2026

CALIFORNIA
GAS REPORT

2026 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

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

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2026 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2026 California Gas Report* (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2040. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission (CPUC or Commission) Decision (D.) 95-01-039. The CGR supports long-term planning and does not necessarily reflect day-to-day utility operations.

The report is organized into four sections: Executive Summary, Statewide Market Conditions, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Statewide Market Conditions section highlights key drivers of natural gas prices and liquified natural gas (LNG) 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), Southwest Gas Corporation (SWG), Wild Goose Storage, LLC., Central Valley Gas Storage, LLC., Gill Ranch Storage, LLC., and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Utilities Department, Southwest Gas Corporation, and San Diego Gas & Electric Company (SDG&E).

Each participating utility provides a narrative outlining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables detailing 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 continued evolution of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used as a substitute for a full, detailed analysis of specific energy requirements.

A working committee comprised of 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.

2026 CALIFORNIA GAS REPORT

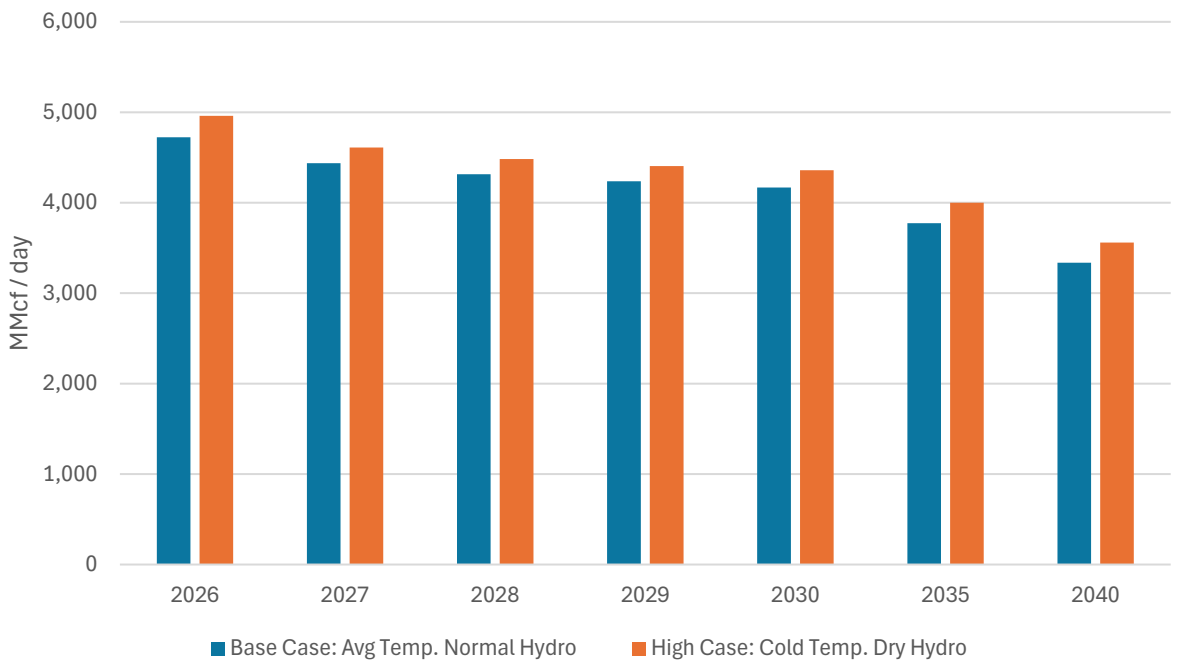
EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

FORECAST RESULTS

California demand for natural gas is forecasted to decline through 2040. The graph below summarizes statewide gas demand under the Average Demand case and the High Demand case. The Average Demand case refers to the expected gas demand for an average temperature year and normal hydroelectric generation (hydro) year, and the High Demand case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under the Average Demand case, gas demand for the entire state is projected to average 4,723 million cubic feet of gas per day (MMcf/d) in 2026 decreasing to 3,337 MMcf/d by 2040, a decline of 2.5 percent per year on average.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK



Compared to the Average Demand case scenario, the Northern California High Demand scenario is 7 percent higher in 2026 while the Southern California High Demand scenario is 4 percent higher for the same year due to differing climate zones and respective energy generation (EG) assumptions.

FORECAST ASSUMPTIONS

The forecasts that comprise the 2026 CGR are based on assumptions related to various state policies, including energy efficiency, fuel substitution, electric generation, integrated resource planning, and system planning. More detailed discussion of each can be found in the Northern California and Southern California sections of the 2026 CGR.

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 2026 through 2040 for average temperature and normal hydro years (Average Demand) and cold weather and dry hydro years (High Demand).

Gas sales and transportation volumes are consolidated under the general category of system 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 Utilities Department, SDG&E, Southwest Gas (SWG), 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.

TABLE 1 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2026-2030, MMcf/d

Line No.	Utility	2026	2027	2028	2029	2030
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	83	83	83	83	83
4	Out-of-State	4,518	4,274	4,178	4,120	4,076
5	Utility Total	4,601	4,357	4,261	4,203	4,159
6	Non-Utility Served Load (1)	443	400	375	354	329
7	**Statewide Supply Sources Total**	**5,043**	**4,757**	**4,636**	**4,557**	**4,488**
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,039	1,033	1,013	985	955
11	Commercial	463	454	444	436	427
12	Natural Gas Vehicles	75	78	79	80	80
13	Industrial	881	876	872	867	864
14	Electric Generation (2)	1,478	1,258	1,199	1,183	1,183
15	Enhanced Oil Recovery Steaming	16	15	14	13	12
16	Wholesale/International + Exchange	264	263	261	260	259
17	Company Use and Unaccounted For	66	61	60	59	59
18	Utility Total	4,281	4,037	3,941	3,883	3,839
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	49	44	42	39	37
21	EOR Cogeneration/Industrial	2	2	2	2	2
22	Electric Generation	392	354	331	312	290
23	Non-Utility Served Total (1)	443	400	375	354	329
24	**Statewide Requirements Total**(3)	**4,723**	**4,437**	**4,316**	**4,237**	**4,168**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave, and TGN pipelines to industrial, EOR cogeneration, 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.

TABLE 2 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2031-2040, MMcf/d

Line No.	Utility	2031	2032	2033	2035	2040
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	83	83	83	83	83
4	Out-of-State	4,034	3,918	3,595	3,438	3,015
5	Utility Total	4,117	4,001	3,678	3,521	3,098
6	Non-Utility Served Load (1)	307	289	275	252	239
7	**Statewide Supply Sources Total**	**4,425**	**4,290**	**3,953**	**3,773**	**3,337**
8	**California's Requirements**					
9	*Utility*					
10	Residential	932	910	891	849	729
11	Commercial	418	408	399	380	336
12	Natural Gas Vehicles	79	77	74	66	85
13	Industrial	861	858	855	848	844
14	Electric Generation (2)	1,179	1,143	1,135	1,060	793
15	Enhanced Oil Recovery Steaming	11	10	10	8	6
16	Wholesale/International + Exchange	259	257	257	256	259
17	Company Use and Unaccounted For	58	57	56	54	46
18	Utility Total	3,797	3,720	3,678	3,521	3,098
19	*Non-Utility*					
21	Enhanced Oil Recovery Steaming	35	33	31	29	28
22	EOR Cogeneration/Industrial	2	2	2	1	1
23	Electric Generation	271	255	242	222	209
24	Non-Utility Served Total (1)	307	289	275	252	239
25	**Statewide Requirements Total**(3)	**4,105**	**4,009**	**3,953**	**3,773**	**3,337**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave, and TGN pipelines to industrial, EOR cogeneration, 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.

TABLE 3 – STATEWIDE TOTAL SUPPLY SOURCES TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2026-2040, MMcf/d

Line No.		2026	2027	2028	2029	2030
1	**Utility**					
2	*Northern California*					
3	California Sources (1)	26	26	26	26	26
4	Out-of-State	2,368	2,191	2,155	2,132	2,131
5	Northern California Total	2,394	2,217	2,181	2,158	2,157
6	*Southern California*					
7	California Sources (2)	57	57	57	57	57
8	Out-of-State	2,150	2,083	2,023	1,988	1,944
9	Southern California Total	2,207	2,140	2,080	2,045	2,001
10	**Utility Total**	4,601	4,357	4,261	4,203	4,159
11	**Non-Utility Served Load (3)**	443	400	375	354	329
12	**Statewide Supply Sources Total**	**4,601**	**4,357**	**4,261**	**4,203**	**4,159**
		2031	**2032**	**2033**	**2034**	**2035**
13	**Utility**					
14	*Northern California*					
15	California Sources (1)	26	26	26	26	26
16	Out-of-State	2,108	2,019	1,709	1,600	1,187
17	Northern California Total	2,134	2,045	1,735	1,626	1,213
18	*Southern California*					
19	California Sources (2)	57	57	57	57	57
20	Out-of-State	1,926	1,899	1,886	1,839	1,828
21	Southern California Total	1,983	1,956	1,943	1,896	1,885
22	**Utility Total**	4,117	4,001	3,678	3,521	3,098
23	**Non-Utility Served Load (3)**	307	289	275	252	239
24	**Statewide Supply Sources Total**	**4,117**	**4,001**	**3,678**	**3,521**	**3,098**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases, 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 cogeneration, EOR steaming and power plant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

TABLE 4 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2026-2030, MMcf/d

Line No.	Utility	2026	2027	2028	2029	2030
1	*Northern California*					
2	Residential	467	468	458	437	415
3	Commercial - Core	203	199	194	189	183
4	Natural Gas Vehicles - Core	9	9	9	10	10
5	Natural Gas Vehicles - Noncore	4	4	5	5	5
6	Industrial - Noncore	469	468	467	465	465
7	Wholesale	8	8	8	8	8
8	SMUD Electric Generation	119	118	110	106	94
9	Electric Generation [2]	727	559	547	555	595
10	Exchange (California)	30	30	30	30	30
11	Company Use and Unaccounted For	37	33	33	32	33
12	Northern California Total [3]	2,074	1,897	1,861	1,838	1,837
13	*Southern California*					
14	Residential	572	564	554	548	540
15	Commercial – Core	211	207	202	199	196
16	Commercial – Noncore	49	49	48	48	48
17	Natural Gas Vehicles - Core	62	64	65	66	65
18	Industrial – Core	50	49	49	48	47
19	Industrial – Noncore	361	359	356	354	352
20	Wholesale (excluding EG)	225	224	222	222	221
21	SDG&E, Vernon, & Ecogas EG	124	122	118	113	108
22	Electric Generation [4]	509	459	424	409	386
23	Enhanced Oil Recovery Steaming	16	15	14	13	12
24	Company Use and Unaccounted For	29	28	27	27	26
25	Southern California Total	2,207	2,140	2,080	2,045	2,001
26	**Utility Total**	4,281	4,037	3,941	3,883	3,839
27	**Non-Utility Served Load [5]**	443	400	375	354	329
28	**Statewide Gas Requirements Total [6]**	**4,723**	**4,437**	**4,316**	**4,237**	**4,168**

Notes:
(1) Includes transportation gas.
(2) Electric generation (EG) 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 cogeneration, 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.

TABLE 5 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2031-2040, MMcf/d

Line No.	Utility	2031	2032	2033	2035	2040
1	*Northern California*					
2	Residential	400	387	373	343	250
3	Commercial - Core	176	169	162	148	116
4	Natural Gas Vehicles - Core	10	11	11	12	13
5	Natural Gas Vehicles - Noncore	5	5	5	6	6
6	Industrial - Noncore	465	465	464	463	464
7	Wholesale	8	8	8	8	8
8	SMUD Electric Generation	94	94	94	94	94
9	Electric Generation [2]	593	563	556	493	210
10	Exchange (California)	30	30	30	30	30
11	Company Use and Unaccounted For	32	31	31	29	21
12	Northern California Total [3]	1,814	1,764	1,735	1,626	1,213
13	*Southern California*					
14	Residential	532	523	518	506	479
15	Commercial – Core	194	191	189	184	172
16	Commercial – Noncore	48	48	48	48	48
17	Natural Gas Vehicles - Core	64	61	58	49	66
18	Industrial – Core	47	46	46	44	42
19	Industrial – Noncore	350	347	345	340	339
20	Wholesale (excluding EG)	220	219	219	218	221
21	SDG&E, Vernon, & Ecogas EG	103	96	91	80	82
22	Electric Generation [4]	390	390	394	393	407
23	Enhanced Oil Recovery Steaming	11	10	10	8	6
24	Company Use and Unaccounted For	26	26	25	25	25
25	Southern California Total	1,983	1,956	1,943	1,896	1,885
26	**Utility Total**	3,797	3,720	3,678	3,521	3,098
27	**Non-Utility Served Load [5]**	307	289	275	252	239
28	**Statewide Gas Requirements Total [6]**	**4,105**	**4,009**	**3,953**	**3,773**	**3,337**

Notes:
(1) Includes transportation gas.
(2) Electric generation (EG) 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 cogeneration, 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.

TABLE 6 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS COLD TEMPERATURE (4) AND DRY HYDRO YEAR, 2026-2030, MMcf/d

Line No.	Utility	2026	2027	2028	2029	2030
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	83	83	83	83	83
4	Natural Gas Vehicles - Core	4,754	4,448	4,345	4,289	4,267
5	Utility Total	4,837	4,531	4,428	4,372	4,350
6	Non-Utility Served Load (1)	443	400	375	354	329
7	**Statewide Supply Sources Total**	**5,280**	**4,931**	**4,803**	**4,725**	**4,679**
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,118	1,113	1,093	1,063	1,030
11	Commercial	481	472	463	454	445
12	Natural Gas Vehicles	75	78	79	80	80
13	Industrial	881	877	872	868	865
14	Electric Generation (2)	1,602	1,318	1,254	1,241	1,265
15	Enhanced Oil Recovery Steaming	16	15	14	13	12
16	Wholesale/International + Exchange	274	273	272	271	270
17	Company Use and Unaccounted For	70	64	63	62	62
18	Utility Total	4,517	4,211	4,108	4,052	4,030
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	49	44	42	39	37
21	EOR Cogeneration/Industrial	2	2	2	2	2
22	Electric Generation	392	354	331	312	290
23	Non-Utility Served Total (1)	443	400	375	354	329
24	**Statewide Requirements Total**(3)	**4,960**	**4,611**	**4,483**	**4,405**	**4,359**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave, and TGN pipelines to industrial, EOR cogeneration, 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.
(4) 1-in-35 cold-year temperature for SoCalGas, 1-in-10 cold-year temperature for PG&E.

TABLE 7 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS COLD TEMPERATURE (4) AND DRY HYDRO YEAR, 2031-2040, MMcf/d

Line No.	Utility	2031	2032	2033	2035	2040
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	83	83	83	83	83
4	Natural Gas Vehicles - Core	4,265	4,163	3,848	3,665	3,238
5	Utility Total	4,348	4,246	3,931	3,748	3,321
6	Non-Utility Served Load (1)	307	289	275	252	239
7	**Statewide Supply Sources Total**	**4,655**	**4,535**	**4,206**	**4,000**	**3,560**
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,007	985	966	924	804
11	Commercial	436	426	417	398	354
12	Natural Gas Vehicles	79	77	74	66	85
13	Industrial	862	859	856	848	844
14	Electric Generation (2)	1,302	1,280	1,280	1,178	908
15	Enhanced Oil Recovery Steaming	11	10	10	8	6
16	Wholesale/International + Exchange	269	268	268	267	270
17	Company Use and Unaccounted For	62	61	61	58	50
18	Utility Total	4,028	3,965	3,931	3,748	3,321
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	35	33	31	29	28
21	EOR Cogeneration/Industrial	2	2	2	1	1
22	Electric Generation	271	255	242	222	209
23	Non-Utility Served Total (1)	307	289	275	252	239
24	**Statewide Requirements Total(3)**	**4,335**	**4,254**	**4,206**	**4,000**	**3,560**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave, and TGN pipelines to industrial, EOR cogeneration, 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.
(4) 1-in-35 cold-year temperature for SoCalGas, 1-in-10 cold-year temperature for PG&E.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE [4] AND DRY HYDRO YEAR, 2026-2040, MMcf/d

Line No.		2026	2027	2028	2029	2030
1	**Utility**					
2	*Northern California*					
3	California Sources [1]	26	26	26	26	26
4	Out-of-State	2,512	2,277	2,235	2,214	2,236
5	Northern California Total	2,538	2,303	2,261	2,240	2,262
6	*Southern California*					
7	California Sources [2]	57	57	57	57	57
8	Out-of-State	2,242	2,170	2,110	2,075	2,032
9	Southern California Total	2,299	2,227	2,167	2,132	2,089
10	**Utility Total**	4,837	4,531	4,428	4,372	4,350
11	**Non-Utility Served Load [3]**	443	400	375	354	329
12	**Statewide Supply Sources Total**	**4,837**	**4,531**	**4,428**	**4,372**	**4,350**
		2031	**2032**	**2033**	**2034**	**2035**
12	**Utility**					
13	*Northern California*					
14	California Sources [1]	26	26	26	26	26
15	Out-of-State	2,261	2,182	1,878	1,742	1,321
16	Northern California Total	2,287	2,208	1,904	1,768	1,347
17	*Southern California*					
18	California Sources [2]	57	57	57	57	57
19	Out-of-State	2,004	1,981	1,969	1,923	1,917
20	Southern California Total	2,061	2,038	2,026	1,980	1,974
21	**Utility Total**	4,348	4,246	3,931	3,748	3,321
22	**Non-Utility Served Load [3]**	307	289	275	252	239
23	**Statewide Supply Sources Total**	**4,348**	**4,246**	**3,931**	**3,748**	**3,321**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases, 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 cogeneration, EOR steaming and power plant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(4) 1-in-35 cold-year temperature for SoCalGas, 1-in-10 cold-year temperature for PG&E.

TABLE 9 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
COLD TEMPERATURE [7] AND DRY HYDRO YEAR, 2026-2030, MMcf/d

Line No.	Utility	2026	2027	2028	2029	2030
1	*Northern California*					
2	Residential	500	503	492	469	445
3	Commercial - Core	212	208	203	198	192
4	Natural Gas Vehicles - Core	9	9	9	10	10
5	Natural Gas Vehicles - Noncore	4	4	5	5	5
6	Industrial - Noncore	469	468	467	465	465
7	Wholesale	9	9	9	9	9
8	SMUD Electric Generation	119	118	110	106	94
9	Electric Generation [2]	825	598	581	593	657
10	Exchange (California)	30	30	30	30	30
11	Company Use and Unaccounted For	40	35	35	34	35
12	Northern California Total [3]	2,218	1,983	1,941	1,920	1,942
13	*Southern California*					
14	Residential	618	610	600	593	586
15	Commercial – Core	219	215	210	207	205
16	Commercial – Noncore	50	50	49	49	49
17	Natural Gas Vehicles - Core	62	64	65	66	65
18	Industrial – Core	51	50	49	49	48
19	Industrial – Noncore	361	359	356	354	352
20	Wholesale (excluding EG)	235	234	232	232	231
21	SDG&E, Vernon, & Ecogas EG	131	130	126	122	116
22	Electric Generation [4]	526	472	437	420	398
23	Enhanced Oil Recovery Steaming	16	15	14	13	12
24	Company Use and Unaccounted For	30	29	28	28	27
25	Southern California Total	2,299	2,227	2,167	2,132	2,089
26	**Utility Total**	4,517	4,211	4,108	4,052	4,030
27	**Non-Utility Served Load [5]**	443	400	375	354	329
28	**Statewide Gas Requirements Total [6]**	**4,960**	**4,611**	**4,483**	**4,405**	**4,359**

Notes:
(1) Includes transportation gas.
(2) Electric generation (EG) 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 cogeneration, 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.
(7) 1-in-35 cold-year temperature for SoCalGas, 1-in-10 cold-year temperature for PG&E.

TABLE 10 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
COLD TEMPERATURE [7] AND DRY HYDRO YEAR, 2031-2040, MMcf/d

Line No.	Utility	2031	2032	2033	2035	2040
1	*Northern California*					
2	Residential	429	416	402	372	279
3	Commercial - Core	185	178	171	157	125
4	Natural Gas Vehicles - Core	10	11	11	12	13
5	Natural Gas Vehicles - Noncore	5	5	5	6	6
6	Industrial - Noncore	465	465	464	463	464
7	Wholesale	9	9	8	8	8
8	SMUD Electric Generation	94	94	94	94	94
9	Electric Generation [2]	704	685	684	594	304
10	Exchange (California)	30	30	30	30	30
11	Company Use and Unaccounted For	35	35	34	32	24
12	Northern California Total [3]	1,967	1,927	1,904	1,768	1,347
13	*Southern California*					
14	Residential	578	569	564	552	525
15	Commercial – Core	202	199	197	192	180
16	Commercial – Noncore	49	49	49	49	49
17	Natural Gas Vehicles - Core	64	61	58	49	66
18	Industrial – Core	47	47	46	45	42
19	Industrial – Noncore	350	347	345	340	339
20	Wholesale (excluding EG)	230	229	229	228	231
21	SDG&E, Vernon, & Ecogas EG	109	103	99	85	88
22	Electric Generation [4]	394	398	403	405	422
23	Enhanced Oil Recovery Steaming	11	10	10	8	6
24	Company Use and Unaccounted For	27	27	26	26	26
25	Southern California Total	2,061	2,038	2,026	1,980	1,974
26	**Utility Total**	4,028	3,965	3,931	3,748	3,321
27	**Non-Utility Served Load [5]**	307	289	275	252	239
28	**Statewide Gas Requirements Total [6]**	**4,335**	**4,254**	**4,206**	**4,000**	**3,560**

Notes:
(1) Includes transportation gas.
(2) Electric generation (EG) 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 cogeneration, 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.
(7) 1-in-35 cold-year temperature for SoCalGas, 1-in-10 cold-year temperature for PG&E.

STATEWIDE RECORDED SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary complements the existing 5-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 available gas nominations and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. Data on daily gas nominations are frequently subject to reconciliation 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.

TABLE 11 – RECORDED 2021 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other [1]	Ruby	Total
Southern California Gas Company [2]									
Core + UAF [3] [4]	217	334	184	20	210	0	(15)	0	950
Noncore C&I, EG/EOR/Wholesale/Int' l	(131)	504	173	206	618	85	18	0	1,473
Total	86	838	357	226	828	85	3	0	2,423
Pacific Gas and Electric Company [5]									
Core	0	29	0	410	(2)	0	0	159	597
Noncore Industrial/Wholesale/EG [6]	23	356	186	942	6	0	0	326	1,840
Total	23	385	186	1,352	4	0	0	485	2,437
Other Northern California									
Core [7]	13	0	0	0	0	0	0	0	13
No-Utilities Served Load [8] [9]									
Direct Sales/Bypass	295	49	0	0	631	42	0	0	1,017
TOTAL SUPPLIER	417	1,272	543	1,578	1,463	127	3	485	5,890
San Diego Gas & Electric Company									
Core	31	48	27	3	30	0	(2)	0	137
Noncore Commercial/Industrial	(11)	44	15	18	54	7	2	0	128
Total	20	91	42	21	84	7	0	0	265
Southwest Gas Corporation									
Core	24	0	0	0	0	0	13	0	37
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	26	0	0	0	0	0	13	0	39

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E; for SoCalGas. Includes net storage inventories for the year, volumes delivered on TGN - Otay Mesa, N. Baja
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale, and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CalGEM.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 12 – RECORDED 2022 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other [1]	Ruby	Total
Southern California Gas Company [2]									
Core + UAF [3] [4]	144	338	150	31	221	0	33	0	917
Noncore C&I, EG/EOR/Wholesale/Int' l	(53)	483	311	189	521	50	(31)	0	1,499
Total	91	821	461	220	742	50	2	0	2,416
Pacific Gas and Electric Company [5]									
Core	0	38	0	391	(4)	0	0	160	585
Noncore Industrial/Wholesale/EG [6]	23	323	145	1,023	14	0	0	176	1,704
Total	23	361	145	1,414	10	0	0	336	2,289
Other Northern California									
Core [7]	0	0	0	0	0	0	0	0	0
No-Utilities Served Load [8] [9]									
Direct Sales/Bypass	256	32	0	0	638	20	0	0	1,017
TOTAL SUPPLIER	370	1,214	606	1,634	1,390	70	2	336	5,722
San Diego Gas & Electric Company									
Core	21	49	22	4	32	0	5	0	133
Noncore Commercial/Industrial	(5)	45	29	18	49	5	(3)	0	141
Total	16	94	51	22	81	5	2	0	274
Southwest Gas Corporation									
Core	26	0	0	0	0	0	0	0	26
Noncore Commercial/Industrial	1	0	0	0	0	0	0	0	1
Total	27	0	0	0	0	0	0	0	27

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E; for SoCalGas. Includes net storage inventories for the year, volumes delivered on TGN - Otay Mesa, N. Baja
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale, and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CalGEM.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 13 – RECORDED 2023 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other [1]	Ruby	Total
Southern California Gas Company [2]									
Core + UAF [3] [4]	261	391	153	19	226	0	(54)	0	996
Noncore C&I, EG/EOR/Wholesale/Int' l	(175)	545	282	147	573	99	56	0	1,527
Total	86	936	435	166	799	99	2	0	2,523
Pacific Gas and Electric Company [5]									
Core	0	34	0	398	(1)	0	0	171	601
Noncore Industrial/Wholesale/EG [6]	22	398	170	1,085	22	0	0	253	1,949
Total	22	431	170	1,482	21	0	0	424	2,550
Other Northern California									
Core [7]	0	0	0	0	0	0	0	0	0
No-Utilities Served Load [8] [9]									
Direct Sales/Bypass	249	32	0	0	601	48	0	0	930
TOTAL SUPPLIER	357	1,399	605	1,648	1,421	147	2	424	6,003
San Diego Gas & Electric Company									
Core	37	55	22	3	32	0	(8)	0	141
Noncore Commercial/Industrial	(28)	41	23	14	51	10	8	0	120
Total	9	97	45	17	82	10	0	0	261
Southwest Gas Corporation									
Core	29	0	0	0	0	0	0	0	29
Noncore Commercial/Industrial	1	0	0	0	0	0	0	0	1
Total	30	0	0	0	0	0	0	0	30

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E; for SoCalGas. Includes net storage inventories for the year, volumes delivered on TGN - Otay Mesa, N. Baja
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale, and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CalGEM.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 14 – RECORDED 2024 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other [1]	Ruby	Total
Southern California Gas Company [2]									
Core + UAF [3] [4]	217	372	141	11	194	0	6	0	941
Noncore C&I, EG/EOR/Wholesale/Int' l	(120)	425	227	191	488	122	(5)	0	1,328
Total	97	797	368	202	682	122	1	0	2,269
Pacific Gas and Electric Company [5]									
Core	0	32	0	378	(4)	0	0	182	588
Noncore Industrial/Wholesale/EG [6]	20	325	174	1,076	18	0	0	131	1,744
Total	20	356	174	1,454	14	0	0	314	2,333
Other Northern California									
Core [7]									
No-Utilities Served Load [8] [9]									
Direct Sales/Bypass	216	11	0	0	553	52	0	0	832
TOTAL SUPPLIER	334	1,164	542	1,656	1,249	174	1	314	5,434
San Diego Gas & Electric Company									
Core	31	53	20	2	27	0	1	0	133
Noncore Commercial/Industrial	(20)	33	19	20	46	13	(1)	0	110
Total	10	85	39	22	73	13	0	0	243
Southwest Gas Corporation									
Core	29	0	0	0	0	0	0	0	29
Noncore Commercial/Industrial	1	0	0	0	0	0	0	0	1
Total	30	0	0	0	0	0	0	0	30

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E; for SoCalGas. Includes net storage inventories for the year, volumes delivered on TGN - Otay Mesa, N. Baja
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale, and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CalGEM.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 15 – RECORDED 2025 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other [1]	Ruby	Total
Southern California Gas Company [2]									
Core + UAF [3] [4]	135	362	184	11	209	0	(5)	0	896
Noncore C&I, EG/EOR/Wholesale/Int' l	(47)	359	247	125	427	79	21	0	1,211
Total	88	721	431	136	636	79	16	0	2,107
Pacific Gas and Electric Company [5]									
Core	0	29	0	452	(14)	0	0	119	586
Noncore Industrial/Wholesale/EG [6]	20	303	135	1,024	27	0	0	66	1,575
Total	20	332	135	1,475	13	0	0	186	2,161
Other Northern California									
Core [7]	2								2
No-Utilities Served Load [8] [9]									
Direct Sales/Bypass	200	5	0	0	471	65	0	0	741
TOTAL SUPPLIER	310	1,058	566	1,611	1,120	144	16	186	5,011
San Diego Gas & Electric Company									
Core	20	55	28	2	32	0	(1)	0	135
Noncore Commercial/Industrial	(10)	29	22	14	42	9	3	0	108
Total	10	83	50	16	73	9	2	0	243
Southwest Gas Corporation									
Core	24	0	0	0	0	0	0	0	24
Noncore Commercial/Industrial	1	25	25	25	25	25	25	25	177
Total	25	25	25	25	25	25	25	25	201

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E; for SoCalGas. Includes net storage inventories for the year, volumes delivered on TGN - Otay Mesa, N. Baja
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale, and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CalGEM.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The tables below summarize the highest sendout days by the state in the summer and winter periods from the last five years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

TABLE 16 – ESTIMATED CALIFORNIA HIGHEST SUMMER SENDOUT, 2021-2025, MMcf/d

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2021	09/09/2021	2,909	2,827	5,736	1,080	6,816
2022	09/06/2022	2,620	3,229	5,849	1,080	6,929
2023	08/16/2023	2,627	3,015	5,642	1,109	6,751
2024	09/05/2024	2,509	2,967	5,476	962	6,438
2025	8/21/2025	2,533	2,638	5,231	928	6,159

TABLE 17 – ESTIMATED CALIFORNIA HIGHEST WINTER SENDOUT, 2021-2025, MMcf/d

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2021	12/14/2021	3,470	3,837	7,307	935	8,242
2022	02/23/2022	3,439	3,953	7,392	838	8,230
2023	01/30/2023	3,607	3,736	7,343	903	8,246
2024	01/08/2024	3,361	3,851	7,212	873	8,085
2025	1/27/2025	3,155	3,346	6,501	799	7,300

Notes:
(1) PG&E Pipe Ranger.
(2) SoCalGas Envoy.
(3) Source: Provided by the CEC. Data are from Geologic Energy Management Division (CalGEM), Monthly Oil and Gas Production, and Injection Report. Nonutility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern-Mojave and California in-state production.
(4) PG&E and SoCalGas sendout(s) are reported for the day on which the Utility Total sendout is maximum for the respective seasons each year. For each calendar year, Winter months are Jan, Feb, Mar, Nov, and Dec; while summer months are Apr, May, Jun, Jul, Aug, Sep, and Oct.

CORE SUPPLY STANDARDS

The following tables are presented pursuant to D.22-07-002 issued in the Gas Planning OIR (R.20-01-007):

TABLE 18 – STATEWIDE FIRM CORE GAS INTERSTATE PIPELINE CAPACITY (% OF AVERAGE DAILY DEMAND)

Time of Year	PG&E	SoCalGas
Winter (PG&E: Dec-Feb, SoCalGas: Nov-Mar)	100%-162%	100%-120%
Shoulder (Mar & Nov)	80%-162%	100%-120%
Summer (Apr-Oct)	80%-105%	90%-120%

TABLE 19 – PG&E FIRM CORE GAS STORAGE ALLOCATION

Firm Core Gas Storage Allocation from PG&E[1]	
Gas Inventory (Bcf)	6.6
Maximum November Withdrawal (MMcf/d)	204
Maximum Dec-Feb Withdrawal (MMcf/d)	407
Maximum March Withdrawal (MMcf/d)	204
Average Apr-Oct Injection (MMcf/d)	33
Maximum Nov-Mar Injection (MMcf/d)	0

TABLE 20 – SoCalGas FIRM CORE GAS STORAGE ALLOCATION

Firm Core Gas Storage Allocation from SoCalGas	
Gas Inventory (Bcf)	80
Winter Withdrawal (MMcfd)	1,890
Summer Withdrawal (MMcfd)	606
Winter Injection (MMcfd)	392
Summer Injection (MMcfd)	150

1 Conversion factor of 1.044 Dth/Mcf applied.

2026 CALIFORNIA GAS REPORT

STATEWIDE MARKET CONDITIONS

MARKET CONDITIONS

The role of natural gas in the energy mix remains significant and it is expected to continue playing a vital role in meeting customers' energy needs, even as emissions reduction targets for 2030 are pursued and reliance on intermittent renewable resources increases. The Energy Information Administration (EIA) reported that the national benchmark Henry Hub price averaged $3.66/Million British thermal units (MMBtu) in 2025, approximately 60% higher than the 2024 average natural gas price. Natural gas consumption also increased, driven by higher liquefied natural gas (LNG) exports and colder-than-average temperatures, both of which contributed to elevated demand.

Over the next few years, gas prices will likely be influenced by demand growth from LNG exports, US exports to Mexico, gas use for power generation as data center loads grow, and temperature. Supply-side factors include North American gas production, gas imports from Canada, and natural gas storage levels.

Over the longer term, market conditions will continue to mature. Similar to the near term, exports, both LNG and to Mexico, are expected to grow. For LNG, the growth becomes more geographically broad, with new global exports from Mexico and expanding in Canada and the United States. Power generation from gas-fired generation is expected to grow in conjunction with data center load growth. Gas production continues to grow with these demand conditions.

DEVELOPMENT OF THE GAS PRICE FORECAST

The 2026 near-term gas price average at the California Citygates[2] is a above $3.00/MMBtu.[3] By the end of the decade, gas prices are projected to reach between $4.00 and $5.00 MMBtu before reaching between $5.00 and $7.00 MMBtu by 2040. The 2026 CGR gas price forecast is based on a February 2026 forecast from S&P Global Commodity Insights.

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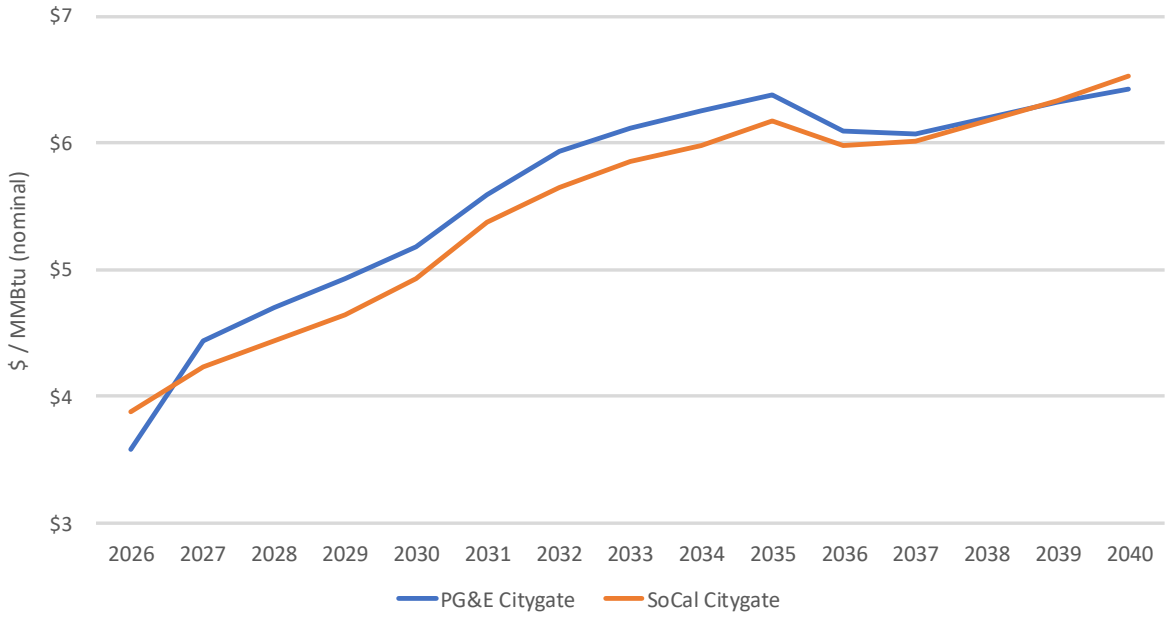
2 The two Citygate price hubs are the Southern California Gas Company Citygate (SoCal Citygate) and the Pacific Gas and Electric Company Citygate (PG&E Citygate).

