES**

### **California-Source Gas**

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2004, PG&E's customers obtained on average 154 MMcf/day of California source-gas.

### **U. S. Southwest Gas**

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

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

### **Rocky Mountain Gas**

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

### **Storage**

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

### **Supplemental Gas Supplies**

Supplemental gas supplies are included as needed 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 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.

## INTERSTATE 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, Gas Transmission Northwest, Southern Trails, and Kern River pipelines. These pipelines provide northern and central California with access to gas producing regions in the U. S. Southwest and Rocky Mountain areas, and in Western Canada.

#### ***U.S. Southwest and Rocky Mountains***

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,140 MMcf/day.

#### ***Canada***

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

## **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 core load demand forecast is estimated to be approximately 3.2 Bcf/day. The APD load forecast shown here excludes all noncore demand and, in particular, excludes all EG demand. PG&E estimates that total noncore demand during an APD event would be 1.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD forecast is developed using 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 21, 1990, the coldest day on record in PG&E's service area.

### **FORECAST OF APD SUPPLY AVAILABILITY**

For APD planning purposes, supplies will flow under core'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 come from Canada, the U.S. Southwest, the Rocky Mountain Region, SoCalGas, and California. Supplies could also be purchased from noncore customers once gas enters the PG&E system. PG&E's 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**

	<b>2004-2005</b>	<b>2005-2006</b>	<b>20062007</b>	<b>2007-2008</b>	<b>2008-2009</b>
APD Core Demand <sup>(1)</sup>	3,170	3,213	3,255	3,290	3,323
Firm Storage Withdrawal	1,006	1,006	1,006	1,006	1,006
Required Flowing Supplies <sup>(2)</sup>	2,164	2,207	2,249	2,284	2,317
Total APD Resources (to meet demands)	3,170	3,213	3,255	3,290	3,323

**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.



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***PACIFIC GAS AND ELECTRIC COMPANY  
TABULAR DATA***

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# PACIFIC GAS AND ELECTRIC COMPANY

## ANNUAL GAS SUPPLY AND REQUIREMENTS RECORDED YEARS 1999-2003 MMCF/DAY

LINE		1999	2000	2001	2002	2003	LINE
<b>GAS SUPPLY TAKEN</b>							
CALIFORNIA SOURCE GAS							
1	Core Purchases	8	12	29	53	0	1
2	Customer Gas Transport & Exchange	143	151	157	134	155	2
3	Total California Source Gas	151	163	186	187	155	3
OUT-OF-STATE GAS							
Core Purchases							
6	Rocky Mountain Gas	62	28	6	4	9	6
7	U.S. Southwest Gas	210	209	204	182	155	7
8	Canadian Gas	595	604	574	578	569	8
Customer Gas Transport							
10	Rocky Mountain Gas	48	24	78	32	170	10
11	U.S. Southwest Gas	286	374	644	468	434	11
12	Canadian Gas	875	939	864	840	595	12
13	Total Out-of-State Gas	2,076	2,178	2,370	2,104	1,932	13
14	STORAGE WITHDRAWAL	128	228	142	303	327	14
15	Total Gas Supply Taken	2,355	2,569	2,698	2,594	2,414	15
<b>GAS SENDOUT</b>							
CORE							
19	Residential	644	581	543	557	546	19
20	Commercial	232	218	244	249	244	20
21	NGV	1	2	2	2	5	21
22	Total Throughput-Core	877	801	789	808	795	22
NONCORE							
24	Industrial	473	537	420	406	418	24
25	Electric Generation <sup>(1)</sup>	703	941	1100	830	739	25
26	EOR	0	0	1	0	0	26
27	NGV	1	1	1	1	1	27
28	Total Throughput-Noncore	1177	1479	1522	1237	1158	28
29	WHOLESALE	12	11	11	9	10	29
30	Total Throughput	2066	2291	2322	2054	1963	30
31	CALIFORNIA EXCHANGE GAS	3	2	1	1	1	31
32	STORAGE GAS <sup>(2)</sup>	162	149	252	316	341	32
33	SHRINKAGE Company Use / Unaccounted for	124	127	123	223	109	33
34	Total Gas Send Out <sup>(3)</sup>	2,355	2,569	2,698	2,594	2,414	34
<b>CURTAILMENT / ALTERNATIVE FUEL BURNS <sup>(4)</sup></b>							
37	Residential, Commercial, Industrial	0	0	0	0	0	37
38	Utility Electric Generation	0	0	0	0	0	38
39	TOTAL CURTAILMENT	0	0	0	0	0	39

