DOCKETED

Docket Number:	22-OII-02
Project Title:	Gas Decarbonization
TN #:	267964
Document Title:	Staff Report - Winter 2025-2026 California Gas Reliability Assessment
Description:	Orta, Jason, Miguel Cerrutti, and Anthony Dixon. 2025. Winter 2025–2026 California Gas Reliability Assessment. California Energy Commission. Publication Number: CEC-200-2025-025.
Filer:	Jann Mitchell
Organization:	California Energy Commission
Submitter Role:	Energy Commission
Submission Date:	12/17/2025 4:43:32 PM
Docketed Date:	12/17/2025

California Energy Commission

STAFF REPORT

Winter 2025–2026 California Gas Reliability Assessment

October 2025 | CEC-200-2025-025

California Energy Commission

Jason Orta
Miguel Cerrutti
Anthony Dixon
Primary Authors

Max Solanki
Program Manager
FUELS ANALYSIS BRANCH

Aleecia Gutierrez
Director
ENERGY ASSESSMENTS DIVISION

Drew Bohan
Executive Director

ABSTRACT

The California Energy Commission (CEC) presents this *Winter 2025–2026 California Gas Reliability Assessment* (Winter Assessment) that assesses the risk of gas service curtailment to customers who receive gas service from Pacific Gas and Electric (PG&E) and the Southern California Gas Company/San Diego Gas and Electric (SoCalGas). Using CEC-produced demand forecasts and estimates of available supplies, the CEC finds that the risk of curtailment for core customers (mainly residential and small commercial) and noncore customers (large users including factories and power plants) is low assuming continued available estimated winter supplies and forecasted demand for winter 2025–2026.

The CEC staff analysis in this report finds that on extremely cold winter days, the PG&E gas system cannot meet demand without withdrawals from underground gas storage facilities owned by independent storage providers that are generally transactions between gas marketers representing power plants and other large customers and the storage facility. Other measures can be deployed to address the shortfall including PG&E procuring gas from the independent storage providers and issuing operational flow orders during system imbalances.

CEC staff estimates that SoCalGas can meet extremely cold day demands without curtailment of noncore customers due to having enough pipeline supply and storage withdrawal capacity. However, there are risks for both gas utility systems, including the potential impacts of scheduled and unscheduled maintenance events on key mainlines and storage facilities.

Keywords: Fossil gas, reliability, system, peak, extreme, balance, demand, Synergi, curtailment, interruption, risk, improved, pipeline, capacity, storage, hydraulic, modeling

Please use the following citation for this report:

Orta, Jason, Miguel Cerrutti, and Anthony Dixon. 2025. *Winter 2025–2026 California Gas Reliability Assessment*. California Energy Commission. Publication Number: CEC-200-2025-025.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

In its Winter 2025-2026 California Gas Reliability Assessment (Winter Assessment) the California Energy Commission (CEC) finds that the risk of curtailment, or reducing fossil gas service, for core customers (mainly residential and small commercial) and noncore customers (large users including factories and power plants) is low assuming continued available estimated winter supplies and forecasted demand for winter 2025–2026. In the Winter Assessment, the CEC assesses the risk of gas service curtailment risk to customers who receive gas service from Pacific Gas and Electric (PG&E) and the Southern California Gas Company/San Diego Gas and Electric (SoCalGas).

Core customers are at low risk of curtailment. In operational settings that require curtailments, gas utilities curtail noncore customers first. Furthermore, reliability standards ensure that even under the most extreme cold conditions, their gas service is maintained without interruption. Curtailment of core customers is a measure of last resort as outages to core customers take a long time to restore — from several days to weeks — and can impose significant workforce requirements. Safety requires that utilities bring gas mains back on-line individually and sequentially and restore service to each home or building.

Curtailment risk to noncore customers can be significant on extremely cold winter days, (roughly 30 degrees Fahrenheit in Northern California and 40 degrees Fahrenheit in Southern California) due to sharp increases in demand, which are driven mainly by the increased space and water heating needs of core customers. Nearly 37 percent of the electricity used in California is produced by fossil gas; therefore, curtailment of gas service to power plants can jeopardize electricity system reliability.

PG&E Analysis

While the CEC estimates a 3.0 billion cubic feet (Bcf) pipeline capacity for PG&E in winter 2025–2026 and PG&E estimates a storage withdrawal capacity of 883 million cubic feet (MMcf) for that period, the CEC predicts a net shortfall of 237 MMcf for Case 1 — 1-in-10 peak cold day (million cubic feet per day [MMcfd]) and 778 MMcf for Case 2 — a 1-in-90 core plus 1-in-10 noncore day. A 28-degree in Northern California is estimated to occur once in 90 years compared to a 35-degree day, which is estimated to occur once in 10 years. There are additional tools to meet this demand before any curtailment of service to noncore customers, such that the net shortfall estimate can be viewed as a worst-case scenario. While it is hydraulically feasible for independent fossil gas storage providers to meet this shortfall, staff cannot estimate those withdrawals and the associated impact because the terms of independent storage providers' transactions, whether they are with PG&E or noncore customers (or marketers), are not public.

In addition, some independent storage provider transactions are between marketers representing noncore customers (power plants and industrial customers) and the storage provider. In some cases, PG&E can issue operational flow orders and emergency flow orders to help address this shortfall in the event of system imbalances. Operational flow orders require parties that deliver gas to balance their supplies with customer demand. These can be issued when demand exceeds supply and when supplies exceed demand. An emergency flow order is issued when forecasted supply and/or capacity shortages threaten deliveries to end-use customers. Under an emergency flow order, end-use customers' usage must be less than or equal to supply. PG&E's backbone transmission system runs through much of the length of California, so there is also significant pipe inventory to support the system before PG&E has to issue emergency or operational flow orders.

SoCalGas Analysis

Based on the gas balance, stochastic analysis, and assessment of SoCalGas transmission system hydraulic models, SoCalGas can meet peak-day demands (the 1-in-10 and the extreme peak day plus 1-in-35 for core customers and 1-in-10 for noncore customers) without curtailment of noncore customers. A 40-degree in Southern California is estimated to occur once in 35 years compared to a 44-degree day, which is estimated to occur once in 10 years. Meeting demand under these scenarios will require storage withdrawals in quantities below the assumed feasible withdrawal estimate on the SoCalGas system of 2,000 MMcfd.

The CEC estimates a 3 Bcf pipeline capacity for SoCalGas in winter 2025–2026, which is estimated to be the same capacity as winter 2024-25. From April through September 2025, SoCalGas reported on its Envoy website that SoCalGas will reduce pressures on Lines 4000 and 4002 in its Northern Zone from June 30, 2025 through November 1, 2026. The pressure reductions were needed to perform mandated assessments by the federal Pipeline and Hazardous Materials Safety Administration. However, SoCalGas reported that this assessment was completed in September 2025 based on completed Transmission Integration Management Program work that places this inspection in compliance with federal requirements based on updated guidance and regulations by the federal Pipeline and Hazardous Materials Safety Administration. As SoCalGas reported that it will not continue with these assessments and that there are no plans for extensive maintenance activity on the SoCalGas transmission system during Winter 2025-26, CEC staff estimates that pipeline capacity will not change significantly compared to the previous winter. . On colder days, SoCalGas is expected to rely on gas storage to meet demand. The storage required to meet this demand is below the assumed withdrawal capability of the SoCalGas system, which CEC staff estimates as 2,000 MMcfd.