3 Nominal dollars.

FIGURE 2 – FORECASTED NATURAL GAS PRICES



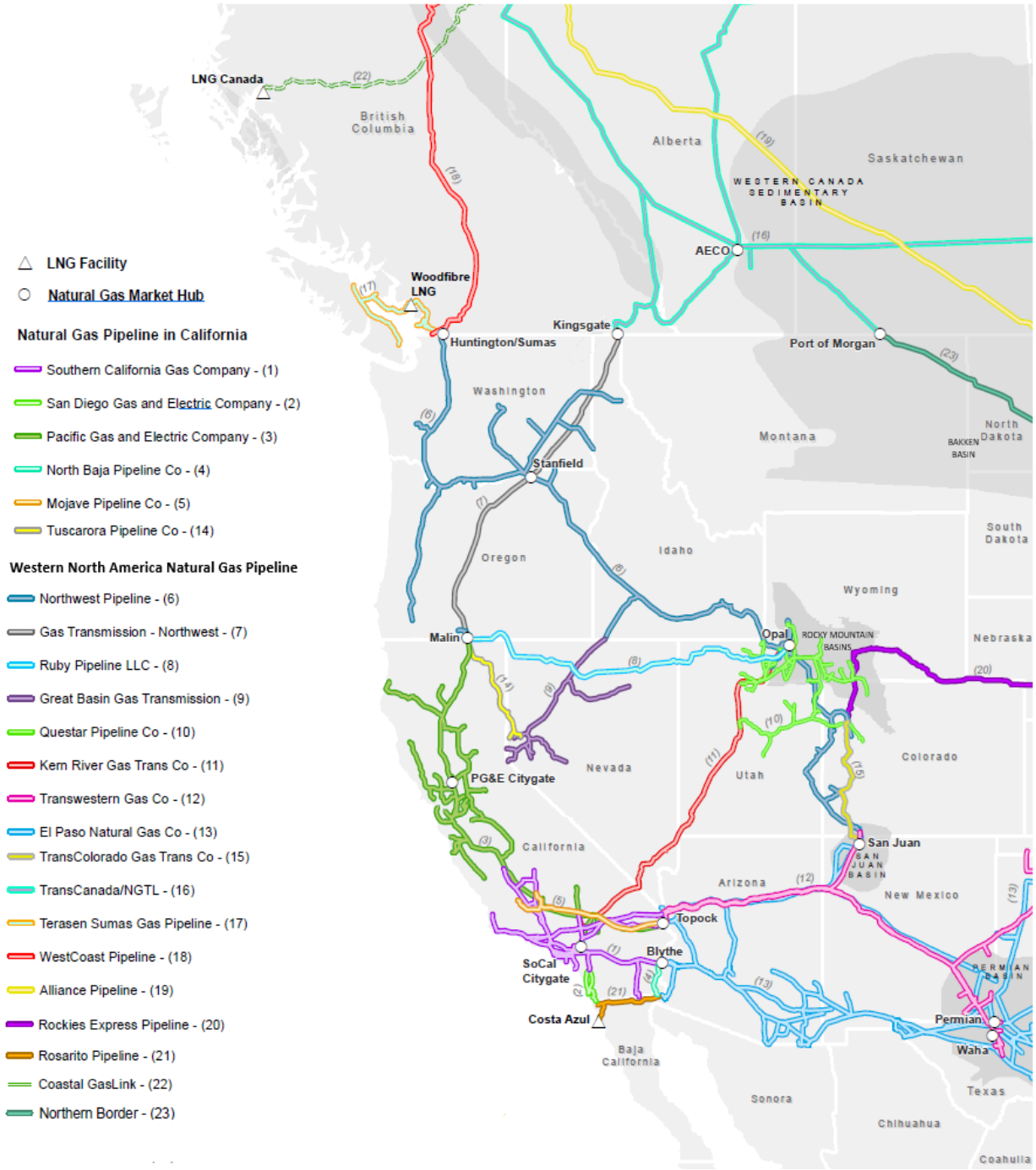
It is important to recognize that natural gas price forecasts are inherently uncertain. PG&E, SoCalGas, and the respondents to this 2026 CGR, individually and collectively, do not warrant the accuracy of these projections and are not liable for any use of, or reliance on, this forecast.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and provides long-term supply availability. California has access to gas production from several regions, including in-state sources (onshore and offshore), the Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains, and Canada.

California natural gas utilities and customers gain access to this diverse supply portfolio using an extensive pipeline system. Interstate pipelines serving California include Ruby Pipeline LLC, El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission Northwest LLC (GTN), Transwestern Pipeline Company, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline. The map on the following page shows the locations of these supply sources and the interstate natural gas pipelines serving California.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES



California benefits from substantial gas storage capacity in dedicated underground gas storage facilities across the state. These facilities supplement pipeline supply during periods of high demand and enhance overall supply reliability. Storage also enables gas customers to take advantage of lower prices by storing gas for use during periods of higher prices. Various regulations and standards[4] have been implemented to help support the safe and reliable operations of California's underground gas storage facilities. The table below presents the current status of gas storage capacity in California.

TABLE 21 – STATEWIDE NATURAL GAS STORAGE CAPABILITIES, 2025 STORAGE

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)	Cite
Northern California				
Independent Storage Providers				1
Lodi Gas Storage	31	550	750	
Wild Goose Storage	75	525	950	
Gill Ranch	15	165	265	
Central Valley	11	300	300	
PG&E-Utility Storage***	37	315	785	2
Northern California Total	169	1,855	3,050	
Southern California				
SoCalGas	119.5	800 (summer) 550 (winter)	1,900 (summer) 2,400 (winter)	3
California Total	288.5	2,655 (summer) 2,405 (winter)	4,950 (summer) 5,450 (winter)	

Citations:
(1) Capacities derived from information provided by Independent Storage Providers.
(2) ***Firm maximum inventory level
(3) SoCalGas/SDG&E Triennial Cost Allocation Proceeding, D.20-02-045

[4] See California Geologic Energy Management Division's (CalGEM) Underground Natural Gas Storage website for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

In addition to traditional sources of natural gas supply, multiple Renewable Natural Gas (RNG) interconnection projects in California have come online in recent years. As further detailed in this CGR, gas utilities see significant potential for RNG and are taking steps to streamline and improve the RNG interconnection process. Currently, incentives such as Low Carbon Fuel Standards (LCFS) and renewable identification number (RIN) credits are supporting the use of RNG in the transportation sector. As policies evolve and new programs, such as California's Renewable Gas Standard (RGS),[5] are implemented, RNG is expected to play an increasingly important role in meeting customers' energy needs beyond the transportation sector.

As California continues transitioning to a decarbonized energy system, hydrogen (H_2) is also emerging as a complementary fuel. Blending pilots have been proposed to demonstrate the use of renewable hydrogen within existing gas infrastructure to reduce emissions while supporting energy needs.

5 See CPUC Decision (D).22-02-025.

2026 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

PG&E owns and operates an integrated natural gas transmission, underground storage, and distribution system across most of Northern and Central California. PG&E's natural gas system spans the region, with a service area that stretches from Eureka to Bakersfield and from the Pacific Ocean to the Sierra Nevada. Our system consists of approximately 45,400 miles of gas distribution pipelines, more than 5,500 miles of gas transmission pipelines, two fully owned underground storage facilities,[6] and a 25 percent interest in Gill Ranch Storage. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its interconnections with interstate pipelines, California gas fields and California RNG facilities to PG&E's local transmission and distribution systems, other local distribution companies, and other pipeline operators.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.6 million residential, commercial, industrial, and electric generation customers.[7] PG&E also provides gas transportation and storage services to a variety of gas-fired EG plants in its service area and serves multiple Natural Gas Vehicle (NGV) fleets, including utility-owned facilities, with its publicly accessible fueling stations throughout California. Other wholesale distribution systems, which receive gas transportation services from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are in 37 counties from southeast 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, including other regulated utilities, utilize the PG&E system to meet their gas needs in Southern California.

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6 PG&E, Pleasant Creek Gas Storage Holdings LLC, and eCORP Natural Gas Storage Holdings LLC submitted a joint application under Pub. Util. Code section 851 to the CPUC on July 18, 2023, seeking approval for the sale. The CPUC granted approval on April 24, 2025 (D.25-04-032), and the sale was completed on April 24, 2026.

7 PG&E does not provide procurement services for noncore customers.

The Northern California section of this report includes details of the following Northern California forecasts and is consistent with the forecasting requirements in the CPUC's Decision 22-07-002 issued in the Long-Term Gas System Planning Order Instituting Rulemaking (OIR)[8]

- Average Demand Annual Forecast
- High Demand Annual Forecast (1-in-10 Cold and 1-in-10 Dry)
- Core Peak Demand and Supply Forecast on an Abnormal Peak Day (APD)
- 1-in-2-Year Cold Winter Day Forecast (High Demand Day in an Average Demand Year)
- 1-in-10-Year Peak Winter Day Forecast (High Demand Day in a 1-in-10 Cold and 1-in-10 Dry Demand Year)
- Dry Year Summer Day High Demand Estimate (High Demand Day in a 1-in-10 Dry Demand Year)

The Northern California section also includes discussions on gas demand sensitivity, policies and legislative developments impacting gas demand, and a chapter on gas supply, pipeline capacity, storage, and related policies.

The following is a summary of key takeaways:

The Northern California Gas Demand Forecast Reflects the Impact of California's Existing Decarbonization Policies: PG&E's average-year demand[9] is forecasted to decline at an annual average rate of 4.0 percent between 2026 and 2040. The decline in forecasted gas demand is in response to the state of California's decarbonization policies and is driven by reductions in Core and electric generation (EG) demand:

- Core: The decline reflects reduced demand due to energy efficiency, building electrification (BE) from switching from natural gas appliances to electric, and climate change. Approved regional and proposed state of California zero emission appliance standards have also been factored into the core demand forecast. The modeled effects of the zero emission appliance standards include potential uncertainties such as legal challenges and technical or supply chain constraints.

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8 Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning, Rulemaking 20-01-007.

9 Gas demand projection for an average temperature year and normal hydroelectric generation year.

- Electric Generation: The decline reflects the impact of renewable generation and energy storage additions to achieve a CAISO-wide greenhouse gas (GHG)-free electric system by 2045, but uncertainty in resource build rates, gas prices, data center demand, and the retirement of Diablo Canyon Power Plant (DCPP) remain.

The Northern California Gas Demand Forecast Does Not Necessarily Achieve 100% Decarbonization of the Gas System: It is important to note that the California Gas Demand Forecast is not constrained to meet a net-zero gas system by 2045. Such a forecast would need to include, but would not be limited to, additional building decarbonization. Additionally, higher levels of RNG and hydrogen, and emerging technologies such as carbon capture and sequestration (CCS), could be deployed to meet the higher demand forecasted in the 2026 CGR. PG&E expects to work with the CPUC and other stakeholders within the Gas Transition OIR (R.24-09-012) to advance California's transition away from fossil natural gas (to electrification and cleaner fuels) affordably.

The Forecasted Demand is Subject to Significant Uncertainties: Key forecast uncertainties include the pace and magnitude of BE, new data center capacity, Northern and Southern California gas price differentials, and planned electric generation buildout and transmission limitations.

PG&E is Taking Actions to Evolve the Natural Gas System to be a Safe, Reliable, and Affordable Energy Delivery Platform Consistent with Decarbonization Goals: PG&E's work is guided by the following four pillars:

1. Reduce the carbon footprint of the gas system by greening the gas supply, leveraging electrification, converting facilities from more impactful fuel sources, and conducting methane abatement.

2. Decrease costs by limiting system expansion, strategically reducing capital and operational expenses, strategically pruning the gas system, and through electrification while continuing to maintain a safe and reliable system.

3. Increase demand through strategic investment in the gas system to increase load by providing cleaner fuels to hard to electrify customers.

4. Leverage innovative financial mechanisms such as changes to depreciation, rate design, and external funding to help close the gap between costs and revenues.

Policy and Regulatory Solutions and a Managed Transition Plan Are Needed to Keep Customers' Bills Affordable: PG&E is committed to working with regulators and other stakeholders to support statewide GHG reduction policies and develop options to minimize customer bill impacts. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. In order to successfully implement the state of California's environmental goals, it is critical that issues such as obligation to serve, treatment of capital versus expense dollars, and non-traditional funding are addressed and resolved in a manner that supports affordably meeting PG&E's and California's climate objectives.

Regulatory bodies and investor-owned utilities (IOU) should continue to work together to ensure that Californians continue to have access to clean, reliable, and affordable energy. In support of these important goals, PG&E is actively participating in the Gas Transition OIR, which addresses crucial topics that will impact the future of the California gas system.

PG&E is accelerating its work on the use of RNG to contribute towards access to clean, reliable, and affordable energy. The current investment and incentives for RNG principally favor the transportation sector, resulting in little RNG availability to comply with the recently enacted Renewable Gas Standard (RGS).[10] If this is to change, California will have to take several actions, mainly (a) incentivize the interconnection costs, (b) help streamline the interconnection process, and (c) incentivize diversified technology and fuel sources so that utilities will have access to cost effective RNG to comply with the RGS.

[10] CPUC Decision 26-04-044 606216379.PDF (ca.gov).

ANNUAL GAS DEMAND

This chapter contains PG&E's annual[11] gas demand forecasts (average and high demand year),[12] a description of the forecast methodology, details on average demand forecast by customer sector, and details on key assumptions driving the forecast. The chapter concludes with an analysis of forecast uncertainty, providing potential changes in Core and EG gas demand if key forecast drivers were to materialize differently than assumed in the 2026 CGR.

AVERAGE DEMAND SUMMARY

PG&E's average-year demand[13] is forecasted to decline at an annual average rate of 4.0 percent between 2026 and 2040. The Core sector is forecasted to decline at an average annual rate of 4.2 percent, driven by building electrification. The Noncore sector is forecasted to decrease at a rate of 4.0 percent annually, driven largely by a decrease in throughput for electric generation. Decline in throughput from Noncore Industrial customers is marginal at a rate of less than 0.1 percent annually.

The projected decline in total demand could result in gas system operating and maintenance costs being allocated over lower usage, potentially causing customer gas rates to increase. Consequently, PG&E is actively developing programs to reduce gas system costs but will need statewide utility stakeholders to partner in work to mitigate customer rate increases.

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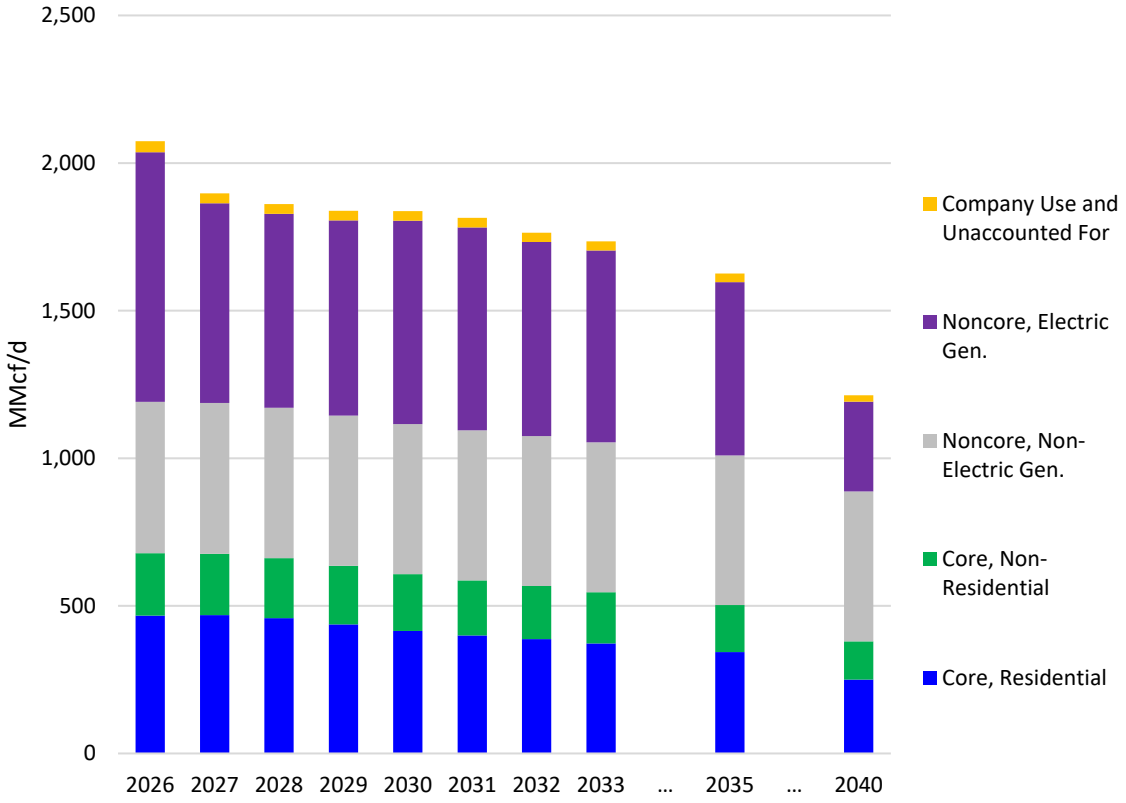
11 Monthly forecasts will be available in PG&E's workpapers.

12 The average demand year gas forecasts are for an average temperature year and average hydroelectric generation for the most recent 15 historical years (2010-2024). The high demand year forecast presents demand under cold temperature and dry hydroelectric generation to provide more information about gas throughput under stressed conditions.

13 Forecasts are presented in tabular form at the end of the Northern California section.

FIGURE 4 – NORTHERN CALIFORNIA ON-SYSTEM GAS DEMAND AVERAGE YEAR



Changes in the major components of on-system gas demand are illustrated in Figure 4 above. Core demand decline is driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore, non-EG demand is forecasted to remain largely flat over the forecast horizon, as potential demand growth is partly offset by increasing gas prices.

The EG demand forecast is largely a function of electric energy demand, the future CAISO generation portfolio, transmission constraints (including imports from other balancing authorities) and gas prices. PG&E's EG demand forecast incorporates the renewable generation and electric storage forecast from the Commission's least-cost portfolio developed as part of the 2024-2026 Integrated Resource Planning process.[14] The electric energy demand input for the EG forecast incorporates the impacts of future data center load and building electrification.

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14 CPUC Integrated Resource Planning Proceeding: https://www.cpuc.ca.gov/irp/; 2026 IRP Rulemaking: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K998/602998487.PDF.

Relative to the gas price forecast utilized in the 2024 CGR, the gas prices in this forecast are on average $1.00/MMBtu lower over the long-term.

AVERAGE DEMAND MARKET SECTOR FORECASTS

Residential

Northern California residential demand is forecasted to decrease from 467 MMcf/d in 2026 to 250 MMcf/d in 2040, primarily driven by a decrease in use per customer from increased building electrification and improvements in appliance and building shell efficiencies. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. This forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the state, regional, and local policies, customer cost savings, or other mechanisms. A key driver is Zero-Energy Appliance Standards (ZEAS), which place a point-of-sale ban on new gas appliances. As noted in the "Gas Demand Assumptions" and "Impact of Zero-Emission Appliance Standards" sections below, there is significant uncertainty in how this impacts future gas demand as new standards are adopted, implemented, and revised as market conditions change. Accordingly, PG&E assumes lower than 100% compliance with currently adopted and proposed standards in the Northern California residential forecast.

2. The warming climate will reduce winter heating needs, gradually decreasing residential gas sales.

3. A forecasted increase in customer counts is expected to partially counteract the trends described here but the overall impact is expected to be a net decrease in residential gas demand.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2040, annual residential gas throughput is projected to be 48% lower than forecasted 2026 throughput, with most of the decrease driven by a higher building electrification assumption as we approach the 2040s. Please note that the Northern California residential demand forecast does not assume full

compliance with appliance ban policy mandates proposed or "on the books." If market barriers are addressed and compliance increases, residential gas demand could decline faster. Refer to the "Forecast Methodology and Assumptions" and "Analysis of Forecast Uncertainty" sections below for more details.

Commercial

Northern California commercial demand, excluding natural gas vehicles, is forecasted to decrease from 203 MMcf/d in 2026 to 116 MMcf/d in 2040. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing existing trends of energy efficiency and climate change, to lead to a long-term decline in commercial throughput although not at the levels needed for full policy compliance. As a result, total commercial gas demand is projected to decline on average 3.9 percent per year through 2040, with the decline accelerating in later years. Core natural gas vehicles (NGV) remain a minor component that is forecasted to grow at about 3 percent per year.

Industrial

Northern California industrial demand is forecasted to decrease nominally from 469 MMcf/d in 2026 to 464 MMcf/d in 2040. Gas requirements for PG&E's industrial sector are affected by the level and the type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector can fluctuate due to a combination of gas prices, noncore to core migration, capacity at local refineries, and manufacturing demand tied to market dynamics. Recorded data shows a drop-off in industrial usage beginning in 2020 corresponding to the impacts of COVID on large industrial users, such as refineries, which seems to have largely recovered. Although demand can fluctuate in the near-term, over the long-term industrial gas consumption is expected to decrease slowly, due to decreasing customer counts and higher gas prices.

As noted above, refinery production is a key driver of industrial gas demand in PG&E's service area. In April 2025, Valero announced that they would be decommissioning their Benicia refinery by the end of April 2026.[15] While it remains uncertain whether the production

[15] https://investorvalero.com/news/news-details/2025/Valero-Announces-Notice-to-the-California-Energy-Commission-Regarding-its-Benicia-California-Refinery/default.aspx

from this refinery will be picked up by other Bay Area refineries or, this closure has the potential to significantly reduce industrial gas demand.

As with the commercial category of NGV, industrial category NGV sees moderate growth from a small base, with some yet unquantified possibilities for additional growth as described in "Gas Demand Trends and Strategy" below.

Given the state's GHG reduction targets, PG&E has been working with many of our industrial customers to begin converting them to natural gas from more polluting fuels, with an eye towards RNG and potentially hydrogen in the future. Although these conversions are in the planning stage and could increase industrial gas use, natural gas demand from the industrial sector is expected to largely remain flat through 2040.

Electric Generation

Northern California EG demand[16] is forecasted to decrease by 18% in 2030, 32% in 2035 and 71% in 2040 compared to 2026 forecasted throughput. EG demand is projected to increase slightly in 2030-2031 due to the retirement of Diablo Canyon[17] (although demand in those years is still forecasted to be lower than present day conditions). The average projected gas demand from 2026-2029 is 597 MMcf/d and from 2030-2035 is 558 MMcf/d, and 329 MMcf/d during the final 5 years of the forecast.

The EG gas demand forecast is subject to significant uncertainty due to factors including:

- Future burner-tip gas prices;
- Electric demand growth from data centers, building electrification, transportation electrification, etc.
- Timing and location of new generation and storage resources; and
- Variable precipitation affecting hydroelectric generation.

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16 Northern California Electric generation demand includes demand from gas-fired cogeneration and power plants connected to PG&E's gas system.

17 CPUC Decision (R-23-01-007) Conditionally Approving Extended Operations at Diablo Canyon Nuclear Power Plant Pursuant to Senate Bill 846, 12/14/2023. OP 1. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496261.pdf

To assess the broad impact of these uncertainties, this report discusses a sensitivity analysis conducted with PG&E's EG model in the "Analysis of Forecast Uncertainty" section.

SACRAMENTO MUNICIPAL UTILITY DISTRICT ELECTRIC GENERATION

Sacramental Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the U.S. and provides electric service to over 575,000 customers within the greater Sacramento area. SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.9 percent in PG&E's Lines 300 A and B and approximately 4.7 percent in Line 401. 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 171 MMcf/d, and the average load is about 96 MMcf/d. This forecast assumes the average load of 119 MMcf/d in 2026 and a decline to 94 MMcf/d by 2030, which is embedded in this forecast.

FORECAST METHODOLOGY AND ASSUMPTIONS

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric regression models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption, such as building electrification. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years.

For the 2026 CGR, PG&E utilized Itron's MetrixND forecasting platform.[18] Itron's industry-leading forecasting engine allows rapid development of accurate forecasts. Itron has developed, tested, and refined MetrixND for more than 10 years, providing a proven track record in the real world of energy forecasting.

Forecasts of EG gas demand by power plants connected to PG&E's gas system are developed by modeling the Western Electricity Coordinating Council (WECC) electricity market using PLEXOS software. PLEXOS is a production cost modeling tool that estimates the generation by, and consumption of, all fuels used for power generation on an economic basis.

[18] For more details, please visit, https://na.itron.com/products/metrixnd.

The tool determines the least cost dispatch of generating resources to meet a given power demand while accounting for high-level transmission limitations.

Temperature Assumptions

Space heating accounts for a high percentage of gas use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Year demand forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 20 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact on the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate.

Actual temperatures in the forecast period will be higher or lower than the assumption including climate change. Temperature variation impacts gas use. PG&E's High Demand (Cold Weather, Dry Hydro) forecast assumes that winter temperatures in the forecast horizon will have a 1-in-10 likelihood of occurrence.

PG&E's EG gas throughput forecast assumes an average summer. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demand and drives up power plant gas demand. This forecast captures the seasonal variations every month.

Hydroelectric Conditions Assumptions

Annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent 15 historical years, 2010-2024, in the Average Year demand forecast. PG&E uses the High Demand (Cold, Dry Hydro) forecast to illustrate the impacts from reduced in-state hydroelectric availability on EG demand. PG&E uses the hydroelectric generation conditions for the calendar years 2015 and 2021 to represent the "1-in-10" dry hydro case.

Gas Price and Rate Assumptions

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand. This is especially true for market sectors that are particularly price sensitive, such as the industrial or EG sectors. PG&E used the gas commodity price forecast described in detail in the Statewide Market Conditions section of this report. It combines transportation rates with the gas commodity price forecast. PG&E's forecast presented in the report assumes that changes to throughput do not directly impact rates. As a reminder, natural gas price forecasts are inherently uncertain and impact market sectors sensitive to price.

Gas Demand Assumptions

As described above, PG&E's Average Year forecast is developed from econometric regression models for non-EG sectors. This forecast is modified by forecasts of policy and technology adoption. The major modifiers are building electrification (BE) and energy efficiency (EE). The demand forecast for Northern California utilizes PG&E's 2026 Annual Load Forecast (ALF) BE forecast. This BE forecast captures an increasing amount of equipment conversions from natural gas to electricity arising from factors such as enacted regional and potential statewide replace-on-burnout appliance bans and new construction standards. Since it is likely that these standards will not be implemented exactly as written, PG&E incorporates input from internal subject-matter experts to reflect the high level of uncertainty inherent in building electrification. For example, PG&E's 2026 ALF incorporates the potential for appliance ban amendments like the Bay Area Air District (BAAD) is currently considering[19] as implementation barriers are better understood. Building electrification quantities in this forecast have accompanying gas reduction quantities. These gas reductions are included in the forecasts as a modifier to the base models.

PG&E also includes the impact of EE in its gas forecasts. PG&E utilized the CEC's "Additional Achievable Energy Efficiency" (AAEE) scenario 3[20] (Planning Scenario) savings.

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19 The most recent amendments can be found on the BAAD webpage here: https://www.baaqmd.gov/rules-and-compliance/rules/reg-9-rule-6-nitrogen-oxides-emissions-from-natural-gasfired-water-heaters?rule_version=2021%20Amendment.

20 https://www.energy.ca.gov/publications/2026/2025-integrated-energy-policy-report.

AAEE represents energy savings from programs that had not yet been funded and new codes and standards (C&S). AAEE is added as a demand reduction modifier on top of the base forecast.

Electric Load Assumptions

PG&E's EG forecasts rely on the "Planning" case electricity demand forecast from the CEC's 2025 Integrated Energy Policy Report (IEPR).[21] The 2025 IEPR Planning Scenario captures an increasing electric load driven by data center growth, electric vehicles, and other policy and technology adoption trends. For Northern California, the electric demand forecast also includes the BE modifier from PG&E's 2026 ALF consistent with the "Gas Demand Assumptions" section above (instead of the 2025 IEPR Planning BE assumption, Additional Achievable Fuel Substitution (AAFS) Scenario 2). For Southern California, PG&E utilized the BE assumption developed by SoCalGas. SoCalGas' assumption utilizes only the programs and incremental codes and standards ("PiCS") impact of the 2025 IEPR's AAFS Scenario 1 forecast and does not include the other component of the AAFS scenario -- impacts from additional zero-emission ("ZE") appliance adoption. In the near term, PiCS represents a majority of the total AAFS impacts but comprises only 20% of the total AAFS 1 forecast by 2040. The AAFS PiCS Scenario 1 assumption is substantially lower in magnitude than PG&E's 2026 ALF and the IEPR "Planning" AAFS assumption, AAFS Scenario 2. PG&E elected to use this assumption for Southern California to develop a consistent set of statewide forecasts.

Electric Generation and Electric Transmission Assumptions

With expected higher electric load and state-wide GHG emission reduction targets, California's portfolio of generation resources is expected to change significantly over the forecast horizon to 2040. PG&E's assumption for the future resource portfolio underlying EG forecasts were developed from two data sources: recent recorded generation and storage additions as reported by the CPUC[22] and the "Least Cost" Portfolio in the current CPUC

21 https://www.energy.ca.gov/publications/2026/2025-integrated-energy-policy-report.

22 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-march-2026-release.pdf.

2024-2026 Integrated Resource Planning proceeding.[23] The incremental resource build from 2026 through 2030 is based on the average of 2024 and 2025 actual additions of approximately 6.5 GW/year, of which 4.2 GW are storage additions and the rest from renewables (mainly solar). The 2024-2026 IRP Least Cost portfolio, in contrast, assumes a near-term build rate of almost 12 GW and a renewable build rate nearly 3 times the current historical rate beyond 2030, the resource portfolio is taken from the aforementioned "Least Cost" portfolio developed by the CPUC to meet rising electric demand, reliability needs, GHG, RPS, and SB100 targets.

Diablo Canyon Power Plant Retirement Dates

For the 2026 CGR, PG&E assumed that Diablo Canyon Power Plant (DCPP) Reactor 1 retires on November 1, 2029, and DCPP Reactor 2 retires on November 1, 2030, in accordance with the CPUC D.23-12-036.[24]

It is worth noting that while DCPP is assumed to remain online for longer than previously assumed, the 2024-2026 IRP Least Cost electric portfolio developed by the CPUC identifies replacement resources as if DCPP retired according to its originally planned deadlines in accordance with SB 846.

HIGH DEMAND SCENARIO: COLD/DRY HYDRO

The Average Year gas demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast presented in the Average Year forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture some of the uncertainties in gas demand, PG&E developed a high gas demand case for cold temperature conditions and dry hydroelectric (hydro) conditions.

The High Demand Scenario forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. The cold weather assumption increases gas and

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23 2024-2026 Integrated Resource Planning Inputs & Assumptions, February 2026. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

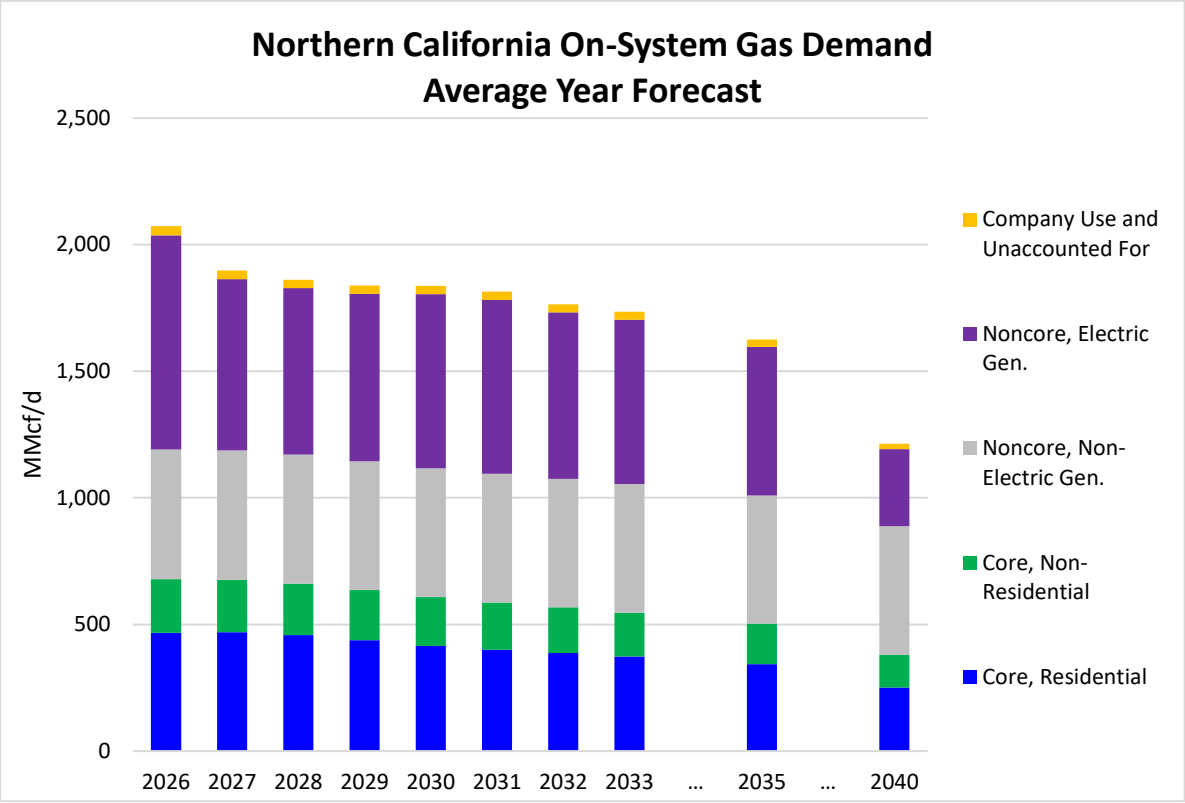
24 D.23-12-036, Decision Conditionally Approving Extended Operations at Diablo Canyon Nuclear Power Plant Pursuant to Senate Bill 846.

electric load for space heating needs and EG gas demand. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same dry hydroelectric generation conditions as those that prevailed during 2015 and 2021.

Total gas demand for the High Demand Scenario forecast averages 8 percent higher than the Average Year demand forecast. The cold weather impact drives gas throughput higher due to increased need for space heating. Winter monthly Core throughput is projected to increase on average by 7 percent, ranging from 6 to 10 percent. The non-core industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the Average Year demand forecast.

This forecast projects that EG gas demand will increase by 18 percent on average over the Average Year demand outlook (approximately 95 MMcf/d). In this forecast, the generation from Northern California hydroelectric resources is about half of the 15-year average assumed in the Average Year demand outlook. This lower generation increases EG gas demand. Hydroelectric conditions can vary widely throughout the WECC and illustrate another degree of uncertainty in EG gas demand forecasting.