**NOTES:**

- (1) Electric generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
- (2) Includes both PG&E and third party storage
- (3) Total gas send-out excludes off-system transportation.
- (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.

# PACIFIC GAS AND ELECTRIC COMPANY

## ANNUAL GAS SUPPLY FORECAST YEARS 2004-2008 MMCF/DAY

### AVERAGE DEMAND YEAR

LINE		2004	2005	2006	2007	2008	LINE
<b>GAS SUPPLY AVAILABLE</b>							
1	California Source Gas	150	150	150	150	150	1
	Out of State Gas						
2	Baja Path <sup>(1)</sup>	1140	1140	1140	1140	1140	2
3	Redwood Path <sup>(2)</sup>	2021	2021	2021	2021	2021	3
4	Supplemental <sup>(3)</sup>	0	0	0	0	0	4
5	Total Supplies Available <sup>(4)</sup>	3311	3311	3311	3311	3311	5
<b>GAS SUPPLY TAKEN</b>							
6	California Source Gas	150	150	150	150	150	6
7	Out of State Gas (via existing facilities)	2148	2138	2237	2271	2303	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2298	2288	2387	2421	2453	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	Total Throughput <sup>(5)</sup>	2298	2288	2387	2421	2453	11
<b>REQUIREMENTS FORECAST BY END USE</b>							
<b>CORE</b>							
12	Residential	562	572	580	587	592	12
13	Commercial	233	236	239	242	243	13
14	NGV	3	4	4	4	5	14
15	Total Core	798	812	823	833	840	15
<b>NONCORE</b>							
16	Industrial	410	409	412	412	410	16
17	SMUD Electric Generation	59	82	128	128	128	17
18	PG&E Electric Generation <sup>(6)</sup>	632	623	661	683	702	18
19	NGV	1	1	1	1	1	19
20	Resale	10	10	10	11	11	20
21	Southwest Exchange Gas	0	0	0	0	7	21
22	California Exchange Gas	1	1	1	1	1	22
23	Total Noncore	1113	1126	1213	1236	1260	23
24	Off-System Deliveries <sup>(7)</sup>	346	309	309	309	309	24
<b>Shrinkage</b>							
25	Company use and Unaccounted for	41	41	42	43	44	25
26	TOTAL END USE <sup>(8)</sup>	2298	2288	2387	2421	2453	26
27	System Curtailment	0	0	0	0	0	27

#### NOTES:

- (1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
- (2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.
- (3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
- (4) Supplies available through utility system.
- (5) Figures exclude pipeline bypass load losses of approximately 440 MMcf/d.
- (6) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
- (7) Deliveries to southern California. The 2004 forecast is a combination of actual (first quarter) and forecasted deliveries. The 2005 forecast, also used for later years, is consistent with PG&E's Gas Transmission and Storage 2005 Rate Case, A.04-03-021.
- (8) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

