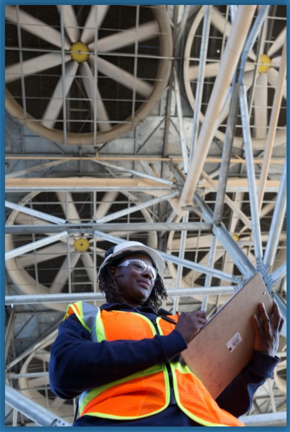
2020 California Gas Report







— Prepared by the California Gas and Electric Utilities —

Prepared in Compliance with California Public Utilities Commission Decision D.95-01-039

2020 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

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

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2020 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2020 California Gas Report* (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. 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 projections in the CGR are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

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

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

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.

2020 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

DEMAND OUTLOOK

Utility-driven, statewide natural gas demand[1] is projected to decline at an average rate of 1.0 percent each year through 2035. The decline comes from reduced gas demand in the major market segment areas of residential, electric generation (EG), commercial, and industrial. Statewide residential gas demand is projected to decrease at an average rate of 1.7 percent each year. EG gas demand is projected to decrease at an average annual rate of 1.5 percent each year. The Commercial segment gas demand, which includes both core and noncore commercial demand, is projected to decrease at an average annual rate of 1.5 percent each year. The Industrial gas demand segment is expected to decline at an average rate of 0.2 percent per year. Though the Natural Gas Vehicle (NGV) market shows moderate growth, it is not sufficient to offset the projected decrease in other market segments over the forecast horizon.

There are several drivers of these declines. Aggressive energy efficiency programs are dampening gas demand in these sectors. In addition, the statewide efforts to minimize greenhouse gas (GHG) emissions are reducing EG demand due to increase in demand side and supply side generation resources that produce few or no carbon emissions. Nevertheless, gas-fired generation and energy storage will continue to be primary technologies to support long-term increases in electricity usage and integrate increasing quantities of intermittent renewable electric generation into the electric grid.

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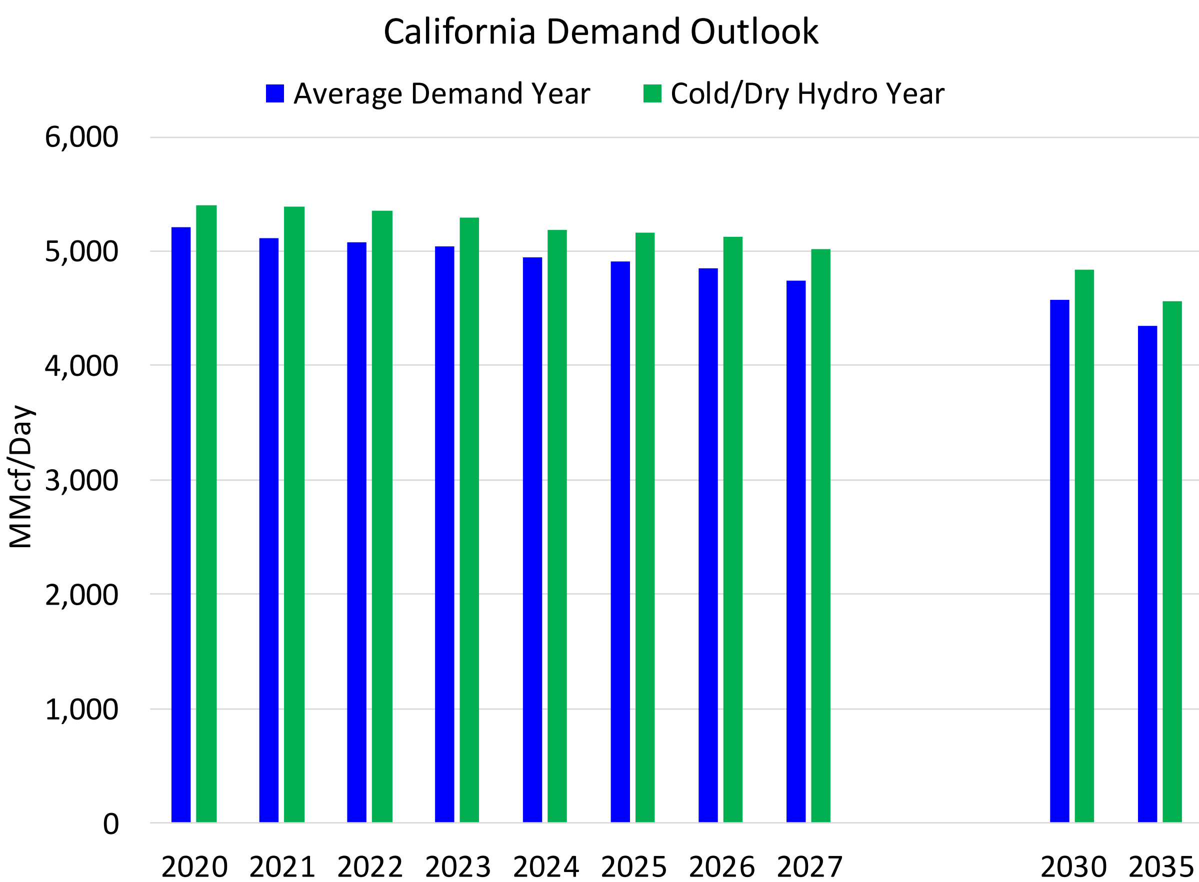
1 Gas Demand served by PG&E, SoCalGas, SWG, City of Long Beach Energy Resources Department, and SDG&E.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK



The graph above summarizes statewide gas demand under the Average Demand year (Average Demand) forecast and the Cold Temperature, Dry Hydroelectric Generation[2] scenario (Cold/Dry Hydro). The Average Demand refers to the gas demand projection for an average temperature year and normal hydroelectric generation (hydro) year, and the Cold/Dry Hydro refers to expected gas demand for a cold temperature year and dry hydro year conditions. Under an average-temperature condition and a normal hydro year, gas demand for the state is projected to average 5,205 million cubic feet of gas per day (MMcf/d) in 2020 decreasing to 4,343 MMcf/d by 2035, a decline of 1.2 percent per year.

In 2020, Northern California is projected to require an additional 5.0 percent of gas supply to meet demand for the Cold/Dry Hydro demand scenario, whereas Southern California is projected to require an additional 3.2 percent of supply to meet demand under this scenario. The

2 Dry Hydroelectric Generation scenario assumes dry hydro generation in the Western Electricity Coordinating Council (WECC).

weather for each year is an independent event and each event has the same likelihood of occurring.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency and other Demand-Side Management programs in their utility electric and gas resource plans. California utilities are committed to helping their customers make the best possible choices regarding use of this valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC mandated goals for electric energy efficiency programs and additional renewable power generation. The Average Year demand forecasts in this report assume that renewable power will meet 33 percent of the state's electric needs by 2020 and 60 percent by 2030 and beyond.

Passed in 2018, Senate Bill (SB) 100 increases and accelerates the Renewables Portfolio Standard (RPS) targets. The increase comes in 2030 with renewable power generation equal to 60 percent of retail electric sales. Previously, the target was 50 percent. The acceleration requires the RPS at 50 percent by 2026. An additional requirement mandated in 2018 establishes a statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy.

Enacted in 2015, SB 350 establishes 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 by January 1, 2030. These targets must be cost-effective and feasible.

Additional California legislation and policy direction[3] provides directives and incentives to increase energy efficiency. Some of these efforts require access to building performance data, encouraging pay-for-performance incentive-based programs, and the use of energy management technology for use in homes and businesses. Moreover, legislation requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive programs.

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

3 For more information, see https://www.cpuc.ca.gov/egyefficiency/.

jurisdictional utilities. Gas savings from electric energy efficiency goals are based on a generic assumption of heat rate per megawatt-hour (MWh) of electricity produced at gas fired peaking and combined cycle power plants.

TABLE 1 – IMPACT OF RENEWABLE GENERATION AND ENERGY EFFICIENCY PROGRAMS ON GAS DEMAND

	2020	2021	2022	2023	2024	2025	2026	2027	2030	2035
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) (1)										
Electricity Demand (GWh)	251,983	250,319	249,569	249,434	249,469	249,490	249,666	249,841	251,392	253,308
33% Renewables by 2020 & 60% Renewables by 2030										
Renewable Electric Generation (GWh/Yr) (2)	83,154	86,861	90,843	95,034	99,289	103,538	107,856	112,179	125,696	126,654
Increase over 2019 Level (GWh/Yr) (3)	23,415	27,121	31,104	35,295	39,549	43,799	48,116	52,439	65,957	66,915
Gas Savings over 2019 Level (Bcf/Yr) (4)	142	165	189	214	240	266	292	318	400	406
Electric Energy Efficieny Goals (5)										
Electricity Savings over 2019 Level (GWh/Yr)	1,256	2,402	3,452	4,690	6,160	7,829	9,659	11,711	18,823	31,410
Gas Savings over 2019 Level (Bcf/Yr) (4)	8	15	21	28	37	48	59	71	114	191
Energy Efficiency Goal for Natural Gas Programs (6)										
Gas Savings over 2019 Level (Bcf/Yr)	9	18	26	34	42	51	57	63	84	84
Total Gas Savings (Bcf/Yr) (7)	159	197	236	277	320	364	408	453	598	680

Notes:

(1) Electricity demand forecast from the California Energy Commission: https://efiling.energy.ca.gov/GetDocument.aspx?tn=222582, LSE_and_BA_Tables_Med_Baseline_Demand_Mid_AAEEAAPV_Revised_CCA.xlsx, "form1.1c" tab. From 2030-2035 the average growth rate was used from the last five years (2026-2030) which is -0.371%.

(2) Assumes 33% renewables by the year 2020 and 60% renewables by 2030.

(3) Increase reflects only the impacts of equipment installed after December 31, 2019.

(4) Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year (24 x 365) and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approximately 10,000 CF) of natural g Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approximately 7,000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,750 hours x 10% x 10 MMBtu, plus 8,760 hours x 75% x 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods produ greater natural gas savings per MWh. Similar estimates apply to renewable electric generators.

(5) Data from the California Energy Commission: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223608, "Electricity Committed Efficiency CED 2017"; Mid Case, sums of STATE TOTAL. From 2030-2035 the average growth rate was used from the last five years (2026-2030): 1.74% for Residential and 3.44% for Non-

(6) Data from the California Energy Commission: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223609, "Natural Gas Committed Efficiency CED 2017"; TOTAL STATE Mid Case Totals. From 2030-2035 the average growth rate was used from the last five years (2026-2030): 1.13% for Residential and 2.29% for Non-

(7) Total gas savings are annual savings from equipment installed after December 31, 2019.

FUTURE GAS SYSTEM IMPACTS RESULTING FROM INCREASED RENEWABLE GENERATION AND ELECTRIFICATION

Since electric utility system operators must balance electrical demand with generation sources on a real time basis, most system operators rely on “dispatchable” resources that can respond quickly to changes in demand. The challenge with renewable resources is that while they can provide energy, they are not always predictable and are not always dispatchable.

In the future, the increase in renewable generation in the state will reduce the total amount of natural gas usage. It is also expected that the increasing renewable generation will add to the daily and hourly load-forecast variance on the gas-fired EG fleet. Although the additional renewable energy will displace some of the natural gas currently being used to generate electricity in California, the intermittent nature of renewable generation will likely cause the electric system to rely on natural gas fired EG for providing the needed ancillary services (A/S) (ramping, voltage support, and quick starts) to balance the electric system in the short-term. In the long-term, this balancing may also come from the higher expected integration of energy storage devices e.g., batteries, fuel cells, and hydroelectric pumped storage.

The amount of gas consumed for integrating more renewables will fluctuate hourly. This is due to an increased need for rapid response from gas-fired generators to follow electric net load fluctuations. Since the gas-fired generation is expected to be the marginal resource in most hours, the gas system will need to be both robust and flexible to handle such fluctuations.

The expected growth in electrification poses considerable uncertainty on when, where, and how large will the impact be on gas demand throughout. In the building sector, electrification could decrease gas use. Recently, some California local jurisdictions[4] have forbidden the use of gas in new building construction. Moreover, it is possible for jurisdictions to require appliance substitution to electric from natural gas. Expected growth in electrification of vehicles and buildings would result in increasing electric load. This load increase could cause additional use of gas-fired generators.

4 See the following for more details for about 30 local jurisdictions implementing these requirements: https://www.sierraclub.org/articles/2020/03/californias-cities-lead-way-gas-free-future.

GAS PRICE FORECAST

MARKET CONDITION

The natural gas industry has seen its fair share of transformations over the last decade with the shale gas revolution, the first Liquefied Natural Gas (LNG) export cargo out of the United States (U.S.) Lower 48, and most recently the rise of associated supply from tight oil production growth. As a result, the North American gas supply portfolio contains a mix of conventional and unconventional natural gas supply sources. Moreover, improvements in fracking technology and horizontal drilling efficiencies in both dry and wet gas plays have resulted in the supply from unconventional shale resources increasing faster than conventional supplies.

The near-term gas price outlook continues to remain below $3.00/Million British Thermal Units (MMBtu) for most supply basins, in constant 2019 dollars. Production gains from the Permian Basin have been significant and are expected to remain strong for at least the next 5 years. Additionally, three Permian-area pipelines are expected to come online by late 2021. Supplies are expected to ramp up from the Permian production area and shale-sourced supplies continue to expand in the Marcellus, Utica, and Haynesville areas.

Natural gas prices will gain further support in most supply basins over the forecast period and move towards the $3.00-$4.00/MMBtu range in constant 2019 U.S. dollars by end of the decade as more demand and exports ramp up to expand the market size. Additionally, the challenges of building new pipeline projects in North America will have a material impact on the Henry Hub price outlook and where resources will be developed in the long term.

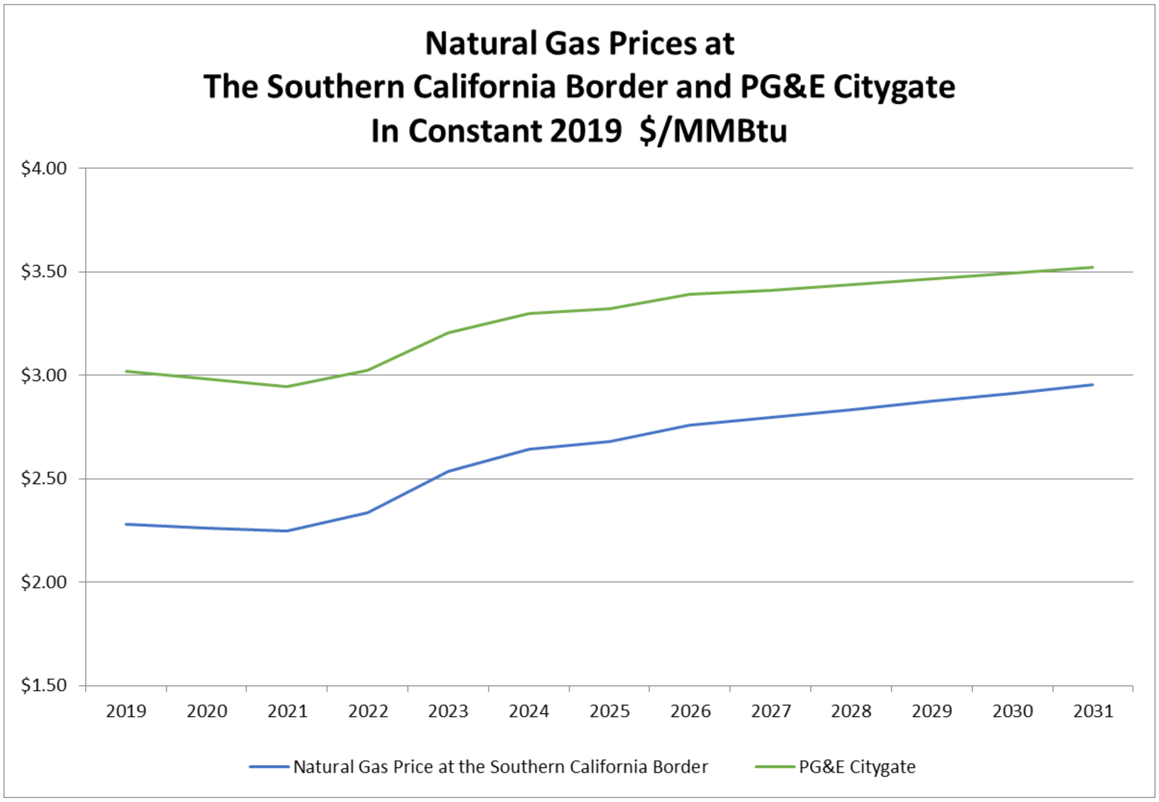
Industry experts continue to forecast that North American gas supplies will be sufficient to meet expected demand growth. North American gas price increases may be somewhat tempered by renewable power generation additions both in the U.S. and in Mexico. Continuing closures of coal-fired generation to meet environmental goals may provide price support but could be tempered by the softening of the global economy due to Coronavirus Disease 2019 (COVID-19) related impacts. Related uncertainties surrounding government policies are expected to create some headwinds for natural gas.

DEVELOPMENT OF THE GAS PRICE FORECAST

Natural gas prices at the SoCalGas border averaged $2.28/MMBtu in 2019. The inflation adjusted SoCalGas border price is expected to rise to $2.95/MMBtu by the year 2035. On average, the SoCalGas Border price is expected to be $2.56/MMBtu over the forecast horizon. For the PG&E Citygate, the natural gas price in 2019 averaged $3.52/MMBtu and is forecasted to decline to an average of $3.23/MMBtu over the forecast horizon.

Consistent with prior CGRs, the 2020 CGR gas price forecast was developed using a combination of market prices and fundamental long-term forecasts. The natural gas custom futures curve was extracted from Intercontinental Exchange and Chicago Mercantile Exchange for the 2020-2025 period. Fundamental price forecasts were used for 2028 and beyond. The forecasts for 2026 and 2027 reflect a blending of market and fundamental prices, with declining weights for market prices (and corresponding increasing weights for the fundamental price forecast) over the 2-year period. The fundamental gas price forecast represents an average of three forecasts developed by the California Energy Commission (CEC) and independent consultants Wood Mackenzie and S&P Global (formerly PIRA).

FIGURE 2 – NATURAL GAS PRICE CHART: SOCALGAS BORDER AND PG&E CITYGATE PRICES 2020-2035



It is important to recognize that the natural gas price forecast is inherently uncertain. PG&E, SoCalGas, and the respondents of the *2020 CGR*, separately and collectively, do not warrant the accuracy of the gas price projection. PG&E, SoCalGas, or the respondents of the *2020 CGR* shall not be liable or responsible for the use of or reliance on this natural gas price forecast.

NATURAL GAS PROJECTS

Over the past 5 years, the natural gas industry has made investments to improve the safety, accessibility, and reliability of natural gas supply. In addition, more projects have been proposed and some are under construction. The following describes the state of supply and regionally important projects.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and ensures long-term supply availability. Gas supply to California includes sources from California (onshore and offshore), Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains and Canada. Interstate pipelines currently 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 natural gas pipelines serving California.

California benefits from substantial gas storage capacity in dedicated gas storage facilities across the state. In recent years, various regulations and standards[5] have been proposed and implemented to ensure safe, reliable operation of California gas storage facilities.

In addition to traditional sources of gas supply, multiple Renewable Gas (e.g., Renewable Natural Gas and hydrogen to name a couple) interconnection projects in California are beginning to come online. As further detailed in this CGR, gas utilities are taking significant steps to make RG interconnection easier and more transparent and see broad potential for RG in California. Currently, incentives (such as Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) credits) are funneling RG towards use in the transportation sector. However, with the help of policy makers and thoughtful incentives, the energy sector hopes to utilize increasing amounts of future RG to meet customer needs and support electric grid reliability.

As California continues towards achieving low or zero emissions from energy, Green Hydrogen (H_2) will become an important fuel source in helping achieve the State's emissions goals. There is also great potential for generating Green[6] H_2 and storing it in existing gas utility infrastructure to help meet California's dynamic energy needs. No other storage technology has the capability for the long-term and large volume storage that H_2 does.

5 See Geologic Energy Management Division's Underground Natural Gas Storage for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

6 Green Hydrogen is hydrogen produced from electricity that comes from renewable sources such as wind, solar or hydro.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

LIQUEFIED NATURAL GAS

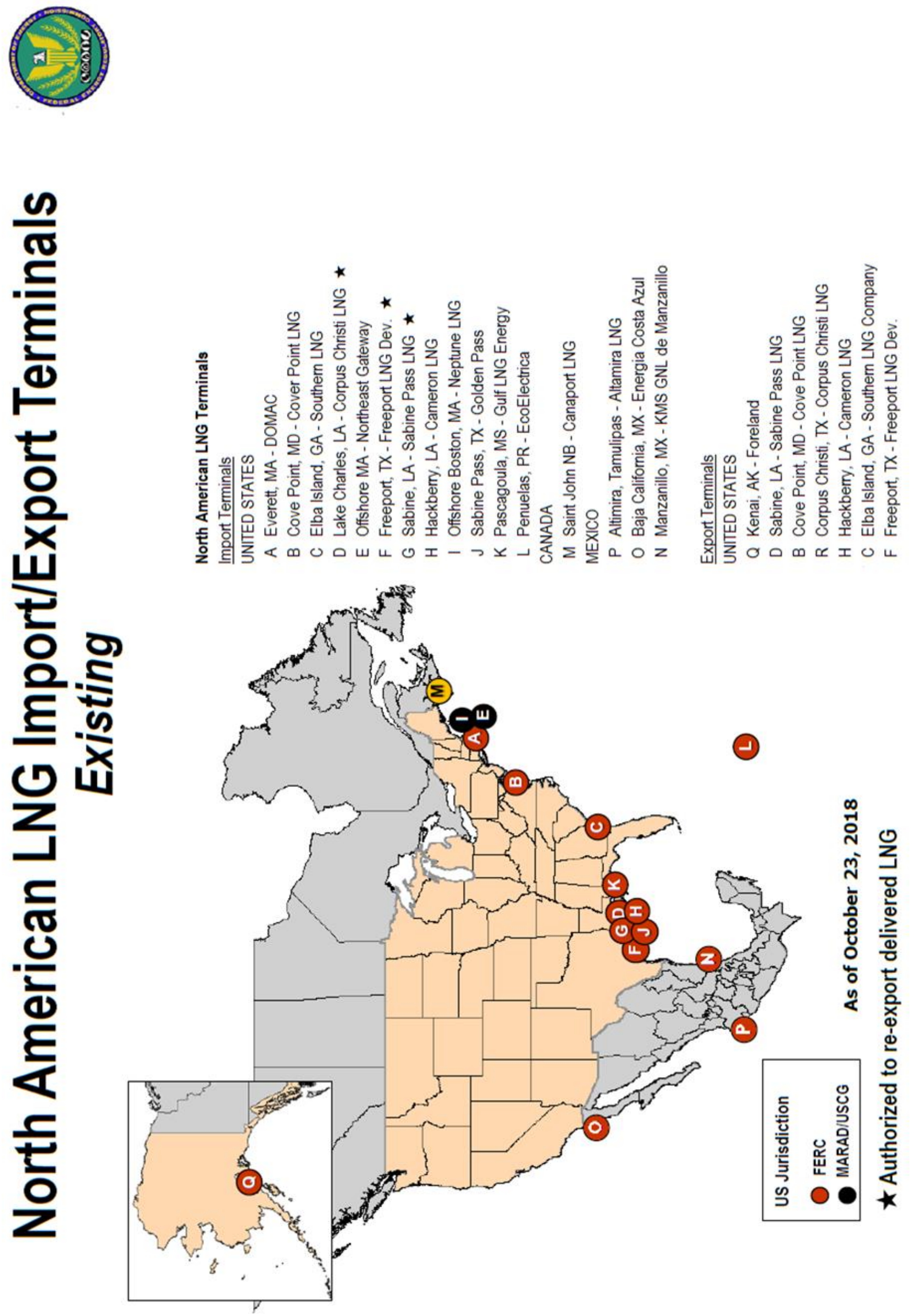
Currently, there are three Western U.S. LNG facilities, two operating in Mexico and one facility in Alaska. The two in Mexico are the Costa Azul terminal and the Altamira terminal operating as import facilities.

The abundance of shale gas has changed the paradigm for LNG in the West. Until the mid-2000s, LNG was thought as being a potential gas supply for California, but that has now changed. Currently, four companies plan on building export facilities. Two in Canada have decided to build these facilities. One in Oregon and one in Baja California, Mexico await final jurisdiction approvals and final investment decisions to begin construction.

TABLE 2 – POTENTIAL AND PROPOSED NORTH AMERICAN WEST COAST LNG TERMINALS AS OF SPRING 2020

Project	Location	Developer	Capacity (bcfd)
Jordan Cove	Oregon, United States	Pembina Pipeline Corporation	1.08
Costa Azul	Baja California, Mexico	Sempra Energy	1.00
LNG Canada	British Columbia, Canada	Shell, Petronas, Petrochinga, Mitsubishi, Korea Gas Corp.	3.50
Woodfibre LNG	British Columbia, Canada	Woodfibre LNG Limited	0.30

FIGURE 4 – NORTH AMERICAN IMPORT/EXPORT TERMINALS EXISTING



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 2020-2035 for average temperature and normal hydro years and cold weather and dry hydro years.

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 Energy Resources Department, SDG&E, 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 3 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2024**

Line No.		2020	2021	2022	2023	2024
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,357	4,274	4,270	4,206	3,984
5	Utility Total	4,454	4,371	4,367	4,303	4,081
6	*Non-Utility Served Load*[(a)]	1,011	1,007	978	983	969
7	**Statewide Supply Sources Total**	5,465	5,378	5,344	5,286	5,050
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,139	1,130	1,106	1,090	1,069
11	Commercial	484	483	487	483	478
12	Natural Gas Vehicles	54	56	57	59	60
13	Industrial	998	997	1,000	997	998
14	Electric Generation[(b)]	1,166	1,093	1,104	1,076	1,018
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	251	251	252	251	251
17	Company Use and Unaccounted-for	71	69	69	69	68
18	Utility Total	4,194	4,111	4,107	4,057	3,974
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	633	635	638	640	643
21	EOR Cogeneration/Industrial	60	59	56	57	49
22	Electric Generation	318	313	284	286	278
23	Non-Utility Served Load[(a)]	1,011	1,007	978	983	969
24	**Statewide Requirements Total**[(c)]	5,205	5,118	5,084	5,040	4,943

(a) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

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

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

TABLE 4 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	3,857	3,813	3,737	3,580	3,497
5	Utility Total	3,954	3,910	3,834	3,677	3,594
6	*Non-Utility Served Load*[(a)]	953	936	908	897	750
7	**Statewide Supply Sources Total**	4,907	4,846	4,742	4,574	4,343
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,053	1,033	1,014	959	884
11	Commercial	472	462	455	436	389
12	Natural Gas Vehicles	62	64	65	70	78
13	Industrial	998	995	983	977	968
14	Electric Generation[(b)]	1,019	1,008	968	890	927
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	251	250	249	249	250
17	Company Use and Unaccounted-for	68	66	66	64	65
18	**Utility Total**	3,954	3,910	3,834	3,677	3,594
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	645	648	650	658	672
21	EOR Cogeneration/Industrial	43	41	23	18	6
22	Electric Generation	265	246	235	220	72
23	Non-Utility Served Load[(c)]	953	936	908	897	750
24	**Statewide Requirements Total**[(c)]	4,907	4,846	4,742	4,574	4,343

(a) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

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

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

**TABLE 5 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2035**

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	California Sources[(a)]	34	34	34	34	34
4	Out-of-State	1,958	1,890	1,875	1,848	1,699
5	Northern California Total	1,992	1,924	1,909	1,882	1,733
6	*Southern California*					
7	California Sources[(b)]	63	63	63	63	63
8	Out-of-State	2,399	2,384	2,394	2,358	2,286
9	Southern California Total	2,462	2,447	2,457	2,421	2,349
10	**Utility Total**	4,454	4,371	4,367	4,303	4,081
11	**Non-Utility Served Load**[(c)]	1,011	1,007	978	983	969
12	**Statewide Supply Sources Total**	5,465	5,378	5,344	5,286	5,050
13						
14	**Utility**	2025	2026	2027	2030	2035
15	*Northern California*					
16	California Sources[(a)]	34	34	34	34	34
17	Out-of-State	1,578	1,559	1,539	1,512	1,457
18	Northern California Total	1,612	1,593	1,573	1,546	1,491
19	*Southern California*					
20	California Sources[(b)]	63	63	63	63	63
21	Out-of-State	2,279	2,254	2,198	2,069	2,040
22	Southern California Total	2,342	2,317	2,261	2,132	2,103
23	**Utility Total**	3,954	3,910	3,834	3,677	3,594
24	**Non-Utility Served Load**[(c)]	953	936	908	897	750
25	**Statewide Supply Sources Total**	4,907	4,846	4,742	4,574	4,343

(a) Includes utility purchases and exchange/transport gas.

(b) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.

(c) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

TABLE 6 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	Residential	509	506	492	484	474
4	Commercial – Core	224	224	223	222	220
5	Natural Gas Vehicles – Core	8	8	9	9	10
6	Natural Gas Vehicles – Noncore	4	5	5	6	6
7	Industrial – Noncore	553	560	559	554	555
8	Wholesale	9	9	9	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	PG&E Electric Generation[(b)]	267	196	196	196	196
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted for	40	38	38	38	38
13	Northern California Total[(c)]	1,732	1,664	1,649	1,636	1,626
14	*Southern California*					
15	Residential	629	624	614	605	596
16	Commercial – Core	209	208	213	210	206
17	Commercial – Noncore	51	51	51	52	51
18	Natural Gas Vehicles – Core	42	43	43	44	45
19	Industrial – Core	54	52	52	51	50
20	Industrial – Noncore	391	386	389	391	393
21	Wholesale	240	241	241	241	240
22	SDG&E + Vernon Electric Generation	113	113	112	106	94
23	Electric Generation[(d)]	669	667	679	657	611
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	31	31	31	31	30
26	Southern California Total	2,462	2,447	2,457	2,421	2,349
27	**Utility Total**	4,194	4,111	4,107	4,057	3,974
28	**Non-Utility Served Load[(e)]**	1,011	1,007	978	983	969
29	**Statewide Gas Requirements Total[(f)]**	5,205	5,118	5,084	5,040	4,943

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

(f) Does not include off-system deliveries.