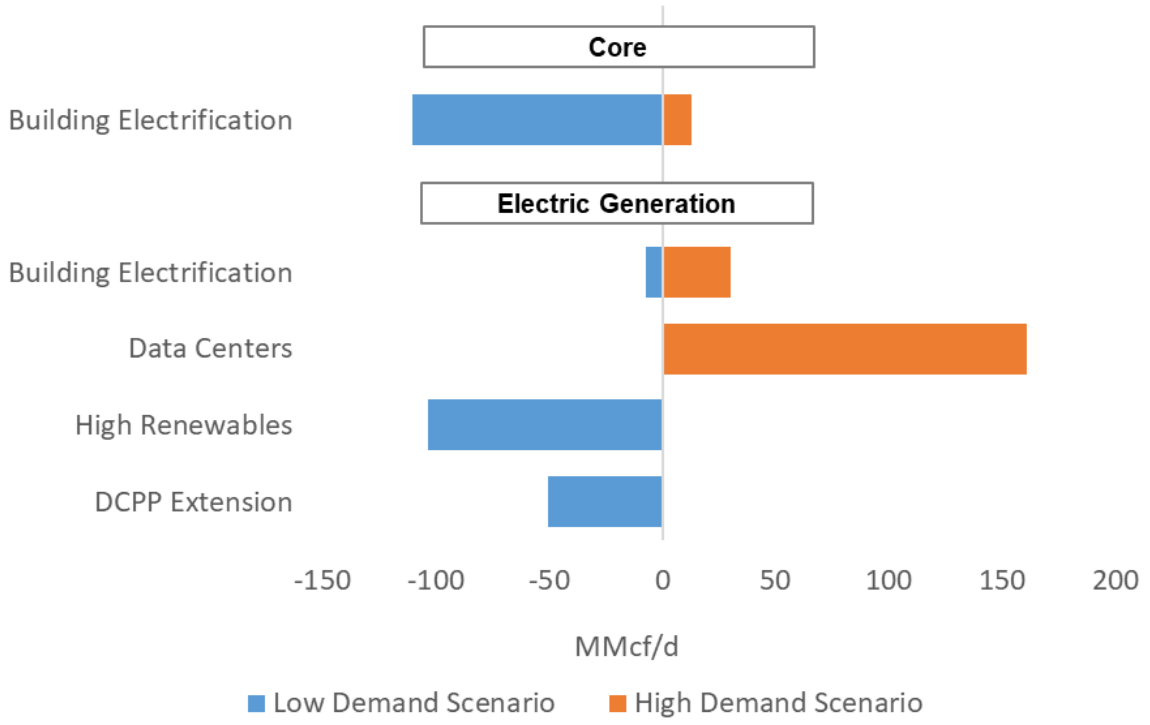
FIGURE 5 – NORTHERN CALIFORNIA ON-SYSTEM GAS DEMAND HIGH DEMAND YEAR



ANALYSIS OF FORECAST UNCERTAINTY

Gas demand forecasts are driven by the assumptions utilized. There is inherent uncertainty in these assumptions that can result in actual gas demand deviating from the forecast. PG&E has developed this section to help illustrate how changes in key assumptions could potentially impact gas demand over different time horizons.

FIGURE 6 – CORE AND EG GAS DEMAND UNCERTAINTY ANALYSIS (2030)



NOTE:
The impact of building electrification on Core and EG gas demand is inversely related. An assumption of overall lower building electrification will increase Core demand and decrease the demand for electricity, thus lowering demand from electric generators on PG&E's gas system.

FIGURE 7 – CORE AND EG GAS DEMAND UNCERTAINTY ANALYSIS (2040)

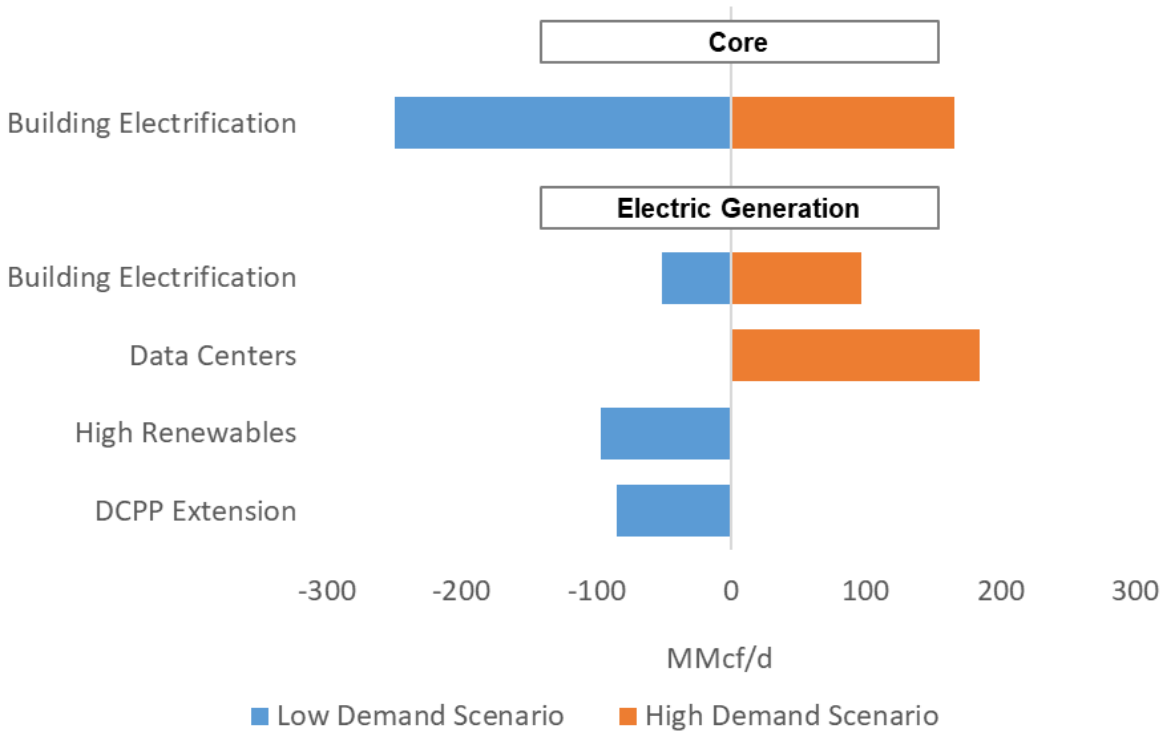


Figure 6 above shows the sensitivity in gas demand from four key drivers in 2030 (a) and 2040 (b) building electrification (impacts both Core and EG), data center demand, renewable portfolio buildout, and the extension of DCPP (each impact EG only). More details on BE and EG uncertainty are provided below. These figures are presented as "Tornado Charts" which illustrate the potential change in impact that varying an assumption could have relative to the "Average Year" demand forecast. A positive value indicates an increase in the forecast and a negative value indicates a decrease. It is important to note that the values in the "Tornado Chart" are not additive. For example, adding more renewables than planned and extending DCPP would have interactive effects since they could both displace the same gas demand. To fully assess the combined impact, scenarios incorporating multiple assumption changes would need to be developed.

Building Electrification Sensitivity Analysis (Core and EG)

BE is one of the most impactful drivers of future forecasted gas demand in California. As noted in the sections above, PG&E utilized the BE assumption from its 2026 ALF for Northern

California. To quantify a range of uncertainty in gas demand associated with BE, PG&E conducted two sensitivities with alternative BE assumptions – one in which the same assumption used for SoCal Gas as described in the "Electric Load Assumptions" section, 2025 IEPR AAFS 1 Programs and incremental Codes and Standards "PiCS" only, is applied to PG&E, and another using the 2025 IEPR's "Local Reliability Scenario" BE assumption, AAFS 3.

The AAFS 1 case represents a "low" case where there is virtually no future appliance bans or building codes. The 2025 IEPR AAFS 3 case represents a "high" case where appliance bans and building codes are 100% realized. Since BE impacts are expected to ramp up over time, the difference between these scenarios in the near-term is much lower than it is in the long term. In the longer term, BE has the potential to be the single largest driver of Core throughput reduction.

Relative to the average year demand forecast, Core demand is forecasted to be 2 percent higher in 2030, 15 percent higher in 2035, and 45 percent higher in 2040 in the "Low BE" sensitivity. In contrast, Core demand is forecasted to be 19 percent lower in 2030, 47 percent lower in 2035, and 68 percent lower in 2040 in the "High BE" case. The results for EG demand are directionally opposite. Under the "Low BE" case, EG is forecasted to be 1 percent lower in 2030, 6 percent lower in 2035, and 25 percent (approximately 52 MMcf/d) lower in 2040. The "High BE" EG demand is higher by 5 percent in 2030, 19 percent in 2035, and 46 percent (approximately 96 MMcf/d) in 2040.

TABLE 22 – BUILDING ELECTRIFICATION UNCERTAINTY RESULTS, MMcf/d

	2026	2027	2028	2029	2030	2031	2032	2033	2035	2040
						Core				
Average Demand	665	663	646	622	594	572	552	532	489	364
Low BE	666	665	650	629	606	593	581	574	560	529
Difference	*1*	*2*	*4*	*7*	*13*	*20*	*30*	*42*	*71*	*165*
High BE	654	633	593	541	484	435	388	345	259	114
Difference	*(11)*	*(30)*	*(53)*	*(81)*	*(110)*	*(137)*	*(163)*	*(187)*	*(229)*	*(250)*
						Electric Generation				
Average Demand	727	559	545	555	595	593	562	556	493	210
Low BE	722	560	545	551	587	588	546	530	461	158
Difference			*(1)*	*(4)*	*(7)*	*(5)*	*(16)*	*(26)*	*(31)*	*(52)*
High BE	728	561	553	568	625	645	636	645	584	306
Difference	*1*	*2*	*7*	*13*	*30*	*52*	*74*	*89*	*91*	*96*

Electric Generation Sensitivities

Since gas-fired electric generation is just one part of a larger electricity market, it is sensitive to many additional uncertainties. In this section, we highlight some of the larger contemporary drivers of that uncertainty. These include electric load (driven by data centers), clean generation and storage resources built to meet electric-sector policy mandates, the retirement of the Diablo Canyon Power Plant (DCPP), and natural gas commodity prices.

Data Centers

One of the critical assumptions underlying the EG electric demand input is future data center buildout. The assumption utilized in the average year demand case is from the 2025 IEPR Planning Scenario and represents a "mid" case of 5.8 GW maximum data center demand statewide by 2040. This sensitivity uses the data center assumption from the 2025 IEPR Local Reliability Scenario for a "high" case of 8.4 GW by 2040.[25] This sensitivity has a significant impact; EG demand is forecasted to be higher by 161 MMcf/d in 2030, 198 MMcf/d in 2035, and 184 MMcf/d in 2040 compared to the average year demand forecast.

Although the CEC electric demand forecasts show high data center capacity additions, the amount of capacity requested for interconnection is even higher. The CEC reports almost 23.3 GW of data center capacity requests in California or within CAISO and almost 15.9 GW of that capacity in Northern California.[26] If more data center capacity comes online than is forecasted, it could result in even higher gas demand unless it is accompanied by a breakthrough in renewable or clean generation or some other mitigation measure (such as a significant installation of behind-the-meter renewables and battery energy storage).

Renewable Portfolio Buildout

As discussed in the "Forecast Methodology and Assumptions" section, PG&E revised the 2024-2026 CPUC's IRP "Least Cost" portfolio to better align annual build rates with the recent

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25 Draft 2025 Integrated Energy Policy Report (pg. 53-56), https://efiling.energy.ca.gov/GetDocument.aspx?tn=269602&DocumentContentId=106694 (Last accessed June 09, 2026)

26 Draft 2025 Integrated Energy Policy Report (pg. 48-49), https://efiling.energy.ca.gov/GetDocument.aspx?tn=269602&DocumentContentId=106694 (Last accessed June 16, 2026)

past. For this sensitivity, the underlying electric resource portfolio for CAISO is this IRP portfolio without any adjustments to annual build rates, and the pace of renewable generation and storage capacity additions is significantly higher. As a result, EG demand is forecasted to decline by 103 MMcf/d in 2030, 154 MMcf/d in 2035 and 96 MMcf/d in 2040.

Diablo Canyon Power Plant Extension

As previously discussed, DCPP is assumed to retire in 2029/2030 in accordance with the CPUC D.23-12-036.[27] DCPP represents over 2.2 GW of clean-firm power currently generating within the CAISO footprint for most of the year. PG&E conducted a sensitivity analysis in which DCPP is assumed to remain online through the 2026 CGR forecast period. The impact in 2029 is marginal (a 1 percent decline in average year demand) given the extension would only affect November and December for one unit. However, EG demand in this sensitivity is lower than the average year demand by 8 percent in 2030, 14 percent in 2031, and 21 percent in 2035.

TABLE 23 – NON-BE KEY DRIVERS FOR EG UNCERTAINTY RESULTS, MMcf/d

	2026	2027	2028	2029	2030	2031	2032	2033	2035	2040
Average Demand	727	559	545	555	595	593	562	556	493	210
High Data Center	734	568	573	627	755	828	817	811	690	394
Difference	*7*	*10*	*28*	*72*	*161*	*234*	*256*	*255*	*198*	*184*
Resource Build	642	515	498	493	491	460	427	398	339	113
Difference	*(85)*	*(44)*	*(47)*	*(62)*	*(103)*	*(133)*	*(135)*	*(157)*	*(154)*	*(96)*
DCPP Extension	727	559	545	550	544	510	468	437	389	124
Difference	*-*	*-*	*-*	*(5)*	*(50)*	*(83)*	*(94)*	*(118)*	*(104)*	*(85)*

CAISO NG Commodity Prices

Gas prices across the state have shown significant variability in the past due to extreme conditions (weather, supply chain, demand from another sector, gas production, gas storage inventories, etc.) within and outside of CAISO. The magnitude of gas prices across CAISO are a key driver of market economic dispatch decisions (i.e., higher commodity prices within CAISO may increase imported generation from other regions). Another key dynamic within CAISO is

27 D.23-12-036, Decision Conditionally Approving Extended Operations at Diablo Canyon Nuclear Power Plant Pursuant to Senate Bill 846.

the relationship between PG&E and SoCal Citygate price hubs. The price differential between the two hubs has an impact on which gas system may receive a greater "share" of total gas generation dispatched to meet electric demand. The sensitivity case represents a scenario in which the price differential is approximately $1.10/MMBtu lower than the average demand differential (PG&E Citygate closer to SoCal Citygate), and the result is overall higher EG forecasted demand, on average 63 MMcf/d higher over 2026 to 2030.

TABLE 24 – EG DEMAND FORECAST GAS COMMODITY PRICE SENSITIVITY, MMcf/d

	2026	2027	2028	2029	2030
Average Demand	727	559	545	555	595
Gas Price Sensitivity	783	636	618	619	641
Difference	*57*	*78*	*73*	*64*	*46*

PEAK DAY GAS DEMAND FORECASTS

This chapter contains forecasts for daily gas demand on peak winter days under various conditions and an estimate of high gas demand on a summer day. The three winter forecasts (1-in-90 Abnormal Peak Day (APD), 1-in-2-year Cold Winter Day, and 1-in-10-year Peak Winter Day) are developed consistently with the orders in the Long-Term Gas System Planning OIR D.22-07-002. While not required by the decision, PG&E also presents an estimate of high gas demand on a summer day for illustrative purposes. These forecasts incorporate the appropriate weather, year, and hydroelectric generation conditions as described in the sections below.

The peak forecasts also incorporate the impacts of climate change where appropriate. For example, climate change has a noticeable impact on winter Core and EG demands, as well as summer EG, but a negligible impact on summer Core since there is already no space heating demand at that time. For climate change impacts on Core, PG&E utilized the models from California's Fifth Climate Change Assessment. For EG, PG&E utilized the CEC's 2025 IEPR Planning forecast which incorporates climate change impacts from the "Business as Usual" Shared Socio-Economic Pathway (SSP3-7.0).[28] This is the same pathway used in the Core forecast.

ABNORMAL PEAK DAY DEMAND FORECAST

The APD forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90-year cold temperate event. The 1-in-90 temperature corresponds to a 28.2° F system-weighted mean temperature across the PG&E system, and under these conditions, PG&E core demand is forecasted to be approximately 2.8 Bcf/d. The PG&E load forecast shown here excludes all noncore and EG demands. Under an APD design scenario, PG&E is only required to ensure that it can supply enough gas to Core customers on the system.

28 CEC Adopted 2023 Integrated Energy Policy Report with Errata, February 2024, p. 113. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463

The APD core forecast in the table below was developed by PowerGEM LLC, a specialized energy demand forecasting firm, using an analysis of historical Core usage and weather data. This forecast was created using an ensemble of mathematical models designed to account for demand forecast uncertainty during design day scenarios like the APD. The APD core demand forecast is developed using a single system wide temperature forecast and represents aggregate system wide demand rather than any single area or summation of areas. Please refer to the accompanying workpapers[29] for a detailed report on the methodology and calculations.

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 production. Also, a significant part of the APD demand can 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 serve approximately 80 percent of PG&E's core gas usage. Core aggregators provide procurement services for the remaining 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 cold weather drops south 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 PG&E's system, cold weather can affect producing wells in the supply basins, which in turn can affect the total supply to the PG&E system and others.

29 See forthcoming 2026 California Gas Report Workpapers

If gas supplies are insufficient to meet core demand, PG&E can curtail noncore customers, including EG customers, to meet core demand.[30] PG&E's tariffs contain Emergency Flow Order noncompliance charges that are designed to cause the noncore market customers to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel burn capability exists today, supply curtailment would necessitate those noncore customers to curtail operations. Under supply shortfall conditions—such as an APD—a significant portion of EG customers could be curtailed, potentially impacting electric system reliability.[31]

The Total Resources to Meet Demands row below is made up of PG&E firm capacities, PG&E storage withdrawals, and Independent Storage Providers (ISP) withdrawals. The PG&E and ISP withdrawal numbers are subject to change based on CalGEM's implementation of underground gas storage regulations. The supply values are calculated under a 1-in-10 year design day but are still used as supply projections for a 1-in-90 year design day scenario. PG&E's design day standard is based on the 1-in-10 year design day scenario, and PG&E does not currently calculate separate supply projections for a 1-in-90 year design day. Since PG&E has more supply available on a day warmer than the APD to meet all forecasted Core demands this line is meant to illustrate that alongside some level of noncore curtailment, all Core demands can be met on an APD.

30 See PG&E's Gas Curtailment Procedure Proposal, Prepared Testimony A.24-05-004.

31 *Ibid.*

TABLE 25 – FORECAST OF ABNORMAL PEAK DAY (APD) CORE GAS DEMAND AND PROJECTED PG&E SUPPLY, MMcf/d

Line No.		2026-2027	2027-2028	2028-2029
1	Unadjusted APD Core Demand (1)	2,816	2,811	2,808
2	Climate Change Modifier	-7	-10	-13
3	APD Core Demand with Climate Change Modifier	2,809	2,801	2,795
4	Independent Storage Provider Withdrawal (2)	2,162	2,162	2,162
5	Firm Flowing Supply (3)	2,877	2,877	2,877
6	Projected Resources to Meet Demands (4)	4,138	4,134	4,141

Notes:
(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 28.2 degrees Fahrenheit system composite temperature, corresponding to 1-in-90 year cold temperature event. PG&E uses a system composite temperature based on six weather sites.
(2) The Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E and internal PG&E analysis.
(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E. These values are the values present in PG&E's 2027 General Rate Case filed 05/15/2025 and subject to change pending the CPUC's approval of PG&E's 2027 General Rate Case.
(4) The Projected Resources to Meet Demands (Line No. 6) are less than the sum of Independent Storage Provider Withdrawal (Line No. 4) and Firm Flowing Supply (Line No. 5) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. The 2027 - 2028 & 2028 - 2029 values are the values presented in PG&E's 2027 General Rate Case filed 05/15/2025 in Table 9-18 and subject to change pending the CPUC's approval of PG&E's 2027 General Rate Case.

WINTER PEAK DAY DEMAND FORECASTS

The tables below provide winter peak day demand projections on PG&E's system for both a 1-in-10-Year Peak Winter Day and a 1-in-2-Year Cold Winter Day.

TABLE 26 – 1-IN-10-YEAR PEAK WINTER DAY DEMAND, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2026-2027	2,294	-4	-6	2,285	513	1,194	3,992
2027-2028	2,291	-10	-9	2,272	515	882	3,669
2028-2029	2,289	-19	-11	2,259	511	884	3,654
2029-2030	2,289	-30	-14	2,245	507	1,100	3,852
2030-2031	2,289	-44	-17	2,228	503	1,219	3,950
2031-2032	2,288	-63	-19	2,207	501	1,285	3,993

The Core demand in the 1-in-10-Year Peak Winter Day Demand table is developed using the observed relationship between historical daily weather and core gas usage. This relationship is then used to forecast the Core load under a 1-in-10 temperature scenario. The building electrification (BE) modifier represents PG&E's 2026 Spring ALF for the month of December. The BE modifier reflects customers moving from natural gas use to electric use. The climate change modifier utilizes climate models from California's Fifth Climate Change Assessment under the SSP3-7.0 scenario. This modifier is calculated as a change in peak temperature relative to the forecasted 2024-2025 winter values, so it increases over time according to temperature changes in the climate models.

The Noncore, Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions, modified to account for the historical relationship between Noncore, Non-EG gas demand on a peak winter day and an average winter day. Since the Noncore, Non-EG sector is largely Industrial which is not statistically sensitive to climate impacts, this forecast does not vary by weather scenario and is not affected by climate change.

Last, the EG, including SMUD projection, is in the 90th percentile for the months of December through February under 1-in-10 cold and 1-in-10 dry hydro demand conditions. This forecasted value already embeds the impacts of building electrification and climate change as described in the sections above.

TABLE 27 – 1-IN-2-YEAR COLD WINTER DAY DEMAND, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2026-2027	2,037	-4	-5	2,028	507	1,139	3,674
2027-2028	2,033	-10	-8	2,016	505	874	3,396
2028-2029	2,032	-19	-11	2,003	504	870	3,377
2029-2030	2,031	-30	-13	1,989	503	1,014	3,507
2030-2031	2,030	-44	-16	1,973	503	1,107	3,583
2031-2032	2,029	-63	-18	1,952	503	1,126	3,581

PG&E's methodology used in the development of the 1-in-2-Year Cold Winter Day table is largely similar to the 1-in-10-Year Peak Winter Day methodology. The main differences are in the temperature and hydroelectric generation conditions. As stated in the title, this table assumes 1-in-2-year, or average, temperature conditions which will result in a warmer high demand day than the 1-in-10-Year. For hydroelectric generation, this table assumes 1-in-2-year, or average, hydroelectric generation conditions which will result in less CAISO electric demand needing to be met by thermal resource generation. Building electrification and climate change are handled in a similar manner to the 1-in-10-Year Winter Peak Day as well.

SUMMER HIGH DAY DEMAND ESTIMATE

This section contains an estimate of what demand on PG&E's gas system could be during a high demand day in the summer. This is not the same as a summer peak demand forecast since the CGR peak forecasts are primarily designed to account for winter conditions when PG&E's gas system peak occurs. Accordingly, future summer peak events could be higher than estimated in this section.

A key factor affecting summer peak demand is electric demand and temperature. The 2026 PG&E forecast presented below assumes 1-in-10 cold winter and 1-in-10 dry hydroelectric generation conditions. Since heating is not a factor in summer demand, this essentially assumes a 1-in-2, or average year, electric peak. If the upcoming summers are hotter than average, demand could exceed what is estimated here.

TABLE 28 – SUMMER HIGH DEMAND DAY ESTIMATE, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2026	388	-4	372	636	1,396	2,404
2027	381	-10	365	634	1,216	2,215
2028	372	-19	356	632	1,195	2,183
2029	362	-30	347	631	1,220	2,197
2030	352	-44	337	631	1,296	2,264
2031	343	-63	329	630	1,323	2,281

The Core demands in the Summer High Demand Day Estimate table represent the average August daily summer demand under 1-in-10 cold conditions. When analyzing historical Core demand during a summer high demand day, PG&E determined that using the average day is appropriate for the Core sector. The building electrification modifier represents PG&E's 2026 ALF for the month of August. Since Core demand during a summer high demand day is not expected to include any space heating, no adjustment for climate change was made.

The Noncore, Non-EG demands utilize the average August daily summer demand, modified to account for the historical relationship between Noncore, Non-EG gas demand on a peak winter day and an average winter day. Since the Noncore, Non-EG sector is largely Industrial which is not statistically sensitive to climate impacts, this forecast does not vary by weather scenario and is not affected by climate change.

Last, the EG including SMUD demand forecast is the 90th percentile for the months of July through September under 1-in-10 cold and 1-in-10 dry hydro demand conditions. This forecasted value already embeds the impacts of building electrification and climate change as described in the sections above.

POLICIES IMPACTING GAS DEMAND

For the forecast horizon covered by this report, there are many policies that may significantly impact the future trajectory of natural gas demand, including:

- **California's economy-wide GHG targets,** established through a sequence of statutes: AB 32 (2006) required emissions to return to 1990 levels by 2020, SB 32 (2016) tightened the target to 40% below 1990 levels by 2030, and AB 1279 (2022) codified a long-term goal of economy-wide carbon neutrality by 2045 (with at least 85% GHG reduction).

- **California Air Resources Board (CARB) Scoping Plan** establishes California's plan for achieving economy-wide GHG targets. The Scoping Plan guides policy, such as cap-and-invest and the low carbon fuel standard (LCFS) and provides guidance on the most cost-effective strategies to reach net zero emissions.

- **CARB** cap-and-invest program, which establishes aggregate declining caps on GHG emissions from all major natural gas end-uses in California, including electricity, industry, and buildings.

- **CARB Zero Emissions Appliance Standards,** currently in rulemaking, propose ramping down the sale of natural gas furnaces, water heaters, and pool heaters. The proposal sets emissive sales limits starting in 2030 at 40-60% that ramp down to 25-50% by 2045.

- **Bay Area Air District (BAAD) Rules 9-4 and 9-6 Amendments** adopted an air district wide zero-emission requirement for residential and commercial water heaters and furnaces sold in the 9 Bay Area counties. The policy is set to begin phasing in 2027 for small water heaters, but the Air District is developing amendments that may include exemptions and delayed implementation. PG&E serves on the Implementation Working Group to assist the Air District with understanding the effect of the policy.

- **The California Public Utilities Commission's Long-Term Gas System Transition Planning OIR (R.24-09-012), Integrated Resource Plan Proceeding (R.25-06-019), and Building Decarbonization OIR (R.19-01-011)** look at issues pertaining to long-term gas planning, electricity decarbonization, building electrification and decarbonization.

GHG POLICIES

The gas demand forecast used in this analysis includes a Cap-and-Invest GHG allowance price projection.[32] The forecast also incorporates complementary policies that aim to achieve California GHG emissions reduction goals. In addition, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Invest market translates to the forecast.

PG&E has a unique responsibility as a combined gas and electric utility serving 5.5 million electric customer accounts and 4.6 million natural gas customer accounts in Northern and Central California. PG&E embraces its foundational role in helping transition the state of California to a decarbonized and more climate-resilient economy. In June 2022, PG&E issued a Climate Strategy Report establishing the company's commitment to achieving a net zero energy system in 2040—five years ahead of California's carbon neutrality goal established in Executive Order B-55-18—and to become climate and nature positive by 2050.[33] Given that the utilization of fossil natural gas represents the bulk of PG&E's Scope 3[34] greenhouse gas emissions, PG&E believes that the evolution of the gas system plays an important role in meeting our ambitious climate goals. This will involve the utilization of renewable gases (RNG or hydrogen), further enhancements to our methane abatement program, and demand-side reductions through strategies such as building electrification.

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32 2025 CEC Integrated Energy Policy Report mid-case forecast.

33 PG&E Climate Strategy Report. https://www.pge.com/en/about/corporate-responsibility-and-sustainability/taking-responsibility.html.

34 The U.S. EPA defines Scope 3 emissions as, "Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly affects in its value chain. An organization's value chain consists of both its upstream and downstream activities." https://www.epa.gov/climateleadership/scope-3-inventory-guidance.

CALIFORNIA STATE SB 100 AND RENEWABLE ELECTRIC GENERATION

On September 10, 2018, Governor Brown signed into law SB 100, which further increases the Renewable Portfolio Standard (RPS) targets and includes the following requirements:

- Accelerates the RPS to 50 percent by 2026 and to 60 percent by 2030.
- Creates a separate state policy that requires 100 percent of all retail sales of electricity to serve end-use customers and 100 percent of electricity procured to serve state agencies to come from RPS-eligible or zero -carbon resources by 2045; and
- Requires the CPUC, in consultation with the CAISO and other balancing authorities, to issue a joint report to the Legislature by January 1, 2021, and every four years thereafter, that evaluates the anticipated costs and benefits of the 100 percent clean policy to electric, gas, and water utilities, including customer rate impacts and benefits.

ENERGY EFFICIENCY PROGRAMS

PG&E engages in many Energy Efficiency and Conservation (EE) programs designed to help customers identify and implement ways to benefit environmentally and financially from EE investments. Programs administered by PG&E include services that help customers evaluate their EE options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as rebates for new hot water heaters.

PG&E's forecast of cumulative natural gas savings is dominated by the residential sector. Most of these forecasted savings are due to codes and standards, such as federal and state appliance standards and state building codes, with state of California building codes (Title 24) making up most of these savings.

IMPACT OF SB 350 ON ENERGY EFFICIENCY

SB 350, which was enacted in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's Additional Achievable

Energy Efficiency (AAEE) mid-case forecast, subject to what is cost-effective and feasible.[35] The CEC issued its final report doubling targets in October 2017,[36] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[37] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy Resources proceeding.[38] The CEC's final report suggests the state of California is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, Publicly Owned Utilities (POU) programs, and codes and standards.[39]

IMPACT OF ZERO-EMISSION APPLIANCE STANDARDS

Electrification policies continue to evolve at both the local and state level. CARB and BAAD have introduced policies regarding gas space and water heating appliances. The BAAD amendments[40] to Rules 9-4 and 9-6 require that only zero Nitrogen Oxide (NOx) tank water heaters be sold beginning in 2027 and zero-NOx furnaces beginning in 2029, though the agency is developing amendments to the 2027 water heater rule to allow exemptions for certain circumstances. Similarly, CARB is developing a zero-emission appliance regulation that sets limits on emissive sales of furnaces, water heaters, and pool heaters. If implemented, this would ramp down the sale of gas water heaters and furnaces in California. These policies are expected

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35 The bill text states: "On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the mid case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety."

36 Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. SB 350: Doubling Energy Efficiency Savings by 2030. CEC. Publication Number: CEC-400-2017-010-CMF.

37 D.17-09-025: Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September 28, 2017.

38 D.17-08-022: Decision Adopting Interim GHG Adder, CPUC, August 24, 2017.

39 See Figure 2 from the CEC report cited above.

40 Building Appliances (baaqmd.gov).

to increase electric load over time while reducing or limiting growth in gas demand, although the magnitude and timing of impacts remain uncertain.

The CPUC has also removed gas line extension allowances, discounts, and refunds as well as the electric line allowance, discounts, and refunds for dual-fuel buildings as part of the Building Decarbonization OIR (R.19-01-011).[41] PG&E did not oppose the removal of residential gas line extension allowances but requested that allowances remain for non-residential customers that provide a financial or environmental benefit to ratepayers.

Although gas demand in the Average Year forecast declines, the forecast is not constrained to meet PG&E or California's carbon neutrality goals. The effort to achieve net-zero emissions goal could come by additional throughput decrease (such as through building electrification), lower carbon fuel options, and carbon capture technologies. The natural gas supply sources could be a cleaner version in the form of RNG or hydrogen (H_2). The next chapter on natural gas supply will elaborate on these potential gas supplies.

As regulations continue to be revised and updated, the cost of providing a safe and reliable gas system could continue to rise. California state and local GHG goals are expected to drive down gas throughput (as household electrification increases). Lower gas throughput will likely result in a higher cost-per-therm for customers if the evolution is not well-managed. PG&E has been working on programs and processes to reduce costs on the gas system to help mitigate the cost-per-therm for our customers that remain on the gas system.

California's gas system is going through unprecedented changes. As it evolves, it is important that regulatory bodies and the utilities work together to ensure that Californians continue to have access to clean, reliable, and affordable energy.

41 D.23-12-037: Decision Eliminating Electric Line Extension Subsidies, CPUC, December 14, 2023.

GAS DEMAND TRENDS AND STRATEGY

PG&E's gas demand forecast projects lower throughput over the long-term (due to GHG policies, such as electrification and procurement of renewable generation resources), which would show a decline in revenues at current rates. At the same time, policies on safe utility operations have put upward pressure on costs. Investments into long-lived assets, such as gas pipelines, are typically recovered over the assets' useful lives, which extend beyond this forecast. The combination of lower throughput and remaining investment in need of recovering could put upward pressure on gas transportation rates if this transition is not well managed.

In addition, the transition from fossil fuel (traditional fuels) to other forms of energy usage needs to be carefully planned and managed. PG&E is committed to working with regulators and other stakeholders to support statewide GHG reduction policies and develop options to minimize rate increases for the remaining gas customers.

To minimize the rate impacts on gas customers, PG&E is following a comprehensive approach while keeping safety as its top priority: (1) reduce carbon footprint, (2) reduce cost, (3) identify alternative revenue sources and (4) leverage innovative financial mechanisms.

- To reduce the carbon footprint of the gas system, PG&E is actively planning to green the gas supply, leverage electrification, convert facilities from using higher GHG emitting fuel sources, and conducting methane abatement.

- To reduce costs, PG&E is pursuing opportunities to systematically retire infrastructure and reduce capital and operating expenses through PG&E's Gas Investments for the Future (GIF) program. The GIF program has been aggressively pursuing cost-effective alternative work such as retiring and downrating gas pipelines and electrifying customers.

- To increase utilization of existing infrastructure where electrification is not feasible or cost effective, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput and exploring new opportunities to support RNG adoption across

new industries. This involves increasing load on the natural gas system in areas that would replace less favorable hydrocarbons fuels (e.g., in the industrial, large commercial, marine, rail and transportation sectors) and seeking opportunities to utilize the gas system to store hydrogen as a long-term and large-scale storage mechanism.

- Innovative financial mechanisms, such as accelerated depreciation, rate reform, and the capital treatment for cost-effective zonal electrification projects will help, but non-traditional funding sources will be critical as we evolve to an affordable, reliable, and decarbonized gas system.

FUTURE OPPORTUNITIES

One recent development that could increase throughput comes from the June 2020 CARB approval of the Advanced Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty trucks sales in California to be zero-emission vehicles (ZEV). The regulation's phase-in began in 2024 with sales percentages ranging between 5 percent and 9 percent depending on truck or chassis type. By 2035, the percentages increase to a range of 40 percent to 75 percent.

Truck manufacturers may choose hydrogen fuel cells as they decide how to meet this requirement. The hydrogen required for this could be transported via utility gas pipelines (under appropriate safety protocols) or produced with advanced technologies such as methane pyrolysis.