Market Prices

Fossil gas prices tend to be higher and more volatile during the winter months due to increased heating demand in the residential and commercial sectors. Staff compared annual average prices with winter-month trends over the past five years and found that winter prices were consistently more volatile. As it is expected that California's utility pipeline infrastructure capacity will remain roughly the same from the previous winter, staff expects prices to remain relatively stable. This reduced capacity can result in some price volatility in Southern California hubs. This price volatility can impact PG&E and SoCalGas as both utilities and their noncore customers procure gas for delivery at these hubs. Overall, prices are likely to rise with increased seasonal demand. Unforeseen events, such as severe weather or unplanned pipeline outages, could significantly impact prices.

CHAPTER 1: Introduction

This assessment provides an independent analysis of the expected reliability of gas service in winter 2025–26 for the Pacific Gas and Electric (PG&E) and Southern California Gas Company/San Diego Gas & Electric (SoCalGas) systems. The winter gas season runs from November 1 through March 31. While stringent reliability standards ensure that gas service is maintained for core customers (mainly residential and small commercial customers), noncore customers (which include industrial customers and electric generators) get curtailed when there is insufficient gas to meet all demand in cold weather conditions and under constrained system conditions.

To assess the respective system reliability of the PG&E and SoCalGas transmission systems, CEC staff prepared demand forecasts that are subsequently compared to CEC staff estimates of winter pipeline and storage withdrawal capacity. For winter 2025–2026, CEC staff prepared monthly demand forecasts for PG&E and SoCalGas under two scenarios: an average temperature/average hydroelectric conditions and a cold winter/dry hydroelectric conditions. Furthermore, CEC staff developed peak day winter demand forecasts for PG&E under two scenarios: a 1-in-10 day along with a 1-in-90 core demand day/1-in-10 noncore demand day.

The CEC forecasted monthly demand for SoCalGas under two scenarios: a 1-in-10 day along with a 1-in-35 core demand day/1-in-10 noncore demand day. The CEC staff developed peak day winter demand forecasts for SoCalGas are a 1-in-10 day along with a 1-in-35 core demand day/1-in-10 noncore demand day. The latter peak day cases for PG&E and SoCalGas, respectively, are not assessed by gas utilities in the *California Gas Report*.[1] These scenarios aim to capture the impact on noncore customers, including power plants on high-demand days driven by increased use of space and water heating by residential and small commercial customers. CEC staff developed pipeline and storage withdrawal capacity estimates based on historical patterns and review of publicly available regulatory filings and maintenance outlook reports.

Using CEC-produced demand forecasts and estimates of available supplies, the CEC finds that the risk of curtailment for noncore customers is low assuming continued available estimated winter supplies and forecasted demand for winter 2025–2026.

Reliability Standards

The California Public Utilities Commission (CPUC) established reliability standards that address physical capabilities of the gas utilities' systems. Historically, meeting the winter gas demand for residential and small commercial customers has been the basis for reliability standards. Those standards include a combination of gas flowing from interstate pipelines through

1 City of Long Beach Utilities Department, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, Southern California Gas Company, Southwest Gas Corporation. 2024. *2024 California Gas Report*.

intrastate pipelines and withdrawal from storage fields to balance supply and demand. As such, storage is an important infrastructure asset in meeting winter demand, managing gas system operations and reducing price spikes. The gas utilities serve two general categories of customers: core includes residential and small commercial customers, while noncore includes electric generators, large commercial and industrial customers, and others. The type of customer matters when it comes to reliability standards.

Gas utilities purchase gas and provide transportation and storage services for core customers. Stringent reliability standards for core customers have been designed to ensure that even under the most extremely cold conditions, gas service is maintained without interruption. Curtailing core demand is a measure of last resort. (If curtailments are required to maintain the operation of the system, noncore customers including factories and power plants would be the first to be curtailed.)[2] Outages to core customers take a long time to restore — from several days to weeks — and impose significant workforce requirements.[3] The gas utilities provide gas transportation services to noncore customers and are prohibited from purchasing gas on their behalf. Noncore customers either buy gas themselves or rely on gas suppliers or marketers for gas purchases and then schedule deliveries over the gas utilities' gas systems.

Generally, reliability standards require the gas utilities meet a high peak winter demand under very cold conditions for core customers, which is driven mostly by space- and water-heating loads, with lower standards for noncore customers as follows:

- PG&E must meet a demand with a 1-in-90-year probability of occurrence, or abnormal peak day, for core local transmission customers and a 1-in-2-year standard for noncore customers, also referred to as a "cold/dry winter day standard."
- SoCalGas must meet a demand that has a 1-in-35-year probability of occurrence, or extreme peak day, for core local transmission customers and a 1-in-10-year cold day standard for noncore customers.

Temperature Outlook for Winter 2025–2026

In August 2025, the National Weather Service released a seasonal temperature outlook for November 2025 through January 2026 (Figure 1).[4] This outlook suggests temperatures will