TABLE 7 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**Utility**					
2	*Northern California*					
3	Residential	464	453	443	413	341
4	Commercial – Core	219	215	212	202	167
5	Natural Gas Vehicles – Core	10	11	12	13	16
6	Natural Gas Vehicles – Noncore	6	7	7	8	10
7	Industrial – Noncore	553	551	545	554	560
8	Wholesale	9	9	9	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	PG&E Electric Generation[(b)]	194	194	191	192	233
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted for	38	37	37	37	38
13	Northern California Total[(c)]	1,612	1,593	1,573	1,546	1,491
14	*Southern California*					
15	Residential	589	580	572	547	543
16	Commercial – Core	201	196	192	182	171
17	Commercial – Noncore	52	51	51	51	51
18	Natural Gas Vehicles – Core	45	46	47	49	52
19	Industrial – Core	49	48	47	44	39
20	Industrial – Noncore	395	395	391	380	369
21	Wholesale	241	240	240	239	241
22	SDG&E + Vernon Electric Generation	94	91	84	78	78
23	Electric Generation[(d)]	614	607	577	503	499
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	30	29	29	27	27
26	Southern California Total	2,342	2,317	2,261	2,132	2,103
27	**Utility Total**	3,954	3,910	3,834	3,677	3,594
28	**Non-Utility Served Load** [(e)]	953	936	908	897	750
29	**Statewide Gas Requirements Total** [(f)]	4,907	4,846	4,742	4,574	4,343

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

(f) Does not include off-system deliveries.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS COLD TEMPERATURE[(d)] AND DRY HYDRO YEAR (MMcf/d) 2020-2024

Line No.		2020	2021	2022	2023	2024
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,522	4,501	4,489	4,406	4,176
5	Utility Total	4,619	4,598	4,586	4,503	4,273
6	*Non-Utility Served Load*[(a)]	1,045	1,043	1,033	1,038	1,025
7	**Statewide Supply Sources Total**	5,664	5,641	5,619	5,541	5,298
8	California's Requirements					
9	*Utility*					
10	Residential	1,235	1,226	1,202	1,186	1,166
11	Commercial	504	503	507	503	498
12	Natural Gas Vehicles	54	56	57	59	60
13	Industrial	1,000	1,000	1,002	999	1,001
14	Electric Generation[(b)]	1,196	1,184	1,187	1,140	1,076
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	264	265	265	265	264
17	Company Use and Unaccounted-for	73	73	73	71	70
18	Utility Total	4,359	4,338	4,326	4,257	4,166
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	633	641	639	636	636
21	EOR Cogeneration/Industrial	75	73	70	74	64
22	Electric Generation	338	335	325	324	318
23	Non-Utility Served Load[(a)]	1,045	1,048	1,034	1,034	1,018
24	**Statewide Requirements Total[(c)]**	5,404	5,387	5,360	5,290	5,184

Note:

(a) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

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

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

(d) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 9 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE[(d)] AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,049	4,013	3,931	3,756	3,684
5	Utility Total	4,146	4,110	4,028	3,853	3,781
6	*Non-Utility Served Load*[(a)]	1,021	1,013	989	980	777
7	**Statewide Supply Sources Total**	5,167	5,123	5,017	4,833	4,559
8	California's Requirements					
9	*Utility*					
10	Residential	1,149	1,129	1,110	1,055	978
11	Commercial	492	483	476	456	409
12	Natural Gas Vehicles	62	63	64	69	76
13	Industrial	1,000	997	985	980	970
14	Electric Generation[(b)]	1,077	1,073	1,029	933	984
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	264	264	263	262	264
17	Company Use and Unaccounted-for	70	70	68	66	67
18	Utility Total	4,146	4,110	4,028	3,853	3,781
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	645	648	650	658	672
21	EOR Cogeneration/Industrial	60	59	39	32	10
22	Electric Generation	316	305	300	290	95
23	Non-Utility Served Load[(a)]	1,021	1,013	989	980	777
24	**Statewide Requirements Total[(c)]**	5,167	5,123	5,017	4,833	4,559

Note:

(a) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

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

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

(d) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 10 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE [d] and DRY HYDRO YEAR
(MMcf/d)
2020-2035

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	California Sources[a]	34	34	34	34	34
4	Out-of-State	2,045	1,967	1,939	1,908	1,759
5	Northern California Total	2,079	2,001	1,973	1,942	1,793
6	*Southern California*					
7	California Sources[b]	63	63	63	63	63
8	Out-of-State	2,477	2,534	2,550	2,497	2,417
9	Southern California Total	2,540	2,597	2,613	2,560	2,480
10	**Utility Total**	4,619	4,598	4,586	4,503	4,273
11	Non-Utility Served Load[c]	1,045	1,043	1,033	1,038	1,025
12	Statewide Supply Sources Total	5,664	5,641	5,619	5,541	5,298
13						
14	**Utility**	2025	2026	2027	2030	2035
15	*Northern California*					
16	California Sources[a]	34	34	34	34	34
17	Out-of-State	1,639	1,619	1,598	1,570	1,529
18	**Northern California Total**	1,673	1,653	1,632	1,604	1,563
19	*Southern California*					
20	California Sources[b]	63	63	63	63	63
21	Out-of-State	2,411	2,394	2,334	2,185	2,155
22	Southern California Total	2,474	2,457	2,397	2,248	2,218
23	**Utility Total**	4,146	4,110	4,028	3,853	3,781
24	Non-Utility Served Load[c]	1,021	1,013	989	980	777
25	**Statewide Supply Sources Total**	5,167	5,123	5,017	4,833	4,559

Notes:

(a) Includes utility purchases and exchange/transport gas.

(b) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.

(c) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

(d) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 11 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
COLD TEMPERATURE[(g)] and DRY HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	Utility					
2	*Northern California*					
3	Residential	552	549	535	528	517
4	Commercial – Core	234	234	233	232	231
5	Natural Gas Vehicles – Core	8	8	9	9	10
6	Natural Gas Vehicles – Noncore	4	5	5	5	5
7	Industrial – Noncore	554	561	560	556	557
8	Wholesale	10	10	10	10	10
9	SMUD Electric Generation	117	117	117	117	117
10	Electric Generation[(b)]	297	216	204	199	199
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted-for	41	40	40	39	39
13	Northern California Total[(c)]	1,819	1,741	1,713	1,696	1,686
14	*Southern California*					
15	Residential	683	677	667	658	648
16	Commercial – Core	218	217	222	219	215
17	Commercial – Noncore	52	52	52	53	52
18	Natural Gas Vehicles – Core	42	43	43	44	45
19	Industrial – Core	55	53	53	52	51
20	Industrial – Noncore	391	386	389	391	393
21	Wholesale	253	254	254	254	253
22	SDG&E + Vernon Electric Generation	113	124	126	118	106
23	Electric Generation[(d)]	669	727	740	706	654
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	32	33	33	32	31
26	**Southern California Total**	2,540	2,597	2,613	2,560	2,480
27	**Utility Total**	4,359	4,338	4,326	4,257	4,166
28	Non-Utility Served Load[(e)]	1,045	1,043	1,033	1,038	1,025
29	**Statewide Gas Requirements Total[(f)]**	5,404	5,381	5,359	5,295	5,191

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

(f) Does not include off-system deliveries.

(g) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

TABLE 12 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
COLD TEMPERATURE[(g)] AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	Utility					
2	*Northern California*					
3	Residential	508	496	486	457	385
4	Commercial – Core	229	225	222	213	177
5	Natural Gas Vehicles – Core	10	11	12	13	16
6	Natural Gas Vehicles – Noncore	6	6	6	7	8
7	Industrial – Noncore	555	552	547	555	561
8	Wholesale	10	10	10	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	Electric Generation[(b)]	199	197	193	194	249
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted-for	39	39	38	38	39
13	Northern California Total[(c)]	1,673	1,653	1,632	1,604	1,563
14	*Southern California*					
15	Residential	641	632	623	598	593
16	Commercial – Core	210	205	201	191	180
17	Commercial – Noncore	53	52	52	52	52
18	Natural Gas Vehicles – Core	45	46	47	49	52
19	Industrial – Core	50	49	48	45	40
20	Industrial – Noncore	395	395	391	380	369
21	Wholesale	254	253	253	252	254
22	SDG&E + Vernon Electric Generation	107	104	98	85	85
23	Electric Generation[(d)]	654	655	621	537	533
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	31	31	30	28	28
26	**Southern California Total**	2,474	2,457	2,397	2,248	2,218
27	**Utility Total**	4,146	4,110	4,028	3,853	3,781
28	Non-Utility Served Load[(e)]	1,021	1,013	989	980	777
29	**Statewide Gas Requirements Total[(f)]**	5,167	5,123	5,017	4,833	4,559

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

(f) Does not include off-system deliveries.

(g) 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 on available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to 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 13 – RECORDED 2015 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									
Core + UAF (2)	(61)	447	76	40	225	0	122	0	849
Noncore Commercial/Industrial	45	142	75	41	106	27	(15)	0	421
EG (3)	86	273	143	79	203	52	(28)	0	808
EOR	5	16	8	5	12	3	(2)	0	47
Wholesale/Resale/International (4)	47	147	77	42	109	28	(15)	0	435
Total	122	1,024	379	207	655	110	62	0	2,559
Pacific Gas and Electric Company (5)									
Core	0	23	124	345	12	0	0	207	711
Noncore Industrial/Wholesale/EG (6)	37	216	145	798	81	0	56	551	1,884
Total	37	239	269	1,143	93	0	56	758	2,595
Other Northern California									
Core (7)	11	0	0	0	0	0	0	0	11
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	478	0	0	0	873	36	0	0	1,387
TOTAL SUPPLIER	648	1,263	648	1,350	1,621	146	118	758	6,552
San Diego Gas & Electric Company									
Core	(8)	59	10	5	30	0	16	0	116
Noncore Commercial/Industrial	23	72	38	21	54	14	(8)	0	211
Total	15	132	48	26	84	14	9	0	327
Southwest Gas Corporation									
Core	21	0	0	0	0	0	11	0	37
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	23	0	0	0	0	0	11	0	39

Notes:

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

(2) Includes NGV volumes

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

(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.

(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.

(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.

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

(9) California production is preliminary.

TABLE 14 – RECORDED 2016 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									
Core + UAF (2)	86	417	114	48	196	0	31	0	892
Noncore Commercial/Industrial	1	94	96	37	150	43	27	0	448
EG (3)	1	156	158	61	248	71	45	0	740
EOR	0	8	8	3	13	4	2	0	39
Wholesale/Resale/International (4)	1	82	83	32	130	37	24	0	390
Total	89	758	460	181	737	155	129	0	2,509
Pacific Gas and Electric Company (5)									
Core	0	40	84	318	0	0	0	194	636
Noncore Industrial/Wholesale/EG (6)	33	198	100	837	30	0	15	400	1,613
Total	33	238	184	1,155	30	0	15	594	2,249
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	418	0	0	0	792	43	0	0	1,253
TOTAL SUPPLIER	562	996	644	1,336	1,559	198	156	594	6,045
San Diego Gas & Electric Company									
Core	11	56	15	6	26	0	4	0	119
Noncore Commercial/Industrial	0	36	37	14	57	16	10	0	171
Total	12	92	52	20	83	16	14	0	290
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 15 – RECORDED 2017 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									
Core + UAF (2)	100	443	127	54	208	0	(27)	0	905
Noncore Commercial/Industrial	(4)	97	80	39	158	52	24	0	446
EG (3)	(4)	156	128	63	252	82	39	0	715
EOR	(0)	9	7	3	14	5	2	0	39
Wholesale/Resale/International (4)	(7)	88	72	35	142	46	22	0	398
Total	84	792	414	195	773	185	60	0	2,503
Pacific Gas and Electric Company (5)									
Core	0	18	65	319	(1)	0	0	179	580
Noncore Industrial/Wholesale/EG (6)	29	208	99	840	34	0	12	420	1,642
Total	29	226	164	1,159	33	0	12	599	2,222
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	698	28	0	0	698	44	0	0	1,468
TOTAL SUPPLIER	833	1,046	578	1,354	1,504	229	84	599	6,227
San Diego Gas & Electric Company									
Core	14	61	17	7	28	0	(4)	0	124
Noncore Commercial/Industrial	(2)	38	31	15	62	20	10	0	175
Total	12	99	49	23	90	20	6	0	299
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:

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

(2) Includes NGV volumes

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

(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.

(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.

(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.

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

(9) California production is preliminary.

TABLE 16 – RECORDED 2018 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									
Core + UAF (2)	158	439	103	37	173	0	(2)	0	908
Noncore Commercial/Industrial	(17)	99	35	57	207	61	7	0	448
EG (3)	(23)	136	48	78	283	83	10	0	615
EOR	(1)	8	3	5	18	5	1	0	38
Wholesale/Resale/International (4)	(13)	74	26	42	153	45	6	0	333
Total	104	756	214	218	834	194	22	0	2,342
Pacific Gas and Electric Company (5)									
Core	0	3	55	303	(4)	0	0	165	522
Noncore Industrial/Wholesale/EG (6)	28	212	221	966	16	0	0	355	1,798
Total	28	215	276	1,269	12	0	0	520	2,320
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	401	49	0	0	686	42	0	0	1,178
TOTAL SUPPLIER	555	1,020	490	1,487	1,532	236	34	520	5,874
San Diego Gas & Electric Company									
Core	22	61	14	5	24	0	(0)	0	127
Noncore Commercial/Industrial	(4)	25	9	14	52	15	2	0	112
Total	18	86	23	19	76	15	2	0	239
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, and SDG&E, as shown.
(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

TABLE 17 – RECORDED 2019 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)	162	476	111	30	223	0	10	0	1,012
Wholesale/Resale/International (5)	(65)	368	47	118	674	213	19	0	1,374
Total	97	844	158	148	897	213	29	0	2,386
Pacific Gas and Electric Company (4)									
Core	0	0	58	286	(2)	0	0	172	514
Noncore Industrial/Wholesale/EG (5)	24	380	223	896	9	0	0	481	2,014
Total	24	380	281	1,182	7	0	0	653	2,528
Other Northern California									
Core (6)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (7, 8)									
Direct Sales/Bypass	388	29	0	0	664	71	0	0	1,152
TOTAL SUPPLIER	531	1,253	439	1,330	1,568	284	41	653	6,100
San Diego Gas & Electric Company									
Core	21	61	14	4	28	0	1	0	129
Noncore Commercial/Industrial	(4)	22	3	7	40	12	1	0	81
Total	17	83	17	11	68	12	2	0	210
Southwest Gas Corporation									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	3	0	0	0	0	0	0	0	3
Total	28	0	0	0	0	0	0	0	28

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) 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 5 years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

TABLE 18 – CALIFORNIA HIGHEST SENDOUT DAYS (2015-2019)

ESTIMATED CALIFORNIA HIGHEST SUMMER SENDOUT (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2015	09/10/2015	2,787	3,601	6,388	1,407	7,795
2016	07/28/2016	2,867	3,136	6,003	1,356	7,359
2017	08/28/2017	2,602	3,484	6,086	1,416	7,502
2018	07/24/2018	2,925	2,926	5,851	1,410	7,261
2019	09/04/2019	2,634	3,106	5,740	1,310	7,050

ESTIMATED CALIFORNIA HIGHEST WINTER SENDOUT (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2015	12/29/2015	3,626	4,036	7,662	1,311	8,973
2016	02/02/2016	3,397	3,838	7,235	1,285	8,520
2017	12/21/2017	3,665	3,456	7,121	1,259	8,380
2018	02/20/2018	3,527	3,621	7,148	1,378	8,526
2019	02/05/2019	3,780	4,180	7,960	1,097	9,057

Notes:

(1) PG&E Pipe Ranger.

(2) SoCalGas Envoy.

(3) Source: Provided by the CEC. Data are from the California Division of Oil, Gas, and Geothermal Resources (DOGGR), Monthly Oil and Gas Production and Injection Report. Non-Utility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCalGas peak day supply from Kern-Mojave and California in-state production.

(4) PG&E and SoCalGas sendouts 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.

2020 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. As of December 31, 2019, PG&E's natural gas system consists of approximately 42,800 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and three underground storage facilities. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution systems.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.3 million residential customers and over 200,000 commercial and industrial customers. PG&E also provides gas transportation and storage services to a variety of gas-fired EG plants in its service area and serves multiple NGV fleets, including utility owned facilities, with its publicly-accessible fueling stations throughout California. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers, including other regulated utilities, also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of this report includes PG&E's gas demand forecast and discussions on gas supply, pipeline capacity, storage, and related policies, as well as the natural gas regulatory environment, including legislative developments and regulatory proceedings. Finally, the report includes PG&E's forecast of supply and demand for an Abnormal Peak Day (APD).

What follows is a summary of key takeaways from the Northern California sections of this report.

- **Gradual Decline in Forecasted Gas Demand:** PG&E's Average Demand[7] is projected to decline at an annual average rate of 1.0 percent between 2020 and 2035. The decline in forecasted gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, climate change, and an increase in GHG-free EG resources.

- **There Is High Uncertainty in Gas Demand Due to Building Electrification:** PG&E's Average Demand forecast reflects the impact of California's current policies for energy efficiency and the impact of existing and anticipated future policies around building decarbonization. Uncertainty around building electrification, especially retrofits, drives uncertainty in gas demand. In a high electrification scenario,[8] PG&E projects on-system gas demand to decline at an annual average rate of 1.3 percent between 2020 and 2035. In a low electrification scenario, PG&E projects gas on-system demand to decline at an annual average rate of 0.8 percent between 2020 and 2035. The rate of decrease for both scenarios is non-linear, with larger rates of decrease in the later years of the forecast.

- **Current Forecast Does Not Reflect Impact From COVID-19 pandemic on Gas Throughput:** When PG&E was preparing the gas throughput forecast for this report, economic shocks associated with the COVID-19 pandemic suddenly appeared. The lasting economic impacts from the COVID-19 pandemic are highly uncertain. As a result, this report does not attempt to forecast COVID-19 pandemic impacts on gas demand. As events unfold and reliable economic and policy forecasts become available, PG&E will consider such information.

- **Without Policy Solutions and a Managed Transition from Fossil Fuel to Other Energy Forms, Lower Forecasted Gas Demand Could Put Upward Pressure on Customer Gas Costs and Rates:** PG&E is committed to working with the regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increases. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. To reduce costs, PG&E is pursuing opportunities to systematically retire infrastructure (where possible) and reduce capital and operating

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7 Gas demand projection for an average temperature year and normal hydroelectric generation (hydro) year representing on-system demand.

8 See "Gas Demand, Future Gas Demand Trends and Policy," section for details.

expenses through PG&E's Integrated Investment Planning. To increase utilization, PG&E is implementing programs to decarbonize existing gas throughput, supporting Renewable Gas (RG) adoption across new industries with existing gas system infrastructure, and adapting to utilize the gas system as a large-scale and long-duration storage mechanism for Green H2. There are broad opportunities for load growth that can help decarbonize the economy, such as marine, rail, and surface-transportation applications.

Regulatory bodies and investor-owned utilities (IOU) should 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 Biomethane Order Instituting Rulemaking (OIR) (Rulemaking (R.) 13-02-008) and the Gas System Planning OIR (R.20-01-007). Both OIRs address crucial topics that will impact the future of the California gas system. In addition to the efforts currently underway, additional steps need to be taken to adequately address:

- The possible impacts of climate change policies and laws on gas throughput and the cost structure of existing and future gas assets; and
- The barriers to Renewable Gas Standard[9] (RGS).[10]

The current investment and incentives for RG principally favor the transportation sector resulting in little RG available to establish a consistent RGS. If this is to change, California will have to balance the funding mechanisms between the transportation sector and a potential RGS so that RG project developers have opportunities to supply RG towards an RGS or the transportation sector.

9 A carbon-based standard for California's gas supply.

10 An RGS does not currently exist. However, with implementation of SB 1440 through Phase IV of the Biomethane OIR and legislation that was proposed earlier this year (SB 1352), it is clear that there is some momentum to establishing an RGS that would require the utility to procure a certain percentage of RG for core gas customers (similar to the RPS on the electric side).

GAS DEMAND

OVERVIEW

PG&E's 2020 CGR Average Demand forecast projects total on-system demand[11] to decline at annual average rate of 1.0 percent between 2020 and 2035. This is due to the combination of a projected annual decline of 2.3 percent in the core market and a projected annual decline of 0.2 percent in the noncore market.

Different factors drive the gas demand decline projection. This projected decline could result in gas system operating and maintenance costs spread over lower usage, causing customer gas rates to increase. Consequently, PG&E and statewide utility stakeholders will need to continue their involvement to mitigate customer rate increases. Additional gas throughput offsetting lower carbon intensive fuel uses could help spread costs more evenly.

This chapter includes PG&E's gas demand forecast and begins with a description of the forecast method, including assumptions driving the projection. After the methodology discussion, a sectorial forecast explanation follows for the Average Demand Year. To provide more robustness to the Average Demand Year forecast, scenarios show how demand looks under cold weather and dry hydroelectric conditions. The discussion finishes with gas demand policies, trends and impacts.

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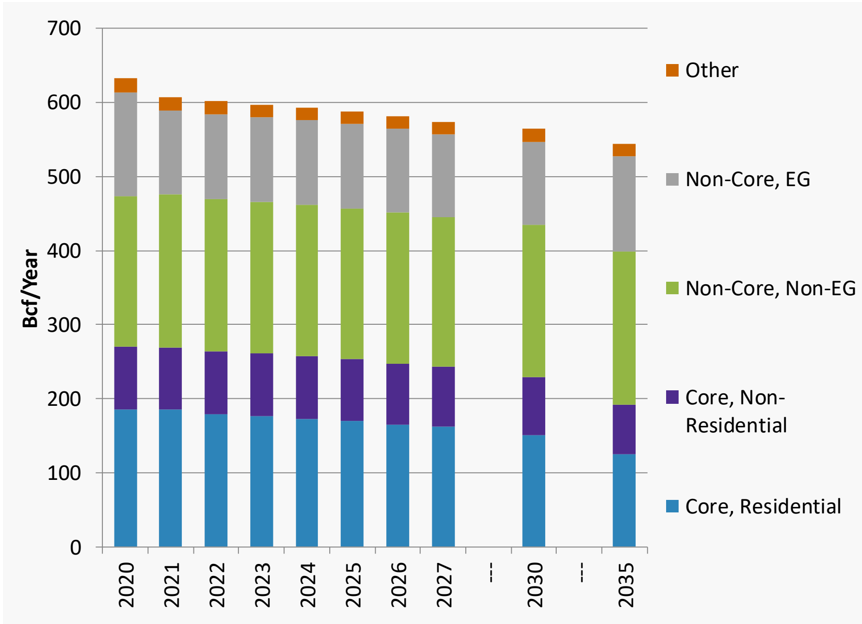
11 Excludes off-system sales.

FIGURE 5 – PG&E AVERAGE DEMAND YEAR GAS FORECAST



As shown in the above chart, total on-system gas demand for PG&E's gas system is projected to decline at an annual average rate of 1.0 percent between 2020 and 2035.[12] Core demand is projected to decline by an annual average rate of 2.3 percent over the 2020-2035 forecast horizon, driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore non-EG demand is projected to remain relatively unchanged over the forecast horizon, as potential demand growth is offset by energy efficiency and increasing gas prices. Finally, the rate of growth of the noncore EG forecast decreases due to higher levels of renewable generation to meet the 60 percent requirement in 2030,[13] more electric storage, and higher burner-tip gas prices for Northern California electric generators. In this projection, total gas demand by electric generators[14] and cogenerators in Northern California[15] decreases at 0.6 percent per year from 2020 through 2035. This projection assumes average hydrological conditions.

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12 With the inclusion of off-system demand, the projection declines at an annual average rate of 1.9 percent between 2020 and 2035.

13 https://www.cpuc.ca.gov/rps/.

14 This gas demand forecast excludes gas delivered by non-utility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in Central California.

15 Northern California electric generation gas demand consists of the generation fleet north of Path 26.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years. Forecasts of gas demand by power plants are developed by modeling the electricity market in the WECC using MarketBuilder software.

While variation in short-term gas use depends mainly on prevailing weather conditions and gas prices, longer-term projections in gas demand are driven primarily by changes in:

- Customer usage patterns influenced by underlying economic, demographic, and technological changes, such as growth in population and employment;
- Forecasted prices;
- Growth in electricity demand;
- Growth of renewable generation;
- Efficiency profiles of residential and commercial buildings and the appliances within them; and
- Impacts from climate change.

In the 2020 CGR, the development of the forecasts comes at the same time as the initial impact of the global experience with the COVID-19 disease.[16] PG&E recognizes that COVID-19 will impact natural gas demand. However, there is considerable uncertainty around the economic impact from COVID-19. For example, it is uncertain how broadly, deeply, and for how long reduced economic activity will persist. It is also unclear whether the public response to the virus will change consumption behavior patterns. Forecasting the load impacts of these factors requires strong assumptions on the epidemiological and political course of the pandemic. Therefore, PG&E's current forecast relies on long-term forecast assumptions and tools to project gas demand and does not attempt to reflect the current and nearer-term impacts of COVID-19. What follows is an explanation of PG&E's forecast assumptions, as well as scenario analyses

16 https://www.who.int/emergencies/diseases/novel-coronavirus-2019/technical-guidance.

that illustrate various potential outcomes from these assumptions. PG&E notes that these scenarios cannot capture all uncertainties.

ASSUMPTIONS

Temperature

Space heating accounts for a high percentage of use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Demand year 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 to the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate. For example, by 2035 the total December/January heating degree days (HDD) are projected to be 8 percent below the 20-year average, lowering core throughput by approximately 6 percent.

Actual temperatures in the forecast period will be higher or lower than those assumed in the climate-change scenario and gas use will vary accordingly. PG&E's high-demand forecast assumes that winter temperatures in the forecast horizon will have a 1-in-10 likelihood of occurrence and have the same hydro conditions as those that prevailed during 2015 (This year represents the lowest hydroelectric generation over the past 20 years).

PG&E's EG gas throughput forecast uses an average temperature approach. The forecast does not capture peak day temperatures. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demands and drives up power plant gas demand. However, this forecast captures the seasonal variations on a monthly basis.

Hydroelectric Conditions Assumptions

In contrast to temperature deviations, 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 20 historical years, 1998-2017, in the average year demand forecast. PG&E uses a cold/dry hydro conditions scenario to forecast impacts from extreme conditions impacting both Core space heating demand

and EG. PG&E uses the hydroelectric generation conditions for the calendar year 2015 to represent the dry hydroelectric condition.

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 industrial or EG. PG&E used the gas commodity price forecast described in detail in the Southern California section. It combines current transportation rates with the gas commodity price forecast. PG&E's forecast 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.

Electric Load Assumptions

PG&E's forecast relies on the mid-case electricity demand forecast from the CEC 2019 Integrated Energy Policy Report (IEPR). The IEPR captures the increasing load projected as electric vehicles become more commonplace. The electric demand forecast includes a component of building electrification as some local jurisdictions require new building construction to use electricity rather than natural gas.

Electric Generation Resource and Electric Transmission Assumptions

With increasing electric load and more stringent environmental requirements, California's portfolio of EG resources is expected to change significantly over the forecast horizon to 2035. Generation resources come from the 2019-2020 CPUC Integrated Resource Plan (IRP) Reference System Plan (RSP) from February 2020. The RSP proposes a target resource mix that includes new renewable resources, as well as energy storage resources. Renewable energy generation provides 33 percent of the state's retail sales in 2020 and is targeted to provide 60 percent by 2030. The gas-fired generation fleet in California will continue to change due to the California State Water Resources Control Board's (SWRCB) once-through cooling rules. Gas-fired plants that employ once-through cooling are assumed to retire by the compliance dates set by the SWRCB in conjunction with the CPUC direction,[17] with some re-powered by new gas-fired units. Lastly, modeled electric transmission import capacity aligns with the RSP.

This forecast does not include A/S impacts on gas demand. As intermittent renewable energy generation increases, more electric resources will be needed to provide A/S, such as regulation. A/S will likely be provided by energy storage resources and gas-fired power plants, thus, affecting gas demand to some extent. This impact requires a more granular forecasting methodology than used for this forecast.

For cogeneration gas demand, PG&E's forecast follows the RSP. Cogeneration gas demand mimics recent past usage throughout the forecast period. Most cogeneration plants are not strongly affected by prices in the wholesale electricity market. The electricity generated comes from some other industrial process, usually steam, and generation does not follow wholesale electric prices. Consequently, the cogeneration gas demand projection exhibits no variation throughout the forecast horizon.

MARKET SECTOR FORECASTS

RESIDENTIAL

Households in the PG&E service area are forecasted to grow 0.9 percent annually from 2020-2035. However, gas use per household has been dropping in recent years due to 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. As of April 2020, 30 cities in California passed local ordinance codes promoting the installation of all-electric appliances in new household construction. PG&E provides natural gas service to many of these cities. While the number of households are forecasted to grow at 0.9 percent annually, PG&E anticipates many of these households to install electric-only appliances.

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17 Final Recommended Compliance Date Extensions for Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach Generation Stations SACCWIS Report, January 23, 2020: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf.

2. In addition to new construction building electrification, PG&E's forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the formation of state or local policies, customer cost savings, or other mechanisms.

3. Finally, PG&E's forecast anticipates that the warming climate will gradually decrease residential gas sales.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2035, annual residential gas throughput is projected to be 33 *percent* lower than forecasted 2020 throughput, with most of this decrease occurring in the later years of the forecast.

COMMERCIAL

The number of commercial customers in the PG&E service area is projected to grow on average by 0.3 percent per year from 2020-2035. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing energy efficiency and climate change, to lead to a long-term decline in commercial throughput. As a result, total commercial gas demand is projected to decline at 1.9 percent per year over the next 15 years.

INDUSTRIAL

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector declined by close to 20 percent in 2001 due to a combination of increasing gas prices, noncore-to-core migration, and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 but has seen slow growth in the recent past due to low natural gas prices and increased capacity at local refineries, though these effects have been tempered by the continuing structural change in California's manufacturing sector. PG&E observed historically high demand from the industrial sector in 2016 and 2017 due in part to refinery demand. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to be relatively flat, with a projected 0.1 percent annual growth rate over the next 15 years as energy efficiency and future gas prices offset growth.[18]

ELECTRIC GENERATION

Gas demand from EG includes gas-fired cogeneration and power plants. Forecasts for this sector are subject to high uncertainty due to:

- Future gas prices, the combination of the commodity and transportation;
- Impact of electrification of appliances on electric load;
- Timing, location, and type of new generation, particularly renewable-energy facilities;
- Precipitation driving hydroelectric generation; and
- Impacts of GHG policies and regulations on generation.

These factors exhibit wide variation with unknown future policy direction that influences gas demand.

Historically, gas demand for EG varied due to these factors above. Over the past 5 years, 2015-2019, demand averaged 770 MMcf/d. In 2017, demand was 650 MMcf/d. One of the major drivers of this low demand came from a high hydroelectric generation period from ample precipitation in the Western U.S. For 2015, EG used about 1,000 MMcf/d. This year represented a low level of hydroelectric generation as drought conditions persisted in 2014 and 2015. For a good portion of 2019, gas prices were less in Northern California than Southern California causing more gas use in the PG&E service territory. The variation demonstrates that demand can be 30 percent higher than average or 15 percent lower than average over the past five years. As more renewable generation projects come online, the industry expects a decline in EG gas demand.

PG&E's forecast for gas use in cogeneration and power generation projects a decline. One of the leading factors to this decline in the near-term comes from the gas price forecast. The gas price forecast shows Northern California prices higher than Southern California. This places the Northern California gas-fired EG plants at a competitive disadvantage compared to plants farther south. The gas price forecast drives the near-term results with 2020 demand around

18 PG&E's industrial forecast includes impacts from California's Cap-and-Trade policies. Future GHG policies may impact industrial demand, adding uncertainty to the forecast.

400 MMcf/d that decreases to 313 MMcf/d in 2021. Consequently, southern-based units should see an uptick in generation based on this forecast.

As renewable generation and storage capacity increase throughout the forecast period, gas-fired generation further decreases. The RPS calls for renewable generation to be 33 percent of electric retail sales in 2020. By 2030, the RPS target percentage increases to 60 percent. Meanwhile, storage increases in the long-term coupled with capacity increases for renewable generation and the gas price forecast assumptions decrease the gas demand projection by 0.6 percent per year.

SMUD Electric Generation

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 operates three cogeneration plants, a gas-fired combined-cycle plant, and a peaking turbine with a total capacity of approximately 1,000 megawatts (MW). The peak gas load of these units is approximately 171 MMcf/d, and the average load is about 117 MMcf/d. This forecast assumes the average load of 117 MMcf/d, which is embedded in this forecast.

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 for about 86 MMcf/d of capacity.

FORECAST SCENARIOS

The Average Demand year gas demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture uncertainties in gas demand, PG&E developed three alternative forecast scenarios of gas demand. The first scenario reflects a high gas demand situation. The second and third scenarios examine the impacts of low and high building electrification.

High Demand Scenario: Cold/Dry Hydro Year

For the high-demand scenario, PG&E relied on cold temperature conditions combined with dry hydro conditions. This forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same hydroelectric generation conditions as those that prevailed during 2015.

The cold weather assumption increases electric load for space heating needs and impacts EG gas demand. The dry hydroelectric conditions show a need for incremental EG.

The gas demand impacts from this scenario project annual demand increasing 4 percent on average over the average year demand forecast. The cold weather impact represents the major driver in the gas throughput increase due to higher space heating. Winter monthly core throughput is projected to increase by 9 to 15 percent. The noncore industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the average year demand forecast.

This scenario projects that EG gas demand increases by 1 to 8 percent. Hydroelectric resources in California represents 47 percent of the 20-year average. Broadly speaking, hydroelectric generation conditions in the rest of the WECC reflect near normal conditions. Electric imports from Southern California help meet the incremental electric load and hydroelectric generation decrement based on current projections for gas commodity prices and transportation rates. However, hydroelectric conditions vary widely. Dry hydroelectric conditions throughout the Western U.S. would raise the EG gas use on the PG&E gas system resulting in a different forecast.

SCENARIOS EVALUATING BUILDING ELECTRIFICATION

PG&E's Average Demand year forecast contains a projected level of new construction[19] and retrofit[20] building electrification; however, PG&E recognizes the uncertainty in this forecast. While a number of cities across California have demonstrated an interest in forming policies that incentivize building electrification or ban the installation of gas appliances in new residences, there has been very little historical adoption to inform a long-term forecast of building electrification. This is particularly true when forecasting the conversion of existing

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19 New construction building electrification applies to residences subject to new construction building codes and standards. This includes brand new homes and homes undergoing renovations large enough to trigger new construction building codes and standards.

20 Retrofit building electrification applies to the conversion of individual appliances from gas to electric in an existing residence that does not undergo a renovation large enough to be classified as new construction.

building appliance stock from gas to electric, which poses multiple barriers to adoption including the remaining lifecycle of existing appliances, the upfront cost of conversion, and the economics of consuming energy in the form of gas versus electricity. PG&E's Average Demand year forecast assumes these barriers are overcome to some extent as a result of state and local funding, technology development, and emerging policies, but recognizes the future could unfold in many different ways.