In addition, companies such as Amazon have internal goals for decarbonizing fleets. Chevron has announced that they are building compressed natural gas fueling stations, including about 15 in Northern California, and truck engine producer Cummins has announced a new 15-liter natural gas vehicle (NGV) truck engine (Next Generation X15N). When powered by renewable natural gas (RNG), the X15N could have up to a 97% reduction in CO2 and 80% reduction in greenhouse gas emissions. While adoption of such NGV technology is determined by market response, and the carbon status of this fuel choice may change over time based on actions taken at CARB, this is a potential path to higher NGV adoption in the near to intermediate term than is reflected in the forecast numbers.

Rail

Another high-horsepower sector for increasing clean fuel throughput via our pipeline system is rail transportation. Based on a study by CARB from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company (BNSF) combined interstate and intrastate locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6 percent, and the remaining 1 percent is from military-industrial locomotives.[42]

Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) as fuel sources have been considered by the rail industry, but thus far have been mostly limited to pilot studies. It is PG&E's understanding that some of the key obstacles to CNG and LNG locomotive adoption include: few, if any, new locomotives are planned to be purchased in the near future, the high cost of converting the fueling infrastructure from diesel to CNG or LNG, and current emission standards inadequately promote fuels cleaner than low sulfur diesel. Additionally, because LNG has an energy density of approximately 60 percent that of diesel, its use for long interstate routes would require increased fuel storage volume. This comes in the form of an LNG tender, which is an additional railcar that includes an insulated cryogenic tank and other equipment to convert LNG back to CNG. The added tender increases cost and complexity of the fuel transition.[43]

One possible path to greater CNG or LNG locomotive adoption is more stringent emissions standards. Locomotive emissions are governed by the U.S. EPA. Prior to 2026, the strictest emission level was Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr., it limits nitrogen oxide (NOx), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14, respectively. In 2025, the U.S. EPA approved a new, stricter, Tier 5 standard with a phased implementation schedule starting in 2028. The Tier 5 standard

42 CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

43 *Ibid.*

would reduce NOx up to 90% and particulate matters (PM) up to 75% compared to Tier 4 requirements.[44]

Technological advancements are occurring in the rail industry. In January 2024, OptiFuel Systems announced its near-term, low-risk, affordable Total-Zero™ RNG-Electric Line Haul Locomotive will have ZERO Well-to-Wheel (WTW) NOx and PM criteria emissions and Negative Carbon Intensity (CI) while simultaneously improving fuel cost and operating range by 25%. In 2026, OptiFuel plans to start a 2-year, 1-million-mile test program with ten pre-production 5,600 hp RNG line haul locomotives and five 10,000 DGE RNG tenders operating around the US.

Marine

California's three major container ports, Oakland, Los Angeles, and Long Beach, collectively handle more than 12 million twenty-foot equivalent units (TEUs) annually and receive thousands of vessel calls per year. In calendar year 2025, the Port of Los Angeles recorded approximately 1,900 vessel arrivals including 146 megaships with capacity exceeding 13,000 TEU.[45] The Port of Long Beach handles approximately 960 container vessel calls per year.[46] The Port of Oakland processed 2.26 million TEUs in 2024, a 9.5 percent increase over the prior year, and handles more than 99 percent of containerized goods moving through Northern California.[47]

A large container vessel operating on LNG on a transpacific route typically consumes 150 to 250 tonnes of LNG per day depending on vessel size and speed, with a single voyage from Asia

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44 https://www2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

45 Port of Los Angeles, Facts & Figures, CY 2025 — https://portoflosangeles.org/business/statistics/facts-and-figures.

46 Port of Long Beach, Operations Dashboard — https://www.econdb.com/maritime/ports/US%20LGB/Long%20Beach/.

47 Port of Oakland, Facts & Figures — https://www.oaklandseaport.com/business/facts-figures.

to California requiring approximately 2,000 to 3,000 tonnes of LNG (equivalent to roughly 100 to 150 million cubic feet of natural gas per voyage).[48]

To provide context for total market size, in 2020, the last year for which EIA vessel bunkering data is available, residual fuel oil deliveries for vessel bunkering in California totaled approximately 11.2 million barrels, or approximately 58 Bcf equivalent.[49] Since 2020, West Coast residual fuel oil imports have declined sharply, falling from 6.8 million barrels in 2021 to just 1.1 million barrels in 2024, reflecting the accelerating transition away from high-sulfur bunker fuel following IMO 2020.[50]

The marine transportation sector is rapidly transitioning to lower-sulfur and lower-GHG fuels, driven by the International Maritime Organization (IMO), which regulates global shipping emissions under MARPOL Annex VI.[51] The IMO's regulatory framework has expanded significantly in recent years. The global sulfur cap of 0.50 percent m/m, which took effect January 1, 2020, remains in force outside Emission Control Areas (ECA). Within ECAs, the stricter 0.10 percent m/m sulfur limit applies. The number of designated ECAs has grown from four to seven, with the Mediterranean Sea becoming an ECA on May 1, 2025, and the Canadian Arctic and Norwegian Sea ECAs entering into force in 2026 and 2027. The North-East Atlantic was approved as an ECA at MEPC 83 in April 2025.[52]

Although ECAs cover a limited share of global ocean area, they capture a meaningful portion of economic activity, with approximately 23 percent of global container port throughput

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48 Fuel Consumption by Containership Size and Speed, The Geography of Transport Systems — https://transportgeography.org/contents/chapter4/transportation-and-energy/fuel-consumption-containerships/.

49 EIA, Sales of Residual Fuel Oil by End Use (Suspended after 2020) — https://www.eia.gov/dnav/pet/pet_cons_821rsd_a_EPPR_VVB_Mgal_a.htm.

50 EIA, West Coast (PADD 5) Imports by Product, Annual — https://www.eia.gov/dnav/pet/pet_move_impcp_d_r50_z00_mbbl_a.htm.

51 IMO MARPOL Annex VI — https://www.imo.org/en/about/conventions/pages/international-convention-for-the-prevention-of-pollution-from-ships-(marpol).aspx.

52 ICCT ECA expansions — https://theicct.org/pr-imo-adopts-worlds-largest-emission-control-area-to-regulate-ship-emissions-in-north-east-atlantic/.

occurring within existing ECA regions, effectively extending low-sulfur fuel requirements across a large share of global trade flows.[53]

Beyond sulfur, the IMO has moved aggressively on greenhouse gas reduction. In July 2023, the IMO adopted its 2023 GHG Strategy, which targets net-zero GHG emissions from international shipping by or around 2050 and calls for zero or near-zero GHG fuels to represent at least 5 to 10 percent of shipping energy by 2030.[54] In April 2025, the IMO approved the landmark Net-Zero Framework, the first globally to combine mandatory emissions limits and a GHG pricing mechanism across an entire industry sector. The framework introduces a Global Fuel Standard requiring ships to progressively reduce their well-to-wake GHG fuel intensity, and a global economic measure under which ships exceeding emission thresholds must acquire remedial units. These regulations, expected to enter into force in 2027, will be mandatory for ocean-going ships over 5,000 gross tonnage, which account for 85 percent of shipping's CO_2 emissions.[55]

The marine fuel mix has evolved in response to these regulations. The market remains dominated by petroleum-based fuels, including heavy fuel oil, intermediate fuel oil, and low-sulfur distillates, which continue to meet ISO specifications for marine fuels. However, the share of high-sulfur residual fuel oil has declined materially following IMO 2020, with substitution toward Very Low Sulfur Fuel Oil (VLSFO) and marine gasoil.[56]

Impact of Liquified Natural Gas on the Marine Sector

LNG has emerged as the leading alternative fuel, driven by its ability to materially reduce sulfur oxides, nitrogen oxides, and particulate emissions, while also lowering well-to-wake greenhouse gas emissions by up to 23 percent relative to conventional oil-based marine fuels for

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53 Port Economics, ECA trade share — https://porteconomicsmanagement.org/pemp/contents/part11/ports-policies-and-politics/emission-control-areas-maritime-shipping/.

54 IMO 2023 GHG Strategy — https://www.imo.org/en/mediacentre/pressbriefings/pages/revised-ghg-reduction-strategy-for-global-shipping-adopted-.aspx.

55 IMO Net-Zero Framework (MEPC 83) — https://www.imo.org/en/mediacentre/pressbriefings/pages/imo-approves-netzero-regulations.aspx.

56 Maritime Optima, ECA sulfur rules — https://maritimeoptima.com/insights/global-sulphur-regulations-eca-seca-zones.

modern two-stroke engines.[57] Unlike other alternative marine fuels, LNG benefits from an established global supply chain, with bunkering now available at 222 ports worldwide, supported by more than 62 dedicated bunkering vessels and over $150 billion in cumulative infrastructure investment over the past decade.[58]

As a globally-traded, fungible commodity with mature production, transportation, and storage networks already in place, LNG represents the lowest-resistance path for the shipping industry to achieve near-term reductions in sulfur and greenhouse gas emissions. LNG adoption is further supported by dual-fuel engine technology, which allows vessels to operate on either LNG or conventional fuel oil depending on price and availability.

As of late 2025, 218 LNG-fueled container ships were in operation, representing 3.5 percent of the global container fleet, with 362 additional LNG container ships on order. The share of newbuild container vessel orders with LNG capability has grown from 23 percent in late 2023 to 40 percent, signaling that LNG is becoming the mainstream fuel choice for new tonnage.[59]

Methanol and ammonia are also gaining traction as future marine fuels, with methanol seeing near-term adoption due to easier handling as a liquid fuel, and ammonia positioned as a longer-term zero-carbon option, though both remain at earlier stages of commercialization and lack comparable global bunkering infrastructure.[60]

LNG also provides a pathway to deeper decarbonization through Bio-LNG and synthetic LNG derived from RNG and green hydrogen. Bio-LNG can reduce well-to-wake greenhouse gas emissions by up to 80 percent compared to marine diesel, and when produced from dairy manure with avoided emissions accounted for, can achieve negative lifecycle emissions.

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57 Sphera / SEA-LNG / SGMF, "2nd Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel," 2021 (ISO 14040/14044, peer-reviewed) — https://sphera.com/resources/report/2nd-life-cycle-ghg-emission-study-on-the-use-of-lng-as-marine-fuel/.

58 SEA-LNG, "View from the Bridge: The Journey," Jan 2026 — https://sea-lng.org/2026/01/shippings-methane-decarbonisation-pathway-becomes-a-clear-runway-for-the-future/.

59 S&P Global Market Intelligence, "LNG increasingly alternative fuel of choice for container lines," Oct 2025 — https://www.spglobal.com/market-intelligence/en/news-insights/research/2025/10/lng-increasingly-alternative-fuel-of-choice-for-container-lines.

60 Lloyd's Register Alternative Fuel Review 2025 — https://www.lr.org/en/knowledge/insights-articles/alternative-fuelled-ship-orders-remain-significant-in-2025/.

Because Bio-LNG is chemically identical to fossil LNG, it serves as a drop-in fuel requiring no modifications to existing LNG engines, storage, or bunkering infrastructure, and is among the most cost-competitive sustainable alternative marine fuels available.[61]

California's growing RNG supply creates a natural bridge to Bio-LNG for the marine sector. Since PG&E's first RNG interconnection began flowing in late 2021, more than 4.3 billion cubic feet (Bcf) of California-produced RNG has been transported through PG&E's pipeline system.[62] PG&E currently operates multiple RNG interconnection points representing dairies, landfill, and food waste projects, with additional interconnections planned through 2026.[63] PG&E has committed to injecting 30 Bcf of RNG per year by 2030.[64] The majority of PG&E's RNG supply is sourced from Central Valley dairy operations, the same feedstock pathway that produces the deepest lifecycle emission reductions when converted to Bio-LNG for maritime use.

This expanding, pipeline-connected RNG supply can be delivered as Bio-LNG to vessels, creating a scalable pathway to reduce lifecycle emissions in the marine sector most responsible for marine sourced emissions impacting Californians while leveraging existing transmission gas infrastructure.

LIQUEFIED NATURAL GAS IMPORTS/EXPORTS

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. Since the mid-2010s, LNG imports have primarily been used to serve peak winter

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61 SEA-LNG / Nanyang Technological University, "The Role of Bio-LNG in the Decarbonisation of Shipping," October 2022 — https://sea-lng.org/wp-content/uploads/2022/10/SEA-LNG_BioLNG-Study-Key-Findings-Document_October-2022_amended.pdf.

62 PG&E Newsroom, "Renewable Natural Gas from California's First Food Waste-to-RNG Facility," Dec 2024 — https://www.pge.com/en/newsroom/currents/future-of-energy/renewable-natural-gas-from-california-s-first-food-waste-to-rng-.html.

63 PG&E Newsroom, "Celebrating National Clean Air Month: Advancing RNG in the Central Valley," May 2025 — https://www.pge.com/en/newsroom/currents/future-of-energy.html.

64 PG&E RNG 30 Bcf/year commitment — https://www.pge.com/en/newsroom/currents/future-of-energy/renewable-natural-gas-from-california-s-first-food-waste-to-rng-.html.

load.[65] The development of low-cost domestic shale gas supplies since the mid-2000s has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

Recent global events have increased the expectations for more LNG exports from North America. As Europe embarks on measures to increase its energy security and diversify its energy sources, LNG export developers in North America are seeking development opportunities. The gas industry anticipates further growth in LNG exports from North America.

The U.S. began exporting LNG in 2016 on a larger scale than in the past. For projects proposing to export LNG, the U.S. Department of Energy (DOE) evaluates the impact of exports to countries without a Free Trade Agreement (FTA) with the U.S. The DOE grants approval if the project is deemed to be in the public interest. The U.S. Federal Energy Regulatory Commission (FERC) evaluates the environmental impacts of proposed LNG projects and authorizes the siting and construction of LNG facilities.

Currently, there are more than a dozen proposed projects to export LNG to world markets.[66] Many of the projects are "brownfield," using existing U.S. import terminals to export LNG. Some are "greenfield" projects where LNG infrastructure has not been developed in the past. Two greenfield projects on North America's West Coast are in British Columbia. The larger project is LNG Canada located in Kitimat.[67]

A brownfield project on North America's West Coast is the Energia Costal Azul (ECA) LNG export facility in Baja California, Mexico. ECA has received authorization from the DOE to liquify and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[68] This facility will have a nameplate capacity of 3.25 million metric tons (MMT) per

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65 U.S. Energy Information Administration (US EIA) U.S. Liquefied Natural Gas Imports https://www.eia.gov/dnav/ng/hist/n9103us2m.htm.

66 U.S. EIA https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx.

67 LNG Canada https://www.lngcanada.ca/media-kit/.

68 https://ecalng.com/.

annum of liquefication capacity. Construction of the project is underway with an online date of 2024.[69]

The ECA LNG export project, which would be the second on the North America's West Coast, is positioned to source gas off the El Paso Mainline System. Thus, it could divert gas supplies currently available to Northern California. ECA diversion of gas supplies from California is currently under consideration at the CPUC in the R.20-01-007 Proceeding.[70] This proceeding will investigate whether the demand from ECA could impact supply reliability to California, especially the southern portion, and put upward pressure on gas prices.

U.S. NATURAL GAS PIPELINE EXPORTS TO MEXICO

With low domestic natural gas prices compared to world markets, the U.S. remained a net exporter of natural gas in 2023.[71] The U.S. natural gas exports to Mexico have grown in recent years from 0.9 Bcf/d in 2010 to 6.4 Bcf/d in 2023,[72] and pipeline exports are projected to reach 8.4 Bcf/d by 2035.[73]

Most of the exports to Mexico are supplied through Texas from the Permian and Western Gulf of Mexico basins. Production growth in the Permian Basin, combined with new pipeline capacity, will enable growing exports to Mexico.

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69 Mexico ECA LNG Development Advancing to 2024 Start Date, Natural Gas Intelligence, https://www.naturalgasintel.com/mexico-eca-lng-development-advancing-to-2024-start-date/#:~:text=The%20facility%20is%20adjacent%20to,the%20facility%20online%20in%202024.

70 OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

71 Energy Information Administration (EIA), The U.S. exported more natural gas than it imported in 2017: https://www.eia.gove/todayinenergy/detail.php?id=35392.

72 EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

73 EIA, Annual Energy Outlook 2023 – Table 60. Natural Gas Imports and Exports Case: AEO2022 Reference case: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2023&cases=ref2023&sourcekey=0.

GAS SUPPLY, CAPACITY, AND STORAGE

This section provides information about current gas supply, natural gas pipeline capacity, and gas storage facilities providing supply and capacity to the PG&E Service Area. This section also includes details of the policies and regulations affecting these topics.

The Gas Supply section includes information about current and anticipated developments regarding RNG, as well as gas supply from sources throughout North America. The Gas Pipeline Capacity section includes information about "upstream" interstate pipelines and intrastate pipelines. The Gas Storage section gives an overview of PG&E's gas storage capacity and facilities. The Policies section looks at a range of current policy and regulatory developments, describing their impacts on PG&E's gas supply, including integration challenges for alternative fuel types, such as hydrogen (H_2).

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services. Since gas demand in California is greater than the limited amount of native California production available, most of the gas supplies that serve PG&E customers are sourced from out of state.

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.

GAS SUPPLY

Renewable Natural Gas

As a result of various policy and regulatory changes to decarbonize gas throughput, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California. RNG producers are leveraging available grants and incentives to encourage the production of RNG, with the goal to reduce GHG emissions from biogas sources and for use as an alternative

fuel source for transportation and other end-use customers. PG&E is engaged in the following efforts regarding RNG:

- Actively working with RNG developers to interconnect their projects through the biomethane program;
- Implementing biomethane (also referred to as RNG) procurement for core customers under CPUC Decision 26-04-044;
- Participation in various Research and Development (R&D) efforts to further understand and develop new methods and technologies to produce RNG that reduce the carbon intensity of the gas in the pipeline; and
- Procuring Contracting RNG for all PG&E-owned Compressed Natural Gas (CNG) fueling stations.

While there is significant potential for renewable gas (RG) to replace some portion of the natural gas supply, the current investments, and incentives for RG end-use principally favor the transportation sector.

PG&E has several RNG projects in various phases. Eight projects are already connected and flowing renewable gas into the PG&E system. Four additional projects are in development and should be online by the end of 2027. PG&E is targeting an additional 3.5 billion cubic feet (BCF) of RNG to be injected in 2026. PG&E anticipates that it will achieve a total of 10 billion cubic feet (BCF) into its system since the initiation of the RNG program in 2021. One of the projects resulted from the SB 1383 Dairy Pilot Program and the other seven are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[74]

Existing interconnections continue to increase volumes annually as each project develops upstream sources. In addition, there are approximately a dozen other projects that are in early-stage development that PG&E anticipates will be online over the next two to three years.

The RNG supply from California Gas Production interconnections is not reserved for PG&E to procure as it is treated as any other natural gas being injected into our system and subject to

74 https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas.

the same market forces. The RNG can be procured directly from the production facility without being injected onto the system, by non-core customers on the system, and/or be shipped off-system. Therefore, this supply may not be available for PG&E to meet core biomethane procurement targets mandated by the state of California.

The following table shows a high-level estimate of the RNG delivered to Core Customers on PG&E's system.

TABLE 29 – PG&E RENEWABLE NATURAL GAS DELIVERIES, MMcf/d

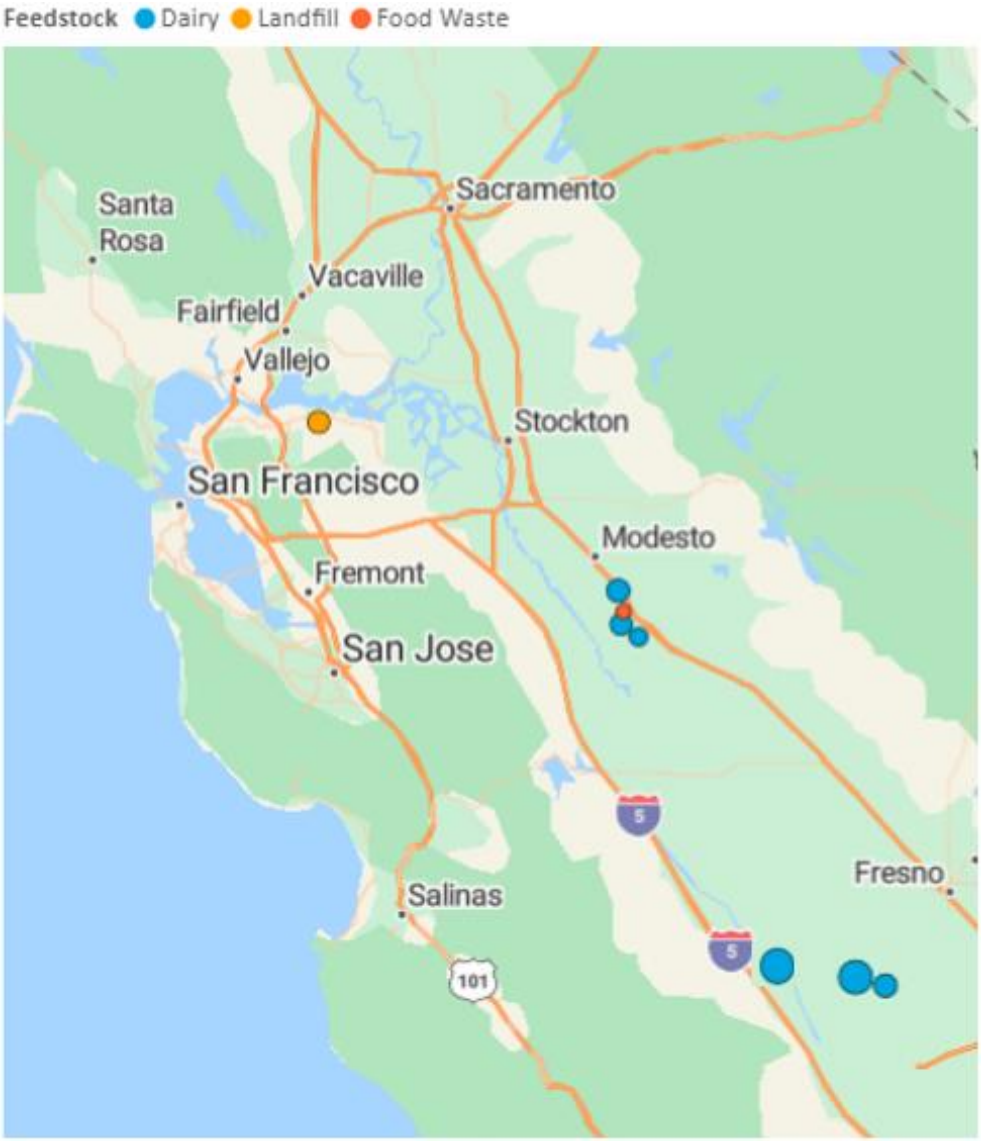
	2023	Approx. % of Core (2023)	2024	Approx. % of Core (2024)	2025	Approx. % of Core (2025)
Total Core Gas Deliveries	745		656		661	
Renewable Gas Standard (RGS)	0	–	0	--	0	–
Natural Gas Vehicles (NGV) Usage (1)	0.50	0.07%	0.59	0.09%	0.54	0.08%
Physical	0		0		0	
Estimated book and claim	0.50		0.59		0.54	

Notes:
(1) NGV deliveries converted from MMBtu using conversion factors in line 37 of Table 26 – Annual Gas Supply and Requirements

Recent Successes

In 2024 and 2025 PG&E interconnected two more dairy clusters, one food waste and one landfill for a total of eight interconnections to date. With these projects PG&E has over 50 dairies feeding into our pipelines and the landfill and food waste feedstocks have further increased PG&E's biomethane gas source portfolio. Since 2021 we have averaged a 50% increase year after year of RNG supply on the system.

FIGURE 8 – PG&E SERVICE AREA: RNG PROJECT LOCATIONS CURRENTLY FLOWING AS OF JUNE 2026



Future RNG Supply in the PG&E Service Area

Biomethane projects capture methane emissions from various organic sources that act as a direct replacement to fossil natural gas which helps California reduce powerful GHG emissions. By reducing greenhouse gases, improving waste management, and preserving soil quality, biomethane projects play a key role in the development of a local circular economy where waste is converted into a resource.

PG&E continues to work with developers in a collaborative and deliberate method to interconnect biomethane gas to PG&E's pipeline system. This program is compliant with CPUC gas rules and implements CPUC's directives to encourage renewable gas usage and production.

Biomethane source development is increasing in volume and diversity. As projects continue to move forward, production rates will continue to increase. PG&E's observation shows that once a project is interconnected, volumes continue to grow on an annual basis due to expansion as well as efficiency. In the coming years, additional feedstock types such as wastewater treatment plants, agriculture waste, and woody biomass are projected to interconnect to PG&E's system. Biomethane production will also involve gasification in addition to anaerobic digestion. In recent years, PG&E has interconnected projects with long gathering line systems connecting multiple dairies and three virtual pipelines hubs allowing new feedstocks access that are too far away for a traditional pipeline.

PG&E's focus is to build the gas network of tomorrow that supports overall decarbonization efforts. By utilizing our existing infrastructure, we are in a unique position to support the energy transition in California, taking advantage of every opportunity to promote gas energy, establishing new uses, and increasing the share of renewable gas in gas consumption.

Interconnecting Biomethane Supply

To encourage effective development of RNG, PG&E has a Biomethane Interconnection page created online.[75] This information is a high-level- overview of our biomethane program and provides information on how to have an Initial Screening Study (ISS) completed at no cost for potential projects. PG&E Gas Rule 29[76] outlines the interconnection process which includes a Preliminary Engineering Study (PES) and then a Detailed Engineering Study (DES) leading to final construction of the new interconnection. Suppliers are encouraged to contact PG&E (Biomethane@pge.com) to discuss opportunities to bring on RNG supplies.

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75 Available at: https://www.pge.com/en/about/doing-business-with-pge/interconnections/biomethane-interconnection.html.

76 Available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_RULES_29.pdf.

NORTH AMERICAN SUPPLY DEVELOPMENT

North America has an abundance of natural gas resources. In the United States, the Potential Gas Committee estimates resources of 3,368 trillion cubic feet (Tcf),[77] with Energy Information Administration (EIA) figures showing a 3% drop in natural gas reserves in 2024 at 583.9 Tcf, compared with the last update in 2022.[78] Natural gas resource development has improved over the past two decades as horizontal drilling and hydraulic fracturing has matured. Furthermore, advancements in drilling know-how and improved efficiencies have enhanced resource development, typically at lower costs. The U.S. produced almost 108 Bcf/d on average in 2025.[79] Three producing regions contributed more than 60 percent of this production: the Haynesville region mainly in Louisiana and Texas, the Permian region in Texas and New Mexico, and the Appalachia region mostly located in Pennsylvania, Ohio, and West Virginia.[80] The resources that contribute to these production regions include both shale gas resources and associated gas from oil production.[81] Most industry forecasts continue to predict that gas production will meet most demand outlooks in the future.

The growth of associated gas production in the Permian Basin and eastern shale (Haynesville and Appalachia) continues to push gas volumes from Canada, the Rocky Mountain area, and the Southwest towards California. These production regions interconnect with California via pipelines as highlighted below.

California Sourced Gas

Northern California sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2025, PG&E's customers obtained on average 20 MMcf/d of California sourced gas. PG&E anticipates that California sourced gas may increase from this level. The primary driver for this growth is RNG production.

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77 http://potentialgas.org. This estimate represents the total mean technically recoverable resource base as of year-end 2020. Technically recoverable resources means gas can be produced using currently available technology and industry practices.

78 U.S. Energy Information Administration U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2024.

79 U.S. Energy Information Administration Natural Gas Dry Production (eia.gov).

80 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis.

81 Production - Amid uncertainty, the United States continues to be an important global supplier of crude oil and natural gas - U.S. Energy Information Administration (EIA).

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 gas in the producing basins and transport it to California via interstate pipelines. They can also purchase gas at the California-Arizona border or at the PG&E Citygate from marketers who hold inter and/or intrastate 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 (GTN) pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold interstate and/or intrastate pipeline capacity.

Rocky Mountain Gas

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

GAS PIPELINE CAPACITY

Interstate Pipeline Capacity

California utilities and end-use customers benefit from access to multiple supply basins, enhanced by produced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and central California include El Paso Natural Gas, Mojave, Transwestern, GTN, Tuscarora Pipeline Company, Ruby, and Kern River Gas Transmission pipelines. These pipelines provide northern and central California with access to gas producing regions in the U.S. Southwest, Rocky Mountains, 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, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 940 MMcf/d.

Canada and Rocky Mountains

PG&E's Redwood Path (Lines 400/401) is connected to GTN and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 1,902 MMcf/d.

In-State Pipelines

PG&E continues to accelerate the analysis of the existing pipeline system for opportunities to minimize rate increases for our customers by reducing our costs while maintaining safety and reliability, looking for new opportunities for load growth, and decarbonizing by increasing throughput of RNG. PG&E is actively pursuing a variety of initiatives including electrification opportunities on "radial feeds" where several miles of pipe may be in place to serve a small handful of customers, pruning the system of pipe that is underutilized or no longer serving customers, downrating lines, and eliminating or streamlining projects. Electrifying these customers and decommissioning these local pipelines could achieve cost savings in the long term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with local governments, to strategize where to reduce spending and predict long-term gas needs more accurately.

GAS STORAGE

In Northern California, PG&E operates key underground gas storage facilities at McDonald Island and Los Medanos, while also holding a 25% ownership in Gill Ranch Storage. Combined, these fields contribute to a total working gas inventory of roughly 55 Bcf, with approximately 12 Bcf reserved for firm services such as Core, Reserve Capacity, and Pipeline Balancing. Supplementing these operations are several independently-owned storage providers (ISPs) including Wild Goose Storage, Lodi Gas Storage, Central Valley Gas Storage, and the remaining 75% of Gill Ranch Gas Storage. Collectively, ISPs and PG&E-owned gas storage offer approximately 185 BCF of working gas capacity within Northern California. These facilities play a pivotal role in meeting the region's peak seasonal and daily natural gas demands.

Within the past ten years, Northern California underground gas storage facilities have experienced legislative and regulatory changes. In response to the Southern California Gas Company's Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM), previously known as the Division of Oil Gas and Geothermal Resources (DOGGR), adopted new underground gas storage well safety regulations across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to dual-barrier tubing and packer.[82] Packers seal off the annular space in the casing and limit the gas flow to the smaller diameter inner tubing only, which was forecasted to reduce traditional storage well injection and withdrawal performance, on average, by 40 percent.[83]

Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

Consistent with the approved strategy, PG&E announced On December 1, 2020, its plans to sell the Pleasant Creek underground gas storage field, located in Yolo County, California. The Pleasant Creek field is the smallest of four underground natural gas storage fields owned wholly or partly by PG&E. PG&E, Pleasant Creek Gas Storage Holdings, LLC, and eCORP Natural Gas Storage Holdings, LLC submitted a joint application under Pub. Util. Code section 851 to the CPUC on July 18, 2023, seeking approval for the sale. The CPUC granted approval on April 24, 2025 (D.25-04-032), and the sale was completed on April 24, 2026.

In PG&E's 2023 GRC application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates included a proposal to drill more wells and retain the Los Medanos storage facility. The proposal to retain Los Medanos was approved by the CPUC in D.23-11-069.

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82 https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf.

83 Workpaper Table 7-37. Pacific Gas and Electric Company 2023 General Rate Case Workpapers.

Separately, PG&E has continued to implement CalGEM's underground gas storage safety requirements. In March 2019, PG&E submitted an underground gas storage risk and integrity management plan and accompanied field-specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details PG&E's well-testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E completed the conversion of all existing wells to tubing and packer in 2025 to meet CalGEM's dual barrier construction standard in CCR 1726.5. PG&E also completed the drilling of twelve new replacement wells as of the year-end 2025. Although all twelve wells have been drilled, to date, six of these wells are operational, with the remaining six wells expected to be operational by the end of 2026.

Following 2021, PG&E proposed that subsequent well re-inspections be conducted using a risk-based approach; however, CalGEM did not approve a risk-based reassessment framework and instead prescribed a casing wall thickness inspection schedule with a maximum reinspection interval of seven-years on May 22, 2025.

POLICIES AND REGULATIONS IMPACTING FUTURE GAS SUPPLY, CAPACITY, AND STORAGE

California's policies to reduce GHGs are expected to impact gas supply and assets. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RNG adoption, enabling the gas system to transport hydrogen, supplying hard-to-electrify industries, and planning to utilize the gas system as a long-term energy storage mechanism.

This section also includes PG&E's GHG and Cap-and-Invest reporting and discusses other regulatory matters that may impact Northern California's gas system.

PG&E is participating in several OIRs, which address crucial topics that will impact the California gas system. For example, the Biomethane OIR (R.13-02-008) helped the utilities make RNG interconnections more efficient and affordable across California as well as established an RNG procurement program for core customers.

Gas System Planning OIR R.20-01-007

The CPUC has closed Rulemaking - Order Instituting Rulemaking to "Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning." This proceeding developed and adopted, as necessary, updated reliability standards that reflect current and future operational challenges to gas system operators and began implementing a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California's decarbonization goals.

Gas Transition Planning OIR R.24-09-012

As a continuation of remaining issues from R.20-01-007 and expansion of new issues, the Commission opened a new Rulemaking Order Instituting to Establish Policies, Processes and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (R.24-09-012). The primary purpose of gas transition planning is to facilitate decarbonization activities over time in a way that supports equity, safety, and affordability; and mitigates reliability challenges, commodity price spikes, and other potential adverse outcomes. Long-term planning work will require consideration of data and analytical needs and provide an additional tool for the Commission to assess the trajectory of developments in the gas sector over time with reference to metrics and milestones set out in scenario analyses while also addressing interim actions that can advance decarbonization and mitigate risks in the nearer term.[84] This Rulemaking will also consider Senate Bill (SB) 1221 (Min, Chapter 602, Statues of 2023) activities for the establishment of a program to facilitate the cost-effective decarbonization of priority decarbonization zones through plot projects.[85]

GHG Reporting and Cap-and-Invest Obligations

In March 2024, PG&E Gas Operations reported to the U.S. Environmental Protection Agency (EPA) GHG emissions in accordance with 40 Code of Federal Regulations Part 98 in four primary categories: GHG emissions in the reporting year 2023 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of CO2

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84 R.24-09-012 Issued October 4, 2024, p. 2-3.

85 R.24-09-012 Assigned Commissioners' Third Amended Scoping Memo, March 4, 2026, p. 1.

equivalent (mtCO2e); the GHG emissions resulting from the complete combustion of the annual volumes of natural gas provided to end users on PG&E distribution system (consuming more less than 460 MMcf in calendar year 2023); vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2026, PG&E reported to CARB GHG emissions of approximately 43.2 million mtCO2e (metric tons carbon dioxide equivalent) in these primary categories for reporting year 2023: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 mtCO2e; the GHG emissions resulting from complete combustion of the annual volumes of natural gas provided to end users on PG&E distribution system; and vented and fugitive emissions from seven compressor stations, one underground gas storage facility, and natural gas distribution system.

In June 2023, PG&E filed the 2022 Annual Natural Gas Leakage Abatement Report and reported 1.49 billion standard cubic feet (Bcf) of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of Rulemaking (R.) 15-01-008 to adopt rules and best practices aiming to reduce methane emissions from the Natural Gas System in application of SB 1371.

In addition, PG&E filed its two-year Leak Abatement Compliance Plan in March 2024. This plan addresses the 26 best practices outlined in the Leak Abatement OIR D.17-06-015. It emphasizes minimizing methane emissions through changes to policies and procedures, personnel training, leak detection, leak repair, and leak prevention. PG&E's plan includes an annual Super Emitter survey of the entire system and a three-year cycle for compliance surveys. In addition, PG&E reduced the Super Emitter threshold from 10 scfh (standard cubic feet per hour) to 7 scfh in 2023 and reduced further to 6 scfh in 2024; extended blowdown reduction strategies to a compressor station and storage facilities, lowering the pipeline pressure to near zero for scheduled transmission projects and applying degassing technologies for In-Line Inspection (ILI) and lower volume transmission projects.