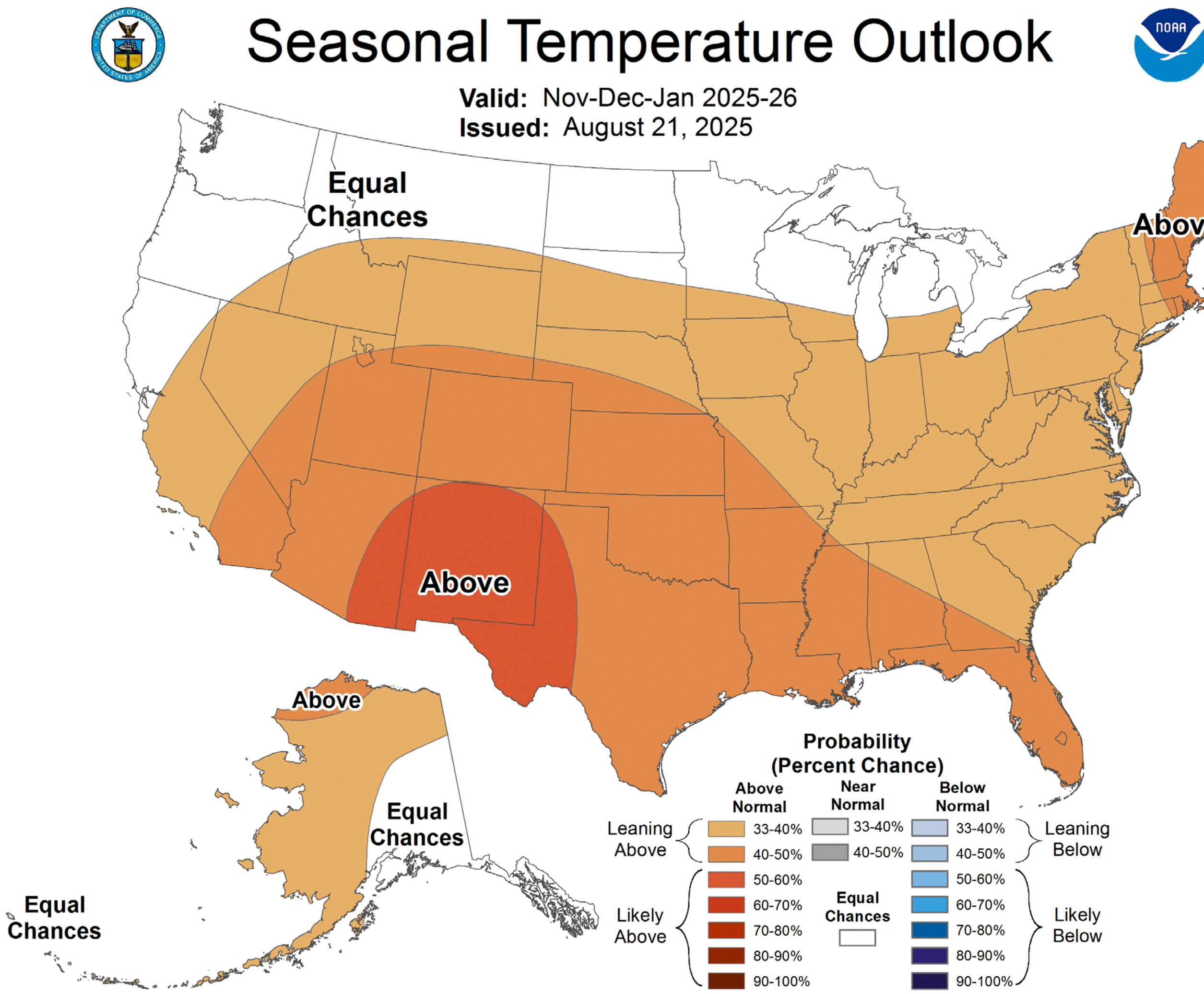
2 When reliability standards were established, many noncore customers, including power plants, had alternatives to burning gas in their facilities such as distillate and diesel fuel. These customers are subject to curtailment when the utility is unable to meet all customer demand, such as in cold weather. Before CPUC Decision 93-09-082 in 1993, noncore customers were required to maintain alternate fuel capability as a condition of receiving noncore service but were subsequently relieved of that requirement. Largely because of air quality regulations, noncore customers no longer have dual-fuel capabilities.

3 Safety requires that gas mains be brought back on-line individually and sequentially, and that service to each home or building is safely restored. This restoration requires gas utility workers to go to each house or business, while someone is home, to ensure that pilot lights are properly lit. Safety concerns include the potential for explosions as pilot lights may flicker out inconsistently as line pressures drop or if restoration is improperly carried out.

4 National Weather Service Climate Prediction Center, https://www.cpc.ncep.noaa.gov/products/predictions/long_range/lead03/off03_temp.gif.

lean above average in much of California with equal chances of above- and below-average temperatures north from the San Francisco Bay Area to the Pacific Northwest.

Figure 1: National Weather Service Seasonal Temperature Outlook (December 2025–February 2026)



Source: National Weather Service

CHAPTER 2: CEC PG&E Gas System Analysis

This chapter summarizes the CEC staff assessment of the ability of the PG&E gas transmission system to meet demand in winter 2025–26. Appendix A has more information about the forecasting method.

Gas Demand Forecast

Tables 1 and 2 present CEC's forecasts for the monthly average, cold peak-day, and abnormal peak-day demand plus forecast for the PG&E system.

Table 1: CEC Forecast of PG&E Monthly Demand

Demand Scenario	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
Average Temperature Demand (MMcfd)[5]	2,426	3,012	2,805	2,565	2,156
Cold Temperature/Dry Hydro Demand (MMcfd)[6]	2,669	3,282	2,971	2,847	2,365

Source: CEC staff

Table 2: CEC PG&E Peak Demand Day Forecasts

Demand Type	1-in-10 peak cold day (MMcfd)**	Abnormal Peak Day Plus (1-in-90 core plus 1-in-10 noncore day Plus) (MMcfd)***
Core[7]	2,524	3,065
Noncore — Non-Electric Generation[8]	521	521
Noncore — Electric Generation[9]	1,016	1,016

5 Average daily demand by month in a normal year.

6 Average daily demand by month at the 90th percentile of demand, which equates to a 1-in-10 probability of occurrence.

7 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

8 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

9 Power plant customers whose average usage exceeds 20,800 therms per month.

Demand Type	1-in-10 peak cold day (MMcfd)**	Abnormal Peak Day Plus (1-in-90 core plus 1-in-10 noncore day Plus) (MMcfd)***
Off System[10]	80	80
Total Demand	4,141	4,682

****January peak.**

*****December peak**

Source: CEC staff forecasts and estimates

PG&E Pipeline Capacity

For the winter assessment, staff estimated available pipeline capacity and storage inventory on the PG&E system (Figure 2). The pipeline capacity estimates are used in all scenarios.

PG&E's backbone transmission system[11] and high diameter pipes run through much of the length of California (from Topock, Arizona, to Malin, Oregon). This system, which includes more than 1,700 miles of pipe,[12] provides significant pipe inventory that PG&E can draw upon to meet demand and maintain operating pressures on the gas system. These unique characteristics enable PG&E to maintain sizable linepack (the quantity of gas stored in a pipeline) even on high-demand days, which effectively offers short-term storage.

10 Gas deliveries to customers outside the utility's service area. For this table, this constitutes an estimate of deliveries to the SoCalGas system.

11 A *natural gas backbone system* refers to the primary network of large, high-pressure pipelines that transport natural gas from production areas to major consumption centers.

12 PG&E staff. N.d. "About California Gas Transmission: Welcome to CGT." PG&E, https://www.pge.com/pipeline/en/about-cgt.html.

Figure 2: Map of the PG&E Gas Transmission System

Source: PG&E

The PG&E Pipe Ranger website reports the capacity available to its customers for scheduling and maintenance and outage events that impact capacity. Monthly average capacities were generated for the Baja (southern backbone) and Redwood (northern PG&E's backbone) pipeline systems. Maintenance activities[13] are scheduled for the Baja and Redwood system in winter 2025–26, but an analysis of PG&E's maintenance outlook report shows that 100 percent of pipeline capacity will be available in December and January, with more than 90 percent on average available in the remaining winter months of November, February, and March. Moreover, PG&E's pipeline system maintains significant pipe inventory to meet demand and maintain operating pressures on the gas system (Table 3).

13 PG&E's Prospective Maintenance document provides a 6–12 month outlook of proposed maintenance on the CGT pipeline system. PG&E revises this a monthly basis. "Pipeline Maintenance," PG&E, https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html.