To illustrate the high degree of uncertainty in retrofit building electrification, PG&E has constructed two scenarios, in addition to the Average Demand year forecast, to analyze low and high levels of retrofit building electrification. To create these scenarios, adoption assumptions were modified in two ways. The first scenario, low electrification retrofit, modifies gas load by substituting 2 percent of residential gas water heater stocks to electric by 2030. This scenario assumes such substitution occurs for single family housing and does not occur for multifamily housing.. For the commercial sector, 3 percent of gas water heaters and space heaters are assumed to be electrified by 2030. The second scenario, high electrification retrofit, assumes higher levels of appliance substitution of water- and gas-heaters.

Table 19 below shows the percentage of existing gas fuel appliances to be replaced by electric appliances by the end of 2030 under different scenarios.

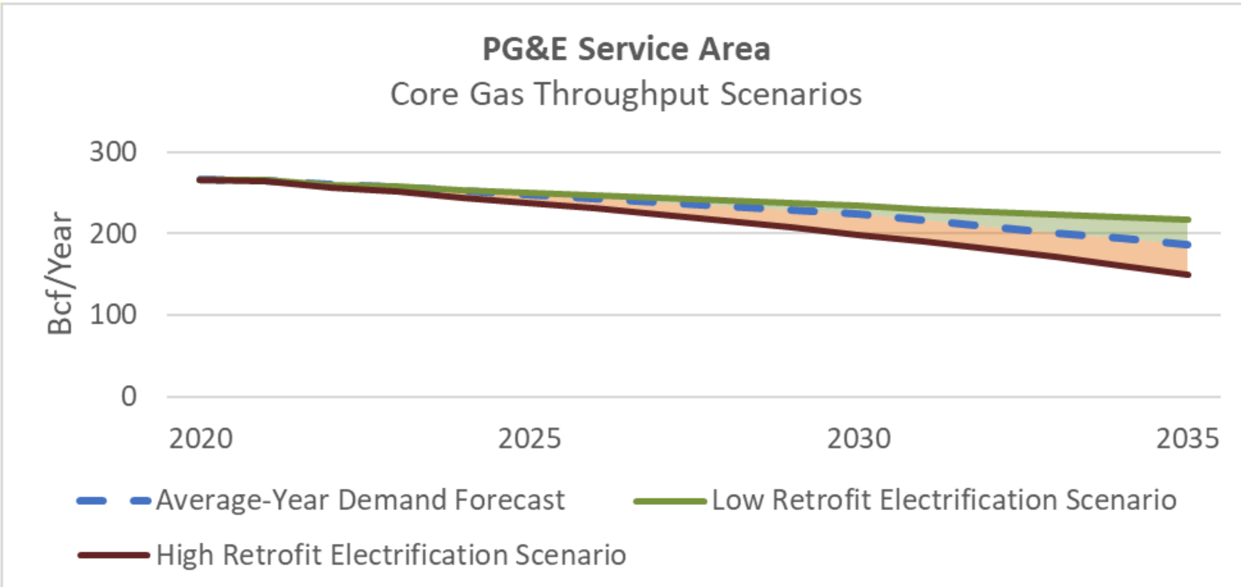
TABLE 19 – PG&E SERVICE AREA ASSUMPTION FOR PERCENTAGE OF GAS APPLIANCES REPLACED BY ELECTRIC APPLIANCES

	Residential		Commercial	
Scenario	Water Heater	Space Heater	Water Heater	Space Heater
Low Retrofit Scenario	2%	–	3%	3%
Base Retrofit Scenario*	6%	2%	10%	8%
High Retrofit Scenario	19%	6%	34%	29%

*The appliance replacement percentage is approximate since the Base Scenario is a weighted average of multiple retrofit scenarios.

The following figure shows the impact of the different levels of building electrification.

FIGURE 6 – PG&E SERVICE AREA: CORE GAS THROUGHPUT BUILDING ELECTRIFICATION RETROFIT SCENARIOS



As shown in the figure above, the level of retrofit building electrification significantly impacts the forecasted long-term trend of core gas throughput. Core throughput is projected to decline in all scenarios driven by energy efficiency, climate change, and building electrification for both new construction and building retrofits. The level of long-term decline varies significantly depending on the amount of building retrofits. The table below highlights the average annual percent decrease for the three forecasts, dividing the forecast horizon into three 5-year periods.

TABLE 20 – PG&E CORE THROUGHPUT AVERAGE ANNUAL GROWTH RATES

Forecast	2020-2025	2025-2030	2030-2035
Low Retrofit Electrification Scenario	-1.2%	-1.3%	-1.5%
Average Year Demand Forecast	-1.3%	-2.0%	-3.7%
High Retrofit Electrification Scenario	-2.2%	-3.5%	-5.4%

Although building electrification causes core gas throughput to decline, it may increase natural gas demand for EG. The forecast from 2030-2035 illustrates the projected impact. In PG&E's Average Demand year forecast, EG gas demand is forecasted to increase by 13 percent, mainly driven by transportation and building electrification.

However, uncertainties are not bounded within these scenarios. The impact of electrification could see no increase in natural gas demand or could grow by about 30 MMcf/d. The EG load may be at or near zero if the additional electric load is served by excess renewable generation. Absent this, the increase in gas-fired EG could be served by non-fossil natural gas, such as Renewable Natural Gas (RNG) or H2. Other factors could come into play, such as electric generators buying carbon offsets for the use of fossil-based natural gas or use technologies not yet commercialized, such as carbon capture and storage. How the future unfolds is uncertain.

POLICIES IMPACTING GAS DEMAND

During the forecast horizon covered by this CGR, there are many policies that may significantly impact the future trajectory of natural gas demand. Executive Order (EO) S-3-05 set a goal to reduce annual GHG emissions to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. EO B-55-18 set a goal to achieve carbon neutrality by 2045. The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) established the 2020 GHG emission reduction goal into law. SB 32 went further, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. These goals are being accomplished by a suite of complementary policies, as well as the Cap-and-Trade Program, which was directly authorized through 2030 with the passage of AB 398.

GHG POLICIES

The gas demand forecast includes a GHG price projection.[21] The forecast incorporates complementary policies that aim to achieve California state GHG emissions reductions goals. (See below for further discussion of these policies.) Any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translates to the forecast.

Since early 2019, several California local government jurisdictions have passed ordinances supporting all-electric new construction or explicitly limiting the expansion of the gas system. This increase in local government activity within PG&E's service territory could contribute to a decline in gas system throughput through the forecast horizon of the CGR and beyond.

21 CEC Integrated Energy Policy Report mid-case forecast to 2030. Extrapolated to 2035 using the real adder to the floor price (5 percent rate).

The ongoing OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning (R.20-01-07) could also have a significant influence on future trends in gas system throughput. In particular, the second track of that proceeding will focus on long-term gas system planning and will warrant active participation from industry stakeholders.

Another uncertainty comes from how GHG policy implementation will be executed. SB 100 has a zero net GHG emissions goal. How this goal will be attained lacks clarity. If the zero net GHG emission goal is attained using more renewable generation and high levels of electric storage, for example, then EG gas demand may not increase in the long-term.

Given that the utilization of fossil natural gas emits GHGs, PG&E believes that RG must be part of the solution to reach California's GHG reduction goals. PG&E will continue to minimize GHG emissions by pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

RENEWABLE ELECTRIC GENERATION

PG&E expects renewable EG to grow due to current RPS and the IRP Proceeding at the CPUC. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent nature of some renewable generation (e.g., wind or solar power) will cause the electric system to rely more heavily on natural gas-fired EG to cover forecast deviations and intra-day and intra-hour variability of intermittent generation.

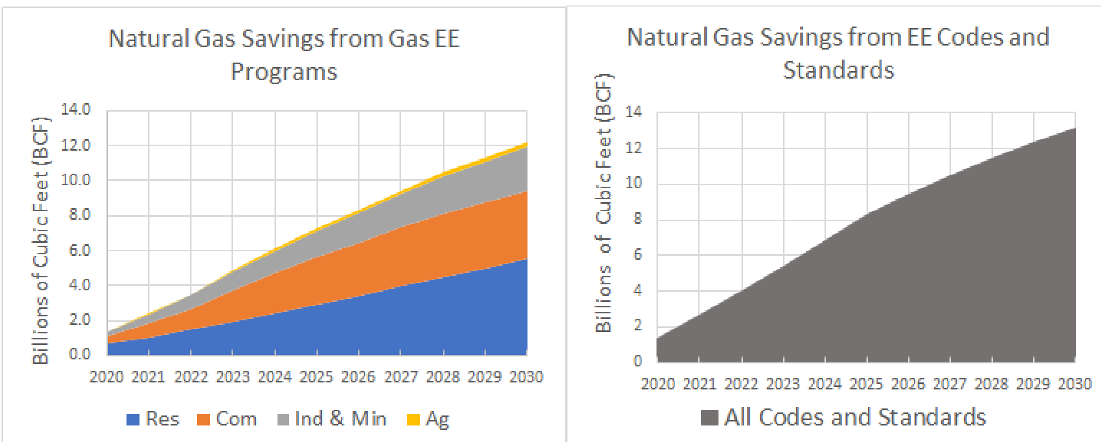
ENERGY EFFICIENCY PROGRAMS

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.

The forecast of cumulative natural gas savings due to PG&E's EE programs is provided in the figures below. Savings for these efforts are based on the CPUC's Potential and Goal Study that informs Additional Achievable Energy Efficiency (AAEE) forecast in the CEC's California

Energy Demand 2020-2030 Revised Forecast.[22] The savings below include any interactive effects that may result from efficiency improvements of electric end uses; for example, efficiency improvements in lighting and electric appliances may lead to increased natural gas heating load. In the case of lighting, replacing a less efficient light bulb with a more efficient light bulb (e.g., replacing an incandescent with a light-emitting diode) that releases less heat leads to a lesser need for space cooling energy in summer and to a greater need for space heating energy in winter.

FIGURE 7 – PG&E SERVICE AREA: NATURAL GAS SAVINGS FROM EE PROGRAMS



Details of PG&E's 2018-2025 Energy Efficiency Portfolio can be found in Commission D.18-05-041, which authorized programs and budgets through 2025, and D.19-08-034, which adopted goals for these programs for 2020.

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22 The California Energy Demand and the AAEE results are on the CEC's website: https://www.energy.ca.gov/sites/default/files/2019-12/AAEE%20Preliminary%20Results%2010-18-19_ada.pdf.

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 AAEE mid-case forecast, subject to what is cost-effective and feasible.[23] The CEC issued its final report on SB 350 EE targets in October 2017,[24] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond. The CEC's final report suggests the state is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, POU programs, and codes and standards.[25]

IMPACT OF REACH CODES AND ELECTRIFICATION

In California, cities and counties have enacted reach codes that require a substitution away from natural gas appliances to electric appliances. This substitution from gas to electric is termed electrification. By February 2020, about 30 local jurisdictions have adopted reach codes.[26] This historical trend may continue its current projection or could change in other ways, either increasing or reversing at some unknown magnitude. Electrification, consequently, appears to be adding electric load in the long-term while removing sources of growth in gas demand.

The impact from electrification could be addressed in multiple ways. For example, the current RPS requirement states that 60 percent of system electric sales will be generated from renewable resources in 2030. As electrification increases load after 2030, the RPS requirement

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23 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."

24 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.

25 See Figure 2 from the CEC report cited above.

26 https://www.sierraclub.org/articles/2020/03/californias-cities-lead-way-gas-free-future.

could increase and mitigate the use of natural gas for EG. The timing of the additional electric load within the day along with the intermittency characteristics of California's renewable resources will impact EG gas demand.

Even if EG gas demand increases, the effort to achieve the GHG emissions goal may come by differing gas supply options. The natural gas supply sources could be a clean version in the form of RNG or H2. The next chapter on natural gas supply will elaborate on these potential gas supplies.

FUTURE GAS DEMAND TRENDS AND POLICY

PG&E's gas demand forecast projects lower throughput over the long term (due to GHG policies, such as electrification and RPS) 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 being recovered will put upward pressure on gas transportation rates. PG&E estimates that the declining throughput represented in the Average Demand year forecast and the scenarios could result in an increase to residential gas rates of approximately 60 percent to 100 percent by 2035 as compared to 2020. These estimates exclude changes to commodity costs, California GHG Emission Allowance costs, or authorized base revenue requirements.[27]

In addition, the transition from fossil fuel 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 the statewide GHG reduction policies and develop options to minimize rate increase for the remaining gas customers.

Another high horsepower sector to consider for increasing gas throughput is rail transportation. Based on a study by the California Air Resource Board (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

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27 The increase of 60 percent to 100 percent is based on nominal dollars. The gas rate increase in real dollars is approximately 35 percent to 50 percent.

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.[28]

LNG as a fuel source has been considered by the rail industry, but thus far has been mostly limited to pilot studies. Based on conversations with representatives from UP, BNSF, and CARB, some of the key obstacles to 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 LNG, and current emission standards don't adequately 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 to the fuel transition.[29]

One possible path to greater LNG locomotive adoption is higher emissions standards. Locomotive emissions are governed by the U.S. EPA. Currently, their strictest emission level is Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr it limits nitrogen oxide (NO_x), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14 respectively.[30] In 2017, CARB petitioned to the U.S. EPA to consider adopting a new, stricter, Tier 5 standard with a proposed effective date of 2025. The Tier 5 standard would limit NO_x, PM, and HC emissions to 0.2, <0.01, and 0.02.[31] Thus far, there does not appear to be any movement by the U.S. EPA to adopt the proposed Tier 5 standard.

Without policy solutions and a managed transition from fossil fuel to other energy forms, the increase in residential rates would be even higher. Gridworks' most extreme estimate for their High Building Electrification – No Transition Strategy scenario could result in residential rates of $19/therm by 2050 (2018 dollars) compared to then-current residential rates near $1.37/therm.

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

29 *Ibid*.

30 CFR 1033.101 (https://www.ecfr.gov/cgi-bin/text-idx?SID=159ba6f126272ea1995c71a43b7af309&mc=true&node=pt40.36.1033&rgn=div5#se40.36.1033_1101).

31 https://ww2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

The drivers to those higher rates come from lower projected gas throughput, higher GHG Emission Allowance costs, and the potential for added infrastructure investment costs.[32]

To minimize the rate increase for the remaining gas customers, PG&E is following a two-pronged approach while keeping safety as its top priority: (1) reduce cost and (2) maximize utilization. To reduce cost, PG&E is pursuing opportunities to systematically retire infrastructure (where possible) and reduce capital and operating expenses through PG&E's Integrated Investment Planning. To increase utilization of existing infrastructure, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput, exploring new opportunities to support RG adoption across new industries, increase load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., marine, rail and transportation sectors) and seek opportunities to utilize the gas system as a long-term and large scale storage mechanism. Gridworks, with a mission to convene, educate and empower stakeholders working to decarbonize electricity grids, published its report[33] that shows these tactics may not be sufficient. Other avenues to explore include aligning financial recovery of gas infrastructure investment with their useful lives and adjusting ratemaking for effective cost recovery.

FUTURE OPPORTUNITIES

One recent development that could improve the outlook for throughput comes from the June 2020 California Air Resources Board (CARB) approval of the Advance 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)[34]. The regulation begins 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.

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32 Then-current rate based on June 2020 G1 (Residential Service) tariff and $19/therm based on Gridworks' report California's Gas System In Transition, Equitable, Affordable, Decarbonized, and Smaller: https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

33 California's Gas System in Transition: Equitable, Affordable, Decarbonize and Smaller, Gridworks, 2019: https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

34 ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.

Truck manufactures 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) which could mitigate the potential for increasing customer costs.

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its SOx and GHG emissions. This is orchestrated by The International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[35] The IMO updated Annex VI on January 1, 2020 to target reductions in nitrogen oxides (NOx) and sulfur oxides (SOx). To reduce SOx, the Sulphur limit for all marine fuels was dropped from 3.50 percent m/m (mass by mass) to 0.50 percent m/m.

The consensus in the marine fuel industry is that the 0.50 percent Sulphur limit is only a stop on the way to a global 0.10 percent Sulphur limit, which currently exists in several Emissions Control Areas (ECA)[36] around the globe. Moving to 0.10 percent would necessitate using road grade diesel fuel as bunker fuel, therefore increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

The push towards lowering SOx is driven by environmental groups, government regulations, and the shipping industry itself. Large European container companies are driving it as part of their corporate carbon strategies,[37] managing their fuel costs while doing so.

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much growth the previous decade. The updated IMO Annex VI are changing that, spurring investments in bunkering equipment[38] and vessels.[39] LNG is also seen as the most practical way to de-carbonize the shipping industry as the fuel can be made from Renewable Gas and, further out, Green Hydrogen.

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35 http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.

36 http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx.

37 https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future.

38 https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/.

39 https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship.

California marine fuel markets can be divided into ocean and coastal. The ocean market is the largest due to the fuel volumes vessels consume. California, with its large container ports in Oakland, Los Angeles, and Long Beach, may see demand for LNG in the future (which will require large investments). Some of the investments needed to meet this demand include storage terminals, bunker loading vessels, or liquefaction terminals.

This demand may come sooner rather than later as modern ship engines are flex-fuel capable in that they can run on either fuel oil or natural gas, thus optimizing fuel costs and environmental compliance.[40] To give an idea of the potential size of this market, in 2016 bunkers delivered across the ports of Los Angeles and Long Beach totaled 21.33 million barrels or 132 Bcf.[41]

Coastal market consists mostly of smaller vessels such as passenger ferries, tugs, fishing vessels etc. Already using an Ultra Low Sulphur Diesel under CARB regulations, they could see a cost reduction by switching to LNG powered fleets.[42] Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe successfully.[43] They can be connected directly to the natural gas grid producing fuel on-demand.

NORTH AMERICAN GAS DEMAND TRENDS

LIQUEFIED NATURAL GAS IMPORTS/EXPORTS

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. However, U.S. imports of LNG have been declining since 2008. Over the past decade, the development of low-cost domestic shale gas supplies has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

The U.S. began exporting LNG in 2016. For LNG 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 in the public interest. On the other hand, the U.S. Federal Energy Regulatory Commission (FERC),

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40 https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level.

41 https://www.bunkerspot.com/americas/43523-americas-la-lb-annual-bunker-volumes-up-25-73-y-o-y.

42 https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels#.

43 https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf.

focuses on evaluating the environmental impacts of proposed LNG projects, and authorizes the siting and construction of LNG facilities.

There are several proposed projects to export LNG to world markets. Many of the projects are "brownfield," using existing U.S. import terminals to export LNG, but some are "greenfield."

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.[44] This facility will have a 4.5 million metric tons (mmt) per annum of liquification capacity.[45] Construction of the project will occur in two phases. Phase 1 is a single LNG facility located adjacent to the existing LNG terminal. Phase 2 includes the addition of two trains and a storage tank. Transportation of gas for the planned ECA project is proposed to be over the expanded North Baja pipeline, subject to FERC approval. Construction and operation of the ECA export plant is contingent on commercial contracts, pertinent Mexican and U.S. government permitting, and financing. ECA anticipates construction to commence in the first half of 2021 with commercial operations beginning no later than 2025.

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.[46] 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.

One greenfield project is the Jordan Cove Project in Oregon. Jordan Cove in early 2020 received authorization from the FERC to site, construct, and operate an LNG export facility. In order to supply the LNG facility with natural gas, FERC authorized the Pacific Connector Gas Pipeline. This pipeline would interconnect with the Ruby Pipeline and the GTN Pipeline. Additional work lies ahead to resolve issues of state and local approvals, financing, and facilities

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44 https://www.sempra.com/energia-costa-azul-lng-receives-us-non-fta-approval-liquefaction-export-infrastructure-project.

45 FE DOCKET NO. 18-145-LNG.

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

planning. The Jordan Cove LNG export project could directly compete for gas supplies available to Northern California.

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 2019.[47] Mexico, accounting for approximately 43 percent of total U.S. gas exports in 2019, became the largest importer of U.S. natural gas in 2015. The U.S. natural gas exports to Mexico have grown in recent years from 0.9 Bcf/d in 2010 to 5.5 Bcf/d in 2019,[48] and pipeline exports are projected to reach 7.5 Bcf/d by 2025.[49] Declining gas production and increasing gas demand for power generation and industrial use in Mexico are main drivers of this export growth. Completion of several gas pipeline capacity expansion projects on both sides of the U.S.-Mexico border have resulted in 15.5 Bcf/d of export capacity as of 2019, with an additional 0.6 Bcf/d expected to come online in 2020.

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

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47 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.

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

49 EIA, Annual Energy Outlook 2020 – Natural Gas Imports and Exports Table (Reference Case): https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2020&region=0-0&cases=ref2020&start=2019&end=2025&f=A&linechart=~~ref2020-d112119a.9-76-AEO2020~ref2020-d112119a.10-76-AEO2020&ctype=linechart&sourcekey=0.

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

The Gas Supply, Capacity, and Storage section provides information about PG&E's current gas supply, natural gas pipelines, gas storage, and policies affecting these topics. The Gas Supply section includes information about current and anticipated developments regarding RG, as well as gas supply from sources throughout North America. The Pipeline section includes information about "upstream" inter-state pipelines, as well as intra-state pipelines. The Storage section gives an overview of PG&E's gas storage capacity and its gas storage facilities. The Policies section looks at a range of current policy developments and their impacts on PG&E's gas supply, including integration challenges for RG, as well as alternative fuel types, such as H2.

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.

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

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. Supply can be delivered through a variety of sources, including any new and expanded interstate pipeline facilities and of PG&E's existing transmission facilities, or other storage facilities.

GAS SUPPLY

RENEWABLE GAS

There are seven Renewable Natural Gas (RNG) projects that are in the process of interconnecting with PG&E's gas system, with the first few expected to begin injecting pipeline quality gas in Q4 2020 and the rest expected to progress through 2021. These seven projects are expected to inject roughly 16,500 MCF/d into PG&E's pipeline system. Two of the projects are a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other five are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[50]

SB 1383 Dairy Pilot Projects

On December 3, 2018, the CPUC, the California Air Resources Board (CARB), and the California Department of Food and Agriculture (CDFA) issued a joint press release announcing the selection of six dairy pilot projects in compliance with CPUC D.17-02-004 and SB 1383. Two of the pilot projects were awarded in PG&E's service territory: (1) the Merced Pipeline project sited at the Vander Woude Dairy in Merced (6 miles south of Merced); and (2) the J.G. Weststeyn Dairy project in Willows (5 miles west of Logandale).

50 https://www.cpuc.ca.gov/renewable_natural_gas/.

FIGURE 8 – PG&E SERVICE AREA: RENEWABLE NATURAL GAS PILOT PROJECTS LOCATION

PG&E is encouraged to see the first wave of RNG interconnection projects in its Northern California service territory.

Future California RNG Supply

A 2016 CARB-sponsored study by University of California (UC), Davis, “The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute” (the “STEPS study”), anticipated that as much as 82 Bcf per year of RNG supply could become available in California with appropriate policy development and investment.[51] The STEPS study identified that the largest opportunity for increasing the supply of RG would come from landfill sites, followed by dairy, municipal solid waste, and waste-water facilities.

A more recent assessment of in-state RNG supply for transportation, conducted by GNA,[52] projects that there will be roughly 16 BCF annually of RNG interconnected into gas pipelines in California by January 2024. Given the STEPS study results, the gas flowing from RNG sources by January 2024 is just the first wave of RNG expected to be eventually injected into the gas system.

Therefore, going forward, PG&E expects to see more RNG projects as developers realize the near and mid-term potential of this supply source.

Gas Absorption Capacity

To encourage effective development of RNG, PG&E created the Gas Supply Absorption Capacity Map.[53] This map is a high-level snapshot of PG&E’s gas system that is designed to help contractors and developers find potential project sites by showing the relative ability (high to low) to accept new gas supply on PG&E transmission pipelines. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies.

NORTH AMERICAN SUPPLY DEVELOPMENT

The biggest development in the North American gas supply picture in the past several years has been the rapid development of various shale gas resources through horizontal drilling

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51 STEPS Program Study, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, prepared by Amy Myers Jaffe, available at: https://steps.ucdavis.edu/the-feasibility-of-renewable-natural-gas-as-a-large-scale-low-carbon-substitute/.

52 https://www.gladstein.org/gna_whitepapers/an-assessment-californias-in-state-rng-supply-for-transportation-2020-2024/

53 Available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-map-overview.page combined with hydraulic fracturing. While the initial developments were concentrated in the U.S. Midcontinent, the large Marcellus and Utica plays in the eastern U.S. and the Permian Basin have become the main source of supply growth, resulting in record U.S. gas production in 2019. While some of the traditional supply basins have shown some modest declines in production, the Marcellus and Utica plays have grown from roughly 10 percent of U.S. production in 2012 to about 33 percent in 2019, with further growth expected in the next few years. Most industry forecasts now expect supply can increase to meet the most aggressive demand scenario in the future.

The growth of associated gas production in the Permian Basin and eastern shale plays (e.g., the Haynesville in east Texas and west Louisiana and the Marcellus and Utica in Pennsylvania) have had the effect of pushing larger volumes of Canadian, Rockies, San Juan, and Permian supplies towards California.

CALIFORNIA-SOURCED GAS

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2019, PG&E's customers obtained on average 26 MMcf/d of California sourced gas. PG&E does not anticipate a material change in this level of supply going forward.

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- or intra-state pipeline capacity.

CANADIAN GAS

PG&E's customers can purchase gas from various suppliers in Western Canada (British Columbia and Alberta) and transport it to California, primarily through the GTN pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

ROCKY MOUNTAIN GAS

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

GAS PIPELINE CAPACITY

INTERSTATE PIPELINE CAPACITY

California utilities and end-users benefit from access to supply basins and enhanced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and Central California include the El Paso, Mojave, Transwestern, GTN, Paiute Pipeline Company, Ruby, and Kern River pipelines. These pipelines provide northern and Central California with access to gas-producing regions in the U.S. Southwest and Rocky Mountain areas, and in Western Canada.

U.S. Southwest and Rocky Mountains

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 960 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 2,060 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 expenses, look for new opportunities for load growth and to decarbonize by increasing throughput of RG. PG&E is actively pursuing opportunities on radial feeds where several miles of pipe are in place to serve a small handful of customers. Electrifying these customers and decommissioning the pipeline will achieve greater cost savings in the short-term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with cities, to strategize where to reduce our spending and predict long-term gas needs more accurately.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. PG&E owns and operates 116 wells at these three natural gas storage fields located in California and is a 25 percent owner of a fourth storage field (Gill Ranch). PG&E's wholly owned storage facilities have a combined maximum capacity of 102.2 Bcf.

Other storage providers include Gill Ranch Storage, LLC (the 20 Bcf facility was co-developed with PG&E), Wild Goose Storage, LLC, Lodi Gas Storage, LLC, and Central Valley Storage, LLC. The abundant storage capacity in the Northern California market has had the effect of creating ample liquidity in the market both in Northern California and in other parts of the West.

In the past few years, the California Geologic Energy Management Division (CalGEM) (formerly, DOGGR) altered safety rules governing natural gas storage facilities. The CalGEM safety rules impact new investment in storage facilities and capacity throughout California while decreasing withdrawal capacity.

In PG&E's recent Gas Transmission and Storage Rate Case, the CPUC in D.19-09-025 adopted PG&E Natural Gas Storage Strategy (NGSS). As part of the strategy, PG&E is focusing the use of PG&E's gas storage facilities on system operations, including balancing supply and demand. Additionally, the strategy calls for the divestiture or decommissioning of the Los Medanos and Pleasant Creek storage facilities rather than investing the substantial amount money needed to make the facilities reliable and compliant with the new CalGEM regulations.

MCDONALD ISLAND

McDonald Island serves as the largest of PG&E's three facilities and is located on a man-made island in a scarcely populated agricultural area near the Sacramento-San Joaquin River Delta. McDonald Island is PG&E's largest gas storage field and has a maximum capacity of 82 Bcf. McDonald Island has 87 total wells; 81 wells operate for injection and withdrawal and 6 operate as observation wells. McDonald Island can provide 25 percent of Northern California's winter peak day gas demand.

Los Medanos and Pleasant Creek

Los Medanos is PG&E's second largest facility and has a maximum capacity of 17.9 Bcf. The facility is in Contra Costa County and contains 22 wells. Pleasant Creek is PG&E's smallest storage facility and has a maximum capacity of 2.0 Bcf. The facility is in Yolo County and contains seven wells. As reflected in the 2019 Gas Transmission and Storage (GT&S) Rate Case, NGSS,[54] PG&E will be selling or decommissioning the Pleasant Creek and Los Medanos storage facilities.

Other California Storage Facilities

In addition to storage services offered by PG&E, there are four other storage providers in Northern California: Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2018, these facilities had an estimated total working gas capacity of roughly 239 Bcf.[55]

POLICIES IMPACTING FUTURE GAS SUPPLY AND ASSETS

Overview

California's policies to reduce the Carbon footprint and sources of GHGs, are expected to impact the gas supply and assets in the near future. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RG adoption across new industries with existing gas system infrastructure, and adapting to utilize the gas system as a long-term storage mechanism.

Renewable Natural Gas

As a result of various policy and regulatory changes, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California during 2020. RNG producers are leveraging available grants and incentives to encourage the production of RNG to reduce GHG emissions from the biogas sources to the environment 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:

- Procuring RNG for all PG&E owned Compressed Natural Gas (CNG) fueling stations;
- Proposed a joint utility RNG Interconnection Rule, filed November 1, 2019;

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54 https://www.cpuc.ca.gov/General.aspx?id=10432.

55 Working gas capacity comes from providers of storage services websites.

- Proposed a joint utility RNG Interconnection and Operating Agreement, filed May 1, 2020; and
- 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.

Chief Interconnection Barriers and Issues

The interconnection of RG projects to the utility pipeline system is critical in the effort to meet the state of California’s GHG reduction goals and must be done first and foremost with consideration of public and employee safety.

The CPUC is continuing its work in R.13-02-008, establishing the process for the consistent interconnection of RNG across California, which should reduce the regulatory and incentive financing uncertainty that has slowed industry growth. At various points in the proceeding, interconnecting developers have indicated that interconnection costs are high, project timelines are long, and that utility gas quality and some contractual requirements are burdensome.

While there is significant potential for RNG to replace some portion of natural gas supply generally, the current investment and incentives for RNG principally favor the transportation sector. With the clear financial advantage towards transportation, there is comparatively little RNG available to establish a consistent RGS to meet PG&E’s customer or third-party needs, should an RGS be established. If this is to change, California will have to balance the funding mechanisms between the transportation sector and a potential RGS so that RNG project developers have opportunities to supply RNG towards an RGS or the transportation sector.

Monetary Incentive Program

D.15-06-029 established a biomethane monetary included program authorizing $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 implements an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened to applications on February 3, 2020 and the queue is published on the CPUC's RNG website.[56]

Based on information provided in D.19-12-009,[57] two projects have received a total of $8.18 million of funding under the incentive program, leaving $31.82 million remaining in the program. PG&E is unaware of any additional incentive awards being issued since December 2019.

Research and Development

PG&E's R&D RNG roadmap[58] further outlines PG&E's goals for incorporating RNG into the supply portfolio.

HYDROGEN

Green H2 is seen as a game changer in decarbonizing many sectors. To achieve the goals set forth in SB 100, California will likely need to incorporate Green H2 into the portfolio of green fuels for various sectors. Many other countries are already embracing H2 and fuel cell technology to reduce their carbon footprint. California is starting to see some movement on the legislative front to increase funding for furthering the use of Green H2. There is potential for Green H2 to be produced and then stored for future use or used to decarbonize the transportation sector. The California IOUs are working together on an action plan for incorporating Green H2 into the pipelines and will be filing an Application for a preliminary H2 injection standard in November 2020.

HYDROGEN STORAGE (CONVENTIONAL AND NEW TECH)

As mentioned above, Green H2 is seen as a game changer and has many potential applications. One such application is to produce Green H2 through electrolysis and stored in the pipeline system (or dedicated underground storage facilities) for later use, such as fuel for EG needed when the sun is not shining or the wind is not blowing. Green H2 storage has incredible

56 https://www.cpuc.ca.gov/renewable_natural_gas/.

57 D.19-12-009, p. 2.

58 https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/RNG_Roadmap_2020.pdf potential for longer-term storage and at larger volumes for seasonal load shifting that would not be possible with batteries alone.

LNG AS MARINE FUEL

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the marine market. The gas supply needed for this demand will need to come from cleaner sources of fuel such as RG and H2.

REGULATORY ENVIRONMENT

OVERVIEW

This section provides an overview of the existing and near-term regulatory policies and their effect on the Northern California gas system and its users.

Given the anticipated state and federal regulatory policies surrounding storage, transportation, inspection, and capacity requirements, the cost to safely and reliably operate PG&E's gas system will continue to rise. At the same time, a decline in throughput—which PG&E anticipates is a result of California's GHG goals and cities pushing for new electric reach codes—will mean those costs will be spread over fewer therms and possibly fewer customers, impacting the affordability of gas.