# PACIFIC GAS AND ELECTRIC COMPANY

## ANNUAL GAS SUPPLY FORECAST YEARS 2010-2025 MMCF/DAY

### AVERAGE DEMAND YEAR

LINE		2010	2013	2016	2020	2025	LINE
<b>GAS SUPPLY AVAILABLE</b>							
1	California Source Gas	150	150	150	150	150	1
<b>Out of State Gas</b>							
2	Baja Path <sup>(1)</sup>	1140	1140	1140	1140	1140	2
3	Redwood Path <sup>(2)</sup>	2021	2021	2021	2021	2021	3
4	Supplemental <sup>(3)</sup>	0	0	0	0	0	4
5	<b>Total Supplies Available<sup>(4)</sup></b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	<b>5</b>
<b>GAS SUPPLY TAKEN</b>							
6	California Source Gas	150	150	150	150	150	6
7	Out of State Gas (via existing facilities)	2341	2376	2439	2587	2773	7
8	Supplemental	0	0	0	0	0	8
9	<b>Total Supply Taken</b>	<b>2491</b>	<b>2526</b>	<b>2589</b>	<b>2737</b>	<b>2923</b>	<b>9</b>
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	<b>Total Throughput<sup>(5)</sup></b>	<b>2491</b>	<b>2526</b>	<b>2589</b>	<b>2737</b>	<b>2923</b>	<b>11</b>
<b>REQUIREMENTS FORECAST BY END USE</b>							
<b>Core</b>							
12	Residential	605	624	639	658	680	12
13	Commercial	247	252	257	263	273	13
14	NGV	5	5	6	6	7	14
15	<b>Total Core</b>	<b>857</b>	<b>881</b>	<b>902</b>	<b>927</b>	<b>960</b>	<b>15</b>
<b>Noncore</b>							
16	Industrial	409	404	397	390	381	16
17	SMUD Electric Generation	128	128	128	128	128	17
18	PG&E Electric Generation <sup>(6)</sup>	722	737	784	911	1070	18
19	NGV	1	1	1	1	1	19
20	Resale	11	11	11	11	11	20
21	Southwest Exchange Gas	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	<b>Total Noncore</b>	<b>1281</b>	<b>1291</b>	<b>1331</b>	<b>1451</b>	<b>1601</b>	<b>23</b>
24	<b>Off-System Deliveries<sup>(7)</sup></b>	<b>309</b>	<b>309</b>	<b>309</b>	<b>309</b>	<b>309</b>	<b>24</b>
<b>Shrinkage</b>							
25	Company use and Unaccounted for	44	45	47	50	53	25
26	<b>TOTAL END USE<sup>(8)</sup></b>	<b>2491</b>	<b>2526</b>	<b>2589</b>	<b>2737</b>	<b>2923</b>	<b>26</b>
27	System Curtailment	0	0	0	0	0	27

**NOTES:**

- (1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
- (2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.
- (3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
- (4) Supplies available through utility system.
- (5) Figures exclude pipeline bypass load losses of approximately 440 MMcf/d.
- (6) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
- (7) Deliveries to southern California. The 2005 forecast, also used for later years, is consistent with PG&E's Gas Transmission and Storage 2005 Rate Case, A.04-03-021.
- (8) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

# PACIFIC GAS AND ELECTRIC COMPANY

## ANNUAL GAS SUPPLY FORECAST YEARS 2004-2008 MMCF/DAY

### HIGH DEMAND YEAR

LINE		2004	2005	2006	2007	2008	LINE
<b>GAS SUPPLY AVAILABLE</b>							
1	California Source Gas	150	150	150	150	150	1
<b>Out of State Gas</b>							
2	Baja Path <sup>(1)</sup>	1140	1140	1140	1140	1140	2
3	Redwood Path <sup>(2)</sup>	2021	2021	2021	2021	2021	3
4	Supplemental <sup>(3)</sup>	0	0	0	0	0	4
5	Total Supplies Available <sup>(4)</sup>	3311	3311	3311	3311	3311	5
<b>GAS SUPPLY TAKEN</b>							
6	California Source Gas	150	150	150	150	150	6
7	Out of State Gas (via existing facilities)	2236	2397	2504	2539	2571	7
8	Supplemental	0	0	0	0	0	8
9	Total Supply Taken	2386	2547	2654	2689	2721	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	Total Throughput <sup>(5)</sup>	2386	2547	2654	2689	2721	11
<b>REQUIREMENTS FORECAST BY END USE</b>							
<b>Core</b>							
12	Residential	622	634	643	650	656	12
13	Commercial	255	258	261	265	266	13
14	NGV	3	4	4	4	5	14
15	Total Core	880	896	908	919	927	15
<b>Noncore</b>							
16	Industrial	413	412	414	415	413	16
17	SMUD Electric Generation	59	85	138	138	138	17
18	PG&E Electric Generation <sup>(6)</sup>	632	785	823	845	864	18
19	NGV	1	1	1	1	1	19
20	Resale	11	11	12	12	12	20
21	Southwest Exchange Gas	0	0	0	0	7	21
22	California Exchange Gas	1	1	1	1	1	22
23	Total Noncore	1117	1295	1389	1412	1436	23
24	Off-System Deliveries <sup>(7)</sup>	346	309	309	309	309	24
<b>Shrinkage</b>							
25	Company use and Unaccounted for	43	47	48	49	49	25
26	TOTAL END USE <sup>(8)</sup>	2386	2547	2654	2689	2721	26
27	System Curtailment	0	0	0	0	0	27