Table 3: PG&E Winter Pipeline Supply

Supply (MMcfd)	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
California Source Gas	22	22	22	22	22
Baja Path	781	945	945	915	787
Redwood Path	2,038	2,060	2,047	2060	2000
Total Pipeline Receipts*	**2,841**	**3,027**	**3,014**	**2,997**	**2,809**

***An average of minimum capacity available in December 2024 and January 2025 based on an analysis of the PG&E's Prospective Maintenance document reported on Pipe Ranger.**

Source: CEC staff

PG&E and Independent Storage Providers

PG&E owns and operates the Los Medanos and McDonald Island underground gas storage facilities,[14] which have a combined maximum working gas capacity of about 49 billion cubic feet (Bcf). Neither the Pipe Ranger website nor the PG&E prospective maintenance report[15] identifies maintenance activities that would reduce injection or withdrawal capacities at PG&E underground gas storage facilities during winter 2025–26. However, PG&E received approval in D. 23-11-069 to add capacity to its storage facilities through new and replacement wells from 2024 through 2027 in compliance with California Geologic Energy Management Division (CalGEM) safety regulations for underground gas storage facilities.

For winter 2025–2026, PG&E reported plans to add 102 MMcfd in storage facility capacity by building new and replacement wells at McDonald Island, Los Medanos, and Gill Ranch. Based on this tracking and analysis, staff estimates that the PG&E-owned gas storage facilities will be at full capacity by the beginning of winter 2025–2026. Based on CEC staff's daily tracking of storage activity and analysis of historical data on withdrawals and injections, staff estimates that the PG&E-owned gas storage facilities will be at full capacity by the beginning of winter 2025–2026.

Independent storage providers (ISPs) are owned and operated by third parties — Wild Goose, Central Valley Gas Storage, Lodi, Pleasant Creek, and Gill Ranch (partially owned by PG&E). They connect to PG&E backbone transmission pipelines and are located within the PG&E service area. This analysis does not include withdrawals from ISPs and estimates of storage inventory levels. Under PG&E's Fossil Gas Storage Strategy, which was approved by the CPUC, PG&E can procure storage services from ISPs to meet reliability standards. But the ISPs themselves are not responsible for supporting system reliability. Noncore customers (electric generators, industrial customers, large commercial) have the option to purchase storage

---

14 A third field, Pleasant Creek, is no longer in operation. In April 2025, the CPUC approved the sale of the facility by PG&E to Pleasant Creek Gas Storage Holdings, LLC, and eCorp Natural Gas Storage Holdings, LLC. In its decision approving the sale, the CPUC designates Pleasant Creek LLC as an Independent Storage Provider authorized to charge market-based rates for natural gas storage services. Decision 25-04-032, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M565/K249/565249273.PDF.

15 PG&E staff. N.d. "Pipeline Maintenance". PG&E. https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html.

services from the gas utility or from ISPs, but the gas utility has no obligation to provide storage services for noncore customers. ISP transactions with customers are conducted independently of PG&E under commercial terms that are confidential. The reasoning for individual transactions- whether to withdraw gas at lower prices or to avoid curtailment is unknown.

PG&E Gas Balance

Staff assessed the availability of supply (Tables 4–5 and Figures 3–6) for meeting demand under four cases: monthly average temperature demand, monthly cold temperature/dry hydro, the 1-in-10 peak cold day, and the abnormal peak day plus (a 1-in-90 core[16] plus 1-in-10 noncore day).[17]

Tables 4 and 5 show the monthly gas balances for November 2025–March 2026 using the CEC's forecast for average temperature demand and cold temperature/dry hydro demand, respectively. This analysis captures planned pipeline maintenance as reported by PG&E in May 2025 and is reflected in available pipeline capacity, where relevant.

Under the average temperature demand scenario, pipeline capacity is sufficient to meet demand, and on average, storage withdrawals are not needed. Some storage withdrawals are needed under the cold temperature/dry hydro demand scenario in December 2025.

Staff demand forecasts for PG&E include estimates of off-system deliveries, particularly to the SoCalGas system at Kern River Station. Demand can be met under the average temperature scenario without withdrawals from underground gas storage facilities. Should it become necessary to preserve the higher-priority deliveries to on-system customers, PG&E can reduce or eliminate the portion of its off-system deliveries that are made on an as-available basis. For December 2025 under the cold temperature/dry hydro scenario, the CEC estimated 320 MMcfd could go off-system, of which only 80 MMcfd is contractually firm. This means 240 MMcfd is interruptible. Thus, under this scenario, PG&E could reduce off-system deliveries to 80 MMcfd and, in turn reduce storage withdrawals in December 2025 to 15 MMcfd.

CEC staff estimates that storage field inventory at the end of winter 2025–26 in March 2026 will range from 41 Bcf to 49 Bcf.

16 Demand with a 1-in-90 year probability of occurrence that generally correlates to a 28-degree day.

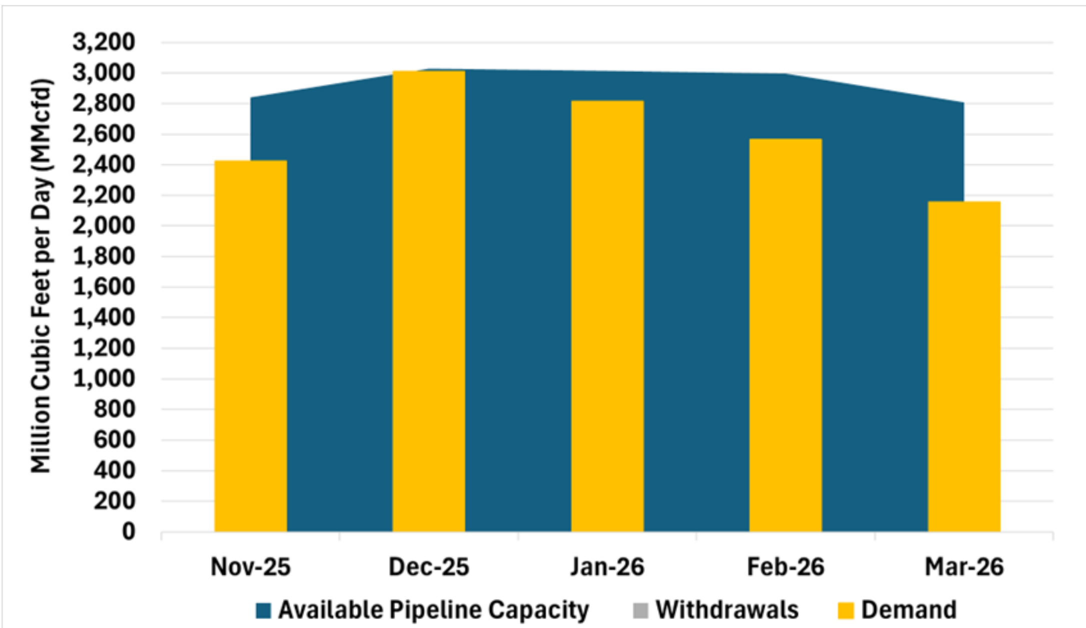
17 Demand with a 1-in-90 year probability of occurrence for core customers (generally an estimate of how much these customers would use on a 28 degree day) and 1-in-10 cold day standard for noncore customers (generally how much these customers would use on a 35 degree day). A 28-degree in Northern California is estimated to occur once in 90 years compared to a 35-degree day which is estimated to occur once in 10 years.