Furthermore, despite readily available domestic gas, operational innovation, and reaching a lower NOVA Gas Transmission Ltd (NGTL) rate for PG&E customers, the complex regulatory environment and evolving policies are likely to create price uncertainty in the medium/long-term.

FEDERAL AND CANADIAN REGULATORY MATTERS

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

GTN AND CANADIAN PIPELINES

On March 10, 2020, GTN, submitted Advance Notification of Natural Gas Facilities Replacement for three compressor stations: Athol Compressor Station, Kent Compressor Stations, and Starbuck Compressor Station. PG&E is monitoring these construction projects as they may affect gas throughput and pipeline costs.

On March 25, 2020, the Commission of the Canada Energy Regulator has approved a rate design methodology and other terms and conditions of service settlement for the NGTL System.[59] This settlement will lower the NGTL rate for PG&E customers.

OTHER PIPELINES

There are currently no significant regulatory issues regarding El Paso Natural Gas Company, LLC (El Paso); Kern River Gas Transmission (Kern River); Ruby Pipeline, LLC (Ruby); or Transwestern Pipeline Company, LLC (Transwestern) pipelines.

FERC AND CAISO GAS-ELECTRIC COORDINATION ACTIONS

While there are no general inquiries or proceedings at FERC addressing gas-electric coordination, the California Independent System Operator (CAISO), which is FERC-jurisdictional, has ongoing policy initiatives that may impact gas demand, supply, and prices. These initiatives include:

- Resource Adequacy Enhancements;
- Flexible Ramping Product Refinements; and
- Flexible Capacity Needs Assessment Process.

These policy initiatives will need FERC approval before the proposed changes can be implemented.

STATE REGULATORY MATTERS

CALIFORNIA STATE SB 100 AND CARBON NEUTRALITY EXECUTIVE ORDER

On September 10, 2018, Governor Brown signed into law SB 100, which would further increase and accelerate the RPS targets and includes the following key requirements:

- Accelerates the RPS to 50 percent by 2026 and increases the RPS 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;

59 *In re NGTL.*, Can. Energy Reg., Decision C05448 (March 25, 2020), available at: https://apps.cer-rec.gc.ca/REGDOCS/Item/Filing/C05448.

- 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 4 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

Additionally, Governor Brown signed an EO on September 10, 2018 establishing a new statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy and to achieve and maintain net negative GHG emissions thereafter. Implementation of the order will require California to undertake additional decarbonization and negative emissions efforts. CARB plans to focus on carbon neutrality in its next Climate Change Scoping Plan, due in 2022.[60]

PIPELINE SAFETY

Since 2011, the CPUC and the California State Legislature have adopted a series of regulations and bills that reinforce the setting of public and employee safety as the top priority for the state's gas utilities. In particular, SB 705 mandated for the first time that gas operators develop and implement safety plans that are consistent with the best practices in the gas industry.

On March 16, 2020, PG&E filed its 2020 Gas Safety Plan with the CPUC. The Gas Safety Plan demonstrates PG&E's commitment to implement processes and procedures to achieve its vision of becoming the safest and most reliable natural gas utility in the nation. One of the plan highlights is the Gas Safety Excellence framework, which guides how PG&E operates, conducts, and manages all parts of its business by putting safety and people at the heart of everything it does; investing in the reliability and integrity of its gas system; and, by continuously improving the effectiveness and affordability of its processes.

Additionally, PG&E submits the following reports to the CPUC: (1) semi-annual Gas Transmission & Storage Compliance Report; and (2) annual Gas Distribution Pipeline Safety Report. These reports are designed to provide the CPUC and other interested stakeholders with insight into the amount of safety and reliability-related work PG&E has completed over the course of the reporting period. Selected highlights from PG&E's 2019 reports, which further demonstrate PG&E's commitment to gas safety, include:

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60 CARB Scoping Plan Implementation Update (April 2020), available at: https://ww3.arb.ca.gov/board/books/2020/042320/20-4-2pres.pdf.

- **Asset Management System:** PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, affordable management and operation of PG&E's gas assets, using the international Publicly Available Specification 55-1, International Organization for Standardization 55001, and American Petroleum Industry (API) Recommended Practice (RP) 1173 standards as guidance. Additionally, in November 2019, Lloyd's Register confirmed Gas Operations' continued compliance with API RP 1173.
- **Process Safety:** PG&E's commitment to implement process safety aligns with API RP 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*. Process Safety and Gas Safety Excellence teams use a risk-sorting criterion to track and tabulate leading and lagging safety indicators. This helps identify emerging issues before incidents occur. In 2019, Gas Operations reached a key milestone in the journey of Process Safety Management maturity. Gas Operations was recognized, through a third-party assessment, for being in compliance with the intent of API RP 754, Process Safety Performance Indicators, insofar as it meets its business operations, demonstrating a commitment to incident prevention.
- **In-Line Inspection (ILI):** In 2019, PG&E increased piggability to roughly 36 percent of the approximately 6,600 miles of its Gas Transmission system. PG&E inspected a total of 478.1 miles, with 266.4 of those miles assessed with ILI for the first time. Approximately two-thirds of PG&E's transmission system (about 4,100 miles) has been or will be upgraded to accept ILI tools by the end of 2029.
- **Third-Party Dig-Ins:** In 2019, PG&E experienced 1.04 dig-ins per 1,000 Underground Service Alert (USA) tickets, out-performing its 2019 target of 1.23 dig-ins per 1,000 USA tickets.
- **Community Pipeline Safety Initiative**: A multi-year program designed to enhance safety by improving access to pipeline rights-of-way. The program was initially anticipated as a 5-year initiative ending in December 2017, but has been extended through December 2020 due to long-lead permitting and outstanding customer agreements. To date, the program has cleared approximately 1,542 vegetation miles and 359.72 structure miles. The remaining 9.27 miles of vegetation and 0.28 miles of structure clearing is expected to be completed in 2020.

STORAGE SAFETY

CalGEM (California Geologic Energy Management Division) finalized underground storage regulations in October 2018. Within the regulations, operators are required to increase monitoring and inspection practices and ensure well construction is in accordance with a dual barrier system by 2025. Implementation of the regulations to convert a targeted percentage of wells each year to dual barrier, tubing and packer completion, began in 2019 and impacts the available withdrawal capacity. PG&E, in its 2019 GT&S Rate Case application, included the impact of the proposed regulations in its NGSS, which includes the decommissioning or sale of the Pleasant Creek and Los Medanos storage facilities. The CPUC approved the NGSS in D.19-09-025, issued on September 23, 2019.

GAS QUALITY

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

THE DOWNSTREAM EFFECTS OF INCREASED REGULATION: CITIES PURSUE ELECTRIFICATION

In response to California's firming GHG laws and strengthening public support, local governments have already begun taking significant steps towards electrification at the city level. As of February 2020, thirty cities have passed new electric reach codes, the majority of which fall within PG&E's territory.[61]

In fact, per the Building Decarbonization Coalition, as of March 2020, 13 California cities have passed reach codes for all-electric new construction.[62]

The spread of all-electric new construction would suggest a flattening demand for gas. However, as cited in the gas demand section, the full effect of these new reach codes has not yet been determined.

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61 "Forward-Looking Cities Lead the Way to a Gas-Free Future." Sierra Club, 6 Mar. 2020: https://www.sierraclub.org/articles/2020/07/californias-cities-lead-way-gas-free-future.

62 "*Active Code Efforts."* The Building Decarbonization Coalition, *30 Mar. 2020: www.buildingdecarb.org/active-code-efforts.html.*

KNOWN REGULATORY HURDLES

Federal regulation along with state and local climate action goals are set to create a challenging environment for gas utilities. To succeed in achieving these operational safety and climate action goals, the following hurdles need to be addressed:

- As regulations continue to strengthen, the cost of providing a safe and reliable gas system continues to rise. This increase in cost, paired with state and local GHG goals, which are expected to drive down gas throughput, will likely result in a higher cost per-therm for customers.
- Barriers to RGS: With the clear financial advantage towards transportation, there is comparatively little RG available to establish a consistent RGS to meet PG&E's customer or third-party needs should a RGS be established.

California's gas system is going though unprecedent changes. As we brace for the future, now, more than ever, it's important that regulatory bodies and IOUs work together to ensure that Californians continue to have access to clean, reliable and affordable energy.

OTHER REGULATORY MATTERS

OVERVIEW

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

PG&E is participating in a number of OIRs, which address crucial topics that will impact the California gas system. For example, the:

- Biomethane OIR (R.13-02-008) will help the utilities make RG interconnections more efficient and affordable across California; and
- Gas System Planning OIR (R.20-01-007) will allow the utilities to: (1) develop updated reliability standards that are in line with current and future operational challenges of gas system operators, (2) improve coordination between gas utilities and gas-fired generators, and (3) develop and implement a long-term strategy to work towards California's decarbonization goals.

GHG REPORTING AND CAP-AND-TRADE OBLIGATIONS

In March 2020, PG&E Gas Operations reported the GHG emissions to the U.S. Environmental Protection Agency (EPA) in accordance with 40 Code of Federal Regulations

(CFR) Part 98 in four primary categories: GHG emissions in reporting year 2019 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of carbon dioxide equivalent ($mtCO_2e$); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMcf; certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2020, PG&E Gas Operations reported GHG emissions of approximately 42.9 million metric tons of carbon dioxide equivalent ($mmtCO_2e$) to the CARB in three primary categories for reporting year 2019: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 $mtCO_2e$; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations, one underground gas storage facility and the natural gas distribution system.

PG&E's deliveries to small customers not directly covered by CARB's Cap-and-Trade program (i.e., PG&E's natural gas supplier function) create compliance obligations for PG&E under the CARB Cap-and-Trade Program. PG&E emissions from covered compressor stations also create compliance obligations for PG&E under Cap-and-Trade. In 2019, CARB determined that PG&E's compliance obligations as a natural gas supplier were approximately 18.3 $mmtCO_2e$ for reporting year 2018. CARB will determine PG&E's natural gas supplier compliance obligation for reporting year 2019 in October 2020. In June 2019, PG&E filed the 2018 Annual Natural Gas Leakage Abatement Report and reported 2.9 billion standard cubic feet of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of 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 2020. 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 transitioning from the 3-year gas distribution leak survey cycle to risk-based leak surveys, continuing repair of its distribution system largest leaks, refining blowdown reduction strategies and beginning to expand the use of these strategies at compressor stations and storage facilities, and improving inventory of other devices that release gas to the atmosphere.

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. In April 2019, PG&E filed its Implementation Plan[63] for this program. The plan includes replacing high-bleed pneumatic devices, replacing rod packing, excavation damage data collection, and utilizing methods such as drafting and cross compression. More information can be found on the EPA's Methane Challenge Webpage.[64] In addition, PG&E is committed through its 1-million-ton challenge to reduce GHG emissions from company operations through 2022. PG&E's strategy to meet this goal includes increased leak survey and repair, removing high-bleed pneumatic devices, replacing vintage distribution main, and reducing transmission pipeline blowdowns.

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 RG interconnection tariff and interconnection agreements.

On November 1, 2019, the joint utilities filed a proposed RG interconnection rule. The CPUC held a workshop on November 13, 2019, to discuss the proposal, and parties filed comments thereafter.

On May 1, 2020, the joint utilities filed the proposed RG interconnection and operating agreement and related documents to be used with the RG rule. The CPUC held a workshop on May 18, 2020 to discuss the proposed agreement and parties filed comments thereafter.

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).

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63 https://www.epa.gov/sites/production/files/2019-06/documents/pacific_gas_and_electric_mc_ip_webready_2019-05.pdf.

64 https://www.epa.gov/natural-gas-star-program/pacific-gas-electric-company-methane-challenge-partner-profile.

By November 21, 2020, the joint utilities are directed to file an application on a preliminary H2 injection standard. The joint gas utilities have hosted technical H2 working group sessions (the first on January 15, 2020 and the second on June 17, 2020) with reports filed by the joint utilities shortly thereafter.

GAS SYSTEM PLANNING OIR R.20-01-007

The CPUC opened a new 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 will be conducted in two phases and will: (1) develop and adopt as necessary updated reliability standards that reflect current and future operational challenges to gas system operators, (2) determine the regulatory changes to improve coordination between gas utilities and gas-fired generators, and (3) implement a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California's decarbonization goals. Phase I of this proceeding is expected to conclude within 18 months.

- Reliability Standards - Phase 1 – Track 1A
- Market Structure and Regulations – Phase 1 – Track 1B
- Long-Term Natural Gas Policy and Planning – Phase 2

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The APD forecast is a projection of demand under extreme weather conditions. PG&E uses a 1-in-90 year cold-temperature event as the design criterion. This criterion corresponds to a 28.3 degree F system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 28.3 degree F temperature is estimated to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore demand and excludes all EG demand. PG&E estimates that total noncore demand served by pipeline and storage withdrawal capability during an APD event would be approximately 1.4 to 1.6 Bcf/d, with EG demand comprising between one half to three quarters of the total noncore demand.

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

APD SUPPLY REQUIREMENT FORECAST

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

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to 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 the cold weather front drops south from Canada with a 2- to 3-day lag before hitting PG&E's service territory. There is also impact on supply from the Southwest. While prices can influence the availability of supply to our system, cold weather can affect producing wells in the basins, which in turn can affect the total supply to the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet it. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. The implication for the future is that under supply-shortfall conditions—such as an APD—a significant portion of EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that noncore demand served by pipeline and storage withdrawals, including gas-fired EG, on an APD would be approximately 1.4-1.6 Bcf/d in the near term. With the Wild Goose, Lodi, Gill Ranch, and Central Valley Gas storage facilities, more noncore demand will be satisfied in the event of an APD. The availability of supply for any given high-demand event, such as an APD, is dependent on a wide range of factors, including the availability of interstate flowing supplies and storage inventories.

TABLE 21 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN APD (MMcf/d)

Line No.		2020-21	2021-22	2022-23
1	APD Core Demand (1)	3,031	3,043	3,055
2	Independent Storage Provider Withdrawal (2)	2,190	2,190	2,190
3	Firm Flowing Supply (3)	3,055	3,055	3,055
4	Total Resources to Meet Demands (4)	4,067	4,067	4,067

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 28.3 degrees F system composite temperature, corresponding to 1-in-90 year cold temperature event.1 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.

(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.

(4) The Total Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals.

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

TABLE 22 – WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core (1)	Noncore Non-EG (2)	EG, Including SMUD (2)	Total Demand
2020	2,561	550	489	3,600
2021	2,571	565	425	3,561
2022	2,580	552	433	3,565
2023	2,589	556	428	3,573
2024	2,600	554	429	3,583
2025	2,612	553	439	3,604

Notes:

(1) Core demand calculated for 34.2 degrees F system composite temperature, corresponding to 1-in-10 year cold temperature event.

(2) Average daily winter (December) demand under 1-in-10 cold and dry conditions.

TABLE 23 – SUMMER PEAK DAY DEMAND (MMcf/d)

Year	Core (1)	Noncore Non-EG(1)	EG, Including SMUD (1)	Total Demand
2020	384	672	489	1,545
2021	385	681	424	1,490
2022	372	675	386	1,433
2023	367	675	376	1,418
2024	359	675	372	1,406
2025	352	673	366	1,391

Notes:

(1) Average daily summer (August) demand under 1-in-10 cold and dry conditions.

2020 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA – TABULAR DATA

TABLE 24 – ANNUAL GAS SUPPLY AND REQUIREMENTS (MMcf/d) – RECORDED SENDOUT

LINE		2015	2016	2017	2018	2019
	GAS SUPPLY TAKEN					
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	37	33	29	28	24
3	Total California Source Gas	37	33	29	28	24
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	219	194	178	161	170
7	U.S. Southwest Gas	147	124	84	58	58
8	Canadian Gas	345	318	319	303	286
	Customer Gas Transport					
10	Rocky Mountain Gas	689	445	461	367	486
11	U.S. Southwest Gas	360	298	304	430	599
12	Canadian Gas	798	837	832	957	888
13	Total Out-of-State Gas	2,558	2,217	2,178	2,276	2,487
14	STORAGE WITHDRAWAL (2)	238	260	328	397	350
15	Total Gas Supply Taken	2,833	2,510	2,534	2,701	2,861
	GAS SENDOUT					
	CORE					
19	Residential	450	461	483	489	503
20	Commercial	209	214	220	225	226
21	NGV	8	8	7	7	7
22	Total Throughput-Core	667	683	710	721	736
	NONCORE					
24	Industrial	534	544	543	562	534
25	Electric Generation (1)(2)	1,025	783	698	855	865
26	NGV	1	1	2	3	4
27	Total Throughput-Noncore	1,560	1,329	1,244	1,421	1,403
28	WHOLESALE	8	8	9	9	9
29	Total Throughput	2,235	2,020	1,963	2,151	2,148
30	OFF-SYSTEM DELIVERIES	251	217	233	264	224
31	CALIFORNIA EXCHANGE GAS	1	1	1	1	1
32	STORAGE INJECTION (3)	291	231	294	244	441
33	SHRINKAGE Company Use / Unaccounted for	56	42	44	41	47
34	Total Gas Send Out	2,833	2,510	2,534	2,701	2,861
	TRANSPORTATION & EXCHANGE					
38	CORE ALL END USES	142	141	139	139	138
39	NONCORE INDUSTRIAL	534	544	543	562	534
40	ELECTRIC GENERATION	1025	783	698	855	865
41	SUBTOTAL/RETAIL	1,701	1,469	1,380	1,557	1,538
43	WHOLESALE/INTERNATIONAL	8	8	9	9	9
45	TOTAL TRANSPORTATION AND EXCHANGE	1,709	1,477	1,389	1,566	1,547
	CURTAILMENT/ALTERNATIVE FUEL BURNS					
48	Residential, Commercial, Industrial	0	0	0	0	0
49	Utility Electric Generation	0	0	0	0	0
50	TOTAL CURTAILMENT (4)	0	0	0	0	0

NOTES:

(1) Electric generation includes SMUD, cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by other pipelines.

(2) Recorded electric generation throughput is the residual of total noncore throughput less non-electric generation throughput.

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

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

TABLE 25 – ANNUAL GAS SUPPLY FORECAST (MMcf/d) AVERAGE DEMAND YEAR

LINE		2020	2021	2022	2023	2024
FIRM CAPACITY AVAILABLE						
1	California Source Gas	34	34	34	34	34
	Out of State Gas					
2	Baja Path[(1)]	960	960	960	960	960
3	Redwood Path[(2)]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	Supplemental[(3)]	0	0	0	0	0
5	Total Supplies Available	3,095	3,095	3,095	3,095	3,095
GAS SUPPLY TAKEN						
6	California Source Gas	34	34	34	34	34
7	Out of State Gas (via existing facilities)	1,958	1,890	1,875	1,848	1,699
8	Supplemental	0	0	0	0	0
9	Total Supply Taken	1,992	1,924	1,909	1,882	1,733
10	Net Underground Storage Withdrawal	0	0	0	0	0
11	Total Throughput	1,992	1,924	1,909	1,882	1,733
REQUIREMENTS FORECAST BY END USE						
	Core					
12	Residential[(4)]	509	506	492	484	474
13	Commercial	224	224	223	222	220
14	NGV	8	8	9	9	10
15	Total Core	741	738	724	716	704
	Noncore					
16	Industrial	553	560	559	554	555
17	SMUD Electric Generation[(5)]	117	117	117	117	117
18	PG&E Electric Generation[(6)]	267	196	196	196	196
19	NGV	4	5	5	6	6
20	Wholesale	9	9	9	9	9
21	California Exchange Gas	1	1	1	1	1
22	Total Noncore	952	888	888	882	884
23	Off-System Deliveries[(7)]	260	260	260	246	107
	Shrinkage					
24	Company use and Unaccounted for	40	38	38	38	38
25	TOTAL END USE	1,992	1,924	1,909	1,882	1,733
	TRANSPORTATION & EXCHANGE					
26	CORE ALL END USES	139	139	137	136	134
27	NONCORE COMMERCIAL/INDUSTRIAL	553	560	559	554	555
28	ELECTRIC GENERATION	384	313	313	313	313
29	SUBTOTAL/RETAIL	1,076	1,011	1,009	1,003	1,002
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9
31	TOTAL TRANSPORTATION AND EXCHANGE	1,085	1,021	1,018	1,012	1,011
32	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 26 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
AVERAGE DEMAND YEAR

LINE		2025	2026	2027	2030	2035
FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	34	34	34	34	34
	Out of State Gas					
2	Baja Path[1]	960	960	960	960	960
3	Redwood Path[2]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	**Supplemental[3]**	0	0	0	0	0
5	**Total Supplies Available**	3,095	3,095	3,095	3,095	3,095
GAS SUPPLY TAKEN						
6	**California Source Gas**	34	34	34	34	34
7	**Out of State Gas (via existing facilities)**	1,578	1,559	1,539	1,512	1,457
8	**Supplemental**	0	0	0	0	0
9	**Total Supply Taken**	1,612	1,593	1,573	1,546	1,491
10	**Net Underground Storage Withdrawal**	0	0	0	0	0
11	**Total Throughput**	1,612	1,593	1,573	1,546	1,491
REQUIREMENTS FORECAST BY END USE						
	Core					
12	Residential[4]	464	453	443	413	341
13	Commercial	219	215	212	202	167
14	NGV	10	11	12	13	16
15	**Total Core**	693	678	666	628	524
	Noncore					
16	Industrial	553	551	545	554	560
17	SMUD Electric Generation[5]	117	117	117	117	117
18	PG&E Electric Generation[6]	194	194	191	192	233
19	NGV	6	7	7	8	10
20	Wholesale	9	9	9	9	9
21	California Exchange Gas	1	1	1	1	1
22	**Total Noncore**	881	878	870	880	929
23	**Off-System Deliveries[7]**					
	Shrinkage					
24	Company use and Unaccounted for	38	37	37	37	38
25	**TOTAL END USE**	1,612	1,593	1,573	1,546	1,491
	TRANSPORTATION & EXCHANGE					
26	CORE — ALL END USES	133	130	128	121	99
27	NONCORE — COMMERCIAL/INDUSTRIAL	553	551	545	554	560
28	ELECTRIC GENERATION	311	311	308	309	350
29	SUBTOTAL/RETAIL	997	991	980	983	1,009
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9
31	TOTAL TRANSPORTATION AND EXCHANGE	1,006	1,000	989	992	1,017
32	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 27 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
HIGH DEMAND YEAR (1-IN-10 COLD YEAR)

LINE		2020	2021	2022	2023	2024
	FIRM CAPACITY AVAILABLE					
1	California Source Gas	34	34	34	34	34
	Out of State Gas					
2	Baja Path[1]	960	960	960	960	960
3	Redwood Path[2]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	Supplemental[3]	0	0	0	0	0
5	Total Supplies Available	3,095	3,095	3,095	3,095	3,095
	GAS SUPPLY TAKEN					
6	California Source Gas	34	34	34	34	34
7	Out of State Gas (via existing facilities)	2,045	1,967	1,939	1,908	1,759
8	Supplemental	0	0	0	0	0
9	Total Supply Taken	2,079	2,001	1,973	1,942	1,793
10	Net Underground Storage Withdrawal	0	0	0	0	0
11	Total Throughput	2,079	2,001	1,973	1,942	1,793
	REQUIREMENTS FORECAST BY END USE					
	Core					
12	Residential[4]	552	549	535	528	517
13	Commercial	234	234	233	232	231
14	NGV	8	8	9	9	10
15	Total Core	793	791	777	769	758
	Noncore					
16	Industrial	554	561	560	556	557
17	SMUD Electric Generation[5]	117	117	117	117	117
18	PG&E Electric Generation[6]	297	216	204	199	199
19	NGV	4	5	5	5	5
20	Wholesale	10	10	10	10	10
21	California Exchange Gas	1	1	1	1	1
22	Total Noncore	984	910	897	888	889
23	Off-System Deliveries[7]	260	260	260	246	107
	Shrinkage					
24	Company use and Unaccounted for	41	40	40	39	39
25	TOTAL END USE	2,079	2,001	1,973	1,942	1,793
	TRANSPORTATION & EXCHANGE					
26	CORE — ALL END USES	147	147	145	144	142
27	NONCORE — COMMERCIAL/INDUSTRIAL	554	561	560	556	557
28	ELECTRIC GENERATION	414	333	321	316	316
29	SUBTOTAL/RETAIL	1,115	1,041	1,026	1,016	1,015
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10
31	TOTAL TRANSPORTATION AND EXCHANGE	1,125	1,051	1,036	1,026	1,025
32	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 28 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
HIGH DEMAND YEAR (1-IN-10 COLD YEAR)

LINE			2025	2026	2027	2030	2035
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		34	34	34	34	34
	Out of State Gas						
2	Baja Path[1]		960	960	960	960	960
3	Redwood Path[2]		2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41
4	**Supplemental[3]**		0	0	0	0	0
5	**Total Supplies Available**		3,095	3,095	3,095	3,095	3,095
GAS SUPPLY TAKEN							
6	**California Source Gas**		34	34	34	34	34
7	**Out of State Gas (via existing facilities)**		1,639	1,619	1,598	1,570	1,529
8	**Supplemental**		0	0	0	0	0
9	**Total Supply Taken**		1,673	1,653	1,632	1,604	1,563
10	**Net Underground Storage Withdrawal**		0	0	0	0	0
11	**Total Throughput**		1,673	1,653	1,632	1,604	1,563
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential[4]		508	496	486	457	385
13	Commercial		229	225	222	213	177
14	NGV		10	11	12	13	16
15	**Total Core**		747	732	720	683	579
	Noncore						
16	Industrial		555	552	547	555	561
17	SMUD Electric Generation[5]		117	117	117	117	117
18	PG&E Electric Generation[6]		199	197	193	194	249
19	NGV		6	6	6	7	8
20	Wholesale		10	10	10	9	9
21	California Exchange Gas		1	1	1	1	1
22	**Total Noncore**		886	882	873	883	946
23	**Off-System Deliveries[7]**						
	Shrinkage						
24	Company use and Unaccounted for		39	39	38	38	39
25	**TOTAL END USE**		1,673	1,653	1,632	1,604	1,563
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	141	138	136	129	107
27	NONCORE	COMMERCIAL/INDUSTRIAL	555	552	547	555	561
28		ELECTRIC GENERATION	316	314	310	311	366
29		SUBTOTAL/RETAIL	1,011	1,004	992	995	1,034
30		WHOLESALE/INTERNATIONAL	10	10	10	9	9
31		TOTAL TRANSPORTATION AND EXCHANGE	1,021	1,013	1,002	1,004	1,044
32	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.

2020 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California, providing retail and wholesale customers with transportation, exchange, storage services and also procurement services to most retail core customers. SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and EG customers in Southern California. SDG&E, SWG, the City of Long Beach Energy Resources Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas also 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 16-year demand and forecast period, from 2020 through 2035; only the consecutive years 2020 through 2027 and the point years 2030 and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

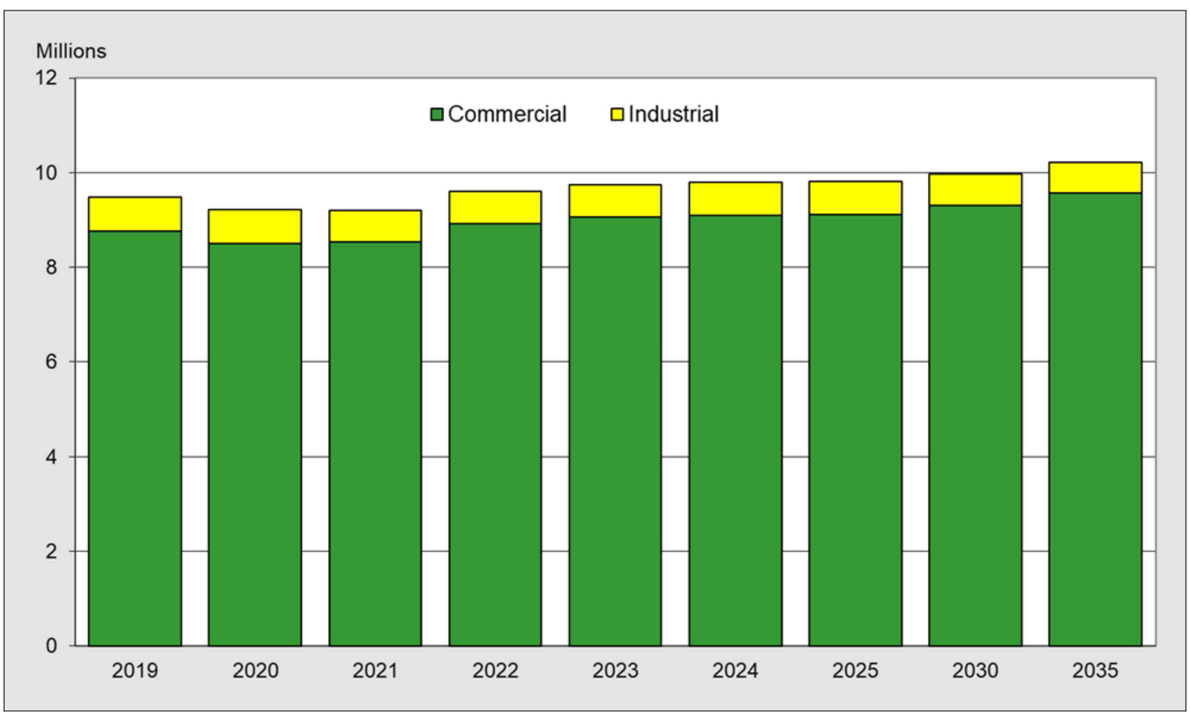
The Southern California section of the 2020 CGR begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The 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.

THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are, in large part, determined by the long-term economic outlook for the SoCalGas service territory. After relatively steady growth from 2012-2019, in the first half of 2020 Southern California's economy plunged into recession with global impacts from the COVID-19 virus pandemic. The economy is likely to suffer substantially in 2020 and 2021 before recovering. Overall SoCalGas' area jobs are expected to average slow 0.6 percent annual growth from 2019 through 2025. Local manufacturing and mining industrial employment are projected to drop an average of 0.9 percent per year in the same period, with commercial jobs growing about 0.7 percent annually. Jobs in professional, business, health, and social services sectors should grow the fastest, averaging about 2 percent per year from 2019-2025.

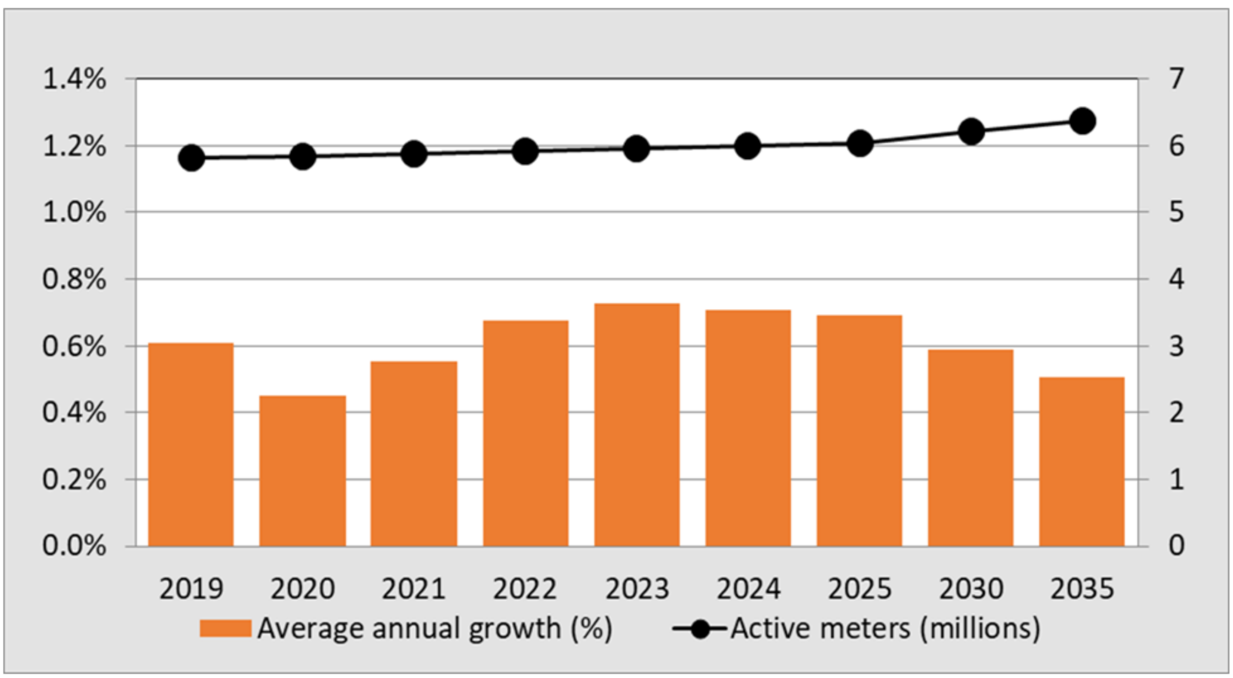
FIGURE 9 – SoCalGas 12-COUNTY AREA EMPLOYMENT



Longer term, SoCalGas' service-area employment is expected to increase slowly as the area population's average age gradually increases—part of a national demographic trend of aging and retiring Baby Boomers. From 2019 through 2035, total area job growth should average 0.5 percent per year. Area industrial jobs are forecasted to shrink an average of 0.7 percent per year through 2035; we expect the industrial share of total employment to fall from 7.7 percent in 2019 to 6.4 percent by 2035. Commercial jobs are expected to grow an average of 0.6 percent annually from 2019 through 2035.