Finally, PG&E is an active member and founding partner in the voluntary EPA Natural Gas STAR and Methane Challenge Programs, respectively, where annual reports are submitted to the

EPA showcasing PG&E's efforts and best practices to reduce methane emissions. Each year, on a mandatory basis, PG&E reports its methane emissions to the California Public Utilities Commission and, on a voluntary basis, also reports—and obtains third-party verification for—a more comprehensive corporate greenhouse gas emissions inventory, including PG&E's methane emissions. Each year, PG&E also completes and publishes the Edison Electric Institute (EEI) and American Gas Association (AGA) voluntary Environmental, Social, Governance (ESG) and Sustainability reporting templates for investors, which includes methane emissions. PG&E believes it's essential that investors, customers, policymakers, and other stakeholders have access to information on PG&E's emissions profile.

Biomethane OIR R.13-02-008 Phase 3

On July 5, 2018, the CPUC reopened R.13-02-008 Phase 3 and ordered the joint California utilities to propose a joint RNG interconnection tariff and interconnection agreements.

On October 28, 2020, the CPUC approved the joint utilities' Standard Renewable Gas Interconnection Tariff pursuant to D.20-08-035 which established standards and requirements to permit the safe injection of RNG into a jurisdictional common carrier pipeline.

The CPUC also instituted a Reservation System in D.19-12-009 that became effective as of February 3, 2020, for the Biomethane Incentive Program implemented by D.15-06-029.

Biomethane OIR R.13-02-008 Phase 4

On November 21, 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection of renewable H2 into gas pipelines and implementation of SB 1440 (RNG procurement).

On February 24, 2022, the CPUC approved D.22-02-025 implementing Senate Bill 1440 establishing a framework of a mandatory Biomethane Procurement Program. This Biomethane Procurement Program will assist the state in meeting short-lived climate pollutant emissions reduction goals by requiring the Joint Utilities to procure biomethane (RNG) produced from organic waste for their core customers.

On April 5, and 6, 2022, the Joint Utilities hosted public workshops to discuss the Standard Biomethane Procurement Methodology (SBPM) that included panelists from each stakeholder group. The Joint Utilities are directed to file a joint Tier 2 Advice Letter with a report of the workshop and feedback received. On April 22, 2022, the Joint Utilities hosted a separate public workshop to discuss the Renewable Gas Procurement Plan (RGPP) that also included panelists from each stakeholder group. The Joint Utilities are directed to file a Tier 1 Advice Letter to establish a template RGPP. The joint utilities plan to file a new application outlining three distinct H2 projects to further understand the capabilities of H2 and inform a statewide injection standard.

Decision Implementing Changes to the Renewable Gas Standard Program and Modifying Renewable Gas Procurement Plans

D.26-04-044, became effective April 30, 2026, This decision (1) adopts a cost containment mechanism to protect ratepayers from extreme rate impacts; (2) reduces the overall procurement target set in Decision 22-02-025 to 36.4 BCF annually; (3) extends both the Diverted Organic Waste procurement target and the overall procurement target to 2035; (4) allows all feedstocks to bid into future Utility solicitations; (5) requires all procurement contracts to be submitted via Tier 2 Advice Letter regardless of contract price; and (6) orders modifications to the gas utilities' draft Renewable Gas Procurement Plans. Collectively, these modifications aim to create a more streamlined Renewable Gas Standard program while protecting ratepayers from excessive above market costs.

Monetary Incentive Program

D.15-06-029 established a biomethane monetary incentive program that included $40 million to encourage biomethane producers to design, construct, and safely operate projects that interconnect and inject biomethane into California's natural gas utilities' pipeline systems.

D.19-12-009 implemented an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened on February 3, 2020, and the queue is published on the CPUC's RNG website.[86]

86 https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas.

D.20-12-031 authorized an additional $40 million of RNG project incentive funding sourced from Cap-and-Invest allowance auction proceeds subject to projects meeting applicable CARB program regulations.

Based on information provided on the CPUC's RNG website, the interconnection incentive program is currently fully subscribed, however the CPUC is still accepting waitlist reservations from interested developers in the event more money is allocated.

RESEARCH AND DEVELOPMENT

PG&E's R&D roadmap[87] further outlines PG&E's goals for incorporating RNG, Hydrogen, and carbon capture into our clean fuels and decarbonization pathways.

RNG

Even though PG&E is maturing processes to get RNG interconnected into our system, R&D work is still needed to advance technologies to incorporate additional feedstock into the RNG fuel mix. Areas that are being piloted include continued work to evaluate woody biomass conversion given the big potential of not only utilizing woody biomass as feedstock for RNG, but also hydrogen. In addition, this will help provide a pathway for dealing with waste from vegetation management programs in our service territory.

Additional research is being done in (a) methanation technologies to create green methane from captured carbon and (b) exploring methanation as a power-to-gas energy storage pathway.

Finally, R&D is being done to upgrade our standardized biomethane interconnection skid.

Hydrogen

Hydrogen is seen as a potential game changer in decarbonizing the gas supply and sectors that are difficult to electrify. To achieve the goals set forth in SB 100 and the carbon neutrality executive order, discussed below, California will need to incorporate hydrogen into its portfolio of clean fuels across multiple sectors. Several countries have already embraced hydrogen to reduce their carbon footprint and diversify their energy mix.

87 Renewable Natural Gas, Hydrogen & Carbon Capture Roadmaps (pge.com).

Given this global momentum, California continues to advance projects across the hydrogen supply chain, including production, storage, delivery, and end-use applications. Early deployments are beginning to demonstrate how hydrogen can support reliability, resiliency, and decarbonization in real-world settings.

One example is the Calistoga Microgrid, operational since September 2025, which represents a first-of-its-kind, fully renewable system delivering up to 48 hours of resilient, zero-emission power. By integrating hydrogen fuel cells with battery storage, the system enhances reliability during Public Safety Power Shutoffs (PSPS) and serves as a scalable blueprint for future clean energy microgrids across California and other high-risk regions.

Additionally, the California IOUs are working collaboratively on an action plan to incorporate hydrogen into the existing gas system through pilot and demonstration projects. These efforts are intended to inform the development of an eventual hydrogen injection standard. A hydrogen blending application was filed with the California Public Utilities Commission (CPUC) in early March 2024 describing these projects, which, once complete, are expected to provide critical data to support a statewide hydrogen blending framework. A decision is anticipated in late 2026.

As part of this application, PG&E is advancing its Hydrogen to Infinity (H2∞) demonstration project, a first-of-its-kind effort to evaluate the safe transport of hydrogen and natural gas blends in a dedicated high-pressure transmission pipeline. The project is designed to generate operational data on system performance and material compatibility, while building experience with hydrogen integration into utility-owned infrastructure. If approved by the CPUC, the project would begin with low levels of hydrogen blending and increase over time to assess system readiness and inform future standards.

Together, these projects illustrate the progression of hydrogen deployment—from early-stage engineering and system integration (H2∞) to operational, customer-serving applications such as the Calistoga Microgrid—while highlighting hydrogen's role across the value chain, including infrastructure, storage, and end-use.

Hydrogen Storage (Conventional and New Technology)

One of the most promising applications for hydrogen is its ability to be produced via electrolysis using excess renewable energy and stored for later use in pipeline systems or dedicated underground storage facilities. This enables hydrogen to function as a form of long-duration energy storage, complementing renewable generation.

Hydrogen storage has the potential to address temporal gaps that battery technologies alone cannot serve—particularly for multi-day or seasonal energy needs. For example, stored hydrogen can be used as a clean fuel for electric generation during periods of low renewable output, helping to maintain grid reliability.

As renewable generation becomes more variable across seasons—especially during winter months—hydrogen offers a scalable solution to provide large volumes of dispatchable, zero-emission energy. Unlike battery storage, which is currently limited in duration and scale, hydrogen storage can support longer-term energy balancing and contribute to a more resilient and reliable energy system.

Carbon Management

Finally, there is no scenario where PG&E will be able to meet our 2040 climate goals without some form of carbon management. We are exploring avenues to evaluate carbon capture technologies, trying to understand how we might be able to utilize our pipeline network to transport captured carbon, and evaluating different means to utilize that captured carbon to help benefit the climate.

CNG as Rail and LNG as Marine Fuel

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the rail and marine markets. The gas supply required for this demand will need to come from cleaner sources of fuel such as RNG and H_2. Additionally, LNG infrastructure developed by third parties would need to be developed at the appropriate scale to meet marine demand for LNG.

Storage

PG&E's Natural Gas Storage Strategy (NGSS) was established in the 2019 Gas Transmission and Storage (GT&S) rate case in response to legislative and regulatory actions following the 2015 Aliso Canyon incident. In that proceeding, the Commission adopted a Reliability Supply Standard requiring PG&E to demonstrate the ability to serve load on a peak day under conditions that include high demand, a major transmission outage, and a storage inventory imbalance. This framework shifted storage planning from a market-based storage program to one focused on deliverability and system reliability.

To support this standard, the Commission approved PG&E's exit from the firm commercial storage market and established the following three firm storage services.

- Inventory Management: Also referred to as pipeline balancing, this service was retained and expanded from 75 mmscf/d of injection and withdrawal to 250 mmscf/d and 300 mmscf/d, respectively.
- Core Firm Storage: The Commission significantly reduced Core's firm storage holdings at PG&E and allowing Core to procure the remaining capacity from Independent Storage Providers.
- Reserve Capacity: A new firm storage service established by the Commission to ensure system reliability by providing 250 mmscf/d of emergency intraday supply of natural gas in case of a significant, unplanned equipment outage or other supply problem.

In the 2023 General Rate Case, the Commission maintained the Inventory Management and Reserve Capacity firm services. It also reaffirmed NGSS and updated the analytical framework the Peak Day Supply Standard (PDSS), previously known as the Reliability Standard. The Commission also ordered PG&E submit an application for review and approval of its gas supply standard along with a revised updated peak-day supply standard analysis and forecast. PG&E filed the application on July 31, 2024 (A.24-07-020), the commission subsequently approved the application in a proposed decision on May 14, 2026.

On May 15, 2025, PG&E submitted the 2027 General Rate Case to the Commission, which includes an updated Peak Day Supply Standard for the 2027-2031 rate period. The case is currently pending, with a decision expected in 2027.

In the 2023 General Rate Case, the Commission maintained the Inventory Management and Reserve Capacity firm services. It also reaffirmed NGSS and updated the analytical framework the Peak Day Supply Standard (PDSS), previously known as the Reliability Standard. The Commission also ordered PG&E submit an application for review and approval of an updated Peak Day Supply Standard. PG&E filed the application on July 31, 2024 (A.24-07-020). The commission subsequently approved the application in a proposed decision on May 14, 2026.

On May 15, 2025, PG&E submitted the 2027 General Rate Case to the Commission, which includes an updated Peak Day Supply Standard for the 2027-2031 rate period. The case is currently pending, with a decision expected in 2027.

2026 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA – TABULAR DATA

TABLE 30 – ANNUAL GAS SUPPLY AND REQUIREMENTS RECORDED YEARS 2021-2025, MMcf/d

Line No.		2021	2022	2023	2024	2025
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	60	43	54	57	50
3	Total California Source Gas	60	43	54	57	50
	OUT-OF-STATE GAS					
	Core Net Purchases					
4	Rocky Mountain Gas	158	156	170	179	105
5	U.S. Southwest Gas	29	38	34	32	29
6	Canadian Gas	410	391	398	378	452
	Customer Gas Transport					
7	Rocky Mountain Gas	329	190	276	149	92
8	U.S. Southwest Gas	539	468	570	499	436
9	Canadian Gas	933	1,023	1,089	1,076	1,015
10	Total Out-of-State Gas	2,397	2,266	2,536	2,312	2,129
11	STORAGE WITHDRAWAL [2]	344	357	258	226	275
12	Total Gas Supply Taken	2,801	2,665	2,848	2,595	2,453
GAS SENDOUT						
	CORE					
13	Residential	488	489	510	441	446
14	Commercial	209	218	227	206	207
15	Natural Gas Vehicle (NGV)	7	8	8	8	8
16	Total Throughput-Core	704	715	745	656	661
	NONCORE					
17	Industrial	453	442	457	470	477
18	Electric Generation [1]	964	891	943	872	791
19	Natural Gas Vehicle (NGV)	4	4	4	4	4
20	Total Throughput-Noncore	1,421	1,337	1,403	1,345	1,272
21	WHOLESALE	8	9	9	8	8
22	Total Throughput	2,133	2,061	2,157	2,009	1,942
23	OFF-SYSTEM DELIVERIES	284	253	181	221	158
24	CALIFORNIA EXCHANGE GAS	38	20	33	37	30
25	STORAGE INJECTION [2]	292	283	434	280	287
26	SHRINKAGE Company Use / Unaccounted For	55	49	44	49	37
27	Total Gas Send Out	2,801	2,665	2,848	2,595	2,453
	TRANSPORTATION & EXCHANGE					
28	CORE All End Uses	111	111	115	101	104
29	NONCORE Industrial	453	442	457	470	477
30	Electric Generation	964	891	943	872	791
31	Subtotal/Retail	1,529	1,445	1,515	1,443	1,372
32	WHOLESALE/INTERNATIONAL	8	9	9	8	8
33	TOTAL TRANSPORTATION AND EXCHANGE	1,537	1,453	1,523	1,450	1,380
	CURTAILMENT/ALTERNATIVE FUEL BURNS					
34	Residential, Commercial, Industrial	0	0	0	0	0
35	Utility Electric Generation	0	0	0	0	0
36	Total Curtailment [3]	0	0	0	0	0
37	Total BTU Factor (Dth/Mcf)	1.035	1.035	1.038	1.038	1.044

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 from other pipelines.

(2) Includes both PG&E and third-party storage.

(3) 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.

TABLE 31 – ANNUAL GAS SUPPLY FORECAST 2026-2030
AVERAGE DEMAND YEAR, MMcf/d

Line No.			2026	2027	2028	2029	2030
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		26	26	26	26	26
	Out-of-State Gas						
2	Baja Path [1]		940	940	940	940	940
3	Redwood Path [2]		1,902	1,902	1,902	1,902	1,902
3.a	SW Gas Corp. from Great Basin Transmission Co.		42	42	42	42	42
4	Supplemental [3]		0	0	0	0	0
5	Total Supplies Available		2,910	2,910	2,910	2,910	2,910
GAS SUPPLY TAKEN							
6	California Source Gas		26	26	26	26	26
7	Out-of-State Gas (via existing facilities)		2,368	2,191	2,155	2,132	2,131
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		2,394	2,217	2,181	2,158	2,157
11	Net Underground Storage Withdrawal		0	0	0	0	0
12	Total Throughput		2,394	2,217	2,181	2,158	2,157
REQUIREMENTS FORECAST BY END USE							
	Core						
16	Residential [4]		467	468	458	437	415
17	Commercial		203	199	194	189	183
18	Natural Gas Vehicle (NGV)		9	9	9	10	10
19	**Total Core**		679	676	661	636	607
	Noncore						
22	Industrial		469	468	467	465	465
23	SMUD Electric Generation [5]		119	118	110	106	94
24	PG&E Electric Generation [6]		727	559	547	555	595
25	NGV		4	4	5	5	5
26	Wholesale		8	8	8	8	8
27	California Exchange Gas		30	30	30	30	30
28	**Total Noncore**		1,358	1,188	1,167	1,170	1,197
30	**Off-System Deliveries** [7]		320	320	320	320	320
	Shrinkage						
33	Company Use and Unaccounted For		37	33	33	32	33
34	**TOTAL END USE**		2,394	2,217	2,181	2,158	2,157
	TRANSPORTATION & EXCHANGE						
35	CORE	All End Uses	103	102	99	96	92
36	NONCORE	Industrial	504	503	502	501	500
37		Electric Generation	846	677	657	661	689
38		Subtotal/Retail	1,453	1,281	1,258	1,258	1,281
39		Wholesale/International	8	8	8	8	8
40		Total Transportation and Exchange	1,461	1,289	1,266	1,266	1,289
41	System Curtailment		0	0	0	0	0

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso 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 system. It excludes deliveries by the Kern Mojave and other pipelines.

(7) Deliveries to Southern California.

TABLE 32 – ANNUAL GAS SUPPLY FORECAST 2031-2040
AVERAGE DEMAND YEAR, MMcf/d

Line No.			2031	2032	2033	2035	2040
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		26	26	26	26	26
	Out-of-State Gas						
2	Baja Path [1]		940	940	940	940	940
3	Redwood Path [2]		1,902	1,902	1,902	1,902	1,902
3.a	SW Gas Corp. from Great Basin Transmission Co.		42	42	42	42	42
4	Supplemental [3]		0	0	0	0	0
5	Total Supplies Available		2,910	2,910	2,910	2,910	2,910
GAS SUPPLY TAKEN							
6	California Source Gas		26	26	26	26	26
7	Out-of-State Gas (via existing facilities)		2,108	2,019	1,709	1,600	1,187
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		2,134	2,045	1,735	1,626	1,213
11	Net Underground Storage Withdrawal		0	0	0	0	0
12	Total Throughput		2,134	2,045	1,735	1,626	1,213
REQUIREMENTS FORECAST BY END USE							
	Core						
16	Residential [4]		400	387	373	343	250
17	Commercial		176	169	162	148	116
18	Natural Gas Vehicle (NGV)		10	11	11	12	13
19	**Total Core**		586	567	546	503	380
	Noncore						
22	Industrial		465	465	464	463	464
23	SMUD Electric Generation [5]		94	94	94	94	94
24	PG&E Electric Generation [6]		593	563	556	493	210
25	NGV		5	5	5	6	6
26	Wholesale		8	8	8	8	8
27	California Exchange Gas		30	30	30	30	30
28	**Total Noncore**		1,196	1,166	1,157	1,094	812
30	**Off-System Deliveries** [7]		320	281	0	0	0
	Shrinkage						
33	Company Use and Unaccounted For		32	31	31	29	21
34	**TOTAL END USE**		2,134	2,045	1,735	1,626	1,213
	TRANSPORTATION & EXCHANGE						
35	CORE	All End Uses	89	85	82	75	57
36	NONCORE	Industrial	500	500	500	499	500
37		Electric Generation	687	657	650	587	304
38		Subtotal/Retail	1,276	1,243	1,232	1,161	861
39		Wholesale/International	8	8	8	8	8
40		Total Transportation and Exchange	1,284	1,251	1,239	1,169	869
41	System Curtailment		0	0	0	0	0

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso 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 system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to Southern California.

TABLE 33 – ANNUAL GAS SUPPLY FORECAST 2026-2030
HIGH DEMAND YEAR, MMcf/d

Line No.			2026	2027	2028	2029	2030
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		26	26	26	26	26
	Out-of-State Gas						
2	Baja Path [1]		940	940	940	940	940
3	Redwood Path [2]		1,902	1,902	1,902	1,902	1,902
3.a	SW Gas Corp. from Great Basin Transmission Co.		42	42	42	42	42
4	Supplemental [3]		0	0	0	0	0
5	Total Supplies Available		2,910	2,910	2,910	2,910	2,910
GAS SUPPLY TAKEN							
6	California Source Gas		26	26	26	26	26
7	Out-of-State Gas (via existing facilities)		2,512	2,277	2,235	2,214	2,236
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		2,538	2,303	2,261	2,240	2,262
11	Net Underground Storage Withdrawal		0	0	0	0	0
12	Total Throughput		2,538	2,303	2,261	2,240	2,262
REQUIREMENTS FORECAST BY END USE							
	Core						
16	Residential [4]		500	503	492	469	445
17	Commercial		212	208	203	198	192
18	Natural Gas Vehicle (NGV)		9	9	9	10	10
19	**Total Core**		721	720	705	677	646
	Noncore						
22	Industrial		469	468	467	465	465
23	SMUD Electric Generation [5]		119	118	110	106	94
24	PG&E Electric Generation [6]		825	598	581	593	657
25	NGV		4	4	5	5	5
26	Wholesale		9	9	9	9	9
27	California Exchange Gas		30	30	30	30	30
28	**Total Noncore**		1,457	1,228	1,202	1,208	1,260
30	**Off-System Deliveries** [7]		320	320	320	320	320
	Shrinkage						
33	Company Use and Unaccounted For		40	35	35	34	35
34	**TOTAL END USE**		2,538	2,303	2,261	2,240	2,262
	TRANSPORTATION & EXCHANGE						
35	CORE	All End Uses	109	107	105	101	97
36	NONCORE	Industrial	504	503	502	501	500
37		Electric Generation	944	716	691	699	751
38		Subtotal/Retail	1,557	1,327	1,298	1,301	1,349
39		Wholesale/International	9	9	9	9	9
40		Total Transportation and Exchange	1,566	1,335	1,306	1,310	1,358
41	System Curtailment		0	0	0	0	0

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso 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 system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to Southern California.

TABLE 34 – ANNUAL GAS SUPPLY FORECAST 2031-2040
HIGH DEMAND YEAR, MMcf/d

Line No.			2031	2032	2033	2035	2040
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		26	26	26	26	26
	Out-of-State Gas						
2	Baja Path [1]		940	940	940	940	940
3	Redwood Path [2]		1,902	1,902	1,902	1,902	1,902
3.a	SW Gas Corp. from Great Basin Transmission Co.		42	42	42	42	42
4	Supplemental [3]		0	0	0	0	0
5	Total Supplies Available		2,910	2,910	2,910	2,910	2,910
GAS SUPPLY TAKEN							
6	California Source Gas		26	26	26	26	26
7	Out-of-State Gas (via existing facilities)		2,261	2,182	1,878	1,742	1,321
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		2,287	2,208	1,904	1,768	1,347
11	Net Underground Storage Withdrawal		0	0	0	0	0
12	Total Throughput		2,287	2,208	1,904	1,768	1,347
REQUIREMENTS FORECAST BY END USE							
	Core						
16	Residential [4]		429	416	402	372	279
17	Commercial		185	178	171	157	125
18	Natural Gas Vehicle (NGV)		10	11	11	12	13
19	**Total Core**		624	605	584	541	417
	Noncore						
22	Industrial		465	465	464	463	464
23	SMUD Electric Generation [5]		94	94	94	94	94
24	PG&E Electric Generation [6]		704	685	684	594	304
25	NGV		5	5	5	6	6
26	Wholesale		9	9	8	8	8
27	California Exchange Gas		30	30	30	30	30
28	**Total Noncore**		1,307	1,288	1,286	1,196	906
30	**Off-System Deliveries** [7]		320	281	0	0	0
	Shrinkage						
33	Company Use and Unaccounted For		35	35	34	32	24
34	**TOTAL END USE**		2,287	2,208	1,904	1,768	1,347
	TRANSPORTATION & EXCHANGE						
35	CORE	All End Uses	94	90	87	80	62
36	NONCORE	Industrial	500	500	500	499	500
37		Electric Generation	798	779	778	688	398
38		Subtotal/Retail	1,393	1,370	1,365	1,267	960
39		Wholesale/International	9	9	8	8	8
40		Total Transportation and Exchange	1,401	1,378	1,373	1,276	968
41	System Curtailment		0	0	0	0	0

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, and El Paso 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 system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to Southern California.

2026 CALIFORNIA GAS REPORT

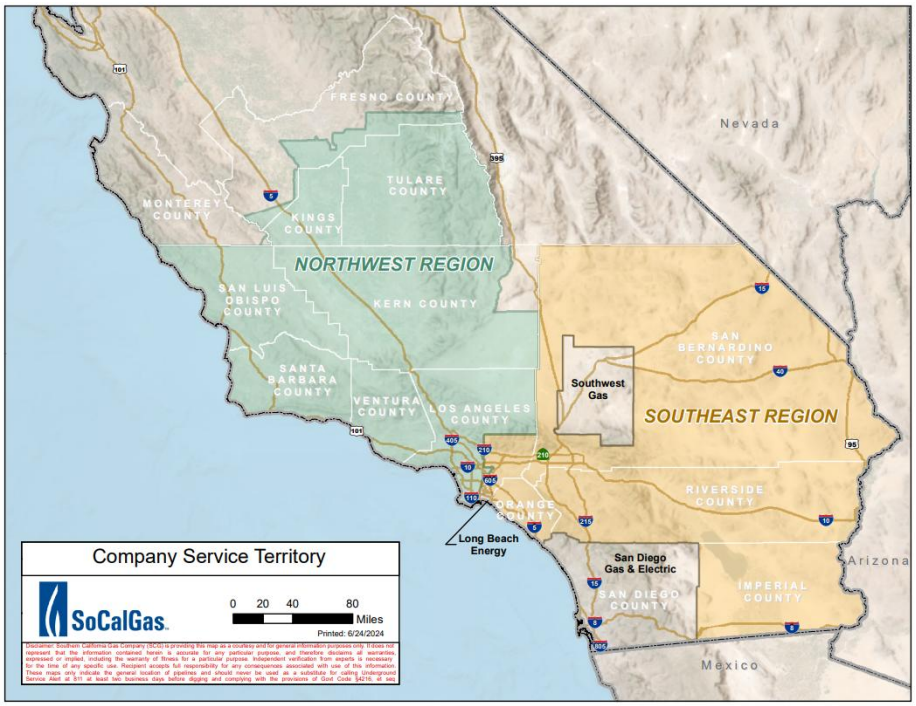
SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California and provides retail and wholesale customers with transportation, exchange, storage services, and procurement services to most retail core customers. SoCalGas' distribution network is composed of approximately 51,070 miles of gas mains across an approximate 20,000 square mile service territory. Together with its intricate distribution network and transmission pipelines and four interconnected storage fields, SoCalGas delivered natural gas to over 5.986 million meters in 2025.

SoCalGas' vast system extends from the Colorado River on the eastern end to the Pacific Ocean on the western end and extending as far North as Tulare County and reaches the U.S./Mexico Border in the South (excluding San Diego County).

FIGURE 9 – SOCALGAS SERVICE TERRITORY MAP



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 (SDG&E), Southwest Gas (SWG), the City of Long Beach Utilities Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas provides gas transportation services across its service territory to a border crossing point at the California--Mexico border at Mexicali to ECOGAS Mexico S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 15 -year demand and forecast period, from 2026 through 2040; only the consecutive years 2026 through 2033, and the point years of 2035 and 2040 are shown in the tabular data in the next sections. All forecasts are inherently subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the 2026 CGR begins with a discussion of economic conditions and regulatory issues facing the utilities, followed by a discussion of 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 regulatory environment and GHG issues are also discussed, followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in part determined by short-term and long-term economic outlook for the SoCalGas service territory. Both gross metro product and employment are expected to grow at levels below both prior and following the height of the COVID pandemic in 2020. Risks to the region's economic outlook include stubborn inflation, elevated interest rates, and slowing domestic as well as international migration.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

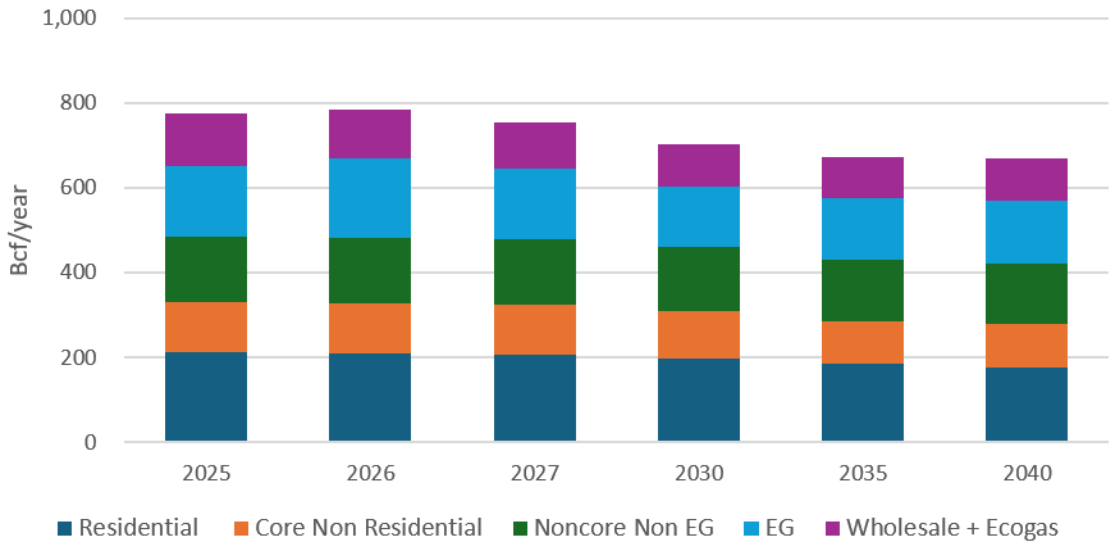
SoCalGas projects total gas demand to decline at an annual rate of 0.9% from 2025 to 2040. By comparison, the total gas demand had been projected to decline at an annual rate of 0.7% in the 2024 CGR. The forecasted decline in demand is being driven by energy efficiency and fuel substitution assumptions.[88] Additional factors that contribute to the overall downward trend are standards created by Title 24 Codes and Standards, the end of multifuel line extension subsidies, and renewable energy goals that impact gas-fired electricity.

The core, non-residential markets (comprised of core commercial, core industrial and natural gas vehicles (NGV)) are expected to decline at an average annual rate of 1.0 percent or from 119 Bcf in 2025 to 102 Bcf by 2040. The noncore, non-EG markets are expected to decline at an average annual rate of 0.5 percent from 155 Bcf in 2025 to 144 Bcf by 2040. That decline is being driven by established energy efficiency goals and associated programs. Total EG load, including large cogeneration and non-cogeneration-EG for a normal hydro year, is expected to decline from 168 Bcf in 2025 to 149 Bcf in 2040, a decrease of 0.8 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2025 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2026 to 2040 forecast period.

[88] For the 2026 California Gas Report, SoCalGas incorporated the California Energy Commission's (CEC) Additional Achievable Fuel Substitution (AAFS) Scenario 1 Programs and incremental Codes and Standards (PiCS).

FIGURE 10 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, Bcf/y



Notes:
(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, NGVs
(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
(3) Retail EG includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration EG.
(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, SWG, and Ecogas in Mexico.

MARKET SENSITIVITY

TEMPERATURE

Core demand forecasts are prepared for two design temperature conditions—average year and cold year—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, core commercial and core industrial markets. The largest core demand variations due to temperature are likely to occur in the month of December. Heating degree day (HDD) differences between the two temperature conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory and a single-zone temperature monitoring procedure within SDG&E's service territory. One HDD is defined as when the average temperature for the day drops 1 degree below 65 degrees F. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis.

Both SoCalGas and SDG&E included a climate change trend that gradually reduces HDDs over the forecast period. The average temperature values of the base year (2025) were computed as the simple average of annual HDDs for the calendar years 2006 through 2025. The annual reductions are based on the latest 20-year trend in 20-year-averaged HDDs. That is, they are based on the observed trend in changes starting with average HDDs for years 1987-2006, then 1988-2007, 1989-2008, and ending with the average HDDs for years 2006-2025. The weather design of annual HDDs is shown in the table below.

TABLE 35 – WEATHER DESIGN OF ANNUAL HDDS

Annual HDDs	SoCalGas		SDG&E	
	Average Year	Cold Year	Average Year	Cold Year
2025	1,235.0	1,472.0	1,181.0	1,434.0
2026	1,228.4	1,465.4	1,175.7	1,428.7
2040	1,136.0	1,373.0	1,101.5	1,354.5
Annual Change	-6.6	-6.6	-5.3	-5.3

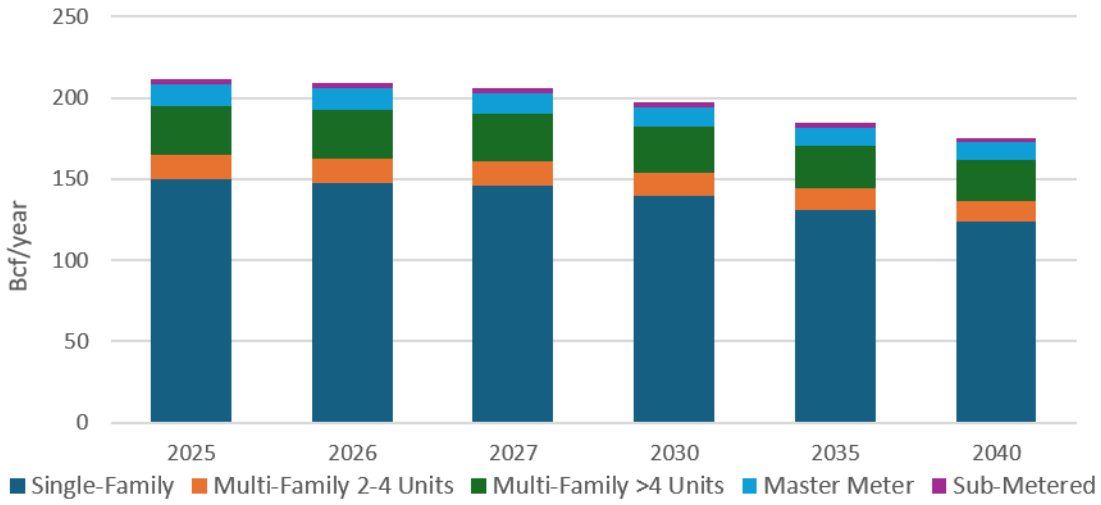
HYDRO CONDITIONS

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

MARKET SECTORS

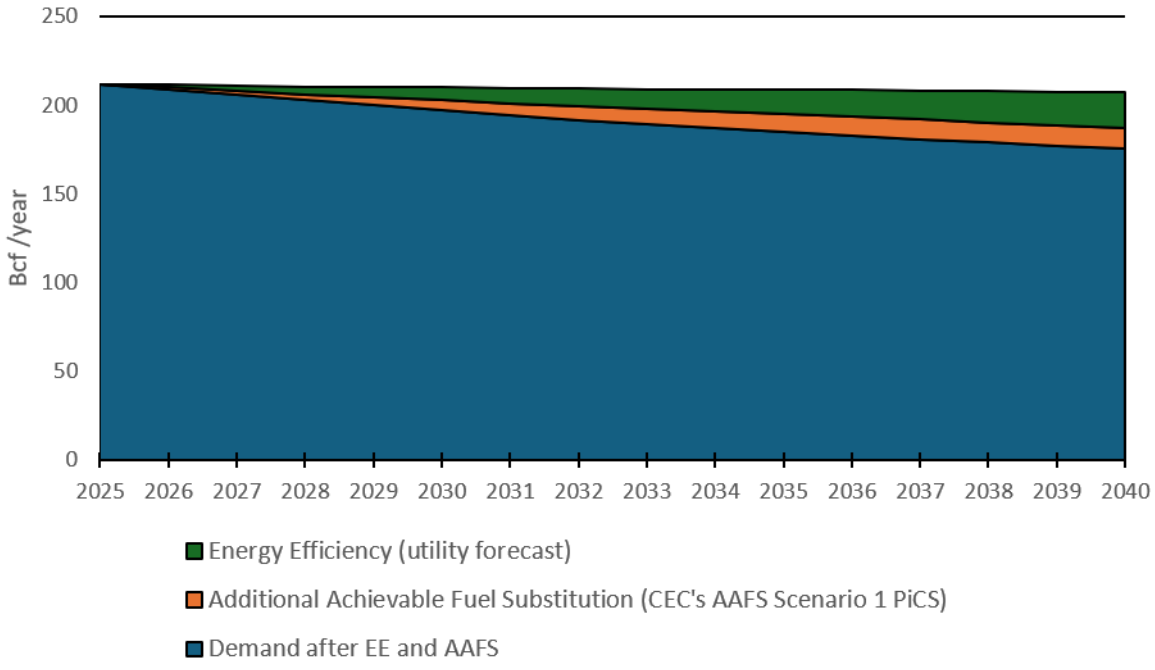
RESIDENTIAL

FIGURE 11 – COMPOSITION OF SOCALGAS RESIDENTIAL DEMAND FORECAST, Bcf/y



Residential gas demand is forecasted to decline from 211 Bcf in 2025 to 175 Bcf by 2040 at an average annual rate of 1.2%. The change is due to declining use per meter, primarily driven by energy efficiency goals, expected fuel substitution, and tightening Title 24 Codes and Standards. The demand reduction created by these policies are partially offset by the load created from new meter growth forecasted over the planning period, although this meter growth is tempered relative to meter growth projected in previous CGRs due to the end of multifuel line extension subsidies.