Table 4: PG&E Monthly Gas Balance Average Demand

Average Demand	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
Demand (MMcfd)	2,426	3,012	2,814	2,565	2,156
Available Pipeline Capacity (MMcfd)	2,841	3,027	3,014	2,997	2,809
PG&E Injection/(Withdrawal) (MMcfd)	0	0	0	0	0
PG&E End-of-Month Inventory (Bcf)	49	49	49	49	49

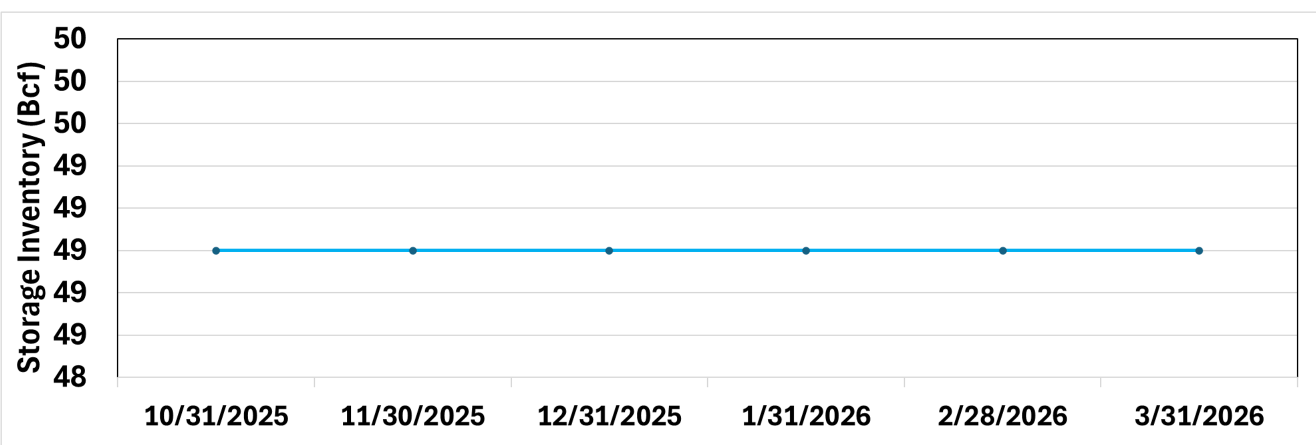
Source: CEC staff

Figure 3: PG&E Available Pipeline Capacity, Needed Withdrawals, and Demand (Average Temperature Demand)



Source: CEC staff

Figure 4: PG&E Storage Inventory (Average Temperature Demand)



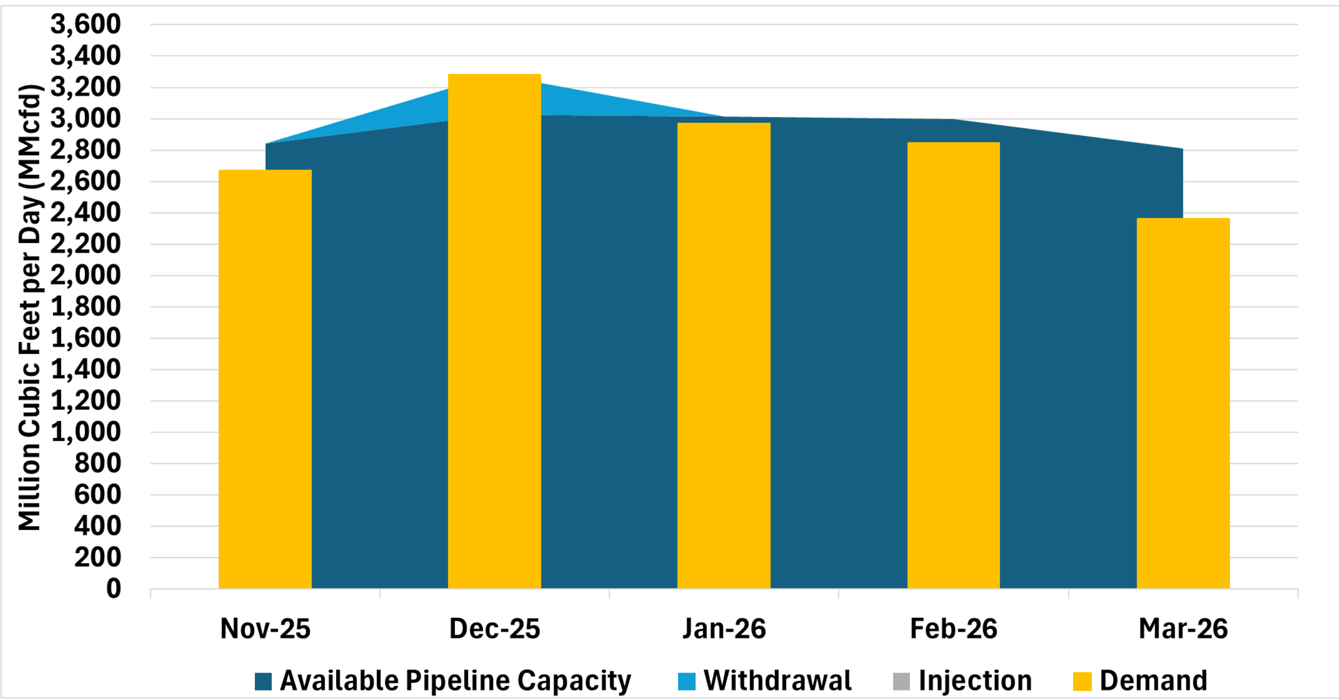
Source: CEC staff

Table 5: PG&E Monthly Gas Balance Cold Temperature/Dry Hydro Demand

Average Demand	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
Demand (MMcfd)	2,669	3,282	2,971	2,847	2,365
Available Pipeline Capacity (MMcfd)	2,841	3,027	3,014	2,997	2,809
PG&E Injection/(Withdrawal) (MMcfd)	0	(255)	0	0	0
PG&E End-of-Month Inventory (Bcf)	49	41	41	41	41