From 2011-2019 SoCalGas' service area housing market gradually strengthened after its prior downturn. Starting in 2020, home building and meter hookups are expected to drop due to disruptions from the COVID-19 pandemic. Net active meter growth is projected to slow from 35,160 (+0.61 percent) in 2019 to 26,200 (+0.45 percent) in 2020 and 32,400 (+0.55 percent) in 2021. Longer term, SoCalGas expects active meters to average moderate 0.58 percent annual growth from 2019 through 2035.

FIGURE 10 – SoCalGas ANNUAL ACTIVE METERS AND GROWTH RATES



GAS DEMAND (REQUIREMENTS)

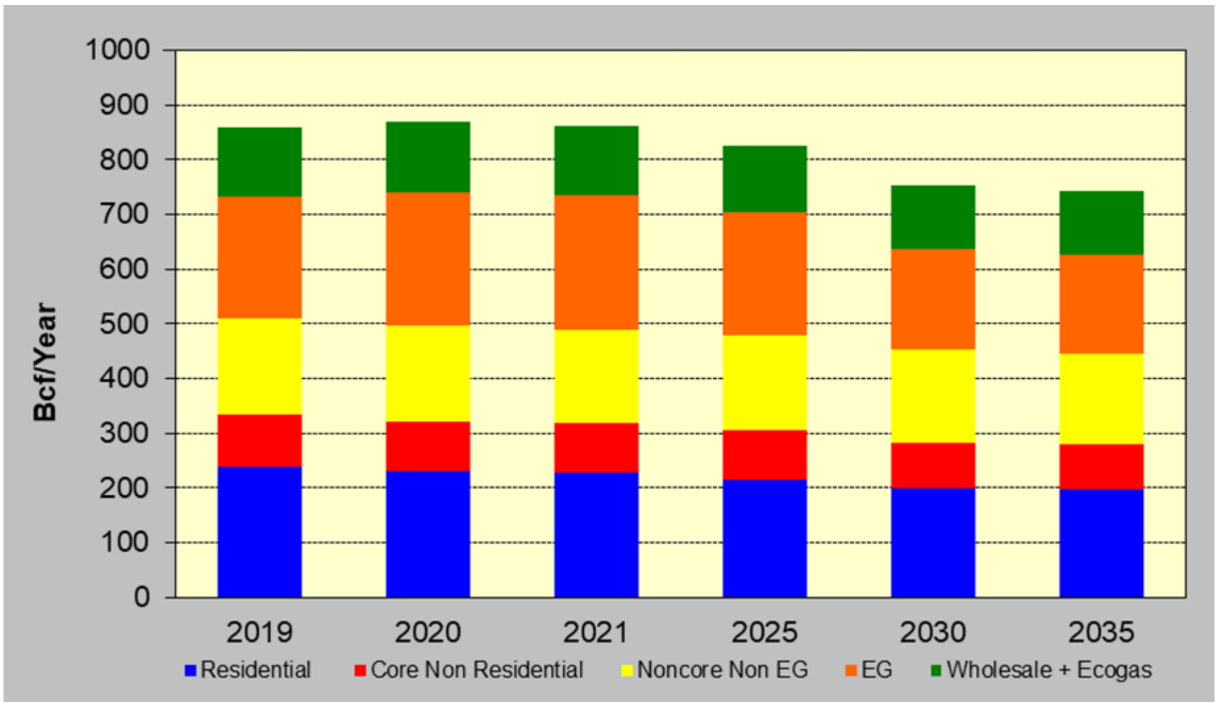
OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 1 percent from 2020-2035. The decline in throughput demand is due to modest economic growth, and CPUC-mandated energy efficiency (EE) standards and programs and SB 350 goals. Other factors that contribute to the downward trend are tighter standards created by revised Title 24 Codes and Standards, renewable electricity goals, a decline in core commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI). By comparison, the 2018 CGR projected an annual decline in demand of 0.74 percent over the forecast horizon.

From 2020-2035, residential demand is expected to decline from 230 Bcf to 198 Bcf. The decline is approximately 1 percent per year, on average. The decline is due to declining use per meter—primarily driven by very aggressive energy efficiency goals and associated programs—offsetting new meter growth. The core, non-residential markets (comprising core commercial, core industrial and NGV) are expected to decline at an average annual rate of 1.0 percent or from 112 Bcf in 2020 to 96 Bcf by 2035. However, the NGV market is expected to grow 1.45 percent over the forecast horizon. The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles as well as the increased use of RNG that provides significant GHG emission reduction benefits. The noncore, non-EG markets are expected to decline 0.3 percent from 174 Bcf in 2020 to 165 Bcf by 2035. That decline is being driven by very aggressive 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 245 Bcf in 2020 to 182 Bcf in 2035, a decrease of 2.0 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2019 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2020-2035 forecast period.

FIGURE 11 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR (2019-2035)



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.

ASSUMPTIONS REGARDING BUILDING DECARBONIZATION POLICY

Signed into law in September 2018, California AB 3232 calls on the CEC (working in consultation with the CPUC and other state agencies) to develop and articulate plans and projections, by year 2021, to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030. Much of the reduction will likely occur by replacing some buildings' gas end-use applications with electric ones. The CEC plans to develop and publish quantified projections of these electric-for gas substitutions in its 2021 IEPR. Since no state projections of AB 3232-driven fuel substitutions are yet available, the 2020

CGR and the ensuing gas demand forecasts do not include impacts from these policy changes. It is anticipated that state-projected impacts will be included in the 2022 CGR, assuming state projections are available by that time.

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. HDD differences between the two temperature conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is defined 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.

In our 2020 CGR, SoCalGas and SDG&E have introduced a climate-change warming trend that gradually reduces HDD's over the forecast period. First, average temperature year values were computed as the simple average of annual HDD's for the calendar years 2000 through 2019: 1,273 HDD's for SoCalGas and 1,186 HDD's for SDG&E. Corresponding cold year HDD's were 1,518 for SoCalGas and 1,399 for SDG&E. For the forecast period, projected annual HDD's were reduced each year by 4 HDD's for SoCalGas and by 2 HDD's for SDG&E. For SoCalGas, projected average year and cold year HDD's both drop by 4 HDD annually: from 1,269 and 1,514 in year 2020, to 1,209 and 1,454 in year 2035. For SDG&E, projected average year and cold year HDD's drop by 2 HHD annually: from 1,184 and 1,397 in year 2020, to 1,154 and 1,367 in year 2035. 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 HDD's for years 1981-2000, then 1982-2001, 1983-2002...and ending with the average HDD's for years 2000-2019.

HYDRO CONDITIONS

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

MARKET SECTORS

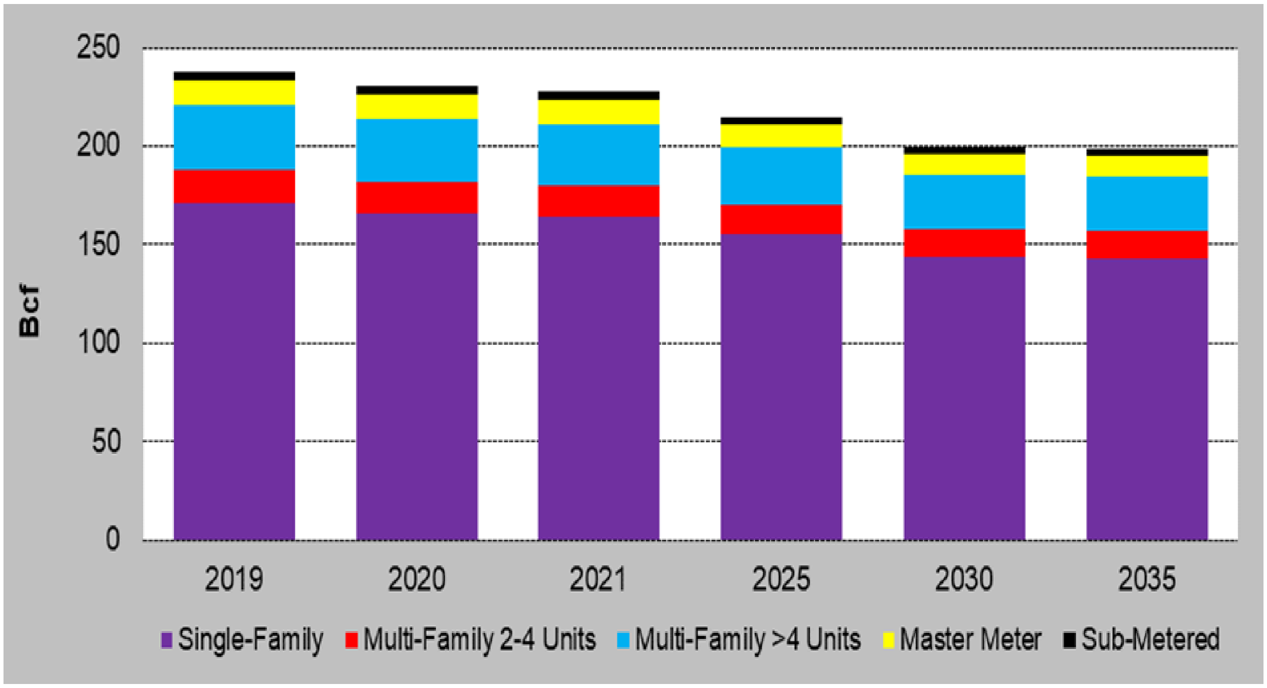
RESIDENTIAL

Residential demand adjusted for temperature totaled 237.5 Bcf in 2019. The residential load is expected to decline on average by 1.1 percent per year from 237.5 Bcf in 2019 to 198.3 Bcf in 2035. The decrease in gas demand results from a combination of continued decline in residential use per meter, increases in marginal gas rates, the impact of savings from SoCalGas' AMI project deployment which began in 2013 and CPUC authorized energy efficiency program savings in this market. These energy efficiency savings are forecasted to lead to demand reductions in the residential sector by a total of 18.8 Bcf in year 2035.

The total residential customer count for SoCalGas consists of five residential segment types: (1) single family, (2) small multi-family, (3) large multi-family, (4) master meter, and (5) sub-metered customers. The active meters for all residential customer classes were 5.61 million at the end of 2019. This amount reflects a 68,331 increase in active meters between 2017 at year end and 2019 at year end. The 2020 CGR shows that in 2019, single family and overall multi-family temperature adjusted average annual use per meter was 468 therms and 292 therms, respectively. Over the forecast period, the demand is expected to decline to 442 therms/customer and 238 therms/customer, respectively. The decline in use per meter for residential customers is explained by conservation, improved building and appliance standards, aggressive energy efficiency programs, and demand reductions anticipated as the result of the deployment of AMI in the Southern California area. With AMI, customers will have more timely information available about their daily and hourly gas use and thereby are expected to use gas more efficiently.

The projected residential natural gas demand is influenced primarily by residential meter growth, moderated by the forecasted decline in use per customer. The residential load trend over the forecast period is illustrated in the graph below.

FIGURE 12 – COMPOSITION OF SoCalGas' RESIDENTIAL DEMAND FORECAST (2019-2035)



COMMERCIAL

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the 2019 core commercial market demand totaled 82.8 Bcf. By the year 2035, the load is anticipated to drop to approximately 62.5 Bcf. The average annual rate of decline from 2019-2035 is forecasted at 1.7 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 in this market.

In 2019, the noncore commercial temperature-adjusted usage was 18.3 Bcf. From 2019 through 2035, demand in this market is expected to rise slightly at approximate annual rate of 0.08 percent. By 2035, the noncore commercial load is expected to reach 18.6 Bcf.

**FIGURE 13 – ANNUAL COMMERCIAL DEMAND FORECAST 2019-2035
BILLION CUBIC FEET PER YEAR (Bcf/y), AVERAGE YEAR WEATHER DESIGN**

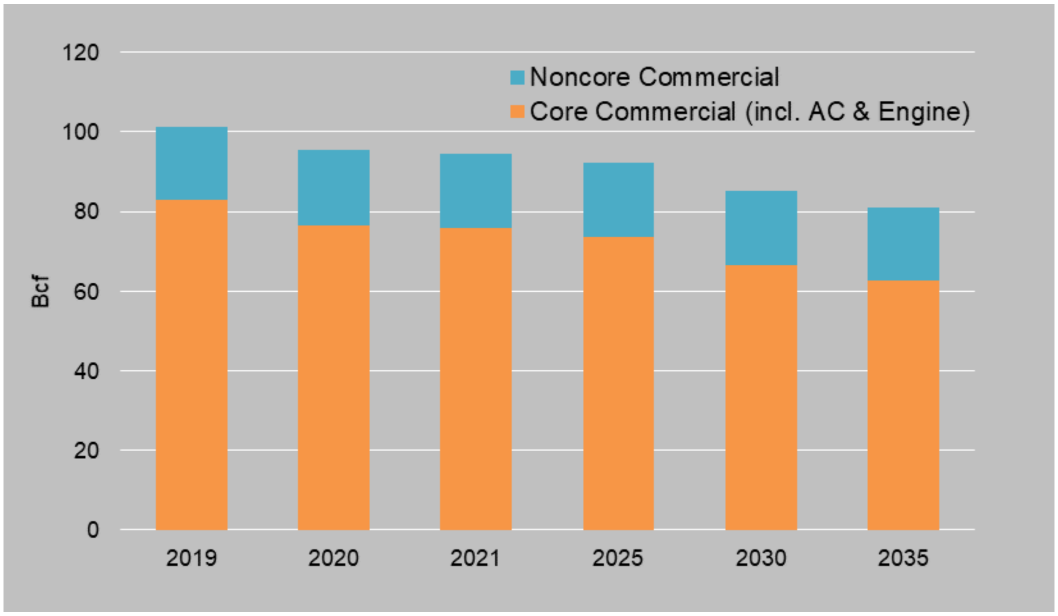
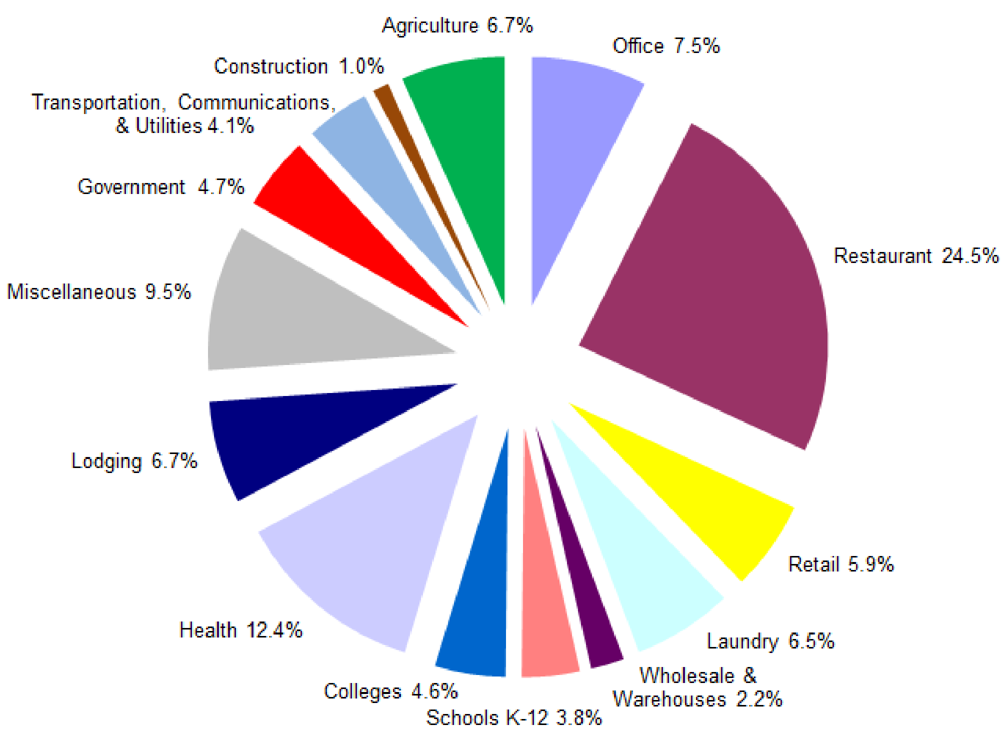


**FIGURE 14 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2019)**



The commercial market consists of 14 business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 24.5 percent of commercial usage in 2019, followed by the health services industry with a 12.4 percent share.

INDUSTRIAL

Non-Refinery Industrial Demand

In 2019, temperature-adjusted core industrial demand was 21.0 Bcf. Core industrial market demand is projected to drop by 2.3 percent per year from 21.0 Bcf in 2019 to 14.4 Bcf in 2035. This decrease results from a combination of factors: an annual 0.7 percent decrease in employment growth, a minor increase in marginal gas rates and CPUC-authorized energy efficiency programs.

The 2019 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 36 percent of the total share, dominates this market. The graph below summarizes the composition of the core and noncore market by business type.

**FIGURE 15 – ANNUAL INDUSTRIAL DEMAND FORECAST (Bcf)
(2019-2035)**

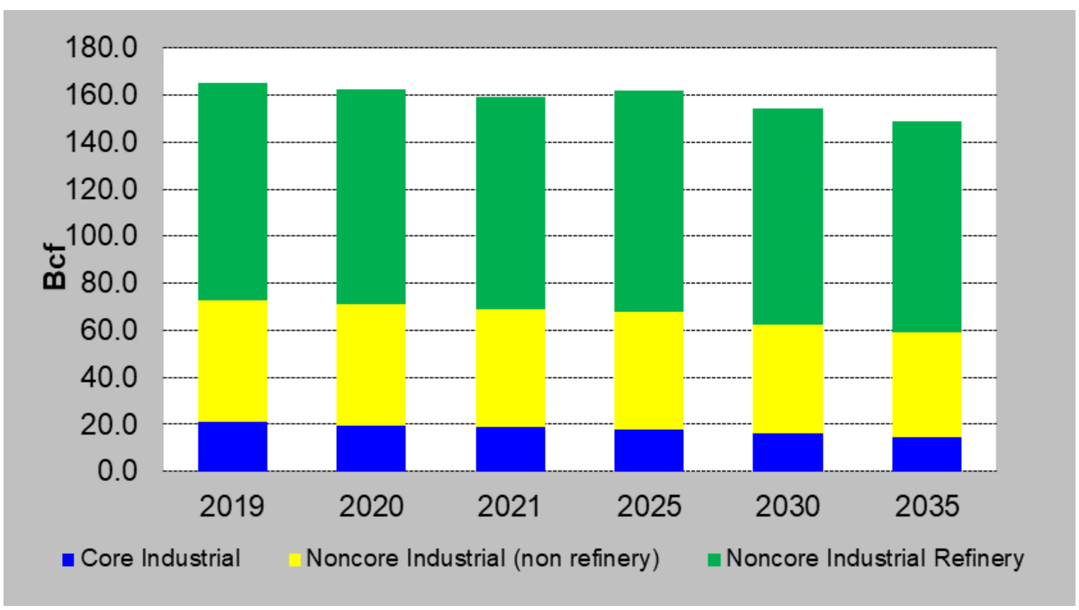
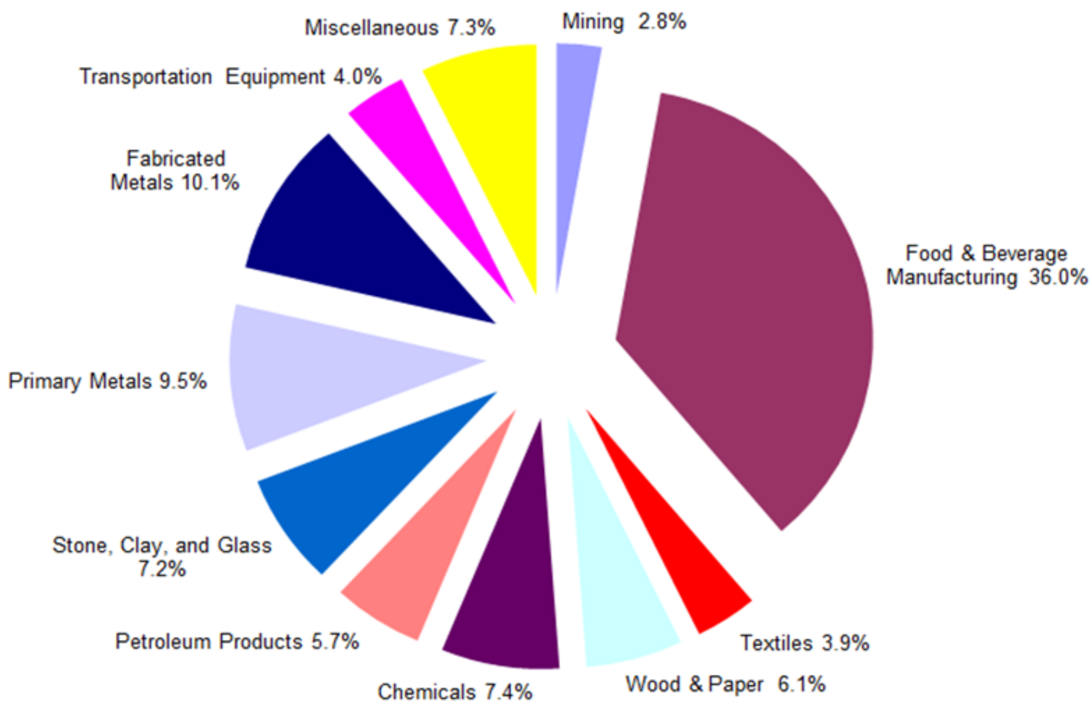


FIGURE 16 – INDUSTRIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2019)



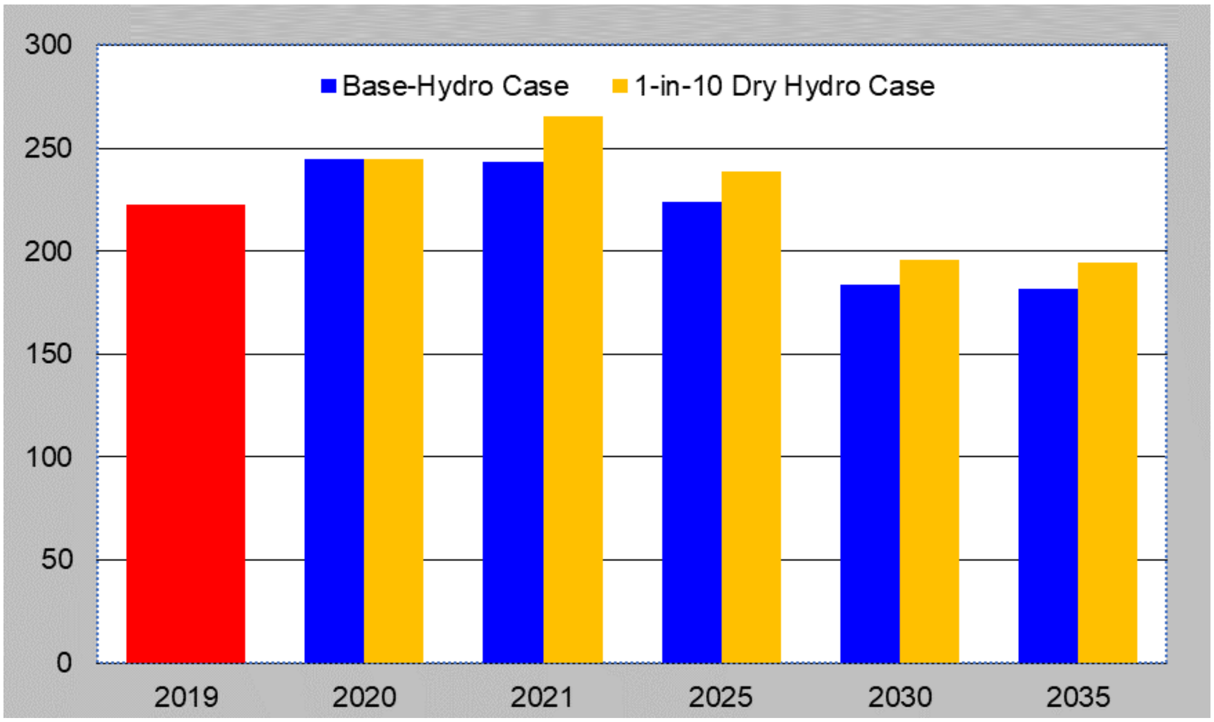
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.9 percent from 51 Bcf in 2019 to 45 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, the departure of customers within the City of Vernon to wholesale service by the City of Vernon, and higher gas costs stemming from California's GHG carbon fees.

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 decline about 0.2 percent per year over the 2019-2035 forecast period, from 93 Bcf in 2019 to 90 Bcf in 2035. The decrease in the forecast period is primarily due to the estimated savings from CPUC-authorized energy efficiency programs.

ELECTRIC GENERATION

FIGURE 17 – SoCalGas SERVICE AREA TOTAL EG
(Bcf)



The electric generation sector includes all commercial/industrial cogeneration, EOR-related cogeneration, and non-cogeneration electric generation. The forecast of electric generation (EG) load is subject to a high degree of uncertainty. 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 Average Demand forecast, depending on the factors mentioned above. Forecasted electricity demand is a major factor. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher. Please refer to the California Energy Commission's (CEC) 2019 Integrated Energy Policy Report 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 mostly gas-fired thermal plants, located near the coast, that use ocean water for cooling. There are several plants that are schedule to shut down by December 31, 2020. However, as of March 18, 2020, SWRCB has amended the OTC Policy to extend the compliance date for some of the power plants for an additional 1-3 years. These plants include Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach generating stations.

The forecast uses a power market simulation for the period of 2020-2030. 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 Average Demand assumes that the state will reach its 60 percent RPS by 2030, as mandated in SB 100. The Average Demand also assumes the IOUs will meet D.13-10-040, or the energy storage procurement framework and design program. Furthermore, the Average Demand also includes additional energy storage as outlined in CPUC's "Revised 2019 Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies." There is substantial uncertainty as to how this will be implemented, and its impact on gas throughput is unknown. Due to the large uncertainty in the timing and type of generating plants that could be added after 2030, the EG forecast is held constant at 2030 levels through 2035.

For electricity demand within California, SoCalGas relies on the CEC's California Energy Demand 2019-2030 Managed Forecast, dated February 2020. SoCalGas selected the Mid Energy Demand scenario with the Mid AAEE. In their CEC forecast, the state-wide energy demand is lower than prior forecasts used in the 2018 CGR from years 2020-2028, and slightly higher for years 2029 and 2030. However, for Southern California, the energy demand is slightly higher for the years 2020-2030 than prior CEC electric demand forecasts.

Industrial/Commercial/Cogeneration <20 MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 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 EG equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). In 2019, gas demand in the small cogeneration market was 28 Bcf. By 2035, cogeneration demand is projected to decline modestly to 27 Bcf (an average of 0.3 percent/year). The reduced demand is primarily due to higher gas costs due to California's GHG carbon fees.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to decline modestly at about 0.1 percent per year, decreasing from 23 Bcf in 2019 to 22 Bcf in 2035. The decline is mainly due to higher gas costs stemming from California's GHG carbon fees.

Enhanced Oil Recovery-Related Cogeneration

In 2019, recorded gas deliveries to the EOR-related cogeneration were 6.2 Bcf. EOR demand is forecasted to remain at 6.2 Bcf throughout the forecast period. Crude oil futures prices appear to be flat for the immediate future which is expected to result in California EOR operations staying steady going forward.

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 Average Demand (average hydro condition), gas demand is forecasted to decrease from 188 Bcf in 2020 to 127 Bcf in 2030. The main factors for the decline are an increasing RPS target level, retirement of older gas-fired plants, and the addition of more efficient gas-fired plants. SB 100 raised the RPS target level from 50 percent to 60 percent by 2030. SoCalGas' forecast includes the addition of approximately 1,382 MW of new, local, gas-fired combined cycle and peaking generating resources in its service area by summer 2020. However, the forecast also assumes 5,370 MW of local, gas-fired plants will be retired during the same time period as a result of the state's OTC regulation and economics. To account for dry climate conditions, a 1-in-10 dry hydro sensitivity gas demand forecast was created. This dry hydro forecast increases gas demand by 17 Bcf per year, on average.

For this forecast, SoCalGas followed CPUC's guideline for energy storage resources. In the model, a state-wide installed capacity of 754 MW was added starting in 2020. Storage capacity increases to 3,638 MW by 2030.

WHOLESALE AND INTERNATIONAL

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Energy Resources Department (Long Beach), 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 decrease from 39 Bcf in 2019 to 38.58 Bcf in 2035. The change reflects a 0.07 percent average annual decrease.

SDG&E

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.6 percent per year from 86.3 Bcf in 2019 to 78 Bcf in 2035. Additional information regarding 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 Energy Resources Department. Long Beach's gas use is expected to decline slightly, from 9 Bcf in 2019 to 8 Bcf by 2035. Refer to the City of Long Beach Energy Resources Department for more information.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2019, SoCalGas delivered 10.3 Bcf to Southwest Gas and the total load is expected to remain flat at this level throughout the forecast horizon. Refer to SWG for more information.

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June 2005. Since 2005, there has also been a gradual increase of commercial/industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 8.5 Bcf in 2019 and increases to 9.24 Bcf by 2035. The forecasted throughput includes Core and Non-Core 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 remain steady at a level of 11.13 Bcf/y over the forecast horizon 2020-2035. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery-Steam

In 2019, recorded gas deliveries to the EOR market were 11.76 Bcf. EOR demand is forecasted to remain at 11.76 Bcf throughout the forecast period. Crude oil futures prices appear to be flat for the immediate future which is expected to result in California EOR operations staying steady going forward.

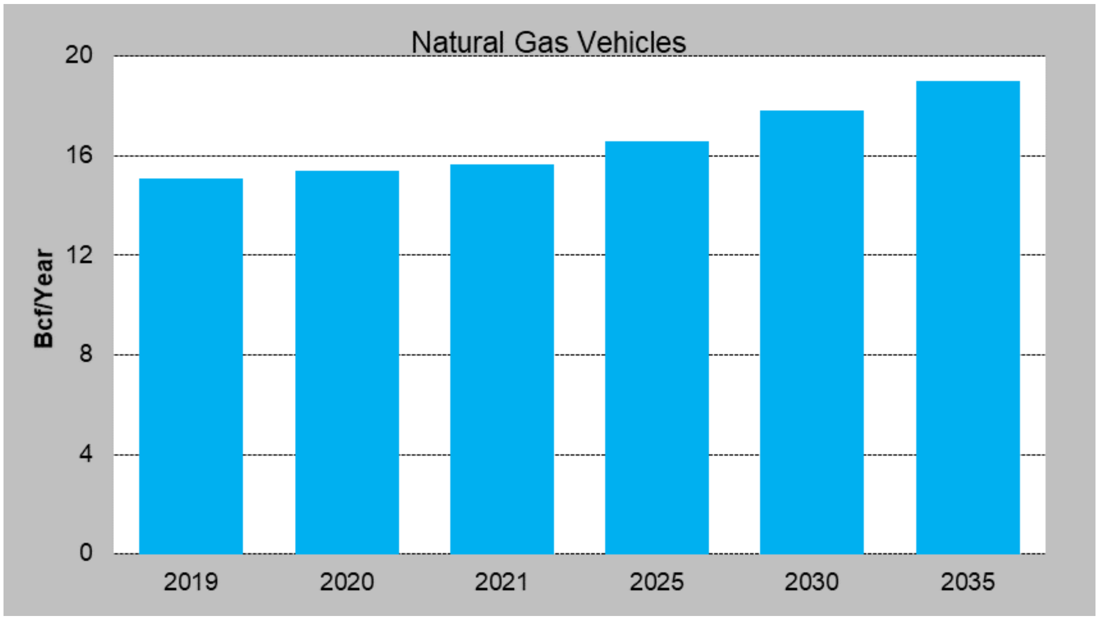
The EOR-related cogeneration demand is discussed in the EG section.

NATURAL GAS VEHICLES

The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles, as well as the increased use of RNG that provides significant GHG emission reduction benefits.