FIGURE 12 – SOCALGAS RESIDENTIAL IMPACTS OF AAEE AND AAFS, Bcf/y



By 2040, energy efficiency removes 9.8% of total residential demand, while assumed additional achievable fuel substitution accounts for 5.5% of total residential demand reduction. For the purposes of the 2026 California Gas Report (CGR), SoCalGas used the CEC's adopted AAFS Scenario 1 Programs and incremental Codes and Standards (PiCS) from the 2025 Integrated Energy Policy Report (IEPR) forecast based on availability and suitability for gas system planning purposes.

COMMERCIAL

The core commercial market demand is expected to decline over the forecast period. On a temperature adjusted basis, the 2025 core commercial market demand totaled 78.5 Bcf. By the year 2040, the load is anticipated to drop to approximately 63.1 Bcf. The average annual rate of decline from 2025-2040 is forecasted to be 1.4 percent. The decline in gas usage is mainly the result of the impact of CPUC-authorized portfolio of energy efficiency programs and Title 24 codes building standards as well as some forecasted fuel substitution in this market.

In 2025, the noncore commercial temperature adjusted usage was 17.4 Bcf. From 2025 through 2040, demand in this market is expected to rise slightly to about 17.5. Bcf in 2040. The

noncore commercial market will be expected to increase at an average annual rate of 0.02 percent per year. Key factors of the trend are increasing commercial employment and commercial customers that move from core to noncore, partially offset by estimated fuel substitution.

FIGURE 13 – SOCALGAS COMMERCIAL GAS DEMAND BY BUSINESS TYPE, 2025

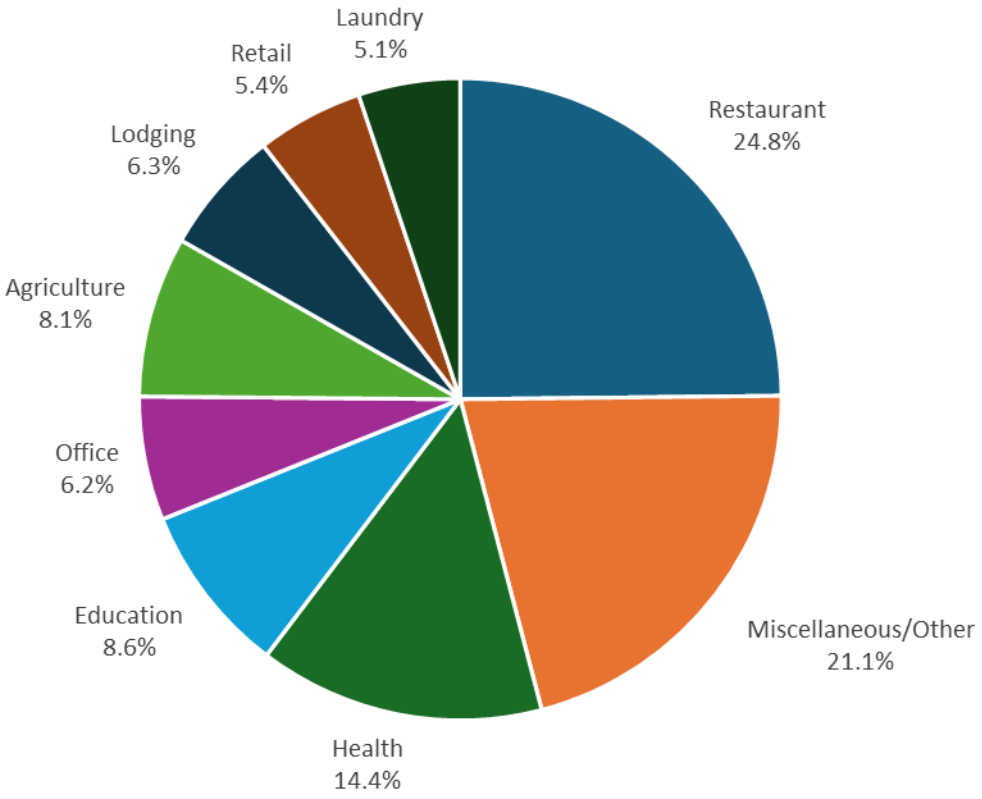
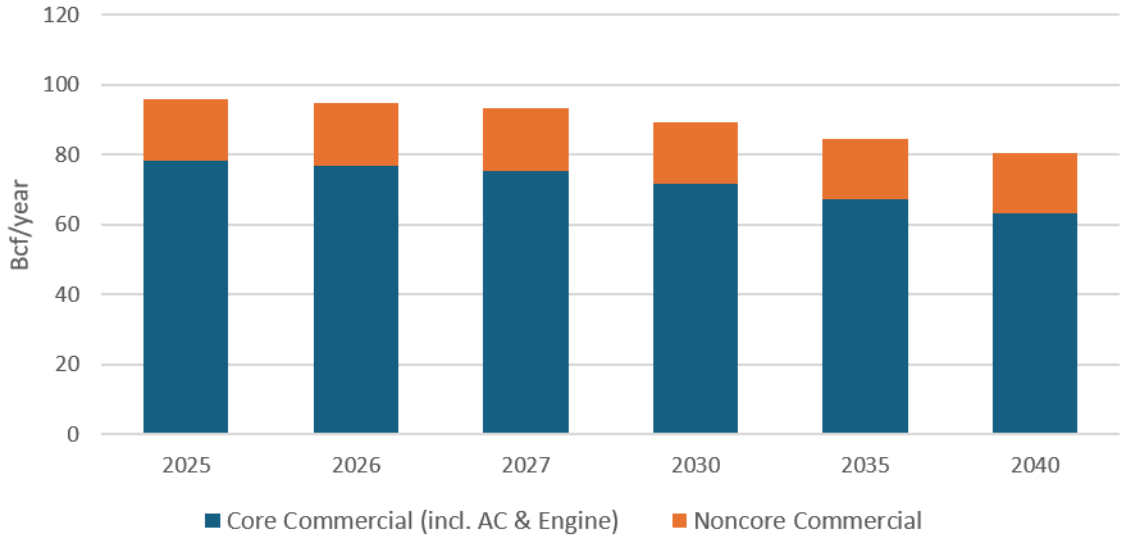


FIGURE 14 – SOCALGAS ANNUAL COMMERCIAL DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN, Bcf/y



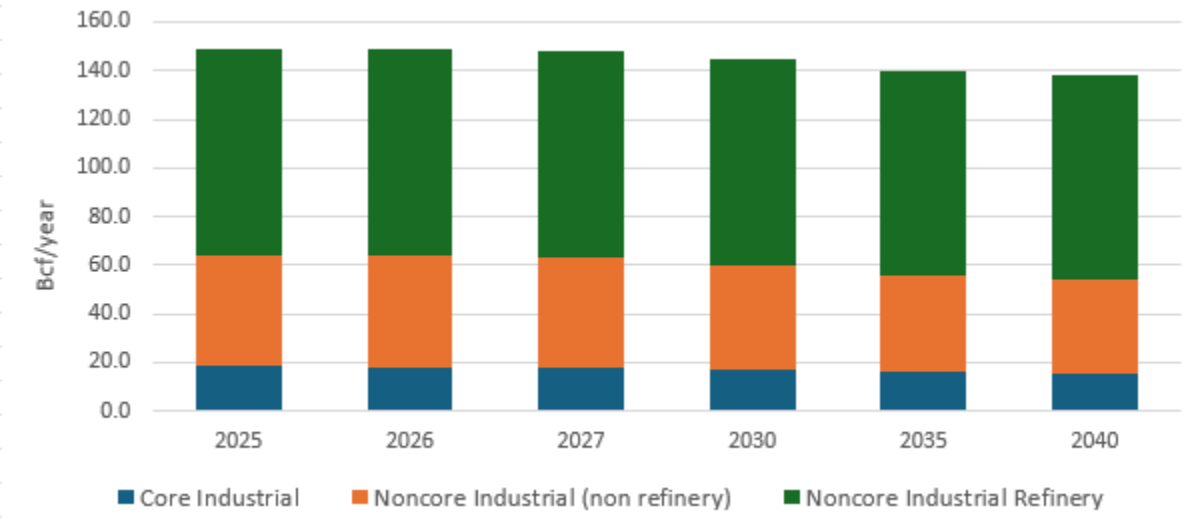
The commercial market consists of nine business types identified by the customers' North American Industry Classification System codes. It represents both core and noncore usage. The restaurant business dominates this market with 24.8 percent of commercial usage in 2025, followed by miscellaneous with a 21.1 percent share. The miscellaneous sector includes, but is not limited to, the warehouse sector, government, transportation/communications/utilities (TCU), construction and other.

INDUSTRIAL

Non-Refinery Industrial Demand

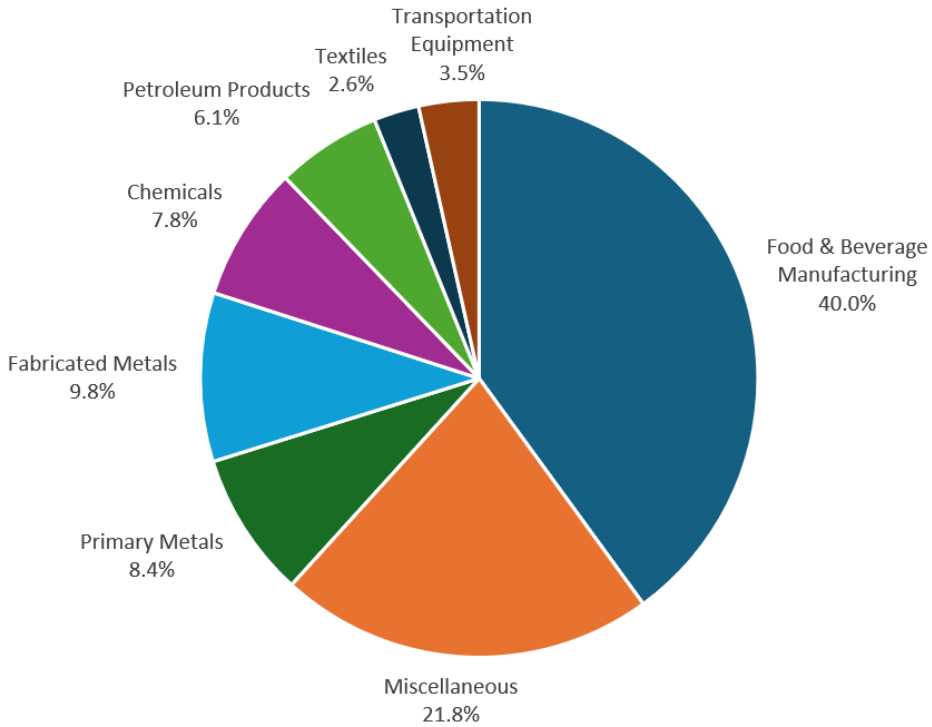
In 2025, temperature-adjusted core industrial demand was 18.6 Bcf. Core industrial market demand is projected to drop by 1.3 percent per year from 18.6 Bcf in 2025 to 15.2 Bcf in 2040. This decline results from a combination of factors: a decrease in core industrial customer counts, an increase in gas rates, the impact of climate change, and the savings from authorized energy efficiency programs in the core industrial sector.

FIGURE 15 – SOCALGAS ANNUAL INDUSTRIAL DEMAND FORECAST, Bcf/y



The 2025 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 40 percent of the total share, dominates this market.

FIGURE 16 – SOCALGAS NON-REFINERY INDUSTRIAL GAS DEMAND BY BUSINESS TYPE, 2025



Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.9 percent from 45.1 Bcf in 2025 to 39.2 Bcf by 2040. The reduced demand is

primarily due to the CPUC-authorized energy efficiency programs, decreasing industrial employment, and the departure of customers within the City of Vernon to wholesale service by the City of Vernon.

Refinery Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, H2 producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to decrease slightly in the forecast period, from 85.0 Bcf in 2025 to 83.7 Bcf in 2040.

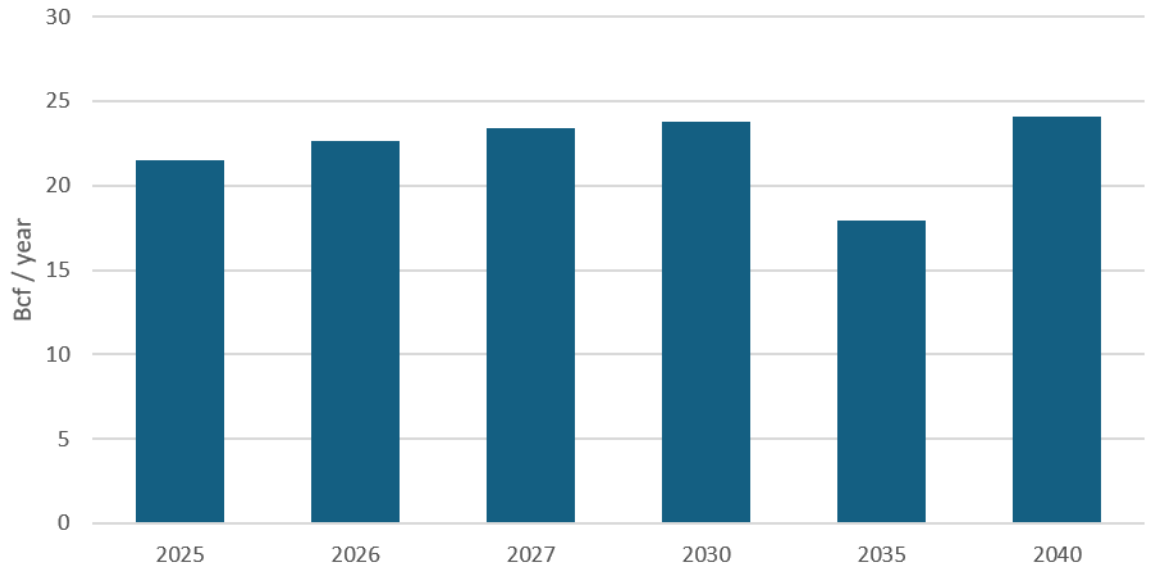
NATURAL GAS VEHICLES

The NGV market is expected to grow 0.8 percent per year over the forecast horizon. The growth is due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles[89] and the affordability of RNG compared to traditional fuels such as gasoline and diesel.[90] SoCal Gas assumes the California Air Resources Board Innovative Clean Transit regulation mandating the purchase of zero emission buses for urban transit bus fleets will negatively impact NGV market growth and decrease NGV market volumes through 2035. Total NGV market growth is expected to resume by the end of the forecast period based on the growth in natural gas-fueled trucking used in goods movement.

89 These include but are not limited to battery electric vehicles (BEV), natural gas vehicles, hydrogen fuel cell electric, and hybrid vehicles.

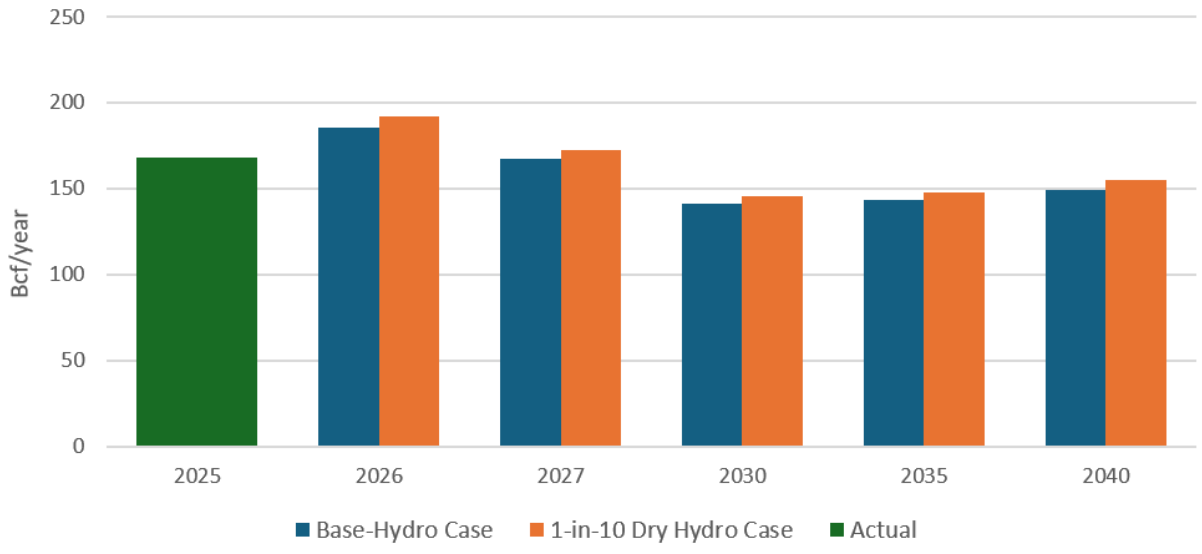
90 https://americanbiogascouncil.org/energy-vision-report-finds-rng-not-electric-vehicles-best-option-to-replace-oldest-dirtiest-diesel-trucks/

FIGURE 17 – SOCALGAS NGV DEMAND FORECAST, Bcf/y



ELECTRIC GENERATION

FIGURE 18 – SOCALGAS TOTAL ELECTRIC GENERATION (EG), Bcf/y



The EG sector includes all commercial/industrial cogeneration, enhanced oil recovery (EOR)-related cogeneration, and non-cogeneration electric generation. The EG load forecast is

subject to a high degree of uncertainty. The forecast uncertainty is, in large part, due to load sensitivity to weather conditions, regional fuel price differences, the construction and retirement of power generating facilities (including thermal, renewable, and energy storage resources), the amount of California's import/export energy, and the state's overall long-term electricity demand growth. The EG gas throughput forecast can be higher or lower than the base case forecast, depending on the factors mentioned above. California's forecasted electricity demand is a major influence on Southern California gas demand from EG. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher, all else being equal. Please refer to the California Energy Commission's (CEC) 2025 Integrated Energy Policy Report (IEPR) for high, mid, and low electricity demand scenarios. On the supply side, lower SoCalGas Citygate gas prices relative to other regions, less energy imported into California, and dry hydro conditions are also factors that would increase the EG gas throughput forecast.

Additionally, many once through cooling (OTC) plants in California are scheduled to either retire or repower during the forecasted period. These are thermal plants, located near the coast, that use ocean water for cooling. A total of 4,520 MW of local gas-fired power plants and a 2,240 MW nuclear plant in Northern California are scheduled to retire by the end of 2030.

The gas-driven EG forecast uses a power market simulation for the period of 2026-2040. The simulation 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 most of the CPUC adopted 2025 Preferred System Plan, which also assumes compliance with the Mid-Term Reliability (MTR).[91] Also assumed in the forecast is compliance with the GHG planning target of 25 million metric tons (MMT) by 2040. This plan includes an aggressive amount of energy storage resources along with significant renewables resources throughout the study period. While California load-serving entities (LSEs) are working to meet their GHG goals, there are uncertainties as to how much renewable power and energy storage resources will be added specifically during the study period.

The EG demand forecast for the state of California, used in the simulation, is sourced from the CEC's California Energy Demand Forecast, 2025-2045, adopted January 2026. This energy

91 D.21-06-035.

demand forecast was developed as part of the CEC's Integrated Energy Policy Report process. The mid energy demand forecast with Additional Achievable Energy Efficiency (AAEE) Scenario 3 and Additional Achievable Fuel Substitution (AAFS) Scenario 1 PiCS was selected as the energy demand forecast. PG&E provided its own version of AAFS for its region.

INDUSTRIAL/COMMERCIAL/COGENERATION <20 MW

A segment of EG demand is the commercial/industrial cogeneration (including self-generation) market. This segment includes customers with a 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). The gas demand in the small cogeneration market was 24.4 Bcf in 2025 and is expected to modestly decrease to 23.9 Bcf by the year 2040, or at an average growth rate of -0.13 percent per year. The decreased demand is primarily due to the decline in average consumption per customer and generally declining industrial activity in the region.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to be stable over the 2026 - 2040 forecast period, maintaining from 20.3 Bcf in 2025 to 20.3 Bcf in 2040.

Enhanced Oil Recovery (EOR) - Related Cogeneration

In 2025, recorded gas deliveries to the EOR -related cogeneration were 0.1 Bcf. EOR Cogeneration demand is forecasted to decrease, reaching 0.0 Bcf by 2040. The forecasted demand remains volatile and uncertain due to factors such as renewable energy goals, fuel substitutions, and shifts in customer demand related to California's energy transition.

Electric Generation, Including Large Cogen

EG customers are comprised of utility electric generation (UEG) customers, various Exempt Wholesale Generator (EWG) customers and large cogeneration customers where usage exceeds 20 MW. For the base case (average hydro condition), gas demand is forecasted to decrease from 123.0 Bcf in 2025 to 104.6 Bcf in 2040. The main factors for the decline are an aggressive energy storage resource addition, a significant renewable resource addition, and the retirement of older gas-fired plants.

WHOLESALE

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Utilities Department (Long Beach), Southwest Gas (SWG), and the City of Vernon (Vernon), and Ecogas Mexico, L. de R.L. de C.V. The wholesale load excluding SDG&E is expected to increase from 33.2 Bcf in 2025 to 36.8 Bcf in 2040. The change reflects a 0.7 percent average annual increase.

SDG&E

Under average-year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 1.27 percent per year from 89.5 Bcf in 2025 to 73.9 Bcf in 2040. Additional information regarding the composition of SDG&E's gas demand is provided in the SDG&E section of this report.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach Utilities Department. Long Beach's gas use is expected to decrease slightly, from 7.3 Bcf in 2025 to 5.4 Bcf by 2040. Additional information regarding the City of Long Beach Utilities Department's gas demand is provided in the City of Long Beach Utilities Department section of this report.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2025, SoCalGas delivered 8.7 Bcf to Southwest Gas and the total load is expected to rise to 10.0 Bcf by 2040. Refer to Southwest Gas for additional information regarding their gas demand.

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 5.30 Bcf in 2025 and slightly decreases to 5.28 Bcf by 2040. The forecasted throughput includes core and noncore customers and includes Malburg Power Plant throughput. 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.

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

SoCalGas used the forecast prepared by Ecogas for this report. Ecogas' use is expected to increase, from 11.9 Bcf in 2025 to 16.1 Bcf by 2040. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

ENERGY EFFICIENCY PROGRAMS

SB 350[92] requires the state to double statewide energy efficiency savings associated with electricity and natural gas end uses by 2030. The U.S. Department of Energy (DOE) sets efficiency standards under the Energy Policy and Conservation Act (EPCA)[93] for more than 70 product categories of consumer appliances and commercial equipment, enforces the standards, and proposes new and revised standards.[94] The ENERGY STAR program supports voluntary reporting by manufacturers of efficiency statistics and administers some efficiency credits.[95]

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92 SB 350 (DeLeon, Chapter 547, Statutes of 2015). SB 350 also set a statewide target of reducing GHG emissions 80% below 1990 levels by 2050; the target date was subsequently changed to 2045 by SB 100.

93 Energy Policy and Conservation Act (EPCA), P.L. 94-163, 89 Stat. 871, 42 USC 6291, https://www.govinfo.gov/content/pkg/STATUTE-89/pdf/STATUTE-89-Pg871.pdf.

94 DOE measures furnace efficiency by examining annual fuel utilization efficiency, room air conditioners by an energy efficiency ratio, and central heat pumps by seasonal energy efficiency.

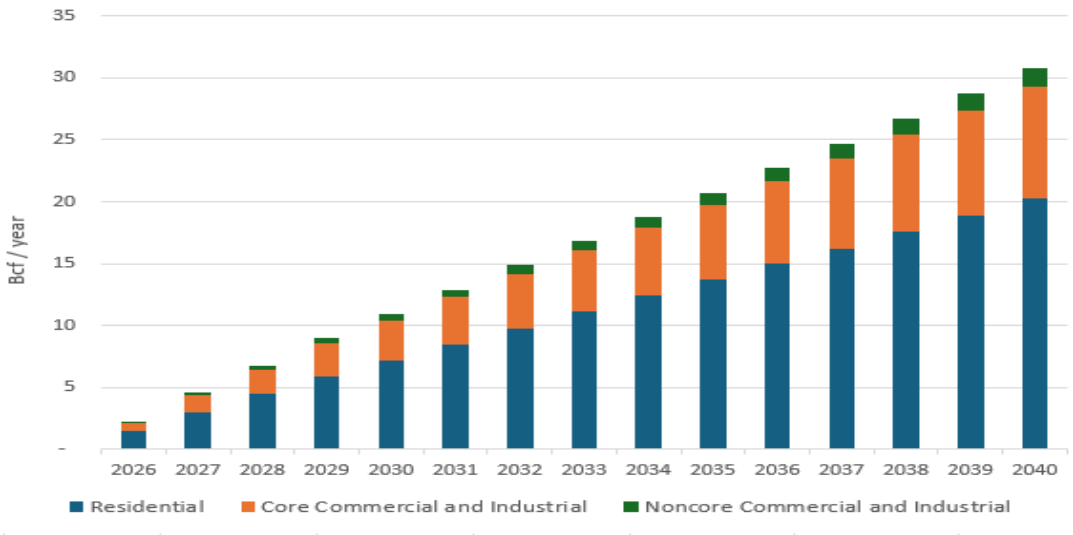
95 Efficiency tax credits largely terminated at the end of 2025. "Federal Tax Credits for Energy Efficiency," *ENERGY STAR*, https://www.energystar.gov/about/federal-tax-credits.

SoCalGas engages in several energy efficiency (EE) and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include 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.

The forecast of cumulative natural gas savings due to SoCalGas' energy efficiency programs is provided in the figure below. The forecasts capture savings from programs developed in support of several goals and standards. Efforts were made to exclude the forecasted fuel substitution from the EE forecast. The forecast for fuel substitution is accounted for separately in the AAFS Scenario 1 PiCS forecast (included in the CEC's 2025 Integrated Energy Policy Report). The savings shown below represent the net load impact for the energy efficiency portfolio that includes program savings and the codes and standards savings that SoCalGas anticipates will occur through year 2040.

Forecasted savings for the 2026-2040 period are based on the 2025 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.25-08-034, which set EE goals through 2037. Forecasted savings beyond 2037 are held constant based on 2037 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2025 and do not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

FIGURE 19 – SOCALGAS COMBINED PORTFOLIO OF EE PROGRAMS, Bcf/y



GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and local California supplies. Recorded 2021 through 2025 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Scheduled gas supply available to SoCalGas and SDG&E from California sources averaged 88 MMcf/d in 2025.

SOUTHWESTERN U.S. GAS

Traditional Southwestern U.S. sources of natural gas continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas pipeline with some volumes also on the Transwestern pipeline. Generally speaking, San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 to 3 percent. Recent developments in 2025, however, have led to an increase in production from the region; it is too early to discern whether this is a momentary feature or longer-term trend. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. Permian gas production increased by over 130 percent during the period 2019-2023. This increase positioned the Permian Basin as a preferred gas supply source of economical gas.

Mexican demand for Southwestern U.S. natural gas along with east of California demand continue to steadily increase and compete for southwestern natural gas supplies. This increasing demand will likely continue to compete with Southern California for southwest natural gas supplies.

ROCKY MOUNTAIN GAS

Rocky Mountain natural gas supplies continue to supplement Southwestern U.S. gas sources for Southern California. Natural gas supply from the Rockies is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although Rockies' gas can also be accessible through pipelines interconnected to the San Juan Basin. Pipelines that supply other markets connect to the Rocky Mountain region, which allows Rockies natural gas supply to be redirected to higher value markets as conditions change. Over the past couple of years, there has been increasing demand for Rockies supplies locally, across the Western Region, and from Eastern demand which has elevated competition for these supplies to Southern California.

CANADIAN GAS

Canadian natural gas provides a small share of Southern California natural gas supplies due to the limited available capacity to transport the gas to Southern California.

RENEWABLE NATURAL GAS (RNG)

With the adoption of SB1440 and the evolution of energy transition at both the national and state levels, physical RNG (biomethane) is planned to be part of the supply portfolio for the customers of the four natural gas investor-owned utilities (IOUs) in California. RNG is methane produced from one of several processes known in the industry as: (1) anaerobic digestion (aka. AD), (2) landfill gas, (3) gasification (also pyrolysis) and 4) dairy (including other animal waste such as swine). According to the most recent SB 1440 procurement targets set by the CPUC, the amount of RNG in SoCal Gas' core supply portfolio would be 18.93 Bcf/year by 2030. Since this RNG supply would be produced at in-state facilities, out-of-state gas supplies would generally be reduced by the same amount. The following table shows a high-level estimate of the RNG delivered to core customers on SoCalGas and SDG&E's system. In the period shown (2022 – 2025), it is estimated that all RNG is utilized by Natural Gas Vehicles end uses (NGVs).

TABLE 36 – SOCALGAS AND SDG&E RENEWABLE NATURAL GAS DELIVERIES, MMcf/d

	2023	Approx. % of System (2023)	2024	Approx. % of System (2024)	2025	Approx. % of System (2025)
Total Core Gas Deliveries [1]	1,087		1,038		1,003	
RGS - RNG [2]	0	0.0%	0	0.0%	0	0.0%
NGVs - Estimated RNG [3,4]	55	5.1%	58	5.6%	63	6.2%
Physical [5,6]	12	1.1%	13	1.2%	16	1.6%
Estimated Book and Claim [7]	43	4.0%	45	4.3%	47	4.7%

Notes:

1) Taken from Tables 34 and 48, SoCalGas and SDG&E Annual Gas Supply and Sendout, Deliveries by End-Use

2) Refers to Renwable Natural Gas procured under SB 1440 (Renewable Gas Standard)

3) SoCalGas Data taken from Table 34, SoCalGas Annual Gas Supply and Sendout Table, Deliveries by End-Use: Core, NGVs. SDG&E data provided by SDG&E.

4) Table assumes: ~98% of NGVs utilize RNG in 2023, ~99% utilize RNG in 2022, and ~98% of NGVs utilize RNG in 2023.
This assumption based on Alternative Fuels Volume data from California Air Resources Board (annual volume of Biomethane and Fossil Natural Gas):
https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

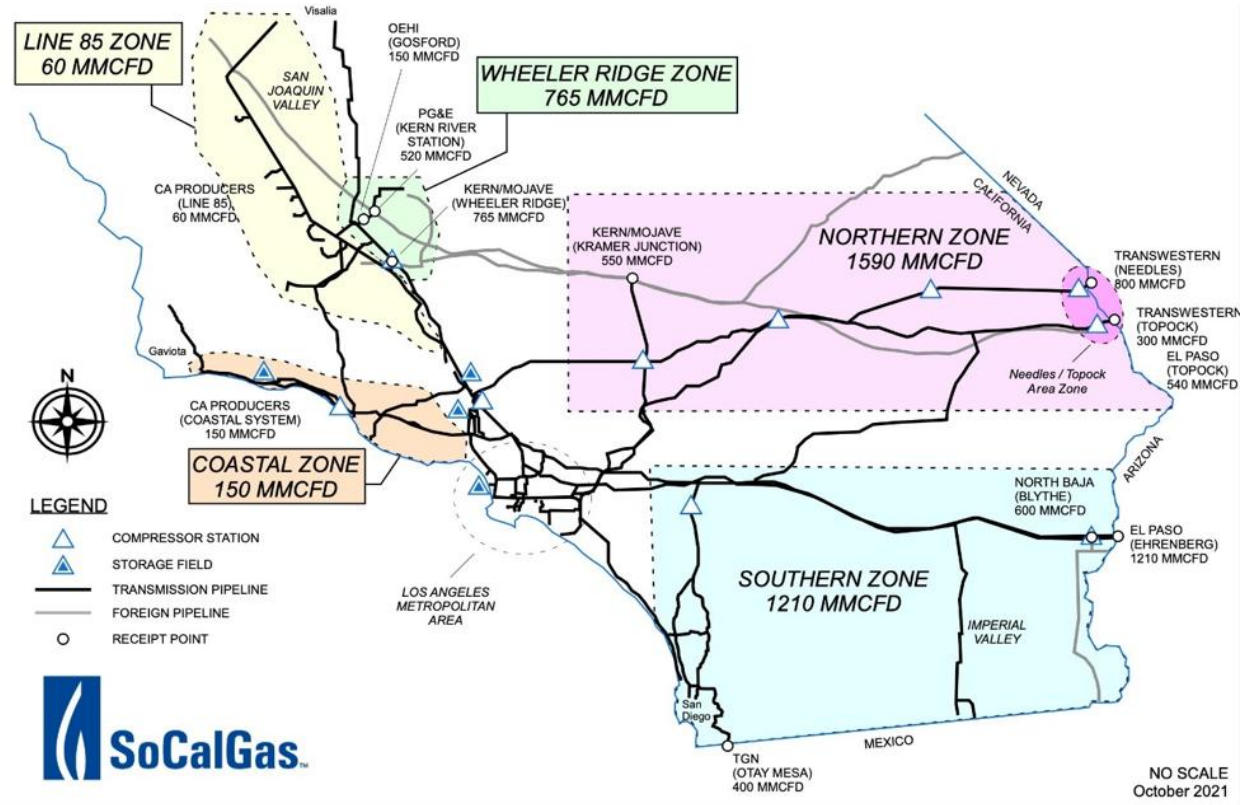
5) Annual RNG delivered from all points of receipt to SoCalGas and SDG&E.

6) Taken from SoCalGas & SDG&E Biomethane Annual Report Biomethane Phase 1 (2023, 2024, and 2025).

7) Book and Claim estimates were calculated by the difference between total NGV supply and interconnected RNG. It should be noted that actual numbers may differ.

FIRM RECEIPT CAPACITY

FIGURE 20 – RECEIPT POINT AND TRANSMISSION ZONE FIRM CAPACITIES



STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for systemwide reliability. Natural gas storage is also used to meet peak daily and seasonal gas demand and to hedge against price volatility in natural gas commodity markets. In addition, natural gas storage has played a role in addressing emergency situations, including extreme weather and wildfires. SoCalGas owns and operates four natural gas storage facilities within Southern California: Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey.

In Southern California, natural gas storage fields are located in areas with specific underground geologic characteristics, and in proximity to local gas consumers and transmission and distribution pipelines. Storage natural gas is withdrawn and delivered to customers through SoCalGas' transmission and distribution systems when customer demand exceeds flowing natural gas supplies and for system balancing.