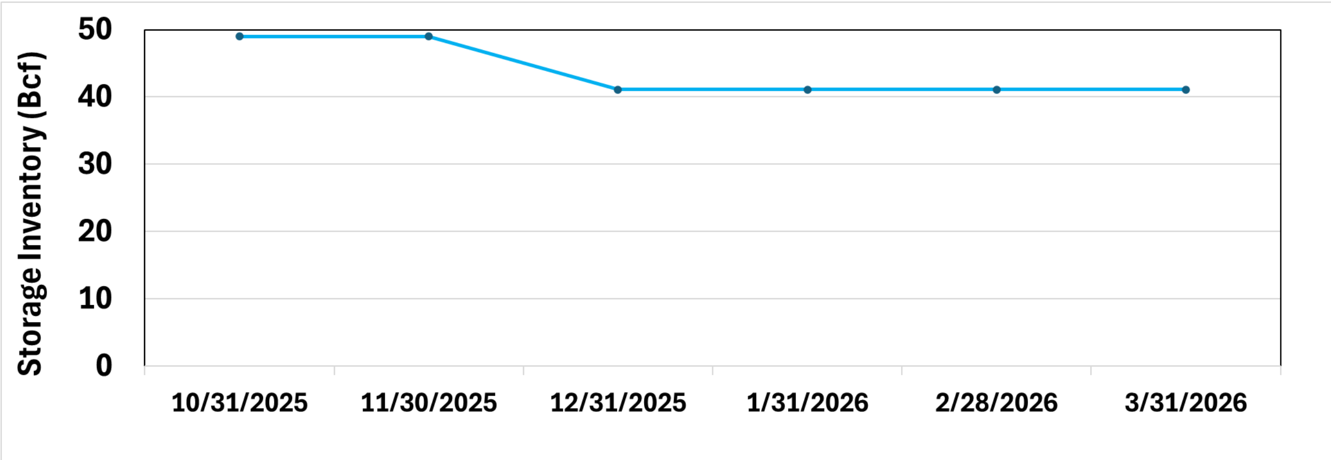
Source: CEC staff

Figure 5: PG&E Available Pipeline Capacity, Needed Withdrawals, and Demand (Cold Temperature/Dry Hydro Demand)



Source: CEC staff

Figure 6: PG&E Storage Inventory (Cold Temperature/Dry Hydro Demand)



Source: CEC staff

PG&E Peak-Day Analysis

Staff evaluated two peak day cases for winter. Case 1 looked at a 1-in-10 peak-temperature cold day for core and noncore load. Case 2 looked at the abnormal 1-in-90 peak-temperature cold day for core plus 1-in-10 peak-temperature cold day for noncore.[18]

The CEC estimates a 3.0 Bcf pipeline capacity for PG&E in winter 2025–2026. The estimated pipeline capacity, combined with PG&E's estimate of a storage withdrawal capacity of 883 MMcfd for that period,[19] yields CEC's estimated net shortfall of 237 MMcfd for Case 1 and 778 MMcfd for Case 2 (Table 6 and Figure 7). The net shortfall is a comparison of demand under this scenario and PG&E pipeline and PG&E storage withdrawal capacity.

There are options including withdrawals from ISPs to meet this demand before any curtailment of service. The net shortfall estimate can be viewed as a worst-case scenario. In both cases, CEC staff assumed that off-system deliveries would be capped at the firm contractual amount of 80 MMcfd. While ISP withdrawals for noncore customers can reduce or zero out the estimates above and are hydraulically feasible, ISPs conduct these transactions independently of PG&E under terms not known to the CEC or publicly available. The CEC recognizes that these withdrawals are not used to meet reliability standards but are based on the economic needs, interests, and goals of market participants.

PG&E also can procure ISP storage to help meet peak-day demands for its core customers, but the CEC cannot estimate the impact of those transactions because those terms are also not publicly available. Furthermore, PG&E can issue operational flow orders (OFOs) or emergency flow orders (EFOs) to noncore customers under cases of supply or capacity shortages or

---

18 Noncore load is less temperature-sensitive, so adding its 1-in-10 probability estimate to the core 1-in-90 allows calculation of total system load that could need to be curtailed on a peak day. Including the noncore load in this calculation allows us to understand how much of the noncore load might be curtailed.

19 Pg.6, PG&E, Application A.24-07-020. "Application of Pacific Gas and Electric Company (U 39 G) for Approval of Peak Day Supply Standard Pursuant to Decision 23-11-069"

both.[20] Under PG&E's fossil gas storage strategy, adopted by the CPUC as part of the 2019 Gas Transmission and Storage (GT&S) rate case in Decision 19-09-025, PG&E established a new reserve capacity. The reserve capacity can provide reliability against a loss of supply of up to 250 MMcfd. PG&E can use the reserve capacity to resolve significant, unplanned equipment outages, among other supply problems. The Reserve Capacity service is an allocated 1.0 Bcf of storage inventory, 25 MMcfd of injection capacity, and 250 MMcfd of withdrawal capacity.[21]

Table 6: PG&E Peak Demand Day Gas Balances

Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Case 1: 1-in-10 peak cold day (MMcfd)*	Case 2: Abnormal Peak Day Plus (1-in-90 core plus 1-in-10 noncore day Plus) (MMcfd)**
Core[22]	2,524	3,065
Noncore — Non-Electric Generation[23]	521	521
Noncore — Electric Generation[24]	1,016	1,016
Off System[25]	80	80
Total Demand	4,141	4,682
Available Pipeline Capacity	3,021	3,021
Needed Withdrawal*	(1,120)	(1,661)
-Assumed Available Withdrawal (PG&E Storage)***	(883)	(883)
Net Shortfall (Does Not Include ISP Withdrawals)	237	778

***January peak.**

****December peak.**

20 PG&E may issue an EFO if deliveries to end-use customers are threatened due to supply and/or capacity shortages. An EFO would normally follow an OFO but may be invoked without a preceding OFO. EFOs do not apply to oversupply (high inventory) situations. This information on EFOs is attributed to PG&E. "Emergency Flow Orders (EFO)," https://www.pge.com/pipeline/en/reference-library/ofo-efo-diversions/efo.html.

21 PG&E. March 12, 2020. "Modified Firm Storage Rights — Effective April 1, 2020," https://www.pge.com/pipeline/en/reference-library/news-archive/20200311_2401_news.html.