However, growth may be offset by competing technologies and fuels as well as the potentially lower cost differential between petroleum (gasoline and diesel) and natural gas.
At the end of 2019, there were 335 CNG fueling stations delivering 15.1 Bcf of natural gas during the year. The NGV market is expected to grow 1.44 percent per year, on average. At the end of 2035, it is expected there will be 418 CNG fueling stations delivering 19 Bcf of natural gas during the year.

FIGURE 18 – NGV DEMAND FORECAST
(2019-2035)



ENERGY EFFICIENCY PROGRAMS

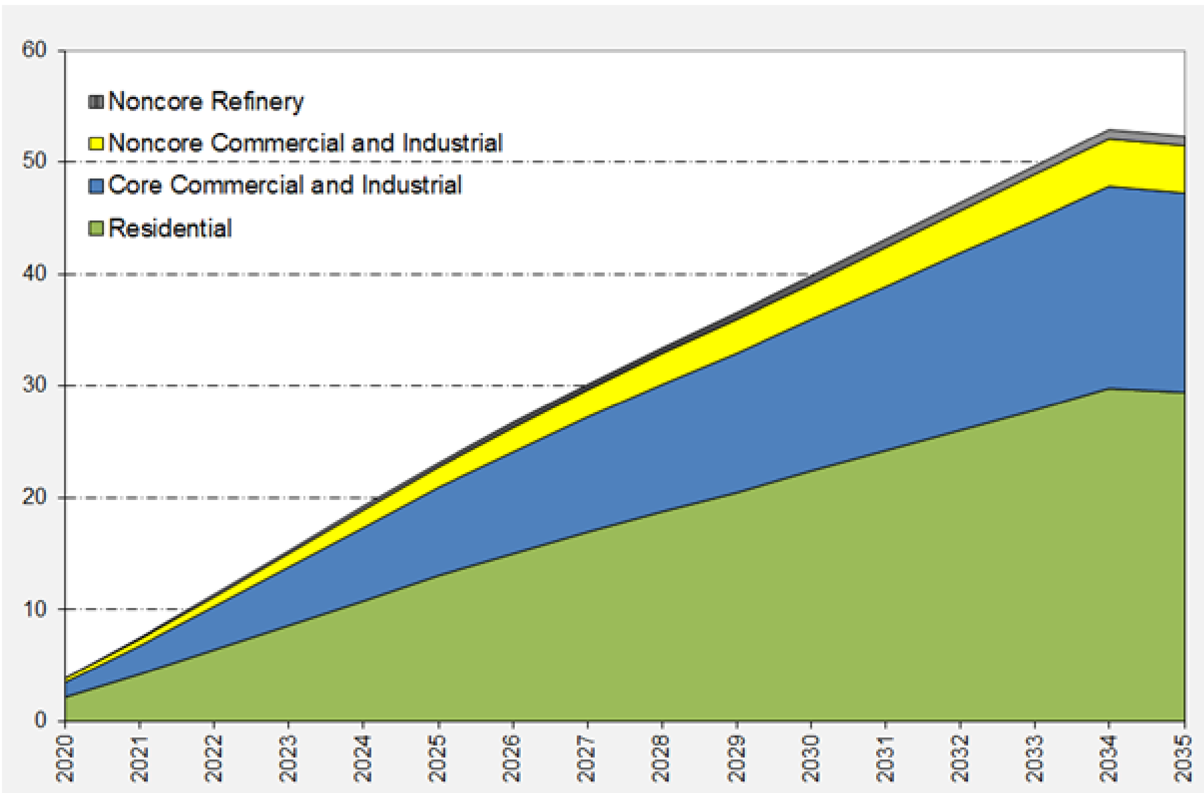
SoCalGas engages in a number of energy efficiency and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include services that help customers evaluate their energy 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 net load impact includes all energy efficiency programs that SoCalGas has forecasted to occur through year 2035.

The EE portfolio combines the EE customer programs goals and the Title 24 Codes and Standards. SoCalGas' EE forecast is based on inputs from the 2020 energy efficiency annual budget advice letter (AL 5510-A), utilizing program level energy savings values forecasted for the 2020 program year. Forecasted savings for the 2021-2030 period are based on the 2020 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.19-08-034, which set EE goals through 2030. Forecasted savings beyond 2030 are held constant based on 2030 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2020 and do not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

COMBINED EE PORTFOLIO OF EE PROGRAMS AND CODES AND STANDARDS

FIGURE 19 – SoCalGas ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVINGS GOALS (BCF)



Savings reported are for measures installed under SoCalGas' energy efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' energy efficiency programs, and only for the estimated measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached.

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 2015 through 2019 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Gas supply available to SoCalGas and SDG&E from California sources averaged 97 MMcf/d in 2019.

SOUTH-WESTERN U.S. GAS

Traditional South-Western U.S. sources of natural gas will 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 Transwestern pipeline. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 percent. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. The increase positioned the Permian Basin as a preferred gas supply source of economical gas. Permian gas production increased over 100 percent during the period 2017-2019. In early 2020 Permian Basin oil and gas production began to decline due to sharply lower oil prices.

Mexican demand for South-Western U.S. gas along with East of California demand continue to steadily increase and compete for South-Western supplies. This increased demand, which has been more than offset by the recent increase in Permian gas production, will continue to compete with Southern California for South-West supplies.

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional South-Western U.S. gas sources for Southern California. This gas is delivered to Southern California primarily on the Kern River

Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Many pipelines that supplying other markets connect to Rocky Mountain region, which allows these supplies to be redirected from lower to higher value markets as conditions change. Kern River Gas Transmissions volumes to Southern California have surpassed Transwestern pipeline's deliveries of South-Western supplies.

CANADIAN GAS

Canadian gas only provides a small share of Southern California gas supplies due to the high cost of transport.

RENEWABLE NATURAL GAS

Since methane can come from the decomposition of organic matter, there are ways to generate natural gas other than extracting it from the ground. Biogas is produced from existing waste streams and a variety of renewable and sustainable biomass sources, including animal waste, crop residuals and food waste. Methane can also be produced by the combustion-free thermal conversion of agricultural crop residues, silvicultural residue, wood waste, and municipal sewage sludge or biosolids. The most common source of biogas is the naturally occurring biological breakdown of organic waste at facilities such as wastewater treatment plants and landfills.

The abundance of these materials allows for production of substantial quantities of biogas. A study conducted by the University of California, Davis estimates that more than 20 percent of SoCalGas's current residential natural gas use can be provided by biogas derived from our state's existing organic waste alone.[65] In the transportation sector, that's enough to replace around 20 percent of the fuel used by heavy-duty trucks in the state. This can help reduce the need for other fossil-based fuels while boosting our supplies with a locally sourced renewable fuel. Looking outside California, the opportunity to produce biogas is vast. According to estimates,

65 *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*, prepared for the CARB and the California EPA by Amy Jaffe, Principal Investigator, STEPS Program, Institute of Transportation Studies, UC Davis.

the U.S. could produce up to 10 trillion cubic feet of biogas annually by 2030—that is more than five times California's projected natural gas consumption.[66]

A more recent study by ICF estimated a nation-wide potential range for RNG in 2040 of between 813-1,425 Bcf per year for RNG from Anaerobic Digestion, between 487-1,713 Bcf per year from Thermal Gasification and 265-695 BCF per year from Municipal Solid Waste.[67] The study also estimated a potential range for RNG in 2040 for the Pacific region[68] of 126-213 Bcf per year for RNG from Anaerobic Digestion, 22-51 Bcf per year from Thermal Gasification and 45-108 BCF per year from Municipal Solid Waste, for a total 'Pacific' region estimate of between 193-372 Bcf per year which would represent approximately 66 percent to 126 percent of SoCalGas' 2035 projected core natural gas consumption.

INTERSTATE PIPELINE CAPACITY

California utilities and end-users benefit from access to supply basins and enhanced gas-on-gas and pipeline-on-pipeline competition. Interstate, international and intrastate pipelines serving Southern and Central California include the El Paso, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. These pipelines provide Southern and Central California with access to gas-producing regions in the U.S. Southwest and Rocky Mountain areas, Western Canada, California Production and Mexico LNG. Indicated firm capacities for each zone are specified in the SoCalGas G-BTS Rate Schedule.

SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe and Otay Mesa (El Paso, North Baja, and TGN). The Southern Zone has a firm capacity of 1210 MMcf/d.

SoCalGas' Northern Zone is connected to U.S. South-West and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River and Mojave) at Needles, west of Topock AZ, and

66 U.S. DOE: *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks*. M. H. Langholtz, B. J. Stokes, and L. M. Eaton (Leads), ORNL/TM-2016/160. Oak Ridge National Laboratory, Oak Ridge, TN. 448p. doi: 10.2172/1271651; 2030 values achievable at $60/ton.

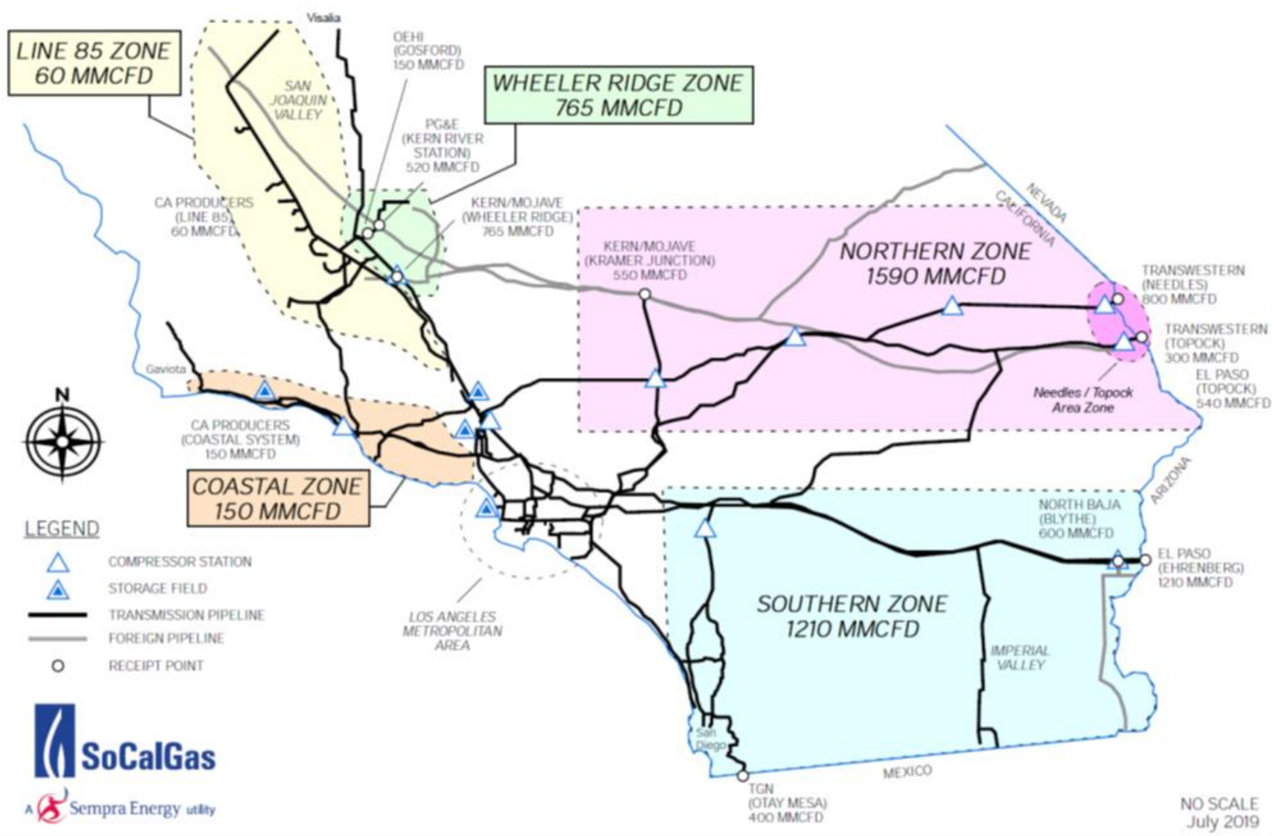
67 *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, ICF, p. 13.

68 Pacific Region is defined as production in the states of Alaska, California, Oregon, Hawaii, and Washington.

Kramer Junction. The Northern Zone has a nominal firm capacity of 1590 MMcf/d, but is projected to be less than this through the CGR plan period, due to extended maintenance activity.

SoCalGas' Wheeler Zone is connected to Kern River/Mojave, OEHI Gosford, and PG&E that access supplies from the U.S. Southwest, Rocky Mountain, and Western Canada production areas and California production from Elk Hills. Wheeler Zone′s firm capacity is 765 MMcf/d.

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 system-wide reliability.[69] Natural gas storage is also used to meet peak

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69 California Council on Science and Technology (CCST), January 2018, Long-Term Viability of Underground Natural Gas Storage in California, An Independent Review of Scientific and Technical Information, Conclusion 2.4 at 504, available at: http://ccst.us/publications/2018/FullTechnicalReportv2.pdf.

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.[70] 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 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 system when customer demand exceeds flowing natural gas supplies and for system balancing.

SoCalGas' natural gas storage fields have a combined theoretical storage working inventory capacity of more than 130 Bcf.[71] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Aliso Canyon historically has had a stated natural gas storage working inventory of 86.2 Bcf.[72] Since 2015,[73] the CPUC and CalGEM[74] have maintained restrictions on SoCalGas' use of Aliso Canyon. In July 2018, the CPUC approved a maximum working inventory of 34 Bcf for Aliso Canyon to support system reliability.[75] The CPUC and CalGEM may, in the future, authorize a different maximum inventory.

Since November 2017, the CPUC also developed a Withdrawal Protocol for Aliso Canyon, describing the process to be followed before making a withdrawal from the storage facility. In July 2019, in order to improve short-term reliability and price

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70 *Id.*, Conclusion 2.5 at 506.

71 SoCalGas 2019 General Rate Case (GRC) Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.

72 As of July 19, 2017, CalGEM has authorized Aliso Canyon to operate with a working inventory of equivalently 68.6 Bcf.

73 Aliso Canyon experienced a natural gas leak in well SS25 on October 23, 2015. The leak was stopped on February 11, 2016 and SS25 was permanently sealed on February 18, 2016.

74 Formerly, DOGGR.

75 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/715Report_Summer2018_Final.pdf.

stability in the Southern California region, the CPUC deemed that Aliso Canyon be used for withdrawals if certain conditions are met.[76]

In recognition of the safety enhancements SoCalGas has completed at Aliso Canyon and the importance of Aliso Canyon to southern California reliability,[77] SoCalGas continues to request that regulators lift withdrawal restrictions at Aliso Canyon.

STORAGE REGULATIONS

Since 2015, the CPUC, CalGEM, and 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 promote safe and reliable energy and natural gas storage services.

Most recently, PHMSA issued their Final Rule for Underground Storage regulations, CFR Part 192.12, amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopts API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

CalGEM established 14 California Code of Regulations §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes, among other things, mechanical testing mandates that require each well to be taken out-of-service as frequently as every

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76 https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-Revised-April12020clean.pdf.

77 SoCalGas completed a comprehensive safety review of the facility and created multiple layers of safety at Aliso Canyon, and in July of 2017 the CPUC and CalGEM formally determined that Aliso Canyon is safe to operate, any risks of failure had been identified and addressed, and well integrity had been verified. See, e.g., July 19, 2017, SB 380 Findings and Concurrence Regarding the Safety of the Aliso Canyon Gas Storage Facility.

24 months, unless an alternative frequency is approved by CalGEM,[78] and semi-annual field shut-in tests for inventory verification.

[78] SoCalGas has submitted its Risk Management Plan to CalGEM, which proposes an alternative inspection frequency that would, among other things, reduce impacts to deliverability associated with a 24-month well re-assessment schedule.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopts a TY 2019 revenue requirement of $2.770 billion for SoCalGas which is $166 million lower than the $2.937 billion that SoCalGas had requested in its Update testimony. The adopted revenue requirement represents an increase of $314 million or a 12.8 percent increase over 2018. The final decision adopts PTY revenue requirement adjustments for SoCalGas of $220 million for 2020 (7.9 percent increase) and $150 million for 2021 (5.0 percent increase).

In January 2020 the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SoCalGas was directed to file a Petition for Modification (PFM) to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional 5-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SoCalGas filed a PFM of its 2019 GRC decision requesting attrition year increases of $155 million (+4.95 percent) for 2022 and $137 million (+4.15 percent) for 2023. SoCalGas requested that a final decision be issued no later than October 1, 2020.

GAS RELIABILITY AND PLANNING OIR

The CPUC initiated a new rulemaking (R.20-01-007) to update gas reliability standards, determine the regulatory changes necessary to improve coordination between gas utilities and gas-fired electric generators, and implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.

The rulemaking will be managed in two phases and Phase 1 will include two tracks. Track 1A will address reliability standards and focus on SoCalGas' and PG&E's system capabilities, the adequacy of existing gas reliability standards, whether slack capacity should be encouraged, whether transportation of gas to the planned Energía Costa Azul LNG export facility will impact reliability and prices, whether updated reliability standards will result in additional costs, and what cost recovery and allocation mechanisms should be used. Track 1B will address market structure and regulations, with a focus on interstate pipeline capacity, impacts on EG, and system operating procedures. A decision in Phase 1 is expected by May 2021. Phase 2 will address long-term planning and a schedule will be established after the completion of Phase 1. Preliminarily, Phase 2 is expected to address the appropriate gas infrastructure portfolio for gas utilities operating in California, the need to reconsider gas rate design and cost allocation methods, management of the natural gas transition indicated by the long-range portfolio modeling in the CPUC's IRP Program, and utility workforce consideration.

BUILDING DECARBONIZATION POLICY

In September 2018, former Governor Brown signed two bills into law related to reducing GHG emissions from buildings, SB 1477 and AB 3232. SB 1477 calls on the CPUC to develop, in consultation with the CEC, two programs (BUILD and TECH) aimed at reducing GHG emissions associated with buildings. AB 3232 calls on the Energy Commission by 2021 to develop plans and projections to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030, working in consultation with the CPUC and other state agencies.

In January 2019, the CPUC issued an OIR on building decarbonization (R.19-01-011). The proposed scope of the rulemaking includes: (1) implementing SB 1477; (2) potential pilot programs to address new construction in areas damaged by wildfires; (3) coordinating CPUC policies with Title 24 Building Energy Efficiency Standards and Title 20 Appliance Efficiency Standards developed at the CEC; and (4) establishing a building decarbonization policy framework. A final decision D.20-03-027 was issued on April 6, 2020, which establishes a framework for CPUC oversight of two building decarbonization pilot programs—the Building Initiative for Low-Emissions Development (BUILD Program) program and the Technology and Equipment for Clean Heating (TECH Initiative) initiative. These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals. SB 1477 makes available $50 million annually for 4 years, for a total of $200 million, derived from the revenue generated from GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the Air Resources Board's (ARB) Cap-and-Trade Program. Incentive eligibility for the BUILD Program shall be limited strictly to newly constructed all-electric building projects, without any hookup to the gas distribution grid.

AFFORDABILITY OIR

On July 12, 2018 the Commission instituted the OIR (R.18-07-006) to develop a common understanding, methods and processes to assess, the impacts on affordability of individual Commission proceedings and utility rate requests. This OIR includes gas, electric, water and communications utilities. On July16, 2020 the Commission issued its decision (D.20-07-032), which defines affordability as the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status. This decision also adopts three metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential utility services, including: hours at minimum wage required to pay for essential utility services; vulnerability index of various communities; and ratio of essential utility service charges to non-disposable household income—known as the affordability ratio. The decision does not adopt an absolute definition of what constitutes affordable essential utility services; rather, the decision adopts metrics and methodologies for assessing affordability across utilities over time. The decision also authorizes a Phase 2 to the proceeding.

PIPELINE SAFETY

In 2011, the CPUC issued an OIR, R.11-02-019, to develop and adopt new regulations on pipeline safety, requiring that the utilities file implementation plans to test or replace natural gas transmission pipelines that do not have sufficient record of a pressure test.

SoCalGas and SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011, pursuant to D.11-06-017. The comprehensive plan covered all of the utilities' approximately 4,000 miles of transmission lines and would be implemented in two phases. Phase 1 focuses on populated areas and Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

In June 2014, the CPUC issued D.14-06-007 approving the utilities' plan for implementing PSEP, subject to after-the-fact reasonableness review, established criteria to determine the costs that may be recovered from ratepayers, and authorized the establishment of balancing accounts to facilitate the recovery of costs for implementing Phase 1.

Subsequently, in D.16-12-063 the Commission approved SoCalGas' and SDG&E's joint application, (Application (A.) 14-12-016, requesting review and recovery of $33.2 million, which is a portion of the tracked PSEP costs incurred prior to June 12, 2014. Additionally, D.16-08-003, approved SoCalGas' and SDG&E's application (A.15-06-013) to establish Phase 2 memorandum accounts. The decision also authorized 50 percent interim cost recovery for Phase 1 actual revenue requirements booked to the regulatory accounts subject to refund, and a long-term procedural schedule for PSEP going forward. D.16-08-003 ordered SoCalGas and SDG&E to transition PSEP to the GRC starting with Test Year 2019 and that future GRC applications could include PSEP costs until implementation of the Plan is complete.

From 2011 through April 2020, SoCalGas and SDG&E have invested approximately $1.8 billion and $464 million, respectively, in PSEP, with additional expenditures planned.

In D,19-02-004, the Commission approved SoCalGas' and SDG&E's second PSEP Reasonableness Review application (A.16-09-005), which presented costs totaling $195 million (including certain costs for which the utilities are not seeking recovery) of pipeline safety projects completed by June 30, 2015. The Commission approved cost recovery of approximately $187 million ($172 million for SoCalGas and $15 million for SDG&E).

In D.19-03-025, the Commission also approved SoCalGas' and SDG&E's PSEP forecast application (A.17-03-021), finding $254.5 million associated with twelve SoCalGas Phase 1B and 2A pipeline projects reasonable and eligible for cost recovery. The decision directs SoCalGas and SDG&E to record costs to a one-way balancing account on an aggregate basis and balance to the authorized revenue requirements.

In December 2018, SoCalGas and SDG&E filed a third joint PSEP reasonableness review application (A.18-11-010) requesting cost review and rate recovery for 83 completed Phase 1 projects. The total costs submitted for review are approximately $941 million ($811 million for SoCalGas and $130 million for SDG&E). SoCalGas and SDG&E anticipate a decision from the Commission in 2020.

SAN JOAQUIN VALLEY OIR

In 2014, Governor Edmund G. Brown, Jr. signed into law AB 2672. This legislation added Public Utilities Code (Pub. Util. Code) Section 783.5, seeking to increase affordable access to energy for disadvantaged communities in the San Joaquin Valley (SJV). Pursuant to Pub. Util. Code § 783.5, R.15-03-010 was initiated in March 2015, with the initial scope of the proceeding limited to identifying eligible disadvantaged communities. D.17-05-014 adopted a methodology for the identification of communities eligible under Section 783.5, and subsequently Phase 2 commenced to address pilot projects and data gathering needs for evaluation of economically feasible energy options for the identified communities.

Pursuant to the updated scoping ruling in R.15-03-010 issued in December 2017, SoCalGas submitted natural gas pilot proposals in January 2018 for seven communities to extend existing pipelines, install gas service to each household, and replace existing propane appliances with new, energy efficient natural gas appliances. In December 2018, SoCalGas was approved to administer a natural gas pilot project in one community, California City, with a budget of $5.6 million.

MOBILE HOME PARK UTILITY UPGRADE PROGRAM

In February 2011, the Commission issued R.11-02-018 to examine what should be done to encourage mobile home parks (MHP) and manufactured housing communities to transfer to direct utility service. In March 2014, D.14-03-021 approved a three-year pilot program (January 1, 2015 through December 31, 2017) to incentivize voluntary conversions of master-metered service at MHPs at a target rate of 10 percent of the spaces within their service territories. In December 2014, the Commission approved Rule No. 44, establishing the MHP Upgrade Program, pursuant to D.14-03-021.

In September 2017, the CPUC issued Resolution (Res.) E-4878 approving SDG&E and SoCalGas' Advice Letters to continue converting 8,100 MHP spaces, or approximately an incremental 5 percent of MHP spaces through 2019. Subsequently, in March 2019, Res.E-4958 authorized an extension of the program through 2021, converting an additional 3.33 percent of spaces in years 2020 and 2021.

In April 2018, the CPUC opened R.18-04-018 to evaluate the existing MHP Pilot Program to determine whether to expand beyond the initial 3-year pilot into a permanent MHP Program. On April 16, 2020, the CPUC voted to establish a 10-year the Mobile Home Park Utility Conversion Program (MHP Program) with a goal of converting 50 percent of eligible MHP spaces, pursuant to D.20-04-004.

FEDERAL REGULATORY MATTERS

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

There has not been any significant activity in this area since the previous CGR was published, as reflected by the items noted below.

EL PASO

El Paso's rates have been the subject of extensive litigation at FERC in recent years. El Paso filed its third GRC in 5 years in September 2010. The 2010 rate case proceeded to a hearing on all issues in 2011 (a first since 1959), with the FERC Commission issuing an initial decision, Opinion No. 528, in 2013, a revised decision, Opinion No. 528-A, issued in 2016, and a further (and likely final) decision, Opinion No. 528-B, in May of 2018. Collectively, these decisions ruled on issues related to revenue requirements, abandonment costs, cost allocation, and rate design. These FERC decisions are currently under review before the U.S. Court of Appeals in the District of Columbia Circuit. A decision from the Court of Appeals is anticipated by the end of 2020.

KERN RIVER

A final ruling was issued in 2013 in Kern River's 2004 GRC. The ruling denied many rehearing requests to revisit the issues litigated in this case and accepted a series of orders retaining Kern River's original 1992 levelized rate design, resulting in reduced rates for eligible shippers, who renew their contracts for another 10- or 15-year period. At the time of this publication, there have not been any new GRC filings made by Kern River.

TRANSWESTERN

Transwestern filed and the FERC approved a settlement agreement in its 2015 rate case. Under the terms of this agreement, settlement transportation base rates remain unchanged through October 2019, and Transwestern may not file another GRC until July 2022. In the interim, the settlement agreement calls for separate proceedings to resolve issues related to capacity release procedures and gas quality.

GTN AND CANADIAN PIPELINES

SoCalGas acquires its Canadian natural gas supplies from the NGTL pipeline located in Alberta, Canada and transports these supplies through the NGTL pipeline in Alberta, to the

Foothills Pipelines Limited Company pipeline (Foothills) in British Columbia, and finally to GTN at the Canadian/U.S. international border.

NGTL filed and received approval in 2016 from its Canadian regulators for a settlement agreement on revenue requirements for its pipeline for 2016-17. Foothills filed and received approval from its Canadian regulators for its annual filing on rate changes for 2015, and separately for 2016.

GTN filed and the FERC approved a settlement agreement in its 2015 rate case. Under the terms of this agreement, transportation base rates will decrease incrementally over 6 years and be approximately 20 percent lower by 2021, relative to current 2014 levels.

GREENHOUSE GAS ISSUES

NATIONAL POLICY

The national GHG Program has been largely based on the Clean Power Plan adopted by the U.S. EPA, pursuant to EPA's authority under the Clean Air Act. The Clean Power Plan established unique emission rate goals and mass equivalents for each state. It was projected to reduce carbon emissions from the power sector 32 percent from 2005 levels by 2030. Individual state targets are based on national uniform "emission performance rate" standards (pounds of carbon dioxide (CO_2) per MWh) and each state's unique generation mix.

On February 9, 2016, the U.S. Supreme Court issued a stay of the EPA's Clean Power Plan, freezing carbon pollution standards for existing power plants while the rule was under review at the U.S. Court of Appeals for the District of Columbia Circuit. In March 2017, President Trump signed an EO to review the Clean Power Plan and if appropriate, suspend, revise or rescind the rule. Subsequently, on October 10, 2017 the EPA released a proposed rule to repeal the Clean Power Plan.

ASSEMBLY BILL 32

The Global Warming Solutions Act of 2006 (AB 32) requires California to reduce GHG emissions to 1990 levels by 2020. AB 32 directed the CARB to adopt rules and regulations to achieve the "maximum technologically feasible and cost-effective GHG emission reductions."[79] The ARB was also required to prepare and approve a Scoping Plan that provides a roadmap to reach the 2020 emissions reduction target. The Scoping Plan was first approved by the ARB in 2008 and must be updated every 5 years. The most recent update, as of this writing, was made in December 2017. The Scoping Plan Updates involve a collaborative process through engagement with the Legislature, State agencies, and a diverse set of stakeholders with public input facilitated through workshops and other meetings. The result is a policy framework that comprises a broad portfolio of GHG reduction strategies and regulations, including market-based compliance mechanisms, performance standards, technology requirements and voluntary reductions.

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79 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

SENATE BILL 32

SB 32 was enacted on September 8, 2016 and went into effect on January 1, 2017. The law extended the goals of AB 32 by setting a 2030 emissions target of 40 percent below 1990 levels. The continuation of the Global Warming Solutions Act keeps California on track with the emission reduction goals of the Paris Agreement. The 2017 Scoping Plan Update incorporated the 2030 goal and constructed California's climate policy portfolio that includes doubling building efficiency, increasing renewable power by 50 percent cleaner zero and near-zero emission vehicles, reducing short-lived climate pollutants such as black carbon and limiting industry emissions through a Cap-and-Trade program. The companion bill to SB 32, AB 197, provided increased legislative oversight of the ARB and directed it to take certain actions to improve local air quality. Those actions include requiring the public posting of air quality and GHG information, adopt rules and regulations that protect disadvantaged communities from air toxins and to consider the social cost of carbon when preparing plans to meet GHG reduction goals.

SENATE BILL 350

The Clean Energy and Pollution Reduction Act, or SB 350, was signed into law on October 7, 2015 and sets ambitious goals that will help the State achieve the emissions reduction targets of SB 32. SB 350 increases and extends the RPS targets to 50 percent by 2030. Additionally, the law requires the state to double statewide energy efficiency savings in both the electric and natural gas sectors by 2030. The GHG reduction targets associated with these requirements are to be incorporated into IRPs, which detail how each required utility will reduce GHGs, deploy clean energy resources and otherwise meet the resources needs of their customers. The Energy Commission is coordinating with other state agencies—including the: CPUC, ARB, and CAISO—to implement the bill. SoCalGas has been engaged with these agencies throughout the process, and has been providing input.

SENATE BILL 1383

SB 1383 was signed into law on September 19, 2016, establishing methane emissions reduction targets in a statewide effort to reduce emissions of Short-Lived Climate Pollutants (SLCP) in various sectors of California's economy.[80] SB 1383 requires a 40 percent reduction in methane, a 40 percent reduction on hydrofluorocarbon gases and a 50 percent reduction in

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80 http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

anthropogenic black carbon by 2030, relative to 2013 baseline levels and requires the ARB, the CPUC, and the CEC to undertake various actions related to reducing SLCPs in the state.
SB 1383 also establishes targets to achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. The law grants CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and establishes an additional target that not less than 20 percent of currently disposed edible food is recovered for human consumption by 2025. The bill mandates the ARB, in consultation with the Department of Food and Agriculture, to adopt regulations to reduce methane emissions from livestock and dairy manure operations. SB 1383 also requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of RG.

Pursuant to SB 1383, the ARB formed a Dairy and Livestock GHG Reduction Working Group in 2017 to help understand ways to reduce dairy and livestock methane emissions by 40 percent from 2013 levels by 2030. The working group's assignment was to identify and address technical, market, regulatory, and other barriers to development of methane reduction projects. SoCalGas actively participated in the working group and its three sub-groups including SoCalGas staff serving as co-chair of the Fostering Markets for Digester Projects sub-group whose task was to establish a roadmap, attentive to the SB 1383 statute dates of July 1, 2020 and January 1, 2024, to significantly expand the number of livestock digester projects in California that support the state's climate and air quality goals.

SoCalGas has participated in the CDFA Dairy Digester Research and Development Program (DDRDP), which provides financial assistance for the installation of dairy digesters in California, which will result in reduced GHG emissions. SoCalGas staff in SJV attended and presented at CDFA DDRDP workshops, webinars and listening sessions held in environmental justice (also known as disadvantaged communities) areas near dairies. We also provide education and assist customers who are interested in the CDFA Program, as well as on other topics related to RNG, such as alternative fuel vehicles. A specific example is our promotion of RNG in our marketing materials especially those developed and displayed at the International Ag Expo held every year in Tulare, California. CDFA also includes a link on their DDRDP website to SoCalGas' RG website.