SoCalGas' natural gas storage fields have a combined authorized storage working inventory capacity of 119.5 Bcf, of which 80.03 Bcf is allocated to our SoCalGas's and SDG&E's combined core residential, small industrial and commercial customers, 12 Bcf is used for system balancing, and the remaining capacity is available to other customers.

STORAGE REGULATIONS

Since 2015, the California Public Utilities Commission (CPUC), the California Geologic Energy Management Division (CalGEM), and the Pipeline and Hazardous Materials Safety Administration (PHMSA) have proposed and adopted various regulations addressing natural gas storage requirements and standards including safety and reliability. SoCalGas is committed to working with various regulating bodies and policy makers to provide safe and reliable energy and natural gas storage services.

PHMSA issued the Final Rule for Underground Natural Gas Storage Facilities regulations (49 Code of Federal Regulations (CFR) §192.12) (The PHMSA Final Rule), amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopted API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, formalizing integrity management practices. On July 1, 2025, PHMSA issued a Direct Final Rule (DFR) adopting the

second edition of API RP 1171, which introduces enhanced requirements for operators related to recordkeeping, inclusion of third-party wells in risk assessments, improved data integration, incorporation of safer work practices, and formalized risk prioritization.

CalGEM established California Underground Gas Storage Projects regulations (14 California Code of Regulations (CCR) §1726), effective October 1, 2018, which includes among other requirements, mechanical testing mandates that require well inspections every 24 months, unless an alternative frequency is approved by CalGEM. On July 1, 2025, CalGEM Implemented new requirements under SB 463 (Chemical Inventory and Root Cause Analysis Regulations), requiring natural gas storage operators to develop and maintain a comprehensive well chemical inventory tracking, conduct fluid testing, develop well control plans, develop well-by-well corrosion risk ranking, and track operational incidents.

POLICIES IMPACTING GAS DEMAND

During the forecast horizon covered by this report, there are many policies that may significantly impact the future trajectory of natural gas demand for SoCalGas, including:

- **Long-term Gas Reliability and Planning Proceeding (R.24-09-012)** has reframed California natural gas planning around an anticipated long-term decline in demand rather than growth, driven by state climate goals, building electrification, energy efficiency, and decarbonization of the power sector. The proceeding requires gas utilities to align forecasts and infrastructure decisions with these policies, emphasizing reliability through system optimization, non-pipeline alternatives, and coordinated gas-electric planning instead of new capacity expansion. At this time, both CPUC and the gas utilities are addressing Senate Bill (SB) 1221 within the proceeding. The bill requires gas utilities to annually submit maps identifying potential gas pipeline replacement projects, which the CPUC will use to designate priority neighborhood decarbonization zones. It directs the CPUC to establish a limited, voluntary pilot program (up to 30 projects) to support cost-effective transition to zero-emission alternatives in those zones, including setting cost-effectiveness criteria and utility cost recovery. The bill also allows utilities to stop providing gas service in pilot areas if adequate alternative energy is available and requires reporting to the Legislature, with the program unsetting January 1, 2031.

- **Aliso Canyon Biennial Assessment (A.26-01-009)** is considering the CPUC Energy Division's Biennial Assessment issued in October 2025, which concluded that the four analyses conducted for winter 2025-26 support a recommendation to reduce the Aliso Canyon maximum inventory by 10 Bcf to a level of 58.6 Bcf. However, the Biennial Assessment further provides that, given current forecasts for higher gas commodity prices in winter 2026-27, the CPUC may wish to consider a smaller incremental reduction or no reduction at all. SoCalGas's Application in response to the Aliso Canyon Biennial Assessment requests that the CPUC: 1) Review the Energy Division's Biennial Assessment and SoCalGas's recommendations presented in this Application and accompanying testimony; 2) Find that reducing Aliso Canyon's maximum inventory level at this time would lead to impacts to gas and electric system reliability and on gas and electric rates; 3) Find that the Commission should not authorize the reduction of Aliso Canyon's maximum inventory level at this time; and 4) Find that the Commission should authorize an increase of Aliso Canyon's maximum inventory level if necessary to maintain reliability and just and reasonable rates.

- **Building Decarbonization** policies in California are generally placing downward pressure on natural gas demand by discouraging new gas connections, promoting electrification, and advancing energy efficiency, even as outright local gas bans have faced legal challenges. State-level efforts—driven by climate mandates such as SB 32 and carbon-neutrality targets—favor electric space and water heating through building codes, attempts at zero-emission appliance standards, and incentive programs like BUILD[96] and TECH Clean California. While some proposed regulations (e.g., SCAQMD rules and CARB initiatives) aim to further reduce gas use, many have been delayed or scaled back due to cost concerns, public resistance, and legal uncertainty. The transition raises equity and reliability challenges, as electrification can impose higher upfront and operating costs and depends on confidence in the electric grid. AB 3232[97] and the California Building Decarbonization Assessment[98] outline a range of strategies—including electrification, efficiency, distributed resources, and renewable gas—to cut building emissions.

- **Renewable Natural Gas (RNG) and SB 1440** programs offered by natural gas utilities can deliver immediate emissions reductions using existing pipelines and appliances, avoiding the significant upfront costs and grid upgrades associated with full electrification, particularly for peak heating demand, legacy buildings, and hard-to-electrify users. RNG also supports system resilience by providing firm, dispatchable energy during extreme weather and outages, while mitigating methane emissions through capturing waste-based gases from landfills, dairies, and wastewater facilities. Additionally, RNG helps spread fixed gas system costs across a broader customer base, reducing bill impacts and equity concerns for low-income and rental households unable to electrify quickly. From 2012–2014, California began opening its gas pipeline system to RNG.[99] Implementation of SB 1440 established biomethane procurement targets for 2025 and 2030, including the Renewable Gas Standard

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96 CEC, "Building Initiative for Low-Emissions Development (BUILD) Program, Second Edition," n.d., https://www.energy.ca.gov/publications/2024/building-initiative-low-emissions-development-build-program-second-edition.

97 AB 3232 (Friedman, Chapter 373, Statutes of 2018).

98 CEC, California Building Decarbonization Assessment, CEC-400-2021-006, August 13, 2021, https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment.

99 Following the legislature's direction in AB 1900 (2012, Gatto), CPUC on February 13, 2013, the Commission opened the Biomethane order instituting rulemaking (OIR) (R.13-02-008), which determined RNG could be safely injected into the natural gas pipeline system. Decision D.14-01 034 (January 16, 2014) adopted pipeline injection standards, concluding Phase 1 of the Biomethane OIR.

(RGS), which requires utilities to procure set shares of RNG from diverse sources.[100] The 2025 target emphasized reducing landfill waste, aligning with CARB's 2022 Scoping Plan goal of diverting 75 percent of organic waste from landfills by 2025,[101] while the 2030 RGS expands procurement obligations; in May 2025, SoCalGas announced the first RGS procurement tied to a San Bernardino landfill project.[102] More broadly, SB 1440 reshapes gas utility planning by requiring alignment with climate targets

- **Cap-and-Invest** is a market-based climate policy that sets a statewide declining limit ("cap") on total greenhouse gas emissions from major sources such as power plants, industrial facilities, and suppliers of fuels—including natural gas. Regulated entities must obtain allowances equal to their emissions, which can be purchased at state-run auctions or traded on a secondary market. Over time, the cap tightens, reducing the number of available allowances and increasing their price, which creates a financial incentive to lower emissions. The "invest" component refers to how the state uses auction proceeds: California directs billions of dollars into programs like clean energy deployment, electrification, energy efficiency, and environmental justice initiatives aimed at reducing emissions further. The program can affect natural gas consumption differently across sectors. In the electric power sector, rising carbon costs tend to make gas-fired generation more expensive relative to zero-emission resources (solar, wind, storage), accelerating a shift away from gas over time while still relying on it for reliability in the near term. In the industrial sector, facilities that use natural gas for heat or processing face compliance costs, which encourage efficiency upgrades, fuel-switching, or adoption of low-carbon technologies (e.g., electrification or hydrogen), though impacts vary depending on trade exposure and available alternatives. For residential and commercial buildings, the effect is indirect: natural gas utilities pass through some allowance costs in rates, which can modestly increase gas prices and encourage reduced consumption, electrification (e.g., heat pumps), or efficiency improvements. Overall, the program is designed to gradually dampen natural gas demand while allowing flexibility for sectors where immediate substitution is more difficult.

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100 On February 24, 2022, CPUC Decision D.22-02-025 implemented SB 1440, defining two biomethane procurement targets for gas IOUs. The short-term 2025 biomethane procurement target was set at 17.6 Bcf of biomethane, corresponding to 8 million tons of organic waste diverted statewide annually from landfills. This target was set to support the organic waste diversion targets established previously in SB 1383. With this target, each utility is responsible for procuring only RNG produced from diverted organic waste, including certain wood waste, at a level proportionate to its share of statewide cap-and-invest allowances.

101 The 2030 target for annual biomethane procurement was established at 72.8 BCF to assist the state achieve its goal to reduce methane emissions 40 percent by 2030. (SB 32, 2006).

102 SoCalGas, "SoCalGas Announces First Renewable Natural Gas Contract Approved Under California Program," May 18, 2026, https://www.socalgas.com/newsroom/stories/socalgas-announces-first-renewable-natural-gas-contract.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's bundled core gas demand are procured as 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. On the extreme peak day event, service to all noncore customers is assumed to be fully interrupted. The criteria for extreme peak day design are defined as a 1 in 35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.6 degrees Fahrenheit for SoCalGas' service area and 43.7 degrees Fahrenheit for SDG&E's service area.

TABLE 37 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND, MMcf/d

Year	SoCalGas Core Demand	SDG&E Core Demand	Other Core Demand	Total Demand
2026	2,710	309	152	3,171
2027	2,694	307	153	3,153
2028	2,677	304	154	3,135
2029	2,659	302	155	3,116
2030	2,644	300	156	3,101
2031	2,627	299	157	3,082
2032	2,610	297	157	3,064

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/ 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.

4/ The criteria for extreme peak day design are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.6 degrees Fahrenheit for SoCalGas' service area and 43.7 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 table above provides forecasted core extreme peak day demand.

SoCalGas aligned around the fuel substitution scenario developed by the California Energy Commission (CEC). SoCalGas emphasizes that we are still in the early stages of any energy transition and forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and policy and market drivers mature. SoCalGas will actively monitor these trends and expects that each update of the CGR will more clearly define these factors and their impact(s) on the resultant gas demand segment forecasts.

It is also important to note that the CGR is relied upon for system planning purposes to inform important infrastructure investment and operating decisions that directly affect natural gas system capacity and reliability. For these reasons, while we recognize the need to evolve alongside the state's decarbonization goals, it is equally important to take a measured approach to prospective load reductions. Prematurely adjusting design standards based on uncertain projections may not serve California well if anticipated load reductions do not materialize. Even as the energy system transitions, we have an obligation to our customers to make sure they continue to receive safe and reliable gas service while supporting affordability, particularly for our most vulnerable communities. Taking a more balanced approach to uncertain future projections will better support these outcomes and serve the public interest.

The CPUC has also mandated that SoCalGas and SDG&E design its system to provide service to both core and noncore customers under a winter temperature condition with an expected recurrence interval of 10 years. The demand forecast for this 1 in 10-year cold day condition is shown in the table below.

TABLE 38 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION, MMcf/d

Year	SoCalGas Core	SDG&E Core	Other Core	Noncore NonEG	Electric Generation	Total Demand
2026	2,567	296	123	571	1,201	4,758
2027	2,550	293	125	568	1,165	4,701
2028	2,533	291	126	561	965	4,477
2029	2,516	288	126	557	991	4,479
2030	2,501	287	127	554	1,097	4,566
2031	2,484	285	128	550	988	4,435
2032	2,467	284	129	547	901	4,327

Notes:

1/ 1-in-10 peak temperature cold day SoCalGas core sales and transportation.

2/ 1-in-10 peak temperature cold day SDG&E core sales and transportation.

3/ 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.

4/ Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily December Noncore-Non-EG demand for all market segments except Refinery and SoCalGas and SDG&E noncore Commercial; SoCalGas and SDG&E noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.

5/ Electric Generation includes UEG/EWG 1-in-10 Dry Hydro, large cogeneration, industrial and commercial cogeneration (<20MW), refinery-related cogeneration, and EOR-related cogeneration.

6/ The criteria for 1-in-10 peak day design are defined as a 1-in-10 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 42.3 degrees Fahrenheit for SoCalGas' service area and 45.1 degrees Fahrenheit for SDG&E's service area.

The SoCalGas and SDG&E system is a winter peaking system and peak demand is expected to occur during the winter operating season of November through March. For this reason, the CPUC has not mandated a summer design standard. For informational purposes only, the table below presents a forecast of summer demand on the SoCalGas and SDG&E system.

TABLE 39 – SUMMER HIGH SENDOUT DAY DEMAND, MMcf/d

Year	High Demand Month	SoCalGas Core	SDG&E Core	Other Core	Noncore NonEG	Electric Generation	Total Demand
2026	Sep	606	85	55	535	1,863	3,144
2027	Sep	600	84	56	531	1,843	3,115
2028	Sep	594	83	58	527	1,787	3,048
2029	Sep	587	81	58	523	1,766	3,015
2030	Sep	580	81	59	520	1,617	2,857
2031	Sep	573	80	59	517	1,457	2,686
2032	Sep	564	79	60	514	1,434	2,651

Notes:

1/ Month of High Sendout gas demand during summer (July, August, or September).

2/ Average daily summer SoCalGas core sales and transportation.

3/ Average daily summer SDG&E core sales and transportation.

4/ Average daily summer core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.

5/ Noncore-Non-EG includes noncore non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas. Average daily September Noncore-Non-EG demand for all noncore market segments, except Refinery; Refinery is at connected load.

6/ Highest demand during the high demand month under 1-in-10 dry hydro conditions.

2026 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

TABLE 40 – ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2021 TO 2025, MMcf/d

LINE			2031	2032	2033	2035	2040	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, CRC) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	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	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		57	57	57	57	57	8
9	Out-of-State		2,004	1,981	1,969	1,923	1,917	9
10	TOTAL SUPPLY TAKEN		2,061	2,038	2,026	1,980	1,974	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,061	2,038	2,026	1,980	1,974	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	578	569	564	552	525	13
14		Commercial	202	199	197	192	180	14
15		Industrial	47	47	46	45	42	15
16		NGV	64	61	58	49	66	16
17		Subtotal-CORE	891	875	865	838	814	17
18	NONCORE	Commercial	49	49	49	49	49	18
19		Industrial	350	347	345	340	339	19
20		EOR Steaming	11	10	10	8	6	20
21		Electric Generation (EG)	394	398	403	405	422	21
22		Subtotal-NONCORE	804	804	807	802	816	22
23	WHOLESALE &	Core	207	206	206	205	208	23
24	INTERNATIONAL	Noncore Excl. EG	24	23	23	23	23	24
25		Electric Generation (EG)	109	103	99	85	88	25
26		Subtotal-WHOLESALE & INTL.	340	332	328	313	319	26
27		Co. Use & LUAF	27	27	26	26	26	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,061	2,038	2,026	1,980	1,974	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	79	77	75	69	76	29
30	NONCORE	Commercial/Industrial	399	396	394	389	387	30
31		EOR Steaming	11	10	10	8	6	31
32		Electric Generation (EG)	394	398	403	405	422	32
33		Subtotal-RETAIL	883	881	882	871	892	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	340	332	328	313	319	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,223	1,213	1,210	1,185	1,211	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., CRC at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, TW & EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2025 recorded California Source Gas for California Line 85 and Coastal Zones; production less than capacity due to reservoir performance and economics.

6/ Excludes own-source gas supply of as procurement by the City of Long Beach: 0.9 0.8 0.8 0.7 0.5

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

8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 833 819 811 790 757

TABLE 41 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2026 THRU 2030
AVERAGE TEMPERATURE YEAR, MMcf/d

LINE			2026	2027	2028	2029	2030	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, GRC) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	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	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		57	57	57	57	57	8
9	Out-of-State		2,150	2,083	2,023	1,988	1,944	9
10	TOTAL SUPPLY TAKEN		2,207	2,140	2,080	2,045	2,001	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,207	2,140	2,080	2,045	2,001	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	572	564	554	548	540	13
14		Commercial	211	207	202	199	196	14
15		Industrial	50	49	49	48	47	15
16		NGV	62	64	65	66	65	16
17		Subtotal-CORE	895	884	870	860	849	17
18	NONCORE	Commercial	49	49	48	48	48	18
19		Industrial	361	359	356	354	352	19
20		EOR Steaming	16	15	14	13	12	20
21		Electric Generation (EG)	509	459	424	409	386	21
22		Subtotal-NONCORE	935	881	842	823	798	22
23	WHOLESALE &	Core	201	200	199	198	198	23
24	INTERNATIONAL	Noncore Excl. EG	24	24	24	23	23	24
25		Electric Generation (EG)	124	122	118	113	108	25
26		Subtotal-WHOLESALE & INTL.	349	346	340	335	329	26
27		Co. Use & LUAF	29	28	27	27	26	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,207	2,140	2,080	2,045	2,001	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	80	81	80	80	79	29
30	NONCORE	Commercial/Industrial	410	408	405	402	400	30
31		EOR Steaming	16	15	14	13	12	31
32		Electric Generation (EG)	509	459	424	409	386	32
33		Subtotal-RETAIL	1,015	962	923	903	877	33
34	WHOLESALE & INTERNATIONAL	All End Uses	349	346	340	335	329	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,363	1,308	1,263	1,238	1,206	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., CRC at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, TW & EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2025 recorded California Source Gas for California Line 85 and Coastal Zones; production less than capacity due to reservoir performance and economics.

6/ Excludes own-source gas supply of as procurement by the City of Long Beach: 1.1 1.1 1.0 0.9 0.9

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

8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 836 825 811 801 790

TABLE 42 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2031 THRU 2040
AVERAGE TEMPERATURE YEAR, MMcf/d

LINE			2031	2032	2033	2035	2040	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, CRC) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	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	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		57	57	57	57	57	8
9	Out-of-State		1,926	1,899	1,886	1,839	1,828	9
10	TOTAL SUPPLY TAKEN		1,983	1,956	1,943	1,896	1,885	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		1,983	1,956	1,943	1,896	1,885	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	532	523	518	506	479	13
14		Commercial	194	191	189	184	172	14
15		Industrial	47	46	46	44	42	15
16		NGV	64	61	58	49	66	16
17		Subtotal-CORE	836	821	810	783	759	17
18	NONCORE	Commercial	48	48	48	48	48	18
19		Industrial	350	347	345	340	339	19
20		EOR Steaming	11	10	10	8	6	20
21		Electric Generation (EG)	390	390	394	393	407	21
22		Subtotal-NONCORE	798	795	797	790	799	22
23	WHOLESALE &	Core	197	196	196	195	198	23
24	INTERNATIONAL	Noncore Excl. EG	23	23	23	23	23	24
25		Electric Generation (EG)	103	96	91	80	82	25
26		Subtotal-WHOLESALE & INTL.	323	314	310	298	303	26
27		Co. Use & LUAF	26	26	25	25	25	27
28	SYSTEM TOTAL THROUGHPUT 6/		1,983	1,956	1,943	1,896	1,885	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	77	75	73	67	75	29
30	NONCORE	Commercial/Industrial	398	395	393	388	386	30
31		EOR Steaming	11	10	10	8	6	31
32		Electric Generation (EG)	390	390	394	393	407	32
33		Subtotal-RETAIL	876	870	870	857	874	33
34	WHOLESALE & INTERNATIONAL	All End Uses	323	314	310	298	303	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,199	1,185	1,180	1,154	1,176	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., CRC at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, TW & EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2025 recorded California Source Gas for California Line 85 and Coastal Zones; production less than capacity due to reservoir performance and economics.

6/ Excludes own-source gas supply of as procurement by the City of Long Beach: 0.9 0.8 0.8 0.7 0.5

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

8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 778 765 756 735 702

TABLE 43 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2026 THRU 2030
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) & DRY HYDRO YEAR, MMcf/d

LINE			2026	2027	2028	2029	2030	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, CRC) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	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	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		57	57	57	57	57	8
9	Out-of-State		2,242	2,170	2,110	2,075	2,032	9
10	TOTAL SUPPLY TAKEN		2,299	2,227	2,167	2,132	2,089	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,299	2,227	2,167	2,132	2,089	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	618	610	600	593	586	13
14		Commercial	219	215	210	207	205	14
15		Industrial	51	50	49	49	48	15
16		NGV	62	64	65	66	65	16
17		Subtotal-CORE	950	939	925	915	904	17
18	NONCORE	Commercial	50	50	49	49	49	18
19		Industrial	361	359	356	354	352	19
20		EOR Steaming	16	15	14	13	12	20
21		Electric Generation (EG)	526	472	437	420	398	21
22		Subtotal-NONCORE	953	895	856	836	811	22
23	WHOLESALE &	Core	211	210	209	208	207	23
24	INTERNATIONAL	Noncore Excl. EG	24	24	24	24	24	24
25		Electric Generation (EG)	131	130	126	122	116	25
26		Subtotal-WHOLESALE & INTL.	366	364	358	354	347	26
27		Co. Use & LUAF	30	29	28	28	27	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,299	2,227	2,167	2,132	2,089	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	82	82	82	82	81	29
30	NONCORE	Commercial/Industrial	411	409	406	403	401	30
31		EOR Steaming	16	15	14	13	12	31
32		Electric Generation (EG)	526	472	437	420	398	32
33		Subtotal-RETAIL	1,035	978	938	917	892	33
34	WHOLESALE & INTERNATIONAL	All End Uses	366	364	358	354	347	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,401	1,342	1,296	1,271	1,239	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., CRC at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, TW & EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2025 recorded California Source Gas for California Line 85 and Coastal Zones; production less than capacity due to reservoir performance and economics.

6/ Excludes own-source gas supply of as procurement by the City of Long Beach: 1.1 1.1 1.0 0.9 0.9

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

8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 890 879 865 855 844

TABLE 44 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2031 THRU 2040
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) & DRY HYDRO YEAR, MMcf/d

LINE			2031	2032	2033	2035	2040	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, CRC) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	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	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		57	57	57	57	57	8
9	Out-of-State		2,004	1,981	1,969	1,923	1,917	9
10	TOTAL SUPPLY TAKEN		2,061	2,038	2,026	1,980	1,974	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,061	2,038	2,026	1,980	1,974	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	578	569	564	552	525	13
14		Commercial	202	199	197	192	180	14
15		Industrial	47	47	46	45	42	15
16		NGV	64	61	58	49	66	16
17		Subtotal-CORE	891	875	865	838	814	17
18	NONCORE	Commercial	49	49	49	49	49	18
19		Industrial	350	347	345	340	339	19
20		EOR Steaming	11	10	10	8	6	20
21		Electric Generation (EG)	394	398	403	405	422	21
22		Subtotal-NONCORE	804	804	807	802	816	22
23	WHOLESALE &	Core	207	206	206	205	208	23
24	INTERNATIONAL	Noncore Excl. EG	24	23	23	23	23	24
25		Electric Generation (EG)	109	103	99	85	88	25
26		Subtotal-WHOLESALE & INTL.	340	332	328	313	319	26
27		Co. Use & LUAF	27	27	26	26	26	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,061	2,038	2,026	1,980	1,974	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	79	77	75	69	76	29
30	NONCORE	Commercial/Industrial	399	396	394	389	387	30
31		EOR Steaming	11	10	10	8	6	31
32		Electric Generation (EG)	394	398	403	405	422	32
33		Subtotal-RETAIL	883	881	882	871	892	33
34	WHOLESALE & INTERNATIONAL	All End Uses	340	332	328	313	319	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,223	1,213	1,210	1,185	1,211	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., CRC at Gosford)

2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, TW & EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2025 recorded California Source Gas for California Line 85 and Coastal Zones; production less than capacity due to reservoir performance and economics.

6/ Excludes own-source gas supply of as procurement by the City of Long Beach: 0.9 0.8 0.8 0.7 0.5

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

8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 833 819 811 790 757

TABLE 45 – ANNUAL GAS REQUIREMENTS
1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR (1), MMcf/d

Year	Core	Noncore	Wholesale & international	Company Use & LUAF	System Total Throughput
2026	931	953	364	30	2,277
2027	920	895	362	29	2,206
2028	906	856	356	28	2,145
2029	896	835	351	28	2,110
2030	885	810	345	27	2,067
2031	872	803	337	27	2,039
2032	856	804	329	26	2,016
2033	846	807	326	26	2,004
2035	819	802	311	26	1,958
2040	795	815	316	25	1,952

NOTES:

(1) SoCalGas' Demand forecast of 1-in-10 cold temperature year and dry hydro year is used to evaluate the backbone transmission capacity and slack capacity in Compliance with CPUC Decision (D.) 06-09-039.

2026 CALIFORNIA GAS REPORT

CITY OF LONG BEACH UTILITIES DEPARTMENT

CITY OF LONG BEACH UTILITIES DEPARTMENT

The annual gas supply and forecast requirements prepared by the City of Long Beach Public Utilities Department (Long Beach) are shown on the following tables for the years 2026 through 2040.

Serving approximately 150,000 customers, Long Beach is the largest California municipal gas utility and the seventh 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 53 percent residential and 47 percent commercial/industrial.

As a municipal utility, Long Beach's rates and policies are established by the City's Utility Board, 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 within Long Beach's service territory and 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 Southwest United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

2026 CALIFORNIA GAS REPORT

CITY OF LONG BEACH UTILITIES DEPARTMENT – TABULAR DATA

TABLE 46 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2021-2025, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2021	2022	2023	2024	2025
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0
10	Subtotal	0.0	0.0	0.0	0.0	0.0
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.3	3.2	1.1	0.4	0.9
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0
15	Total California Source Gas	1.3	3.2	1.1	0.4	0.9
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0
19	Incremental Supplies	24.2	20.2	24.7	26.3	20.2
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0
21	Total Out-of-State Gas	24.2	20.2	24.7	26.3	20.2
22	Subtotal	25.5	23.4	25.8	26.7	21.1
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0
24	TOTAL Gas Supply Taken & Transported	25.5	23.4	25.8	26.7	21.1

TABLE 47 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2021-2025, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2021	2022	2023	2024	2025
1	CORE	Residential	12.6	11.9	12.1	11.7	11.3
2	CORE/NONCORE	Commercial	5.7	5.8	6.0	6.3	6.2
3	CORE/NONCORE	Industrial	4.3	4.2	4.7	4.2	2.4
4		Subtotal	22.6	21.9	22.8	22.2	19.9
5	NON CORE	Non-EOR Cogeneration	2.3	1.1	2.2	3.7	0.7
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0
8		Subtotal	2.3	1.1	2.2	3.7	0.7
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0
13		Co. Use & LUAF	0.6	0.4	0.8	0.8	0.5
14		Subtotal-END USE	25.4	23.4	25.8	26.7	21.1
15		Storage Injection	0.0	0.0	0.0	0.0	0.0
16	SYSTEM TOTAL-THROUGHPUT		25.4	23.4	25.8	26.7	21.1
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	N/A
18		Commercial/Industrial	3.1	2.9	3.1	3.4	1.6
19		Non-EOR Cogeneration	2.3	1.1	1.9	3.7	0.7
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A
22		Subtotal-RETAIL	5.4	4.0	5.0	7.1	2.3
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	4.0	5.0	7.1	2.3
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	0.0
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0
30		Wholesale	0.0	0.0	0.0	0.0	0.0
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0
32	REFUSAL		0.0	0.0	0.0	0.0	0.0

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

TABLE 48 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT
AVERAGE YEAR FORECAST 2026-2040, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2026	2027	2028	2030	2035	2040
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	0.0
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	0.0
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	0.0
10	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	0.0
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	1.1	1.1	1.0	0.9	0.7	0.5
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0
15	Total California Source Gas	1.1	1.1	1.0	0.9	0.7	0.5
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0
18	Additional Core Supplies	20.0	19.6	19.3	18.7	17.2	15.8
19	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0
21	Total Out-of-State Gas	20.0	19.6	19.3	18.7	17.2	15.8
22	Subtotal	21.1	20.7	20.3	19.6	17.9	16.3
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0
24	TOTAL Gas Supply Taken & Transported	21.1	20.7	20.3	19.6	17.9	16.3

TABLE 49 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 2A-LB
ANNUAL GAS SUPPLY AND SENDOUT
AVERAGE YEAR FORECAST 2026-2040, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2026	2027	2028	2030	2035	2040
1	CORE	Residential	11.3	11.0	10.8	10.4	9.4	8.5
2	CORE/NONCORE	Commercial	6.2	6.1	5.9	5.7	5.2	4.7
3	CORE/NONCORE	Industrial	2.4	2.4	2.4	2.3	2.2	2.1
4		Subtotal	19.9	19.5	19.1	18.4	16.8	15.3
5	NON CORE	Non-EOR Cogeneration	0.7	0.7	0.7	0.7	0.7	0.6
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0
8		Subtotal	0.7	0.7	0.7	0.7	0.7	0.6
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0
13		Co. Use & LUAF	0.5	0.5	0.5	0.5	0.4	0.4
14		Subtotal-END USE	21.1	20.7	20.3	19.6	17.9	16.3
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0
16	SYSTEM TOTAL-THROUGHPUT		21.1	20.7	20.3	19.6	17.9	16.3
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A
18		Commercial/Industrial	1.6	1.6	1.6	1.6	1.5	1.4
19		Non-EOR Cogeneration	0.7	0.7	0.7	0.7	0.6	0.6
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A
22		Subtotal-RETAIL	2.3	2.3	2.3	2.3	2.1	2.0
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0
24	TOTAL TRANSPORTATION & EXCHANGE		2.3	2.3	2.3	2.3	2.1	2.0
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0

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

TABLE 50 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 3C-LB
ANNUAL GAS SUPPLY AND SENDOUT
COLD YEAR FORECAST 2026-2040, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2026	2027	2028	2030	2035	2040
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	0.0
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	0.0
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	0.0	0.0	0.0	0.0	0.0
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	0.0
10	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	0.0
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	1.1	1.1	1.0	0.9	0.7	0.5
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0
15	Total California Source Gas	1.1	1.1	1.0	0.9	0.7	0.5
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0
18	Additional Core Supplies	21.8	21.4	21.1	20.4	18.8	17.3
19	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0
21	Total Out-of-State Gas	21.8	21.4	21.1	20.4	18.8	17.3
22	Subtotal	22.9	22.5	22.1	21.3	19.5	17.8
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0
24	TOTAL Gas Supply Taken & Transported	22.9	22.5	22.1	21.3	19.5	17.8

TABLE 51 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 4C-LB
ANNUAL GAS SUPPLY AND SENDOUT
COLD YEAR FORECAST 2026-2040, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2026	2027	2028	2030	2035	2040
1	CORE	Residential	12.3	12.0	11.8	11.3	10.2	9.2
2	CORE/NONCORE	Commercial	6.7	6.6	6.4	6.2	5.6	5.1
3	CORE/NONCORE	Industrial	2.6	2.6	2.6	2.5	2.4	2.3
4		Subtotal	21.6	21.2	20.8	20.0	18.2	16.6
5	NON CORE	Non-EOR Cogeneration	0.7	0.7	0.7	0.7	0.7	0.6
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0
8		Subtotal	0.7	0.7	0.7	0.7	0.7	0.6
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0
13		Co. Use & LUAF	0.6	0.6	0.6	0.6	0.6	0.6
14		Subtotal-END USE	22.9	22.5	22.1	21.3	19.5	17.8
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0
16	SYSTEM TOTAL-THROUGHPUT		22.9	22.5	22.1	21.3	19.5	17.8
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A
18		Commercial/Industrial	1.6	1.6	1.6	1.6	1.5	1.4
19		Non-EOR Cogeneration	0.7	0.7	0.7	0.7	0.6	0.6
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A
22		Subtotal-RETAIL	2.3	2.3	2.3	2.3	2.1	2.0
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0
24	TOTAL TRANSPORTATION & EXCHANGE		2.3	2.3	2.3	2.3	2.1	2.0
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0

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

2026 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

San Diego Gas & Electric (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 919,724 customers in San Diego County in 2025, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2025 were approximately 89.5 billion cubic feet (Bcf), which is an average of 245 MMcf/d.

GAS DEMAND

SDG&E's gas demand forecast is determined in part by the both the short-term and 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.

SDG&E used the same Energy Additional Achievable Fuel Substitution (AAFS) forecast as SoCalGas. These assumptions are discussed in the earlier SoCalGas section of this California Gas Report.

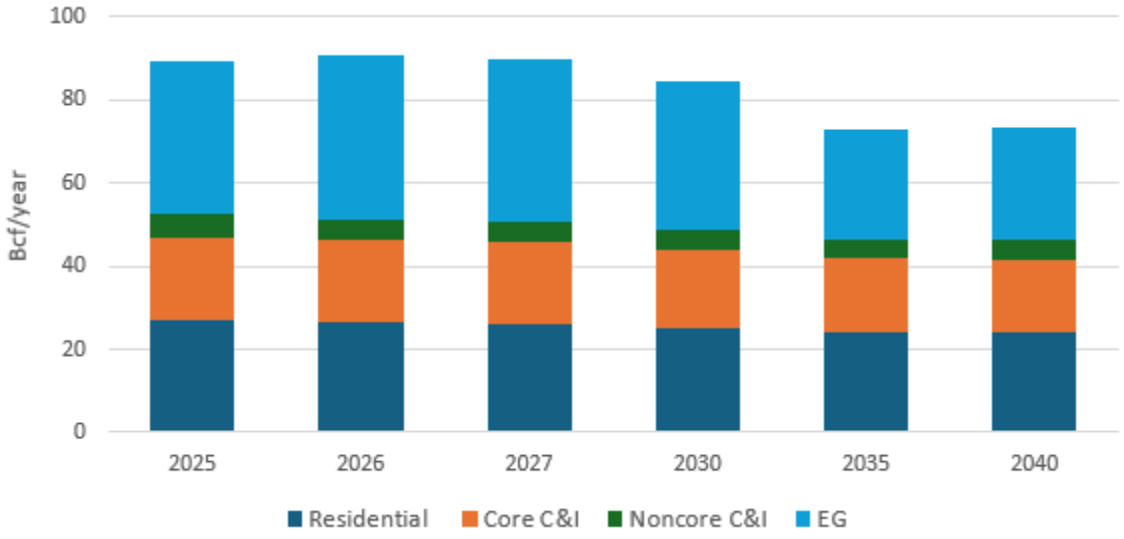
Altogether, SDG&E's gas demand, not inclusive of gas driven EG, is projected to drop slightly from 52.5 Bcf in 2025 to 46.2 Bcf in 2040, which is an average annual rate of decline of 0.9 percent. Including EG, overall demand adjusted for average temperature conditions totaled 89.1 Bcf in 2025 and is expected to drop about 1.3 percent per year to 73.6 Bcf by 2040.

Assumptions of SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

ECONOMICS AND DEMOGRAPHICS

SDG&E's gas demand forecast is determined in part by the short-term and long-term economic outlook for its San Diego County service area. Like the SoCalGas service territory, both gross metro product and employment are expected to grow at levels below both prior and following the height of the COVID pandemic in 2020. Risks to the region's economic outlook include stubborn inflation, elevated interest rates, and slowing domestic as well as international migration.