22 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

23 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

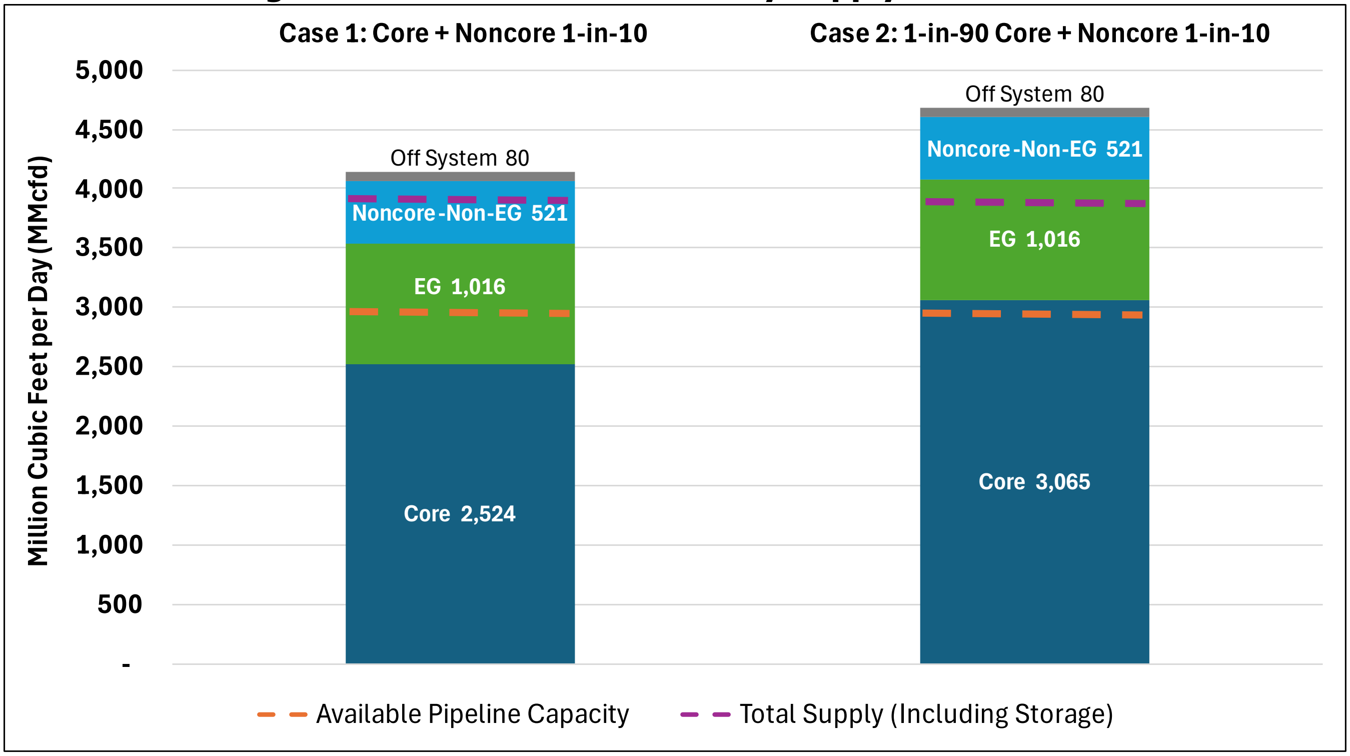
24 Power plant customers whose average usage exceeds 20,800 therms per month.

25 Gas deliveries to customers outside the utility's service area. For this table, this constitutes an estimate of deliveries to the SoCalGas system.

***PG&E estimate of storage capacity for winter 2025–2026 in facilities it owns in CPUC Application 24-07-020.**

Source: CEC staff

Figure 7: PG&E Peak Demand Day Supply and Demand



Source: CEC staff

PG&E Hydraulic Analysis

Staff used the Synergi Gas hydraulic modeling platform to assess PG&E gas system operations.[26] PG&E's hydraulic model for its Baja and Redwood transmission systems estimates system capacity using demand scenarios input by staff with considerable hydraulic modeling experience. The hydraulic analysis also identifies pressure violations and allows simulation testing of different operational solutions. Staff modeled the peak demand scenarios. Staff assumed pipeline supply of 3,021 MMcfd from the gas balances and that 883 MMcfd would be available for withdrawal on a peak day in either December 2025 or January 2026. Analysis of PG&E's hydraulic models shows that receipts of fossil gas from interstate pipelines combined with storage withdrawals from PG&E- and ISP-owned facilities[27] can eliminate the shortfalls shown in Table 6 and Figure 7.

26 Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

27 ISPs withdrawals are hydraulically feasible based on the withdrawal capacities of the facilities that are reported to the CEC. While hydraulically feasible, CEC staff cannot estimate which facilities and how much withdrawals can be relied upon by each facility as some withdrawals are not for reliability reasons and the terms of the transactions are unknown.

PG&E Conclusion

While the CEC estimates a 3.0 Bcf pipeline capacity for PG&E in winter 2025–2026 and PG&E estimates a storage withdrawal capacity of 883 MMcfd for that period, the CEC predicts a net shortfall of 237 MMcfd for Case 1 and 778 MMcfd for Case 2 (see Table 6 and Figure 7) under the assumed conditions. There are additional tools to meet this demand before any curtailment of service to noncore customers, such that the net shortfall estimate can be viewed as a worst-case scenario.

While a combination of available storage facility working gas and pipeline capacity can make it feasible for ISPs to meet this shortfall, staff cannot estimate those withdrawals and associated impact because terms of ISP transactions, whether they are with PG&E or noncore customers (or marketers), are not public. In some cases, PG&E can issue EFOs and OFOs to help address this shortfall in the event of system imbalances. PG&E's backbone transmission system runs through much of the length of California, so there is also significant pipe inventory to support the system before PG&E has to issue emergency or operational flow orders.

CHAPTER 3:
CEC SoCalGas System Analysis

This chapter summarizes the CEC staff assessment of the ability of the SoCalGas transmission system to meet demand in winter 2025–26.

Gas Demand Forecast

Tables 7 and 8 present the findings from the monthly average, cold-peak-day (1-in-10 for core and noncore customers), and extreme-peak-demand (1-in-35 for core customers and 1-in 1-in-10 for noncore customers) forecasts for the SoCalGas system.[28] Appendix A has more information about the forecasting method.

Table 7: CEC Forecast of SoCalGas Monthly Demand

Demand Scenario	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
Average Temperature Demand (MMcfd)[29]	2,352	3,071	2,803	2,591	2,380
Cold Temperature/Dry Hydro Demand (MMcfd)[30]	2,460	3,297	2,807	2,814	2,472

Source: CEC staff

Table 8: CEC Staff Forecast — SoCalGas Cold-Day and Extreme-Peak-Day Demand

Demand Type	1-in-10 peak cold day (MMcfd)	Extreme Peak Day Plus (1-in-35 core plus 1-in-10 noncore day Plus) (MMcfd)
Core[31]	2,843	2,991

28 Demand with a 1-in-35 year probability of occurrence for core customers (demand that generally corresponds to a 40°F day in Southern California) and 1-in-10 cold day standard for noncore customers. A 40-degree day in Southern California is estimated to occur once in 35 years compared to a 44-degree day, which is estimated to occur once in 10 years.

29 Average daily demand by month in a normal year.

30 Average daily demand by month at the 90th percentile of demand, which equates to a 1-in-10 probability of occurrence.

31 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

Demand Type	1-in-10 peak cold day (MMcfd)	Extreme Peak Day Plus (1-in-35 core plus 1-in-10 noncore day Plus) (MMcfd)
Noncore — Nonelectric Generation[32]	594	594
Noncore — Electric Generation[33]	1,067	1,067
Total Demand	**4,504**	**4,652**