SENATE BILL 100 AND EXECUTIVE ORDER B-55-18

The 100 Percent Clean Energy Act of 2019, or SB 100, was signed into law on September 10, 2018. SB 100 sets a state policy that eligible renewable energy and zero-carbon resources supply 100 percent of all retail sales of electricity in California by 2045. The bill also accelerates California's RPS, which, pursuant to a 2016 bill by the same author (SB 350), already mandates that load-serving entities procure at least 50 percent of retail sales from eligible renewable energy resources by 2030; under SB 100, the 2030 target will be increased to 60 percent, and the 50 percent target will be advanced to 2026, in recognition that California retail sellers are well on their way to achieving the target in advance of the existing deadlines. EO B-55-18 establishes a new statewide goal to achieve economy-wide carbon neutrality no later than 2045.

ASSEMBLY BILL 3232

The zero-emissions buildings and sources-of-heat energy bill requires the CEC to assess the potential for the state to reduce the emissions of GHGs from the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030. Their report is due January 2021.

GHG RULEMAKING

Beginning on January 1, 2015, the ARB's Cap-and-Trade Program expanded to include emissions from all SoCalGas customers. SoCalGas is required to purchase carbon allowances or offsets on behalf of our end-use customers for the emissions generated from the full combustion of the natural gas we deliver. Large end-use customers who emit at least 25,000 mtCO_2e equivalent per year have a direct obligation to the ARB for their own emissions; therefore, SoCalGas' obligation does not include these customers and they will not be responsible for compliance costs related to end-users from SoCalGas.

The CPUC completed a rulemaking proceeding in late 2015 to determine how the costs related to compliance with the Cap-and-Trade program will be included in end-use customers' rates.[81] The rulemaking had also addressed how revenues generated from the sale of directly allocated allowances will be returned to ratepayers. The rulemaking had initially determined that all Cap-and-Trade compliance costs will be included on a forecasted basis in customers'

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81 CPUC D.15-10-032.

transportation rates beginning April 1, 2016. Customers with a direct obligation to the ARB for their emissions are exempt from SoCalGas' end-users' compliance obligation, and will receive a volumetric credit called the "Cap-and-Trade Cost Exemption" for the amount of their transportation rates that contribute to these costs. All customers' rates will also include compliance costs related to SoCalGas' covered facilities, as well as for Lost and Unaccounted For (LUAF) gas.

In the same CPUC decision, it was determined that revenues generated from the sale of directly allocated allowances would be returned as a fixed, once-annual, California Climate Credit to all residential households on their April bills. Nonresidential customers were not to receive a California Climate Credit. An Application for Rehearing on the use of the revenues generated from the sale of directly allocated allowances was granted in April 2016. As such, the introduction of Cap-and-Trade costs into rates and the distribution of the gas California Climate Credit was delayed. In March 2018, the CPUC issued its Final Decision (D.18-02-017), which directed IOUs to recover Cap-and-Trade costs and distribute the California Climate Credit. It found that: (1) only residential customers are eligible for the California Climate Credit, with the initial Climate Credit to be distributed in October 2018 and in April ever year thereafter; (2) GHG compliance costs can be incorporated in transportation rates beginning July 1, 2018, with 2018 costs amortized over 18 months; and (3) the accumulated 2015-2017 GHG costs and revenues are to be netted, with the remaining balance either distributed in the 2018 Climate Credit or amortized in transportation rates.

REPORTING AND CAP-AND-TRADE OBLIGATIONS

The ARB publishes total, covered and non-covered emissions because total emissions are used to calculate California's GHG emissions inventory and covered emissions are used to determine a facility's Cap-and-Trade obligation. At the time of the writing of the 2020 CGR, the 2019 GHG numbers have not been verified by the independent third party. The 2018 numbers are the most recent verified numbers for the reporting category. As of 2018, SoCalGas reported to the ARB *verified* GHG emissions of approximately 41.4 mmtCO_2e in three primary categories: (1) combustion emissions at five compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2e; (2) vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

In 2018, GHG emissions for gas delivered to all customers was 39.9 mmtCO_2e, but 20.7 mmtCO_2e for gas delivered to non-covered customers. Non-covered customers consist of smaller customers with emissions of less than 25,000 mtCO_2e. For Cap-and-Trade obligation, 20.7 mmtCO_2e is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and-Trade bill.

Four of the five facilities subject to the EPA's mandatory reporting regulation are also subject to ARB's Cap-and-Trade Program. On January 1, 2015, natural gas suppliers became subject to the Cap-and-Trade Program and now have a compliance obligation for GHG emissions from the natural gas use of their small customers (i.e., those customers who are not covered directly under ARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 22.0 mtCO_2e for 2019. ARB will issue final 2019 GHG emissions compliance obligations for natural gas suppliers in November 2020.

The adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Pub. Util. Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, and the Commission's General Order 112-F are covered under R.15-01-008. As part of this rulemaking, natural gas utilities are required to annually report their methane emissions from intentional and unintentional releases as well as their leak management practices. In 2020, SoCalGas reported 2.2 Bcf of methane emissions from intentional and unintentional releases for the year 2019. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

MOTOR VEHICLE EMISSIONS REDUCTIONS

National GHG policymakers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Under the EPA's Mandatory Reporting of GHGs rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of CO_2, nitrous oxide, and methane from their products.

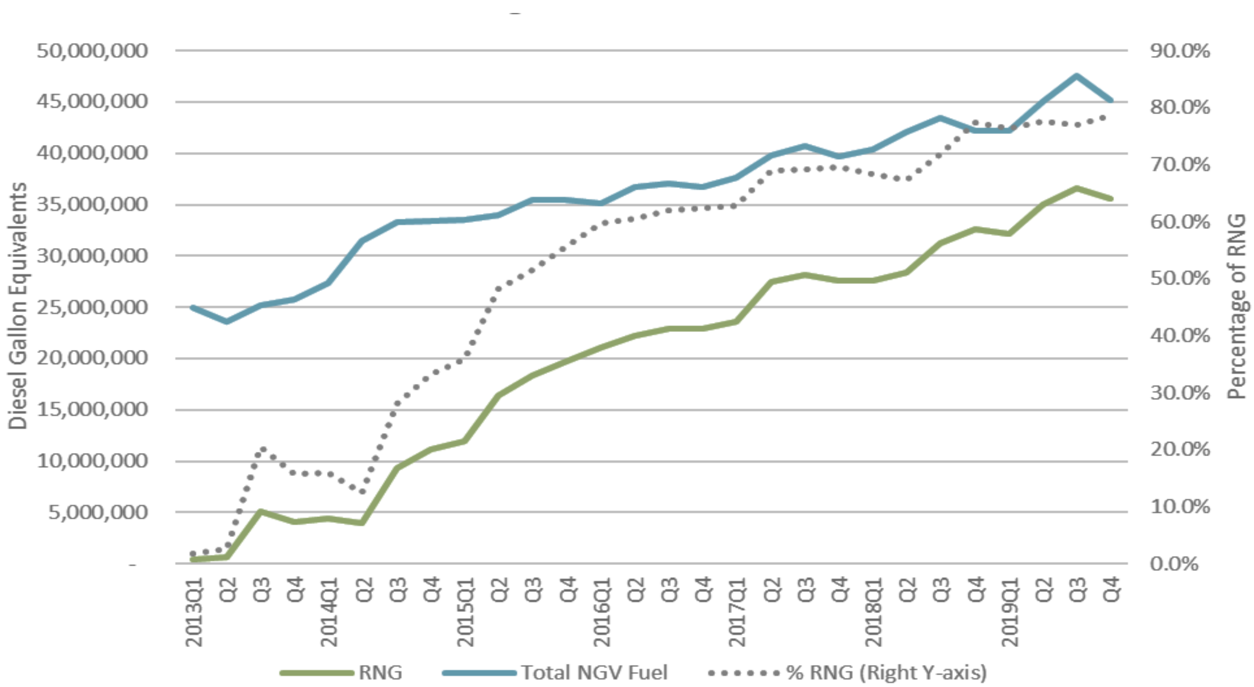
LOW CARBON FUEL STANDARD

Established by EO, signed by then Governor Arnold Schwarzenegger in 2007, the LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. In 2019, the LCFS was updated and now requires a 20 percent carbon intensity by 2030 in the transportation sector. The LCFS requires fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, a declining standard for GHG emissions measured in CO_2 equivalent grams per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for natural gas, H2 and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet. Further, the CPUC has authorized the utilities to sell LCFS credits generated both by their use of low-carbon fuel vehicles and those generated by utility-owned public refueling stations. The revenue generated by the sale of these credits is being returned to the customers who generated the credits, further enhancing the value of low-carbon fuels.

SoCalGas opted into the LCFS program in 2013 and began generating credits from utility-owned CNG refueling stations that serve both company vehicles and the general public. The value from the credits generated is returned to CNG customers by reducing the price at the pump. In 2018, the CPUC approved a SoCalGas Advice Letter to initiate a Voluntary RNG Procurement Pilot program. The program enables SoCalGas to procure and dispense RNG at its utility-owned CNG stations. RNG is an eligible alternative fuel under LCFS program and EPA's Renewable Fuel Standard (RFS). Therefore, it generates Renewable Identification Number credits from the RFS Program in addition to the LCFS credits. Also, RNG has as lower carbon intensity than traditional CNG and will generate more credits per unit of energy under the LCFS program. On April 1, 2019, SoCalGas began procuring 100 percent RNG at all utility-owned CNG stations. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market.

To date, there is a significant amount of RNG being used in California NGVs. The most recent data from the LCFS Program shows that approximately 78 percent of fuel delivered to NGVs in 2019 was RNG. The chart below shows how RNG's role in this important program has grown over time. Since 2013, RNG has delivered more than 3.9 mmt of carbon reductions and displaced more than 560 million gallons of diesel fuel.[82]

**FIGURE 21 – LCFS PROGRAM NGV FUEL STATISTICS
RNG'S GROWING ROLE IN CALIFORNIA'S TRANSPORTATION FUEL MARKET**



The California NGV market represents an important growth opportunity for RNG due to the economic incentives available from the LCFS Program and the Federal Renewable Fuel Standard, which help to offset the price premium between RNG and relatively-abundant traditional natural gas. NGV demand in California is forecasted to grow, driven primarily by the urgent need to reduce smog-forming tailpipe NOx emissions from heavy-duty diesel engines, and the growing price spread between gasoline and diesel and natural gas. The EIA forecasts a 5.3 percent annual growth rate for NGV volumes in the Pacific region through 2050.[83]

82 LCFS Reporting Tool Quarterly Summaries: https://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

83 EIA 2018 Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/.

PROGRAMMATIC EMISSIONS REDUCTION: CALIFORNIA GHG REDUCTION STRATEGIES

The ARB has the responsibility to develop the broad strategies to achieve California's GHG emissions reduction targets. The 2017 Scoping Plan Update identified several strategies to achieve the 2030 target to reduce emissions by 40 percent from 1990 levels: double building efficiency; 50 percent renewable power; cleaner transportation; and reduce SLCPs and Cap emissions from various sectors. The SLCP includes targets to reduce methane emissions from organic sources of methane and methane leakage from the oil and gas industry.

The CPUC has an on-going R.15-01-008 to implement SB 1371, which requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities. In D.17-06-015, utilities were ordered to implement a Natural Gas Leak Abatement Program consistent with 26 Best Practices for emission mitigation. This proceeding is led by the CPUC in consultation with the ARB. The first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

RENEWABLE NATURAL GAS

Biomethane, or RNG, plays an important and growing role in helping California meet its environmental goals. Currently, RNG is predominantly recovered from organic waste streams, including landfills, agricultural operations, and wastewater treatment facilities. Sourcing RNG from these resources not only provides GHG reductions for natural gas users, but also helps to better manage these waste streams.

In March of 2019, SoCalGas announced a plan to replace 20 percent of its traditional natural gas supply with RNG by 2030 as part of SoCalGas' vision to be the cleanest gas utility in North America, delivering affordable and increasingly renewable energy to its customers. To kickstart the plan, SoCalGas will pursue regulatory authority to implement a broad RNG procurement program with a goal of replacing 5 percent of its natural gas supply with RNG by

2022. SoCalGas also recently filed a request with the CPUC to allow customers to purchase RNG for their homes. SoCalGas aims to have CPUC approval of its voluntary program by the end of 2020.

SoCalGas is currently procuring RNG for use in its fleet and utility-owned public access NGV fueling stations, thereby encouraging further development of RNG sources, reducing GHG emissions, and advancing California's environmental policies.

In addition to decarbonizing California's transportation sector, RNG can play a significant role in decarbonizing other existing natural gas end uses in California. Approximately 90 percent of Californians use natural gas for space and water heating, and for delivering RNG to these appliances through existing natural gas infrastructure has the potential to seamlessly decarbonize these end-uses without disrupting customer behavior or preferences.

When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane" or "renewable natural gas," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[84] Biogas may also be consumed onsite for a variety of uses, including electrical power generation from internal combustion engines, fuel cells, and turbines, or as a fuel source for NGVs. Currently, there are instances where biogas is being vented naturally or flared to the atmosphere. Venting and flaring wastes this valuable renewable resource and fails to support the state in achieving its emission reduction targets set forth by AB 32 and SB 1383, whereas captured and processed RNG injected into a gas pipeline system can ultimately count towards satisfying AB 32 and SB 1383 emission reduction goals. In light of this, the legislature established SB 1440 which would require the CPUC, in consultation with the ARB, to consider adopting biomethane procurement targets or goals for each of the state's gas corporations.[85]

AB 1900 (2012, Gatto) required that the Commission open a rulemaking to ensure that each gas corporation provide non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the

84 SoCalGas' Tariff Rule 30 (https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

85 SB 1440 (Hueso, 2018): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1440.

safe delivery of gas.[86] On February 13, 2013, the Commission opened R.13-02-008, OIR to Adopt Biomethane Standard and Requirement, Pipeline Open Access Rules, and Related Enforcement Provisions (Biomethane OIR). In collaboration with and the Office of Environmental Health Hazard Assessment, the Commission determined that biomethane could be safely injected into the natural gas pipeline system in D.14-01-034 (adopted January 16, 2014).[87] D.14-01-034 adopted Pipeline injection standards for 17 "constituents of concern" potentially found in biomethane. H2 is one of the 17 "constituents of concern, and an injection standard of 0.1 percent of H2 was adopted for biomethane injected into gas pipelines. The statute directs that the pipeline injection standards shall be revisited every 5 years.[88] The establishment of biomethane injection standards is Phase 1 of the Biomethane OIR. Phase 2 of the Biomethane OIR resulted in D.15-06-029, which adopted a biomethane interconnector monetary incentive program. The objective of the program is to encourage the development of biomethane projects that are interconnected to the utilities' gas pipeline systems. Initially, the incentive program authorized a total of $40 million for incentives, up to $1.5 million per project, for projects that successfully interconnect and operate by June 11, 2020. The incentives are paid by the gas utility that operates the pipeline system where the facility interconnects. Pub. Util. Code § 399.19[89] extended the monetary incentive program to December 31, 2021 and increased the incentives to $3 million for non-dairy clusters and $5 million for dairy clusters.

In October 2019 Governor Newsom signed into law SB 457, which extends the program until December 31, 2026, or until all available program funds are expended, whichever occurs first. In accordance with SB 457, CPUC D.19-12-009[90] extends the date for awarding pipeline interconnection incentives. This Decision also implements an Incentive Reservation System for the biomethane monetary incentive program established in D 15-06-029. The Incentive

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86 AB 1900 (Gatto 2012): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201120120AB1900.

87 D.14-01-034: Decision Regarding the Biomethane Implementation Tasks in AB 190: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF.

88 See Health and Safety Code, §§ 25421(a) and 25421(e).

89 AB 2313 (Williams 2016): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB2313.

90 D.19-12-009: Decision Establishing a Reservation System for the Biomethane Incentive Program, Extending Date and Addressing Rate Recovery for Pipeline Interconnection Infrastructure: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M321/K901/321901043.PDF.

Reservation System allows project developers to reserve incentive funds during the development phase of a project and receive the funds once the project is interconnected and operating. Applications for the Incentive Reservation System are designed to ensure that only viable projects can secure a spot on the reservation list. The Commission maintains the Incentive Reservation System and makes it publicly available to promote the transparency of the use of funds. As of the time of this writing, all $40 million for incentives have been reserved by 11 biomethane projects currently in development, while an additional 8 projects are on a waiting list for possible incentive funding.[91]

Phase 3 of the Biomethane OIR addresses the need for a standard statewide RG interconnection tariff and interconnection agreement. An August 22, 2019 Ruling established a schedule to develop the standard tariff and required SoCalGas, SDG&E, Southwest Gas, and PG&E to file a standard RG Interconnection Tariff (Rule) and Agreement.[92] The proposed joint utility RG Interconnection Rule was filed on November 1, 2019, and the proposed RG Interconnection Agreement was filed on May 1, 2019.

Phase 4 of the Biomethane OIR was opened November 21, 2019.[93] It will address two issues: (1) standards for injection of renewable H2 into gas pipelines; and (2) implementation of SB 1440 to consider adopting biomethane procurement targets or goals for each gas corporation.

One of the primary policy drivers of California RNG development is SB 1383 (as discussed above). SB 1383 required, among other things, that the CPUC implement "at least 5 dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system."[94] For these pilot projects the gas corporations may fund and recover in rates the cost of pipeline infrastructure, including biogas collection lines and interconnection to existing pipelines, removing many upfront costs developers would otherwise have to incur. The pilot

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91 https://www.cpuc.ca.gov/renewable_natural_gas/.

92 Assigned Commissioner's Ruling on Joint Motion Regarding Further Procedural Schedule for a Standard Renewable Gas Interconnection Tariff and Agreements: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K290/311290174.PDF.

93 Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of R.13-02-008: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.

94 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

project Selection Committee consisted of staff members and attorneys from the CPUC, the ARB, and the CDFA. On December 3, 2018 the Selection Committee identified the selected six Dairy Biomethane Pilot Projects.[95] Four of these are in SoCalGas' service territory: CalBioGas Buttonwillow LLC; CalBioGas North Visalia LLC; CalBioGas South Tulare LLC; and Lakeside Pipeline LLC. (The other two projects are in PG&E's service territory: Maas Energy Works in Merced; and DVO's Weststeyn Dairy in Willows.)

HYDROGEN

Hydrogen is the simplest and most abundant element, making up approximately 75 percent of the observable universe. Hydrogen can be utilized as a fuel to generate energy. With its abundance and simple chemical structure, hydrogen can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen has favorable emissions characteristics because it does not contain carbon or produce GHG when it is consumed. For this reason, hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[96]

As part of the State of California's climate strategy, hydrogen can provide important GHG emissions reductions, and can also play a key role in enabling the use of zero-emissions fuel cell electric vehicles, which can reduce criteria emissions from on-road diesel, the largest and hardest to electrify contributors to the State's black carbon and nitrogen oxides (NOx) inventories.[97] California has also been at the forefront of developing hydrogen fueling stations to demonstrate the feasibility of hydrogen-fueled transportation and the potential that such a network creates for deployment of light duty fuel-cell electric vehicles (FCEVs).

Hydrogen fuel for transportation was adopted in California through the policy framework by Assembly Bill (AB) 8, which provided certainty for hydrogen fueling station deployment.[98] In addition, new programs and policies have been developed and initiated to ensure that some of the most ambitious public-private goals are met as projected. The Low Carbon Fuel Standard's (LCFS) Hydrogen Refueling Infrastructure (HRI) credit provisions took effect, predicated on the

95 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

96 http://hydrogencouncil.com.

97 https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm.

98 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8.

goal of reaching 200 hydrogen stations by 2025 as described by Governor Brown's Executive Order B-48-18 (EO B-48-18).[99]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. The two primary technological processes used today to produce hydrogen are electrolysis and reformation, including steam methane reformation (SMR) and autothermal reformation (ATR). Hydrogen is also produced when organic mass is gasified, but this "syngas," consisting of mainly carbon monoxide (CO) and hydrogen, is typically an intermediate product often used to generate methane or electricity. Reforming is a mature technology and is the most economical way to produce hydrogen, supplying 95 percent or more of the hydrogen used in the United States today.[100] The electrolysis process uses renewable electricity to split water (H_2O) into H_2 and oxygen (O_2).

As a gaseous fuel, hydrogen can help decarbonize the gas grid and be used in a variety of end use applications, beyond transportation. The hydrogen can either be stored directly, or methanated and injected into the natural gas grid to be stored and delivered to a variety of end uses, supplementing or displacing traditional natural gas. Storing hydrogen from electrolysis is a scalable and versatile energy storage pathway.

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99 https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html.

100 The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology, Institute of Transportation Studies, UC Davis (March 2017), available at https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS- RR-17-04-1.pdf

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 is defined as a 1-in-35 likelihood event foreach utility's service area. This criteria correlates to a system average temperature of 40.5 degrees F for SoCalGas' service area and 43.0 degrees F 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 following table provides forecasted core extreme peak day demand.

TABLE 29 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND (MMcf/d)

Year	SoCalGas Core Demand (1)	SDG&E Core Demand (2)	Other Core Demand (3)	Total Demand
2020	2,912	425	123	3,460
2021	2,892	424	124	3,440
2022	2,878	425	125	3,427
2023	2,856	423	126	3,405
2024	2,834	422	126	3,382
2025	2,809	420	127	3,357
2026	2,782	419	128	3,329

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 SWG, City of Long Beach, and City of Vernon.

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 30 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION (MMcf/d)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore Non-EG (4)	EG (5)	Total Demand
2020	2,752	400	103	661	1,068	4,983
2021	2,732	399	104	659	1,072	4,967
2022	2,718	400	105	664	1,105	4,992
2023	2,698	398	105	668	1,106	4,975
2024	2,676	397	106	671	1,089	4,940
2025	2,652	395	107	674	1,119	4,948
2026	2,626	394	108	674	1,101	4,902

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 SWG, City of Long Beach, and City of Vernon.

(4) Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, SWG, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.

(5) EG includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20 MW), refinery-related cogeneration, and EOR-related cogeneration.

The SoCalGas and SDG&E system is a winter peaking system; 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 31 – SUMMER HIGH SENDOUT DAY DEMAND
(MMcf/d)

Year	High-Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore Non-EG (5)	EG (6)	Total Demand
2020	Sep	620	94	28	536	1,928	3,206
2021	Sep	613	94	28	531	1,894	3,160
2022	Sep	612	94	28	536	1,936	3,206
2023	Sep	605	94	28	538	1,952	3,217
2024	Sep	598	93	29	540	1,631	2,891
2025	Sep	589	93	29	542	1,646	2,899
2026	Sep	580	92	29	541	1,626	2,868

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 SWG, City of Long Beach, and City of Vernon.

(5) Average daily summer Noncore-Non-EG demand. Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, SWG, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.

(6) Highest demand during the high-demand month under 1-in-10 dry hydro conditions, except year 2020, when the EG highest demand is based on 2020 hydro condition.

Highest demand during the high-demand month under 1-in-10 dry hydro conditions, except year 2020, when the EG highest demand is based on 2020 hydro condition.

2020 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

TABLE 32 – SoCalGas
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019

Line	CAPACITY AVAILABLE		2015	2016	2017	2018	2019
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		122	89	84	104	97
	Out-of-State Gas						
11	Other Out-of-State		2,397	2,342	2,434	2,246	2,305
12	Total Out-of-State Gas		2,397	2,342	2,434	2,246	2,305
13	TOTAL SUPPLY TAKEN		2,519	2,431	2,518	2,350	2,402
14	Net Underground Storage Withdrawal		40	80	(14)	(8)	7
15	TOTAL THROUGHPUT (1)(2)		2,559	2,511	2,504	2,342	2,409
	DELIVERIES BY END-USE						
16	Core	Residential	548	557	565	569	645
17		Commercial	207	213	214	217	226
18		Industrial	58	55	55	57	61
19		NGV	35	36	38	40	41
20		Subtotal	848	861	872	883	973
21	Noncore	Commercial	52	57	56	59	58
22		Industrial	362	391	389	389	357
23		EOR Steaming	46	39	39	38	51
24		Electric Generation	795	740	713	615	589
25		Subtotal	1,255	1,228	1,198	1,102	1,055
26	Wholesale/International		428	390	401	333	342
27	Co. Use & LUAF		28	31	33	25	39
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,559	2,511	2,504	2,342	2,409
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	52	56	62	71	74
30	Noncore	Commercial/Industrial	414	449	446	448	415
31		EOR Steaming	46	39	39	38	51
32		Electric Generation	795	740	713	622	589
33		Subtotal-Retail	1,307	1,284	1,260	1,181	1,129
34	Wholesale/International		428	390	401	333	342
35	TOTAL TRANSPORTATION & EXCHANGE		1,735	1,674	1,660	1,513	1,471
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0353	1.0345	1.0343	1.0319	1.0336

NOTES:

(1) The wholesale volumes only reflect natural gas supplied by SoCalGas; and, do not include supplies from other sources. Refer to the supply source data provided in each utility's report for a complete accounting of their supply sources.

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

(3) The table does not explicitly show any curtailment numbers for the recorded years because, during some curtailment events, the estimate of the curtailed volume is not available. While the table does not explicitly show any curtailment numbers for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 33 – SoCalGas: TABLE 1-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
RECORDED YEARS 2020-2024
AVERAGE TEMPERATURE YEAR

LINE			2020	2021	2022	2023	2024	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, OEHI) 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/		990	990	990	1,250	1,250	5
6	Total Out-of-State Gas		2,965	2,965	2,965	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,175	3,175	3,175	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,399	2,384	2,394	2,358	2,286	9
10	TOTAL SUPPLY TAKEN		2,462	2,447	2,457	2,421	2,349	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,462	2,447	2,457	2,421	2,349	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	629	624	614	605	596	13
14		Commercial	209	208	213	210	206	14
15		Industrial	54	52	52	51	50	15
16		NGV	42	43	43	44	45	16
17		Subtotal-CORE	934	926	922	911	896	17
18	NONCORE	Commercial	51	51	51	52	51	18
19		Industrial	391	386	389	391	393	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	669	667	679	657	611	21
22		Subtotal-NONCORE	1,143	1,136	1,152	1,132	1,088	22
23	WHOLESALE &	Core	187	188	188	188	187	23
24	INTERNATIONAL	Noncore Excl. EG	53	53	53	54	54	24
25		Electric Generation (EG)	113	113	112	106	94	25
26		Subtotal-WHOLESALE & INTL.	353	353	353	347	335	26
27		Co. Use & LUAF	31	31	31	31	30	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,462	2,447	2,457	2,421	2,349	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	70	70	71	71	70	29
30	NONCORE	Commercial/Industrial	442	437	441	443	444	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	669	667	679	657	611	32
33		Subtotal-RETAIL	1,213	1,206	1,222	1,203	1,158	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	353	353	353	347	335	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,566	1,560	1,575	1,550	1,493	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., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)
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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2020	2021	2022	2023	2024
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.6	0.6	0.6	0.5	0.5

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

	2020	2021	2022	2023	2024
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	894	885	880	868	854

TABLE 34 – SoCalGas: TABLE 2-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
RECORDED YEARS 2025-2035
AVERAGE TEMPERATURE YEAR

LINE			2025	2026	2027	2030	2035	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, OEHI) 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/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,279	2,254	2,198	2,069	2,040	9
10	TOTAL SUPPLY TAKEN		2,342	2,317	2,261	2,132	2,103	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,342	2,317	2,261	2,132	2,103	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	589	580	572	547	543	13
14		Commercial	201	196	192	182	171	14
15		Industrial	49	48	47	44	39	15
16		NGV	45	46	47	49	52	16
17		Subtotal-CORE	885	871	858	822	806	17
18	NONCORE	Commercial	52	51	51	51	51	18
19		Industrial	395	395	391	380	369	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	614	607	577	503	499	21
22		Subtotal-NONCORE	1,093	1,086	1,051	966	951	22
23	WHOLESALE &	Core	187	186	186	185	187	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	54	54	24
25		Electric Generation (EG)	94	91	84	78	78	25
26		Subtotal-WHOLESALE & INTL.	334	331	323	317	319	26
27		Co. Use & LUAF	30	29	29	27	27	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,342	2,317	2,261	2,132	2,103	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	70	69	69	68	68	29
30	NONCORE	Commercial/Industrial	447	447	442	431	419	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	614	607	577	503	499	32
33		Subtotal-RETAIL	1,162	1,155	1,119	1,034	1,018	33
34	WHOLESALE & INTERNATIONAL	All End Uses	334	331	323	317	319	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,497	1,486	1,443	1,351	1,337	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., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)
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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach: 0.5 (2025), 0.5 (2026), 0.4 (2027), 0.4 (2030), 0.4 (2035)
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: 843 (2025), 829 (2026), 816 (2027), 779 (2030), 763 (2035)

TABLE 35 – SoCalGas: TABLE 3-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2020	2021	2022	2023	2024	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, OEHI) 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/		990	990	990	1,250	1,250	5
6	Total Out-of-State Gas		2,965	2,965	2,965	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,175	3,175	3,175	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,477	2,534	2,550	2,497	2,417	9
10	TOTAL SUPPLY TAKEN		2,540	2,597	2,613	2,560	2,480	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,540	2,597	2,613	2,560	2,480	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	683	677	667	658	648	13
14		Commercial	218	217	222	219	215	14
15		Industrial	55	53	53	52	51	15
16		NGV	42	43	43	44	45	16
17		Subtotal-CORE	998	989	985	974	959	17
18	NONCORE	Commercial	52	52	52	53	52	18
19		Industrial	391	386	389	391	393	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	669	727	740	706	654	21
22		Subtotal-NONCORE	1,144	1,197	1,214	1,183	1,131	22
23	WHOLESALE &	Core	200	201	201	200	200	23
24	INTERNATIONAL	Noncore Excl. EG	53	53	54	54	54	24
25		Electric Generation (EG)	113	124	126	118	106	25
26		Subtotal-WHOLESALE & INTL.	366	378	381	372	359	26
27		Co. Use & LUAF	32	33	33	32	31	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,540	2,597	2,613	2,560	2,480	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	72	72	73	73	72	29
30	NONCORE	Commercial/Industrial	443	438	442	444	445	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	669	727	740	706	654	32
33		Subtotal-RETAIL	1,216	1,269	1,287	1,255	1,204	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	366	378	381	372	359	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,582	1,647	1,668	1,628	1,563	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., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)
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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2020	2021	2022	2023	2024
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.7	0.7	0.6	0.6	0.5

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

	2020	2021	2022	2023	2024
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	957	948	943	931	916

TABLE 36 – SoCalGas: TABLE 4-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2025	2026	2027	2030	2035	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, OEHI) 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/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,411	2,394	2,334	2,185	2,155	9
10	TOTAL SUPPLY TAKEN		2,474	2,457	2,397	2,248	2,218	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,474	2,457	2,397	2,248	2,218	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	641	632	623	598	593	13
14		Commercial	210	205	201	191	180	14
15		Industrial	50	49	48	45	40	15
16		NGV	45	46	47	49	52	16
17		Subtotal-CORE	948	933	920	883	866	17
18	NONCORE	Commercial	53	52	52	52	52	18
19		Industrial	395	395	391	380	369	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	654	655	621	537	533	21
22		Subtotal-NONCORE	1,134	1,135	1,096	1,000	985	22
23	WHOLESALE &	Core	200	199	199	198	199	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	54	54	24
25		Electric Generation (EG)	107	104	98	85	85	25
26		Subtotal-WHOLESALE & INTL.	361	358	350	337	339	26
27		Co. Use & LUAF	31	31	30	28	28	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,474	2,457	2,397	2,248	2,218	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	72	71	71	70	70	29
30	NONCORE	Commercial/Industrial	448	448	443	432	420	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	654	655	621	537	533	32
33		Subtotal-RETAIL	1,206	1,206	1,167	1,070	1,055	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	361	358	350	337	339	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,567	1,564	1,518	1,408	1,394	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., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)
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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

Note	2025	2026	2027	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.5	0.5	0.5	0.5	0.5

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

Note	2025	2026	2027	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	905	891	877	840	823

2020 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Energy Resources Department (Long Beach) are shown on the following tables for the years 2020 through 2035.

Long Beach operates the fifth largest municipally owned natural gas utility in the country and is one of only three in the State. The gas utility provides safe and reliable natural gas services to about 500,000 residents and businesses via approximately 150,000 connected gas meters, delivered through more than 1,800 miles of gas pipelines. 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 gas use is split at 53 percent residential and 47 percent commercial/industrial.

Long Beach serves core and noncore customers from three incremental supply sources: (1) interstate supplies delivered into the SoCalGas' intrastate pipeline system; (2) gas storage withdrawals; and (3) local gas delivered directly to Long Beach Energy Resources Department's pipeline system from gas fields within the city. Currently, local production supplies about 5 percent of Long Beach's gas use. Long Beach purchases most of its gas supplies from producers in the South-Western U.S. As a Wholesale customer, Long Beach contracts with SoCalGas for intrastate transmission service to deliver that gas from the California border to its service area.

The City of Long Beach is the only municipal government in the State of California that manages oil operations. Through its Energy Resources Department, the City operates the Wilmington Oil Field and has various financial interests in smaller oil fields throughout the City, such as the Signal Hill East and West Units, Recreation Park, and City Wasem.