FIGURE 21 – COMPOSITION OF SDG&E'S NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR, Bcf/y



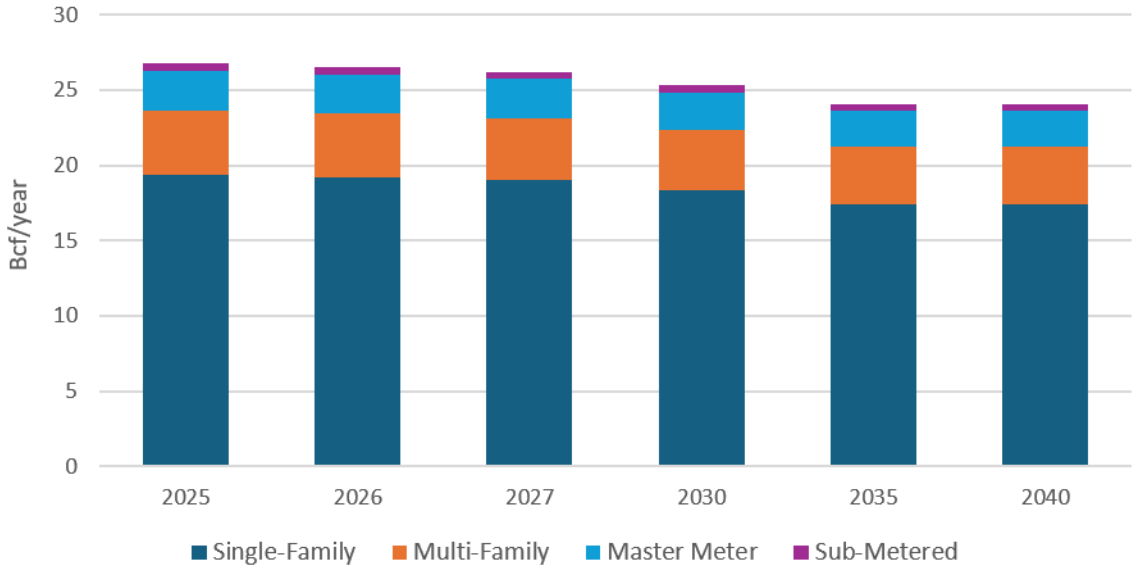
From 2025 through 2040, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 1.3 percent. The decline is being driven by future projected reductions in the EG load, energy efficiency programs (including new requirements on Title 24 building codes and standards), and assumed fuel substitution over the forecast period.

MARKET SECTORS

RESIDENTIAL

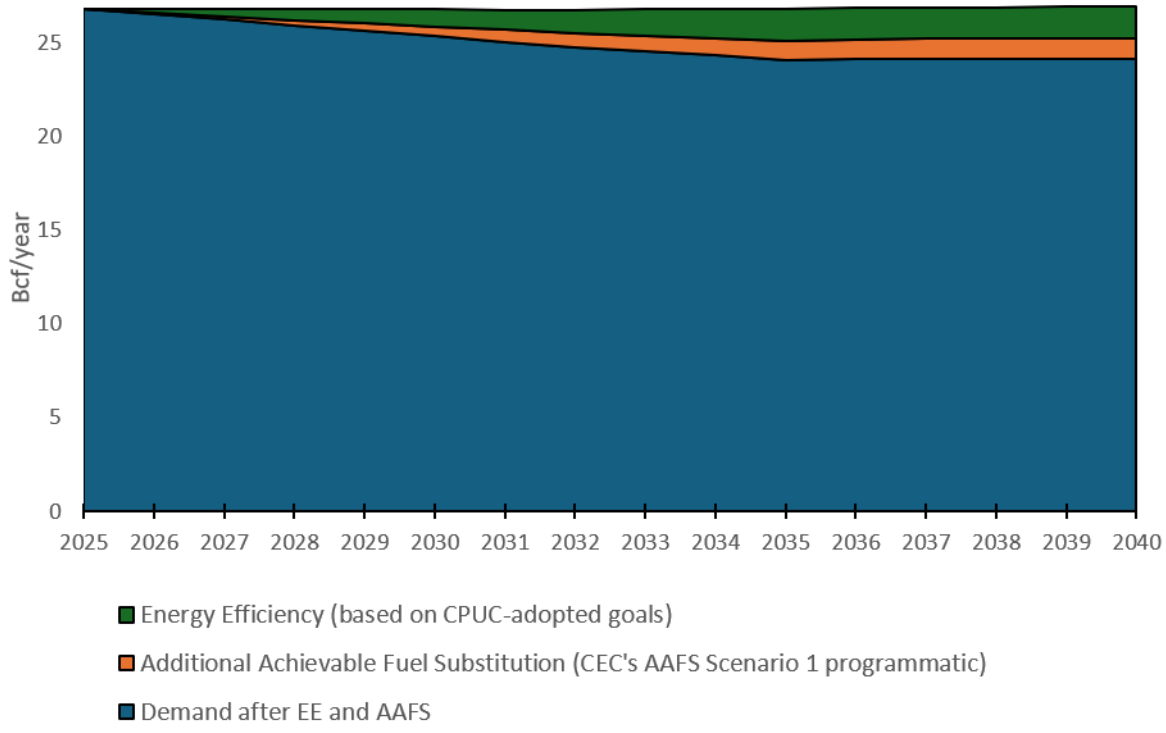
Residential gas demand is forecasted to decline from 26.8 Bcf in 2025 to 24.1 Bcf by 2040 at an average annual rate of 0.7%. The decline is due to declining use per meter, primarily driven by aggressive energy efficiency goals, potential fuel substitution, and tightening Title 24 Codes and Standards. The demand reduction created by these policies is partially offset by the load created from new meter growth forecasted over the planning period, although this meter growth is tempered from the meter growth projected in previous CGRs due to the end of multifuel line extension subsidies.

FIGURE 22 – COMPOSITION OF SDG&E'S RESIDENTIAL DEMAND FORECAST AVERAGE YEAR WEATHER DESIGN, Bcf/y



The effects of both energy efficiency and fuel substitution have an impact on the residential market as shown in the following figure. The largest impact is reached in year 2040.

FIGURE 23 – SDG&E EE AND FUEL SUBSTITUTION, Bcf/y



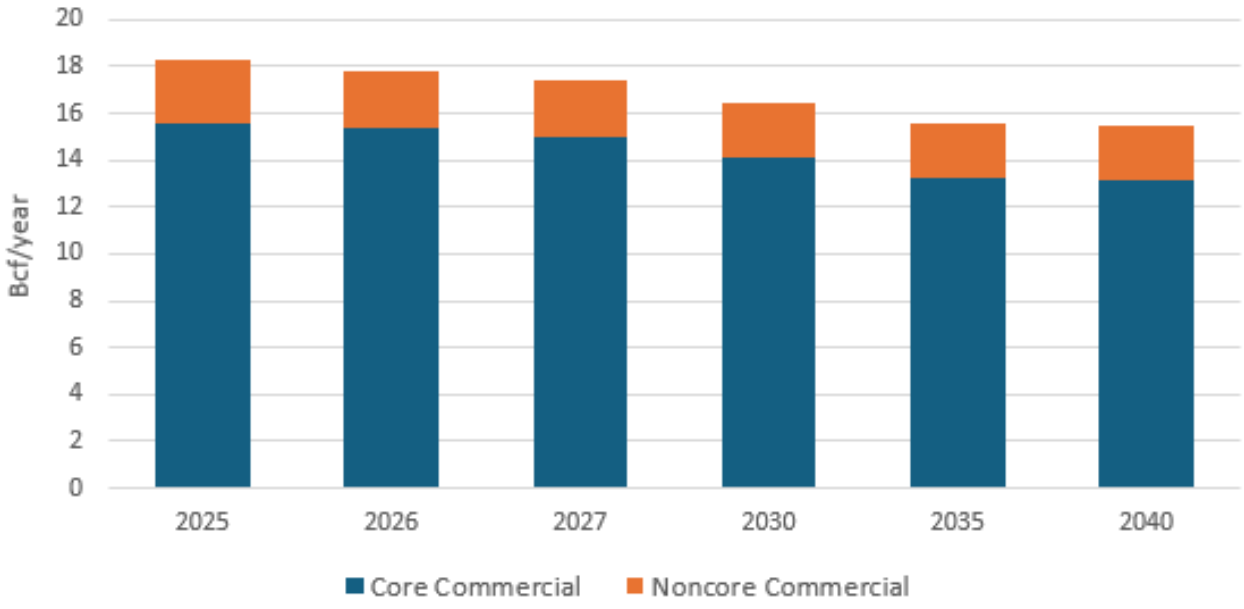
By year 2040, the assumed additional energy efficiency removes 6.2 percent of residential gas demand. Evaluated separately, the assumed additional fuel substitution removes another 4.2 percent of residential gas demand by the year 2040. Similar to SoCalGas, the CEC's 2025 IEPR AAFS 1 PiCS scenario was used as the fuel substitution assumption for SDG&E. See the SoCalGas section for discussion regarding this assumption selection.

Commercial

On a temperature- adjusted basis, SDG&E's core commercial demand in 2025 totaled 15.5 Bcf. By the year 2040, the core commercial load is forecasted to decline to 13.1 Bcf. The annual average rate of decline of the core commercial market over the forecast horizon is expected to be 1.1 percent.

SDG&E's non-core commercial load in 2025 was 2.7 Bcf. Over the forecast period, gas demand in this market is projected to decline slightly to be about 2.4 Bcf by 2040.

FIGURE 24 – SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN, Bcf/y

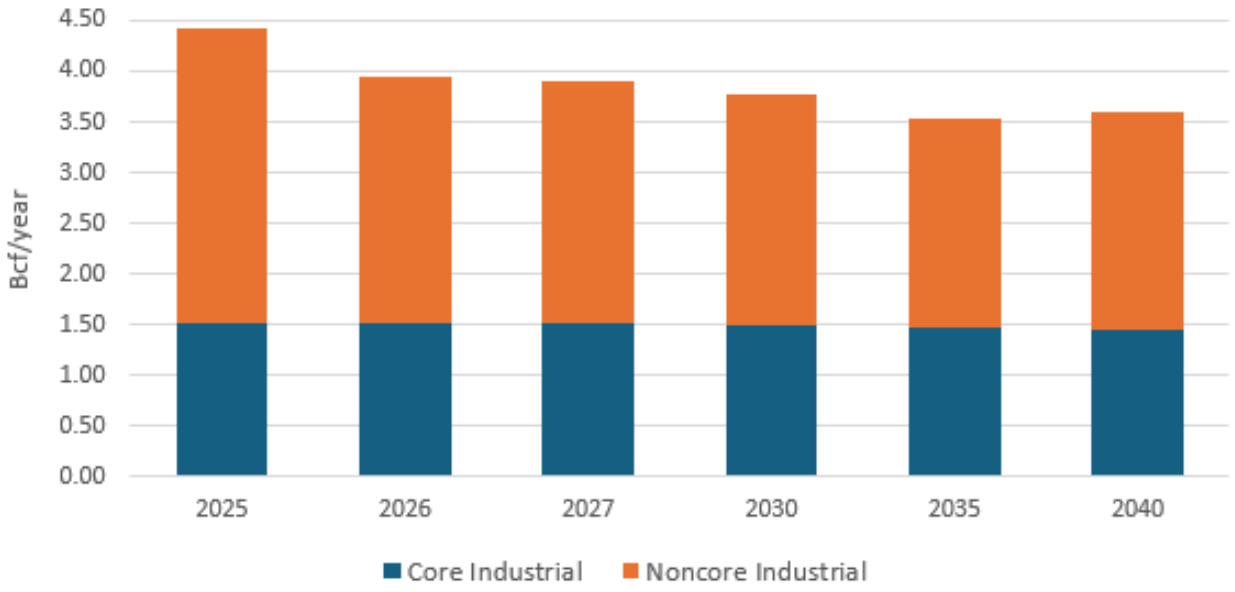


Industrial

Temperature-adjusted core industrial demand was 1.5 Bcf in 2025 and is expected to decline to 1.4 Bcf by 2040, an average decrease of 0.3 percent per year. This result is due to a combination of factors: a decrease in core industrial customer counts, the impact of climate change, and the impact of savings from CPUC-authorized energy efficiency programs in the core industrial sector.

Non-core industrial load in 2025 was 2.9 Bcf and is expected to shrink about 2.0 percent per year to 2.2 Bcf by 2040. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs and decreasing industrial employment.

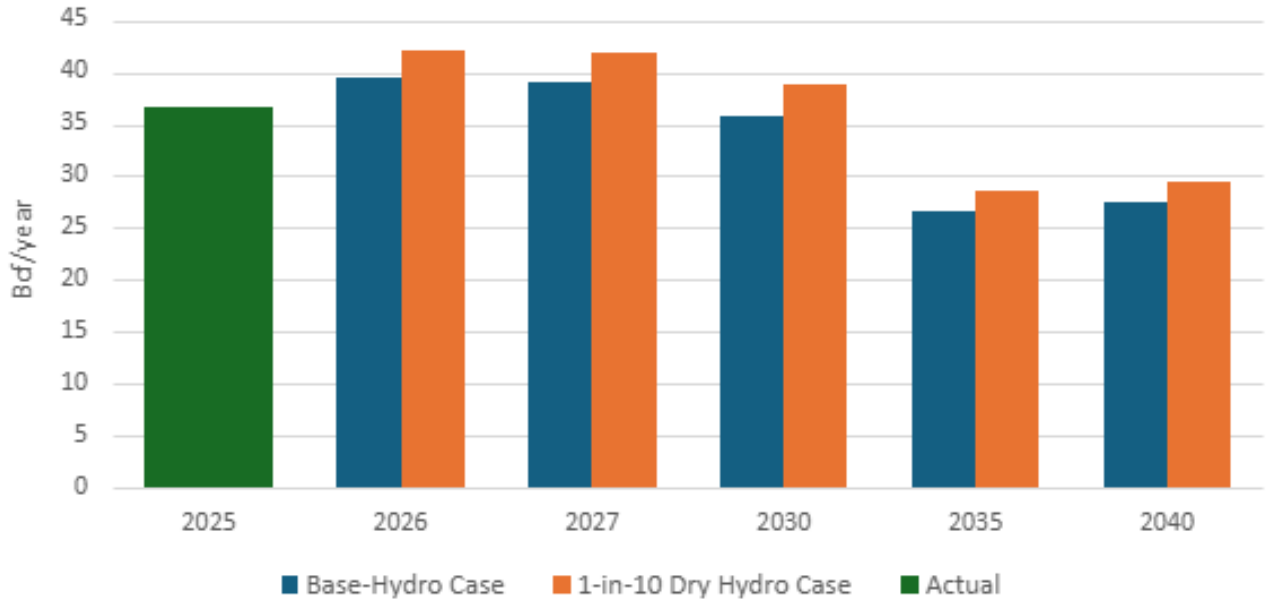
FIGURE 25 – SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN, Bcf/y



Electric Generation

Total EG, including cogeneration and non-cogeneration EG, was 36.6 Bcf in 2025. From 2025, EG load is expected to decline an average of 1.9 percent per year to 27.4 Bcf by 2040. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 26 – SDG&E TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, Bcf/y



Small Cogeneration (<20 MW)

Small Electric Generation load from self-generation totaled 6.9 Bcf in 2025 and is projected to decrease to 6.4 Bcf by 2040.

Electric Generation Including Large Cogeneration (>20 MW)

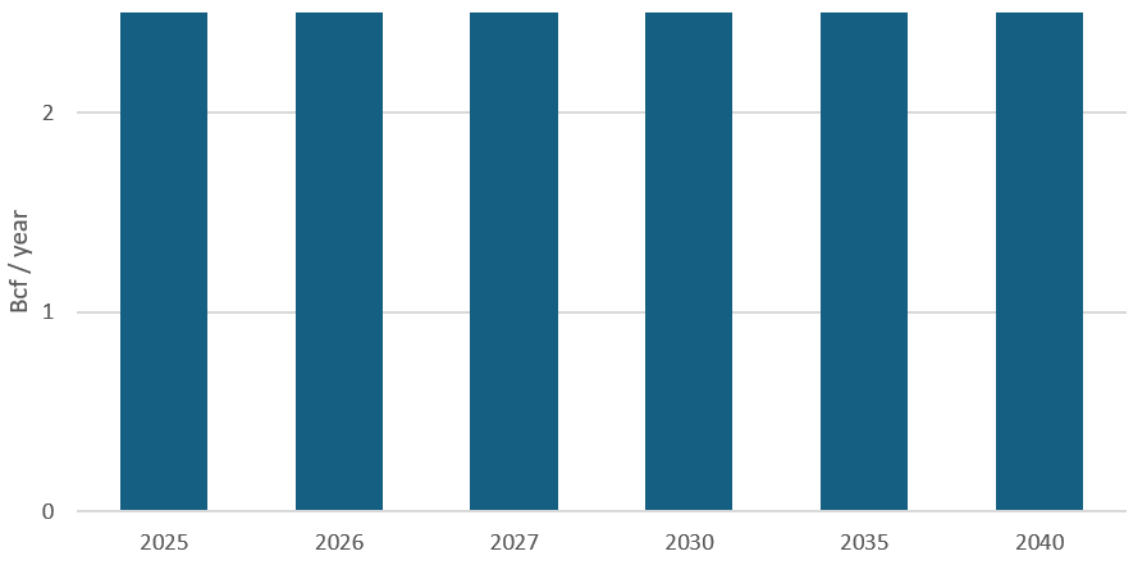
The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter. Electric Generation, including Large Cogeneration EG demand, is forecasted to decrease from 29.8 Bcf in 2025 to 21.1 Bcf in 2040. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. It assumes the same 2025 Preferred System Plan as discussed in the Southern California Gas Company's EG section.

Natural Gas Vehicles

The clean vehicle market is expected to grow due to strong economic fundamentals, increased vehicle options, the continuation of government (federal, state, and local) incentives, additional regulations encouraging alternative fuel vehicle adoption, and regional collaboration for the deployment of necessary infrastructure. Additionally, since April 2019 SDG&E has been procuring 100% RNG at all utility owned CNG stations, which provides significant GHG emission reduction benefits.

However, NGV growth may be offset by competing technologies such as vehicle electrification and hydrogen fuel-cell technologies. In 2025, SDG&E served 42 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 3 Bcf of natural gas. The SDG&E NGV market is expected to remain stable over the forecast horizon.

FIGURE 27 – SDG&E ANNUAL NGV DEMAND FORECAST, Bcf/y

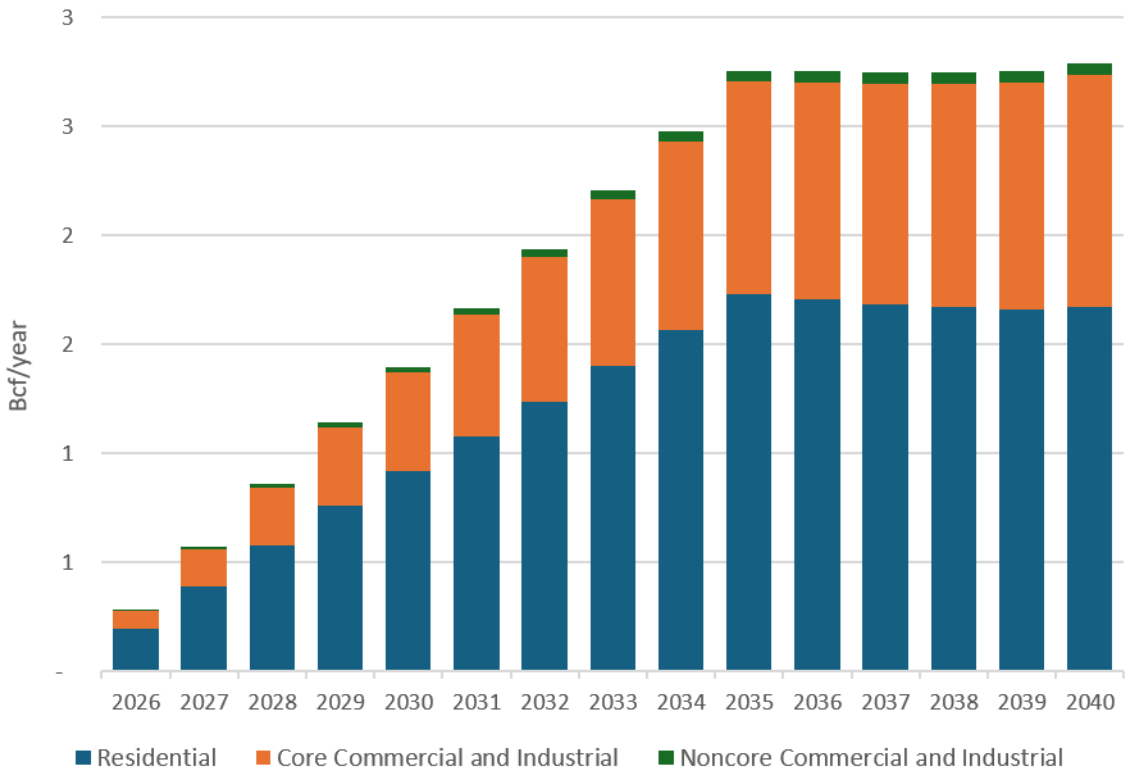


ENERGY EFFICIENCY PROGRAMS

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 load impact forecast from SDG&E's integrated gas and electric energy efficiency programs for selected years is shown in the graph below. The net load impact includes all energy efficiency programs, both gas and electric, that SDG&E has forecasted to be implemented beginning in year 2026 and occurring through the year 2040 in addition to the Title 24 Codes and Standards expected over the 2026-2040 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034 and D.21-09-037.

FIGURE 28 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS, Bcf/y



Savings reported are for measures installed under SDG&E's gas and electric 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.[103] Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included.

[103] 1"Hard" impacts include measures requiring a physical equipment modification or replacement. SDG&E does not include "soft" impacts, e.g., energy management services type measures 110. This EE forecast does not include the impacts of fuel substitution measures (natural gas to electric measures). Fuel substitution is addressed in the overview section of the writeup.

GAS SUPPLY

Beginning in 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 D.07-12-019 of December 6, 2007. For more information, refer above to the "Gas Supply, Capacity, and Storage" section in the Southern California part of this report.

REGULATORY ENVIRONMENT

For more information on regulatory matters, refer above to the "Regulatory Environment" section in the Southern California part of this report, which generally applies to SDG&E's gas business as well.

PEAK DAY DEMAND

Gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio that contains 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 and SDG&E) retail core peak day demand.

The table below shows SDG&E's Core 1-in-35 Year Extreme Peak Day Demand and Winter 1-in-10 Year Cold Day System Demand. As discussed in the SoCalGas Peak Day Demand section, SDG&E has observed a decline in recorded core winter peak demand in recent years, which is contributing to a lower forecast in peak demand.

TABLE 52 – SDG&E WINTER PEAK DAY DEMAND, MMcf/d

Year	Core 1-in-35 Extreme Peak Day Demand		1-in-10 Cold Day Demand			
			Core	Noncore C&I	EG	Total
2026	309		296	17	204	517
2027	307		293	17	201	512
2028	304		291	17	178	486
2029	302		288	17	175	480
2030	300		287	17	210	513
2031	299		285	16	193	495
2032	297		284	16	173	473

Notes:
1/ The criteria for core 1-in-35 extreme peak day design is defined as a 1-in-35 likelihood event for SDG&E's service area. The criteria correlates to a system average temperature of 43.7 degrees Fahrenheit for SDG&E's service area.
2/ The criteria for 1-in-10 peak day design is defined as a 1-in-10 likelihood event for SDG&E's service area. The criteria correlates to a system average temperature of 45.1 degrees Fahrenheit for SDG&E's service area.
3/ 1-in-10 peak day demand for noncore commercial and average daily December demand for noncore industrial.
4/ Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW).

2026 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 53 – ANNUAL GAS SUPPLY TAKEN
RECORDED YEARS 2021-2025, MMcf/d

LINE			2021	2022	2023	2024	2025
	Capacity Avaiaible						
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		**2021**	**2022**	**2023**	**2024**	**2025**
	California Source Gas						
11		Regular Purchases	0	0	0	0	0
12		Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**		0	0	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	126	122	128	119	120
18		Out-of-State Transport-Others	139	152	132	124	125
19	**Total Out-of-State Gas**		265	274	260	243	245
20	**TOTAL Gas Supply Taken & Transported**		265	274	260	243	244

TABLE 54 – ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 2021-2025, MMcf/d

LINE			2021	2022	2023	2024	2025
	Actual Deliveries by End-Use						
1	**CORE**	Residential	78	74	82	74	73
2		Commercial	52	56	58	56	56
3		Industrial	-	-	-	-	-
4	*Subtotal -*	*CORE*	130	130	140	130	129
5	**NONCORE**	Commercial	-	-	-	-	-
6		Industrial	15	19	18	18	20
7		Non-EOR Cogen/EG	77	76	77	74	61
8		Electric Utilities	36	46	25	18	29
9	*Subtotal -*	*NONCORE*	128	141	120	110	110
10	**WHOLESALE**	All End Uses	-	-	-	-	-
11	*Subtotal -*	*Co Use & LUAF*	7	3	1	3	6
12	**SYSTEM TOTAL THROUGHPUT**		265	274	261	243	245
	Actual Transport & Exchange						
13	**CORE**	Residential	0	0	1	1	1
14		Commercial	11	11	12	13	14
15	**NONCORE**	Industrial	15	19	18	18	20
16		Non-EOR Cogen/EG	77	76	77	74	61
17		Electric Utilities	36	46	25	18	29
18	*Subtotal -*	*RETAIL*	139	153	132	124	125
19	**WHOLESALE**	All End Uses	-	-	-	-	-
20	**TOTAL TRANSPORT & EXCHANGE**		139	153	132	124	125
	Storage						
21		*Storage Injection*	-	-	-	-	-
22		*Storage Withdrawal*	-	-	-	-	-
	Actual Curtailment						
23		Residential	-	-	-	-	-
24		Com/Indl & Cogen	-	-	-	-	-
25		Electric Generation	-	-	-	-	-
26	**TOTAL CURTAILMENT**		-	-	-	-	-
27	**REFUSAL**		-	-	-	-	-
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.030	1.028	1.025	1.026	1.020

TABLE 55 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2026-2030
AVERAGE TEMPERATURE YEARS, MMcf/d

LINE			2026	2027	2028	2029	2030	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		251	248	242	239	233	5
6	TOTAL SUPPLY TAKEN		251	248	242	239	233	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		251	248	242	239	233	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	73	72	71	70	69	9
10		Commercial	42	41	40	39	39	10
11		Industrial	4	4	4	4	4	11
12		NGV	8	8	8	8	8	12
13		Subtotal-CORE	127	125	123	121	120	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	7	6	6	6	15
16		Electric Generation (EG)	108	107	104	102	98	16
17		Subtotal-NONCORE	121	120	117	115	111	17
18		Co. Use & LUAF	3	3	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		251	248	242	239	233	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	13	13	13	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	108	107	104	102	98	22
23	TOTAL TRANSPORTATION & EXCHANGE		135	134	130	128	124	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2026 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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: 115 114 112 110 109

TABLE 56 – Annual Gas Supply and Requirements
Estimated Years 2031 Thru 2040
Average Temperature Years, MMcf/d

LINE			2031	2032	2033	2035	2040	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		228	220	215	201	203	5
6	TOTAL SUPPLY TAKEN		228	220	215	201	203	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		228	220	215	201	203	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	69	68	67	66	66	9
10		Commercial	38	37	37	36	36	10
11		Industrial	4	4	4	4	4	11
12		NGV	8	8	8	8	8	12
13		Subtotal-CORE	119	117	117	114	114	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	94	88	84	73	75	16
17		Subtotal-NONCORE	107	100	96	85	87	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		228	220	215	201	203	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	13	20
21	NONCORE	Commercial/Industrial	13	12	12	12	12	21
22		Electric Generation (EG)	94	88	84	73	75	22
23	TOTAL TRANSPORTATION & EXCHANGE		120	113	109	97	100	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2026 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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: 108 106 106 104 103

TABLE 57 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2026 THRU-2030
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) & DRY HYDRO YEAR, MMcf/d

LINE			2026	2027	2028	2029	2030	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		265	263	258	254	249	5
6	TOTAL SUPPLY TAKEN		265	263	258	254	249	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		265	263	258	254	249	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	78	77	76	75	75	9
10		Commercial	43	42	41	40	40	10
11		Industrial	4	4	4	4	4	11
12		NGV	8	8	8	8	8	12
13		Subtotal-CORE	134	132	130	128	127	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	7	6	6	6	15
16		Electric Generation (EG)	115	115	112	110	106	16
17		Subtotal-NONCORE	129	128	125	123	119	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		265	263	258	254	249	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	14	14	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	115	115	112	110	106	22
23	TOTAL TRANSPORTATION & EXCHANGE		143	142	139	137	133	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2026 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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: 122 120 118 117 116

TABLE 58 – ANNUAL GAS SUPPLY AND REQUIREMENTS
ESTIMATED YEARS 2031 THRU-2040
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) & DRY HYDRO YEAR, MMcf/d

LINE			2031	2032	2033	2035	2040	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		242	234	229	214	215	5
6	TOTAL SUPPLY TAKEN		242	234	229	214	215	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		242	234	229	214	215	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	74	73	73	71	71	9
10		Commercial	39	39	38	38	37	10
11		Industrial	4	4	4	4	4	11
12		NGV	8	8	8	8	8	12
13		Subtotal-CORE	125	124	123	121	121	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	101	95	91	78	80	16
17		Subtotal-NONCORE	114	108	103	90	93	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		242	234	229	214	215	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	13	20
21	NONCORE	Commercial/Industrial	13	13	13	12	13	21
22		Electric Generation (EG)	101	95	91	78	80	22
23	TOTAL TRANSPORTATION & EXCHANGE		127	121	117	103	106	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

1/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2026 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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: 114 113 112 110 110

GLOSSARY

GLOSSARY

A.
Application.

AAEE
Additional Achievable Energy Efficiency.

AB
Assembly Bill.

AMI
Advanced Metering Infrastructure.

APD
Abnormal Peak Day.

API
American Petroleum Institute.

A/S
Ancillary services.

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.

BAAD
Bay Area Air District.

Bcf
Billion cubic feet.

Bcf/d
Billion cubic feet per day.

Bcf/y
Billion cubic feet per year.

BTU (British Thermal Unit)
Unit of measurement equals the amount of heat energy required to raise the temperature of one pound of water 1 degree F. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

CAISO
California Independent System Operator.

CalGEM
California Geologic Energy Management Division (formerly, DOGGR).

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

CARB
California Air Resources Board.

CCST
California Council on Science and Technology.

CDFA
California Department of Food and Agriculture.

CEC
California Energy Commission.

CFR
Code of Federal Regulations.

CGR
California Gas Report.

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

CO_2
carbon dioxide.

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.

Combined Heat and Power (CHP)
Combined Heat and Power (CHP) is the sequential production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted in California as a preferred EG resource.

Commercial (SoCalGas and 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 EG, EOR, or gas resale activities with usage less than 20,800 therms per month.

Commission
California Public Utilities Commission (see also CPUC).

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

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

Conversion Factor (Natural Gas)

- 1 cf (Cubic Feet) = Approximately 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

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.

Core Customer (PG&E)
All customers with average usage less than 20,800 therms per month.

Core Customers (SoCalGas and 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 Subscription
Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

COVID-19
Coronavirus Disease 2019.

CPUC
California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
Volume of natural gas, which, at a temperature of 60 degrees 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.

D.
Decision.

DDRDP
Dairy Digester Research and Development Program.

DOE
Department of Energy.

DOGGR
California Division of Oil, Gas, and Geothermal Resources (now CalGEM).

ECA
Energia Costal Azul.

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.

EO
Executive Order.

EOR (Enhanced Oil Recovery)
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.

EWG (Exempt Wholesale Generator)
A category of customers consuming gas for the purpose of generating electric power.

F
Fahrenheit.

FERC
Federal Energy Regulatory Commission.

FTA
Free Trade Agreement.

Futures (Gas)
Unit of natural gas futures contract trades in units of 10,000 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 (Green House Gas)
GHGs 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 abundant GHGs are, in order of relative abundance are water vapor, CO_2, methane, nitrous oxide, ozone, and CFCs.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H2
Hydrogen.

HDD (Heating Degree Day)
A HDD is accumulated for every degree F the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 degrees F; PG&E 60 degrees F). A basis for

computing how much electricity and gas are needed for space heating purposes. For example, for a 50 degrees F 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 60 degrees F and a pressure base of 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 7 pounds or less per one million cubic feet, the natural gas shall be considered dry.

IEPR
Integrated Energy Policy Report.

ILI
In-Line Inspection.

Industrial (PG&E)
Non-residential customers not engaged in EG, EOR, or gas resale activities using more than 20,800 therms per month.

Industrial (SoCalGas and SDG&E)
Category of gas customers who are engaged in mining and in manufacturing.

IOU
investor-owned utility.

IRP
Integrated Resource Plan.

LCFS
Low Carbon Fuel Standard.

LDC
Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)
Natural gas that has been super cooled to -260 degrees F (-162 degrees 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 ensure that generators are producing neither too little nor too much energy to supply the utilities' customers.

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

MHP
Mobile Home Park.

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

MMcf/d
Million cubic feet per day.

MMT
million metric tons.

MMTCO_2e
million metric tons of carbon dioxide equivalent.

MTCO_2e
metric tons of carbon dioxide equivalent.

MW
megawatt.

MWh
megawatt-hour.

NGSS
Natural Gas Storage Strategy.

NGTL
NOVA Gas Transmission Ltd.

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.

OIR
Order Instituting Rulemaking.

OTC
Once-through-cooling.

Out-of-State Gas
Gas from sources outside the state of California.

PFM
Petition for Modification.

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

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); and
5. Market Center Services.

Priority of Service (SoCalGas + SDG&E)
In the event of a curtailment situation, SoCalGas and SDG&E curtail gas usage to customers in the following order:

- Up to 60 percent (November thru March) or 40 percent (April thru October) of dispatched EG load;
- Up to 100 percent of non-EG noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched EG load;
- Non-Residential Core customers; and
- Residential Core customers.

PSEP
Pipeline Safety Enhancement Plan.

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

Pub. Util. Code
Public Utilities Code.

Purchase from Other Utilities
Gas purchased from other utilities in California.

R.
Rulemaking.

R&D
Research and Development.

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

Res.
Resolution.

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.

RNG
Renewable Natural Gas.

RGS
Renewable Gas Standard.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
Reference System Plan.

SB
Senate Bill.

SDG&E
San Diego Gas & Electric Company.

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

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SoCalGas
Southern California Gas Company.

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.

SWG
Southwest Gas Corporation.

SWRCB
State Water Resources Control Board.

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 than 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.

UC
University of California.

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.

U.S.
United States.

USA
Underground Service Alert.

WACOG
Weighted average cost of gas.

WECC
Western Electricity Coordinating Council.

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.

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 Utilities 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

SoCalGas/SDG&E

- Eduardo Martinez (Utility Lead)
- Jeff Huang
- Heng Yeng
- Yu Guan
- Magu Diagne

PG&E

- Kurtis Kolnowski (Utility Lead)
- Anupama Pandey
- Joy Hill
- Ryan Scanlan
- Peter Schevtchenko

Observers

- Jean Spencer – CPUC Energy Division
- Eileen Hlavka-CPUC Energy Division
- Rosemarie Payan-CPUC Energy Division
- Melissa Jones-CEC
- Ingrid Neumann-CEC
- Robert Gulliksen-CEC

Please visit the SoCalGas/SDG&E or PG&E websites for digital copies of this report and earlier versions, including accompanying workpapers. They are in the regulatory sections of the following websites:

https://www.socalgas.com/regulatory/cgr

https://www.sdge.com/rates-and-regulations/regulatory-filing/20381/california-gas-report

https://www.pge.com/pipeline/en/reference-library/regulatory/cgr.html