#### NOTES:

- (1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
- (2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.
- (3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
- (4) Supplies available through utility system.
- (5) Figures exclude pipeline bypass load losses of approximately 440 MMcf/d.
- (6) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
- (7) Deliveries to southern California. The 2004 forecast is a combination of actual (first quarter) and forecasted deliveries. The 2005 forecast, also used for later years, is consistent with PG&E's Gas Transmission and Storage 2005 Rate Case, A.04-03-021.
- (8) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

# PACIFIC GAS AND ELECTRIC COMPANY

## ANNUAL GAS SUPPLY FORECAST YEARS 2010-2025 MMCF/DAY

### HIGH DEMAND YEAR

LINE		2010	2013	2016	2020	2025	LINE
<b>GAS SUPPLY AVAILABLE</b>							
1	California Source Gas	150	150	150	150	150	1
<b>Out of State Gas</b>							
2	Baja Path <sup>(1)</sup>	1140	1140	1140	1140	1140	2
3	Redwood Path <sup>(2)</sup>	2021	2021	2021	2021	2021	3
4	Supplemental <sup>(3)</sup>	0	0	0	0	0	4
5	<b>Total Supplies Available<sup>(4)</sup></b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	<b>3311</b>	5
<b>GAS SUPPLY TAKEN</b>							
6	California Source Gas	150	150	150	150	150	6
7	Out of State Gas (via existing facilities)	2609	2647	2711	2864	3161	7
8	Supplemental	0	0	0	0	0	8
9	<b>Total Supply Taken</b>	<b>2759</b>	<b>2797</b>	<b>2861</b>	<b>3014</b>	<b>3202</b>	9
10	Net Underground Storage Withdrawal	0	0	0	0	0	10
11	<b>Total Throughput<sup>(5)</sup></b>	<b>2759</b>	<b>2797</b>	<b>2861</b>	<b>3014</b>	<b>3202</b>	11
<b>REQUIREMENTS FORECAST BY END USE</b>							
<b>Core</b>							
12	Residential	670	691	707	729	753	12
13	Commercial	270	275	280	288	298	13
14	NGV	5	5	6	6	7	14
15	<b>Total Core</b>	<b>945</b>	<b>971</b>	<b>993</b>	<b>1023</b>	<b>1058</b>	15
<b>Noncore</b>							
16	Industrial	411	406	400	392	383	16
17	SMUD Electric Generation	138	138	138	138	138	17
18	PG&E Electric Generation <sup>(6)</sup>	883	899	946	1073	1232	18
19	NGV	1	1	1	1	1	19
20	Resale	12	12	12	12	12	20
21	Southwest Exchange Gas	9	9	9	9	9	21
22	California Exchange Gas	1	1	1	1	1	22
23	<b>Total Noncore</b>	<b>1455</b>	<b>1466</b>	<b>1507</b>	<b>1626</b>	<b>1776</b>	23
24	<b>Off-System Deliveries<sup>(7)</sup></b>	<b>309</b>	<b>309</b>	<b>309</b>	<b>309</b>	<b>309</b>	24
<b>Shrinkage</b>							
25	Company use and Unaccounted for	50	51	52	56	59	25
26	<b>TOTAL END USE<sup>(8)</sup></b>	<b>2759</b>	<b>2797</b>	<b>2861</b>	<b>3014</b>	<b>3202</b>	26
27	System Curtailment	0	0	0	0	0	27

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