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

2020 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT – TABULAR DATA

TABLE 37 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT: TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMCF/D RECORDED YEARS 2015-2019 FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2015	2016	2017	2018	2019	LINE
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	8
		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	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	0.7	0.9	0.6	0.6	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	0.7	0.9	0.6	0.6	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	21.9	22.8	24.6	23.9	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	21.9	22.8	24.6	23.9	25.2	21
22	Subtotal	22.5	23.7	25.2	24.5	26.3	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	22.5	23.7	25.2	24.5	26.3	24

TABLE 37 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2009-2019 FOR THE 2020 CGR REPORT
(CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2015	2016	2017	2018	2019	LINE
1	CORE	Residential	11.9	11.9	11.8	12.1	12.9	1
2	CORE/NONCORE	Commercial	5.4	5.8	6.0	5.9	6.1	2
3	CORE/NONCORE	Industrial	3.7	3.9	4.7	4.3	4.7	3
4		Subtotal	20.9	21.6	22.5	22.3	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.2	1.9	2.2	1.9	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	1.2	1.9	2.2	1.9	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.4	0.2	0.5	0.2	0.8	13
14		Subtotal-END USE	22.5	23.7	25.1	24.5	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		22.5	23.7	25.1	24.5	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.3	2.6	2.9	3.0	3.1	18
19		Non-EOR Cogeneration	1.1	1.8	2.0	1.9	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	3.4	4.3	5.0	4.9	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		3.4	4.3	5.0	4.9	4.7	24
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	32

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

TABLE 38 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2020	2021	2022	2023	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.1	1.1	1.1	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.1	1.1	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	25.2	25.2	25.2	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	25.2	25.2	25.2	25.2	21
22	Subtotal	26.3	26.3	26.3	26.3	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	26.3	26.3	26.3	26.3	24

TABLE 38 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2024	2025	2030	2035	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.1	1.1	1.1	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.1	1.1	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	25.2	25.2	25.2	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	25.2	25.2	25.2	25.2	21
22	Subtotal	26.3	26.3	26.3	26.3	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	26.3	26.3	26.3	26.3	24

TABLE 39 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2020	2021	2022	2023	LINE
1	CORE	Residential	12.9	12.9	12.9	12.9	1
2	CORE/NONCORE	Commercial	6.1	6.1	6.1	6.1	2
3	CORE/NONCORE	Industrial	4.7	4.7	4.7	4.7	3
4		Subtotal	23.8	23.8	23.8	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.7	1.7	1.7	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	1.7	1.7	1.7	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.8	0.8	0.8	0.8	13
14		Subtotal-END USE	26.3	26.3	26.3	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		26.3	26.3	26.3	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.1	3.1	3.1	3.1	18
19		Non-EOR Cogeneration	1.5	1.5	1.5	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	4.7	4.7	4.7	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		4.7	4.7	4.7	4.7	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 39 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2030	2035	LINE
1	CORE	Residential	12.9	12.9	12.9	12.9	1
2	CORE/NONCORE	Commercial	6.1	6.1	6.1	6.1	2
3	CORE/NONCORE	Industrial	4.7	4.7	4.7	4.7	3
4		Subtotal	23.8	23.8	23.8	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.7	1.7	1.7	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	1.7	1.7	1.7	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.8	0.8	0.8	0.8	13
14		Subtotal-END USE	26.3	26.3	26.3	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		26.3	26.3	26.3	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.1	3.1	3.1	3.1	18
19		Non-EOR Cogeneration	1.5	1.5	1.5	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	4.7	4.7	4.7	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		4.7	4.7	4.7	4.7	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 40 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
COLD YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2020	2021	2022	2023	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	21
22	Subtotal	30.8	30.8	30.8	30.8	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.76	30.8	30.8	30.8	24

TABLE 40 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2024	2025	2030	2035	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	21
22	Subtotal	30.8	30.8	30.8	30.8	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.8	30.8	30.8	30.76	24

TABLE 41 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
COLD YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2020	2021	2022	2023	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.8	30.8	30.8	30.8	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.8	30.8	30.8	30.8	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 41 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2030	2035	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.8	30.8	30.8	30.8	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.8	30.8	30.8	30.8	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

2020 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

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 890,818 customers in San Diego County in 2019, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2019 were approximately 86 billion cubic feet (Bcf), which is an average of 235 MMcf/d.

GAS DEMAND

OVERVIEW

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

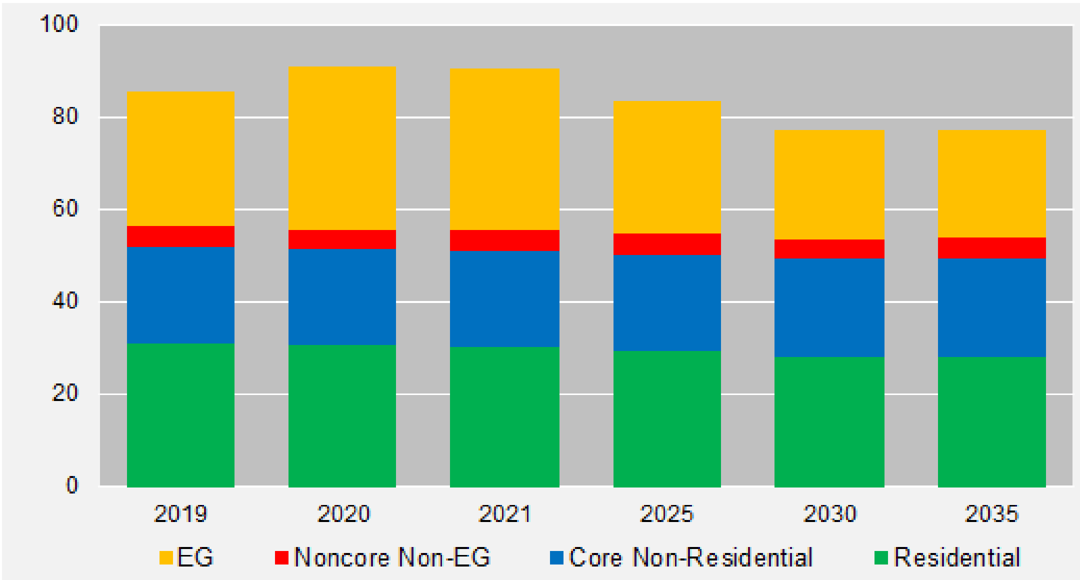
This projection of natural gas requirements, excluding EG demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Weather-normalized non-EG gas demand is projected to drop slightly from 57 Bcf in 2019 to 54 Bcf in 2035. Including EG, overall demand adjusted for average temperature conditions totaled 86 Bcf in 2019 and is expected to drop about 0.6 percent per year to 77 Bcf by 2035.

Assumptions for 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 largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above. San Diego County's total employment is forecasted to grow an average of 0.7 percent annually from 2019-2035; the subset of industrial (mining and manufacturing) jobs is projected to shrink an average of 0.3 percent per year during the same period. The number of SDG&E gas meters is expected to increase an average of 0.73 percent annually from 2019 through 2035.

FIGURE 22 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR (2019-2035) (Bcf/y)



From 2019 through 2035, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 0.6 percent. The decline is driven by future projected reductions in the EG load. Additional factors reducing the load forecast are energy efficiency programs and new requirements on Title 24 building codes and standards.

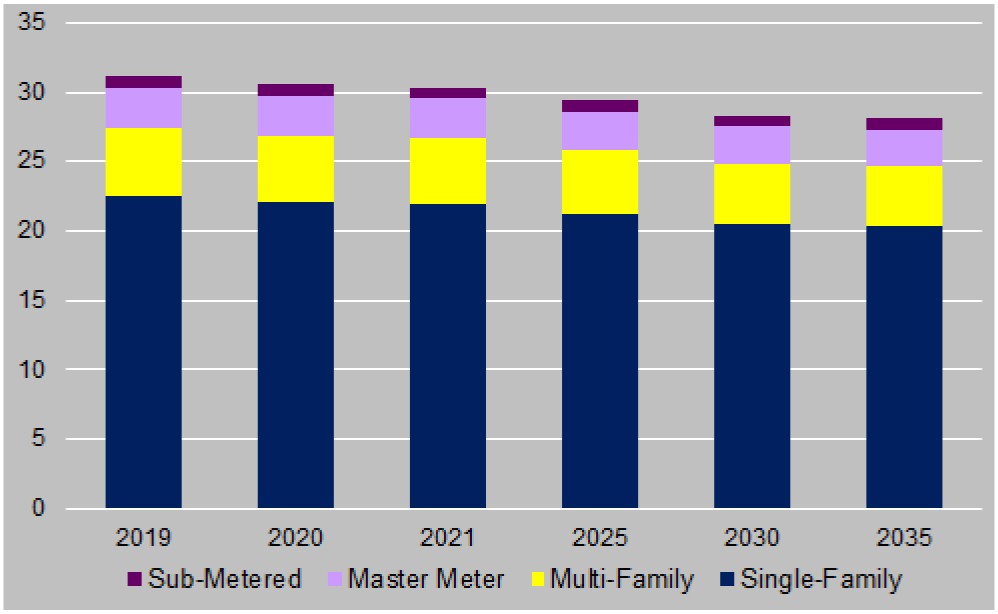
MARKET SECTORS

RESIDENTIAL

The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. Residential demand adjusted for average temperature conditions totaled 31 Bcf in 2019. By the year 2035, the residential demand is expected to drop to 28 Bcf. The change reflects a 0.53 percent average annual rate of decline.

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

FIGURE 23 – COMPOSITION OF SDG&E'S RESIDENTIAL DEMAND FORECAST AVERAGE YEAR WEATHER DESIGN, 2019-2035 (Bcf/y)

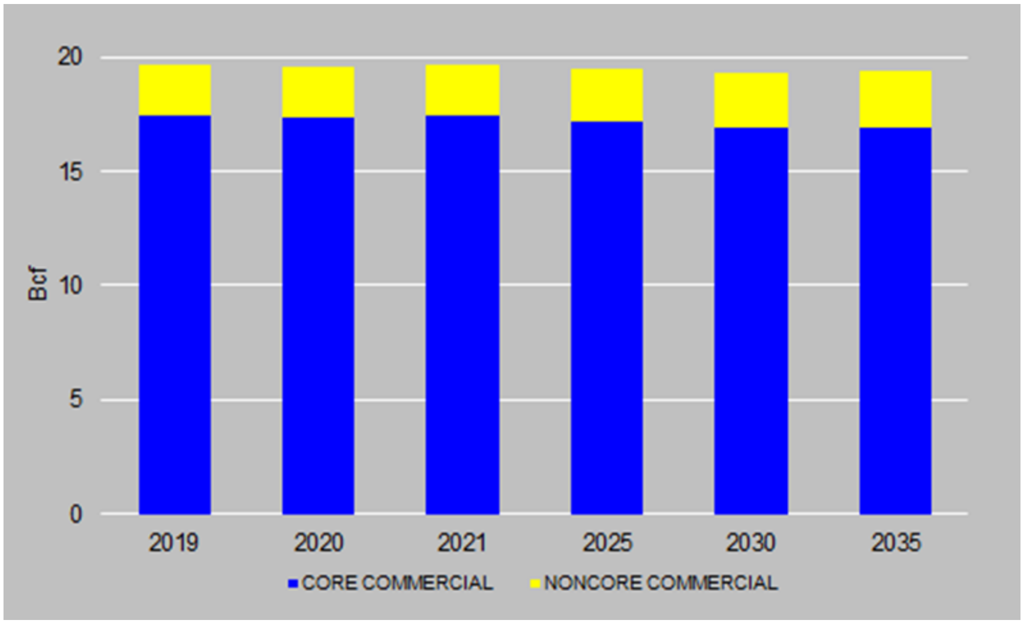


COMMERCIAL

On a temperature-adjusted basis, SDG&E's core commercial demand in 2019 totaled 17.4 Bcf. By the year 2035, the core commercial load is expected to decline slightly to 16.9 Bcf.

SDG&E's non-core commercial load in 2019 was 2.3 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 0.6 percent per year to 2.5 Bcf by 2035, driven by increased economic activity and employment.

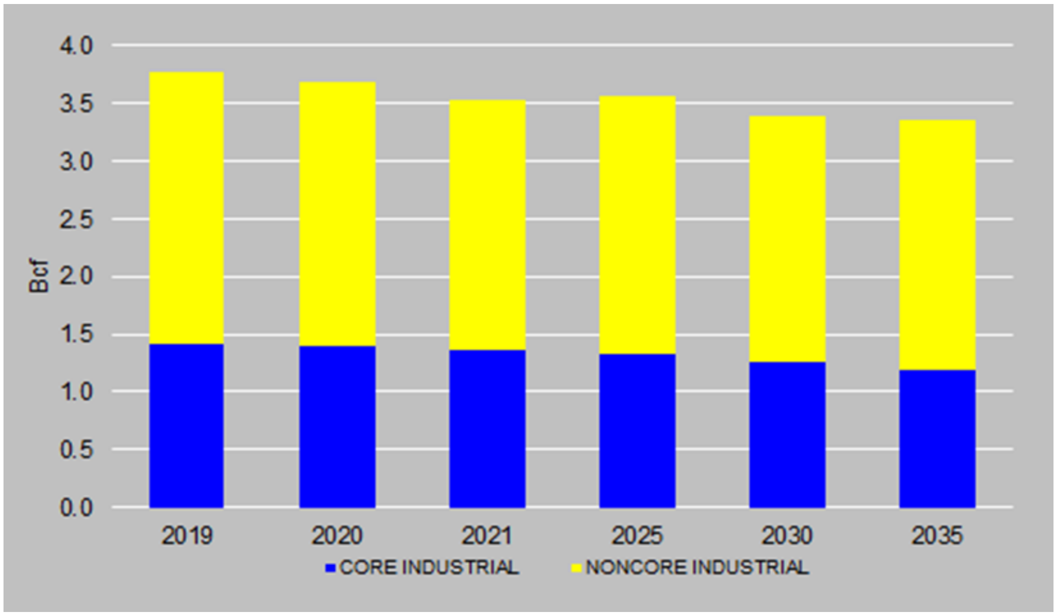
**FIGURE 24 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2019-2035)**



INDUSTRIAL

Temperature-adjusted core industrial demand was 1.41 Bcf in 2019 and is expected to decline to 1.19 Bcf by 2035, an average decrease of 1.1 percent per year. This result is due to slightly lower employment growth and the impact of savings from CPUC-authorized energy efficiency programs in the industrial sector.

**FIGURE 25 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2019-2035)**

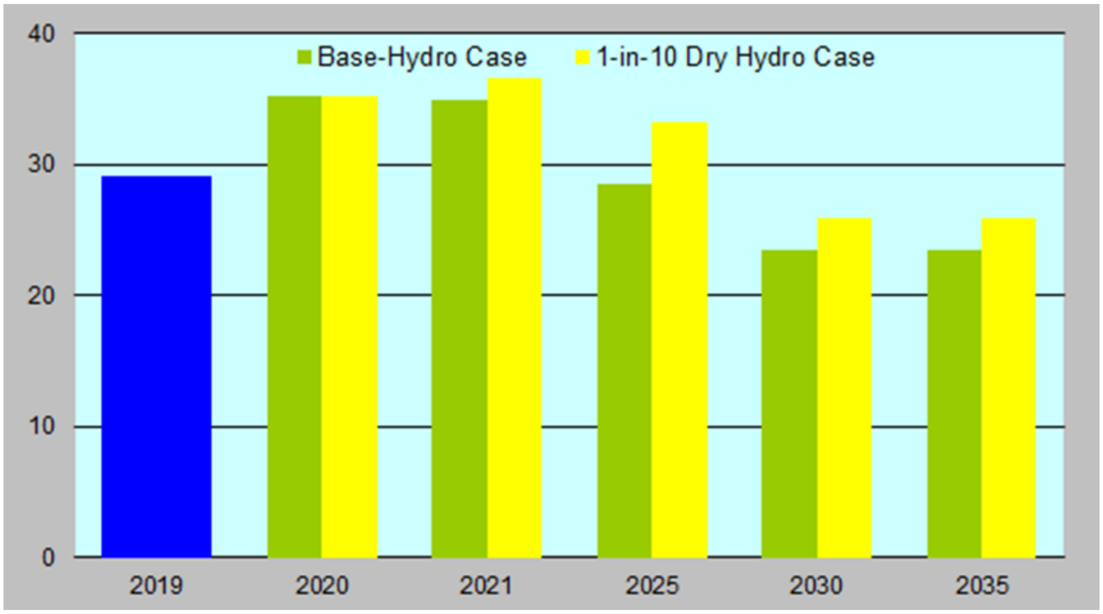


Non-core industrial load in 2019 was 2.4 Bcf and is expected to shrink about 0.6 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher energy efficiency and higher carbon-allowance fees will more than offset slight increases from economic growth.

ELECTRIC GENERATION

Total EG, including cogeneration and non-cogeneration EG, was 29 Bcf in 2019. From 2019, EG load is expected to decline an average of 1.35 percent per year to 23 Bcf by 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 26 – SDG&E'S TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, 2019-2035
(Bcf/y)



Small Cogeneration (<20 MW)

Small EG load from self-generation totaled 7.0 Bcf in 2019. By 2035, small EG load is expected to drop to 5.8 Bcf – dropping an average of 1.2 percent per year. Demand-dampening effects of higher carbon-allowance fees will more than offset slight increases from economic growth.

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 for "Electric Generation Including All Cogeneration EG demand is forecasted to decrease from 29 Bcf in 2020 to 18 Bcf in 2030. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. The EG forecast is held constant at 2030 levels through 2035, as previously explained.

A 1-in-10 year dry hydro sensitivity forecast has also been developed. A dry hydro year increases SDG&E's EG demand on average for the forecast period by approximately 4 Bcf per year. For additional information on EG assumptions, such as renewable generation, GHG adders and sensitivity to electric demand and attainment of renewables' goals, refer to the EG section of the SoCalGas EG chapter.

NATURAL GAS VEHICLES

Natural gas is a clean-burning alternative vehicle fuel that offers several advantages to users when compared to diesel. According to the Clean Cities Guide to Alternative Fuel and Advanced Medium- and Heavy-Duty Vehicles by the U.S. DOE,[101] a switch from conventional diesel vehicles to NGVs has the potential to result in lower levels of emissions, including NOx and particulate matter. In 2019 alone, SDG&E's NGVs displaced the equivalent of 17 million gallons of gasoline and prevented around 75 thousand metric tons of emissions. Additionally, natural gas is generally less expensive than diesel or gasoline, which can become an attractive option for buyers in the heavy-duty vehicle industry.

SDG&E customers benefit from the LCFS credits generated from the gas consumed at utility owned CNG stations. The revenue from the sales is distributed to consumers as a price reduction at those fueling stations.

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 percent renewable natural gas (RNG) at all utility-owned CNG stations, which provides significant GHG emission reduction benefits.

However, growth may be offset by competing technologies and fuels, as well as the potentially lower cost differential between petroleum (gasoline and diesel) and natural gas. In 2019, SDG&E served 33 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 2 Bcf of natural gas. The SDG&E NGV market is expected to grow at an average annual rate of 3 percent over the forecast horizon.

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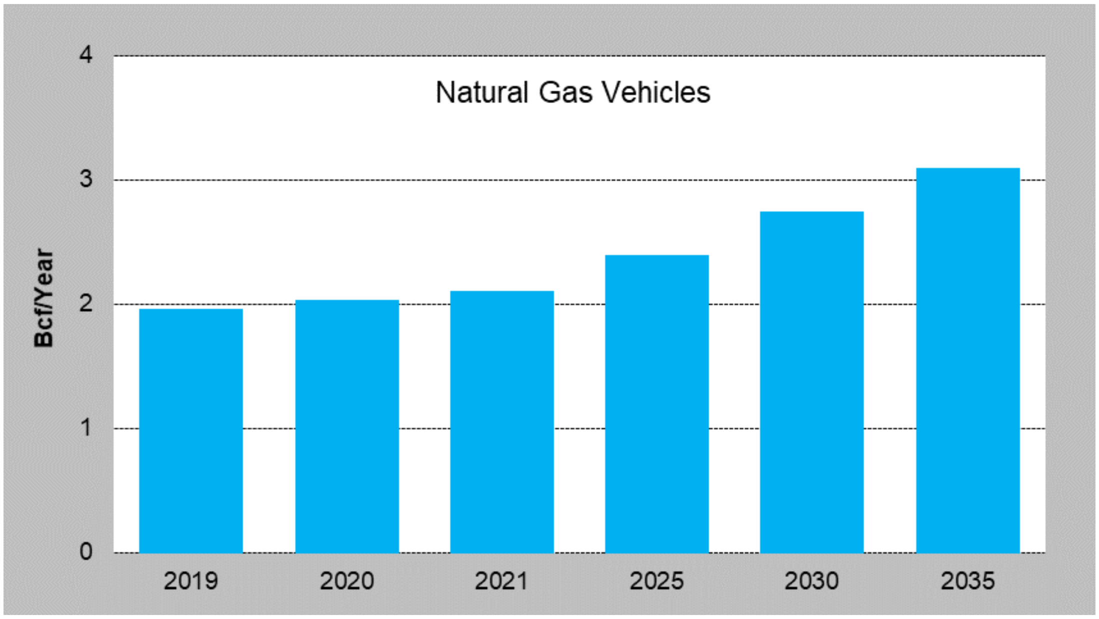
101 U.S. DOE | Energy Efficiency & Renewable Energy: *Clean Cities Guide to Alternative Fuel and Advanced Medium- and Heavy-Duty Vehicles.*

FIGURE 27 – ANNUAL NGV DEMAND FORECAST

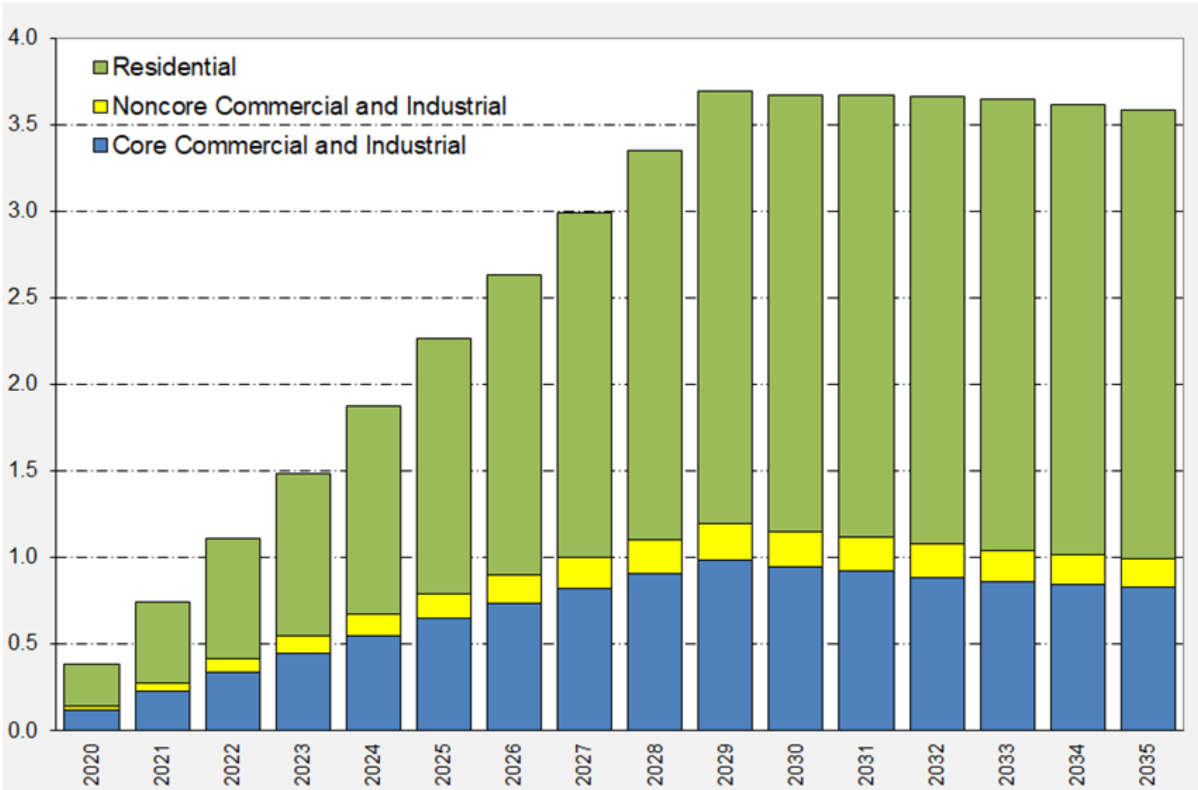


ENERGY EFFICIENCY PROGRAMS

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 2020 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2020-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034.

FIGURE 28 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS (Bcf)



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.[102] 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 in the Energy Efficiency forecast.

102 "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.

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

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopts a TY 2019 revenue requirement of $1.990 billion for SDG&E's combined operations ($1.590 billion for electric, $0.400 billion for gas) which is $213 million lower than the $2.203 billion (including OMEC) that SDG&E had requested in its Update testimony. The adopted revenue requirement represents an increase of $107 million or a 5.7 percent increase over 2018. The final decision adopts PTY revenue requirement adjustments for SDG&E of $134 million for 2020 (6.7 percent increase) and $102 million for 2021 (4.8 percent increase).

In January 2020 the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SDG&E was directed to file a PFM to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional five-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SDG&E filed a PFM of its 2019 GRC decision requesting attrition year increases of $94 million (+4.24 percent) for 2022 and $96 million (+4.13 percent) for 2023. SDG&E requested that a final decision be issued no later than October 1, 2020.

OTHER REGULATORY MATTERS

For more information on non-GRC 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.

2020 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 42 – SDG&E
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019

LINE			2015	2016	2017	2018	2019
	Actual Deliveries by End-Use						
1	**CORE**	Residential	67	71	72	70	81
2		Commercial	49	51	52	54	57
3		Industrial	0	-	-	-	-
4	*Subtotal -*	*CORE*	116	122	124	124	138
5	**NONCORE**	Commercial	0	-	-	-	-
6		Industrial	11	12	11	12	13
7		Non-EOR Cogen/EG	74	60	71	51	43
8		Electric Utilities	126	99	92	49	33
9	*Subtotal -*	*NONCORE*	211	171	174	112	89
10	**WHOLESALE**	All End Uses	0	-	-	-	-
11	*Subtotal -*	*Co Use & LUAF*	9	(3)	1	3	4
12	**SYSTEM TOTAL THROUGHPUT**		336	290	299	239	230
	Actual Transport & Exchange						
13	**CORE**	Residential	1	1	1	1	1
14		Commercial	12	13	13	14	14
15	**NONCORE**	Industrial	11	12	11	12	13
16		Non-EOR Cogen/EG	74	60	71	51	43
17		Electric Utilities	126	99	92	49	33
18	*Subtotal -*	*RETAIL*	224	185	188	127	103
19	**WHOLESALE**	All End Uses	0	-	-	-	-
20	**TOTAL TRANSPORT & EXCHANGE**		224	185	188	127	103
	Storage						
21		*Storage Injection*	0	-	-	-	-
22		*Storage Withdrawal*	0	-	-	-	-
	Actual Curtailment						
23		Residential	0	-	-	-	-
24		Com/Indl & Cogen	0	-	-	-	-
25		Electric Generation	0	-	-	-	-
26	**TOTAL CURTAILMENT**		0	-	-	-	-
27	**REFUSAL**		0	-	-	-	-
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.040	1.036	1.040	1.038	1.032

TABLE 42 – SDG&E
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019
(CONTINUED)

LINE		2015	2016	2017	2018	2019
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					
	Gas Supply Taken	**2015**	**2016**	**2017**	**2018**	**2019**
	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	112	105	111	112	127
18	Out-of-State Transport-Others	224	185	188	127	103
19	**Total Out-of-State Gas**	336	290	299	239	230
20	**TOTAL Gas Supply Taken & Transported**	336	290	299	239	230
	(MMCFD)					

TABLE 43 – SDG&E: TABLE 1-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
AVERAGE TEMPERATURE YEARS

LINE			2020	2021	2022	2023	2024	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		250	251	250	243	231	5
6	TOTAL SUPPLY TAKEN		250	251	250	243	231	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		250	251	250	243	231	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	83	83	83	82	81	9
10		Commercial	47	48	48	48	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	140	141	141	140	138	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	96	96	95	89	79	16
17		Subtotal-NONCORE	108	108	107	101	91	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		250	251	250	243	231	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	14	14	14	14	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	96	96	95	89	79	22
23	TOTAL TRANSPORTATION & EXCHANGE		121	122	121	115	105	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 valu based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2020	2021	2022	2023	2024
transportation (CAT) in MDth/d:	131	131	131	130	128

TABLE 44 – SDG&E: TABLE 2-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
AVERAGE TEMPERATURE YEARS

LINE			2025	2026	2027	2030	2035	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		231	227	220	212	213	5
6	TOTAL SUPPLY TAKEN		231	227	220	212	213	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		231	227	220	212	213	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	81	80	79	77	77	9
10		Commercial	47	47	47	46	46	10
11		Industrial	4	4	4	3	3	11
12		NGV	7	7	7	8	8	12
13		Subtotal-CORE	139	138	137	134	134	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	78	75	69	64	64	16
17		Subtotal-NONCORE	90	87	81	76	77	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		231	227	220	212	213	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	15	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	78	75	69	64	64	22
23	TOTAL TRANSPORTATION & EXCHANGE		104	101	95	91	93	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 val
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 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:

	2025	2026	2027	2030	2035
transportation (CAT) in MDth/d:	129	128	127	123	122

TABLE 45 – SDG&E: TABLE 3-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2020	2021	2022	2023	2024	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		260	270	271	263	251	5
6	TOTAL SUPPLY TAKEN		260	270	271	263	251	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		260	270	271	263	251	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	91	91	90	90	89	9
10		Commercial	49	49	49	49	49	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	150	150	149	149	148	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	96	106	108	100	89	16
17		Subtotal-NONCORE	108	118	120	112	101	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		260	270	271	263	251	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	14	14	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	96	106	108	100	89	22
23	TOTAL TRANSPORTATION & EXCHANGE		122	132	134	126	115	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 val
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2020	2021	2022	2023	2024
transportation (CAT) in MDth/d:	140	140	139	139	138

TABLE 46 – SDG&E: TABLE 4-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2025	2026	2027	2030	2035	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		253	248	242	230	229	5
6	TOTAL SUPPLY TAKEN		253	248	242	230	229	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		253	248	242	230	229	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	88	87	87	85	84	9
10		Commercial	49	48	48	48	48	10
11		Industrial	4	4	4	4	3	11
12		NGV	7	7	7	8	8	12
13		Subtotal-CORE	148	146	146	145	143	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	91	88	82	71	71	16
17		Subtotal-NONCORE	103	100	94	83	84	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		253	248	242	230	229	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	15	15	15	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	91	88	82	71	71	22
23	TOTAL TRANSPORTATION & EXCHANGE		118	115	109	98	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 val
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2025	2026	2027	2030	2035
	137	135	135	134	131

2020 CALIFORNIA GAS REPORT

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.

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 equal to 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) = Approx. 1,000 Btus
- 1 Ccf = 100 cf = Approximately 1 Therm
- 1 Therm = 100,000 Btus = Approximately 100 cf = 0.1 Mcf
- 10 Therms = 1 Dth (dekatherm) = Approximately 1 Mcf
- 1 Mcf = 1,000 cf = Approximately 10 Therms = 1 MMBtu
- 1 MMcf = 1 million cubic feet = Approximately 1 MDth (1 thousand dekatherm)
- 1 Bcf = 1 billion cf = Approximately 1 million MMBtu

Conversion Factor (Petroleum Products)
Approximate heat content of petroleum products (MMBtu per Barrel).

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

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 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
CPUC SB350 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 insure 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.

RIN
Renewable Identification Number.

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.

RG
Renewable Gas.

RGS
Renewable Gas Standard.

RNG
Renewable Natural Gas.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
CPUC SB350 IRP 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.

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.

2020 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

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

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

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

- City of Long Beach Municipal Energy Resources 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

- Eric Semelius - Statewide Chair- PG&E
- Todd Peterson - PG&E
- Anupama Pandey - PG&E
- Rose-Marie Payan - SoCalGas/SDG&E
- Sharim Chaudhury - SoCalGas/SDG&E
- Scott Wilder - SoCalGas/SDG&E
- Nasim Ahmed - SoCalGas
- Jeff Huang – SoCalGas/SDG&E
- Michelle Clay-Ijomah - SDG&E
- Gary Lenart - SoCalGas
- Preston Miller - Kern River

Observers

- Jean Spencer - CPUC
- Renee Guild - CPUC
- Munir Fellahi - CPUC
- Robert Gulliksen - CEC

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Decision D.95-01-039