*** January Peak**

**** December Peak**

Source: CEC staff

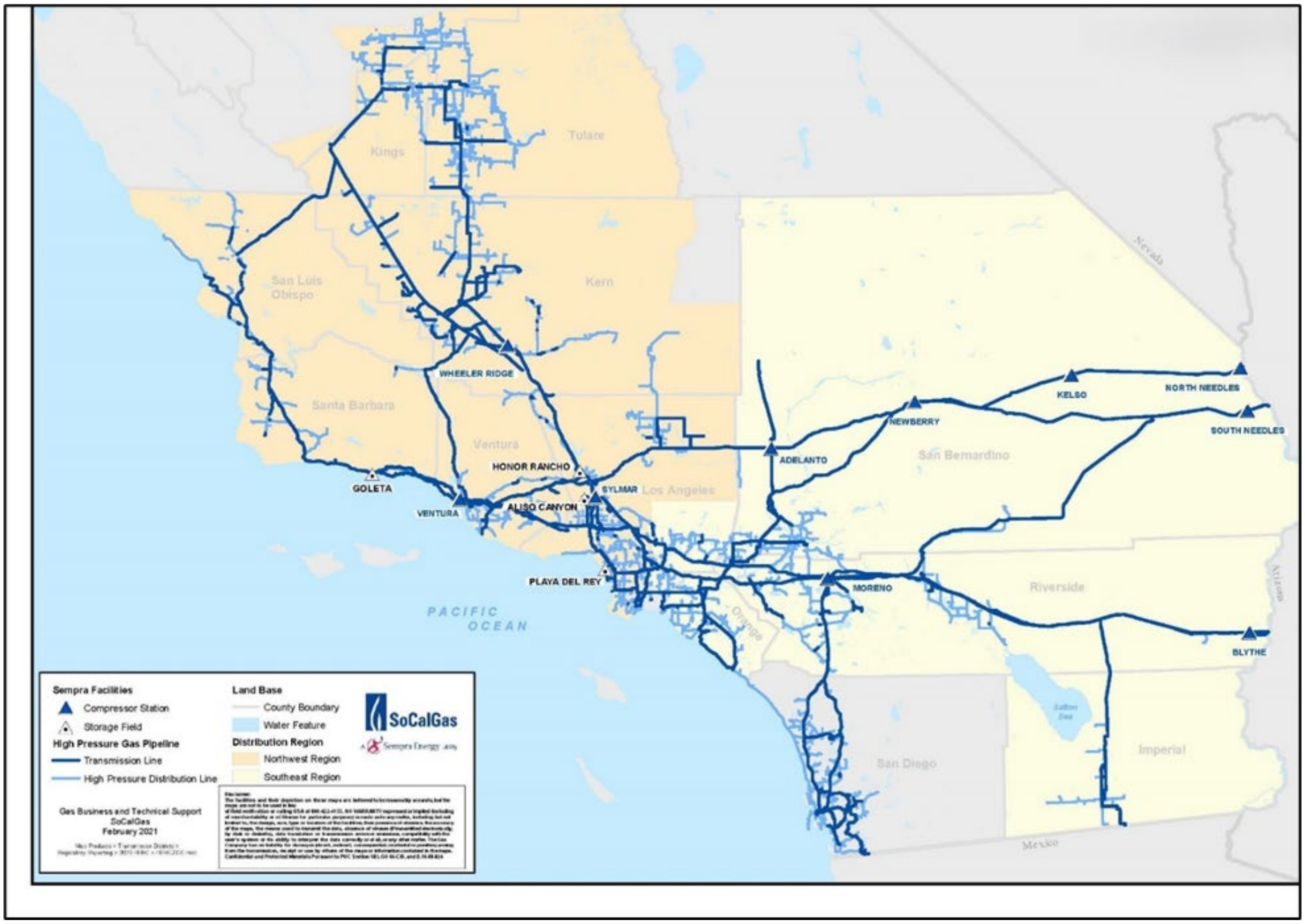
SoCalGas Pipeline Capacity

For the winter assessment, staff estimated available pipeline capacity on the SoCalGas system (Figure 8) using maintenance outlook and scheduling information provided on the SoCalGas Envoy website. The SoCalGas system was designed to meet winter demand with flowing pipeline supply and storage withdrawals.

32 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

33 Power plant customers whose average usage exceeds 20,800 therms per month.

Figure 8: Map of SoCalGas/SDG&E Transmission System



Source: California Energy Commission Docket 21-IEPR-05

Staff estimated capacity for winter 2025–2026 (Table 9). The SoCalGas Envoy website reports the capacity available to its customers from scheduled maintenance or outages. The CEC estimates a 3 Bcf pipeline capacity for SoCalGas in winter 2025–2026, which equals that of winter 2024-25 (Table 10). From April through September 2025, SoCalGas reported on its Envoy website that SoCalGas will reduce pressures on Lines 4000 and 4002 in its Northern Zone34 from June 30, 2025 through November 1, 2026. The pressure reductions were needed to perform mandated assessments by the federal Pipeline and Hazardous Materials Safety Administration. However, SoCalGas reported that this assessment was completed in September 2025 based on completed Transmission Integration Management Program work that places this inspection in compliance with federal requirements based on updated guidance and regulations by the federal Pipeline and Hazardous Materials Safety Administration. As SoCalGas reported that it will not continue with these assessments and that there are no plans for extensive maintenance activity on the SoCalGas transmission system during Winter 2025-

34 SoCalGas' Northern and Southern Zones represent portions of its system connected to different interstate pipelines. SoCalGas' Northern Zone is connected to the U.S. Southwest (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of Topock, Arizona. It also connects to Kern River Gas Transmission to receive Rockies gas at Kramer Junction in San Bernardino County and at Wheeler Ridge, south of Bakersfield. SoCalGas' Southern Zone receives gas primarily from the Permian Basin in Texas via the El Paso Natural Gas pipeline.

26, CEC staff estimates that pipeline capacity will not change significantly compared to the previous winter. Additionally, there are no plans for extensive maintenance activity on the SoCalGas transmission system. CEC staff estimates that pipeline capacity will not change significantly compared to the previous winter. However, on colder days, SoCalGas is expected to rely on will further rely on gas storage to meet demand.

Table 9: SoCalGas Pipeline Capacity Assumptions

Supply (MMcfd)	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
California Line 85 Zone	40	40	40	40	40
Wheeler Ridge Zone	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone	980	980	980	980	980
Otay Mesa into Southern Zone	0	0	0	0	0
Kramer Junction into Northern Zone	550	550	550	550	550
North Needles/Topock into Northern Zone	700	700	700	700	700
Total Supply	3,035	3,035	3,035	3,035	3,035

Source: CEC staff

Table 10: SoCalGas Winter Pipeline Capacity Comparison

Season	Winter 2021–2022	Winter 2022–2023	Winter 2023–2024	Winter 2024–2025	Winter 2025-2026
Pipeline Capacity (in MMcfd)	2,835	2,815	3,065	3,035	3,035

Source: CEC staff

SoCalGas Storage

SoCalGas owns and operates the Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey facilities underground gas storage facilities, which have a combined maximum working gas capacity of about 120 billion cubic feet (Bcf). Based on CEC staff's daily tracking of storage activity and analysis of historical data on withdrawals and injections, staff estimates that the SoCalGas-owned gas storage facilities will be at full capacity by the beginning of winter 2025–2026. The full capacity includes the 68.6 Bcf working gas limit at Aliso Canyon, which the CPUC authorized in 2023 under Decision 23-08-050, which essentially removed all operating conditions at Aliso Canyon (Table 11).

Table 11: SoCalGas Storage Inventory Comparison

Season	Winter 2021–2022	Winter 2022–2023	Winter 2023–2024	Winter 2024–2025	Winter 2025-2026
Total Storage Inventory (in Bcf)	~81	~90	~90	~120	~120
Percentage Full (Total Storage)	96%	97%	75%	88%	100%
Allowed Aliso Inventory (Bcf)	34	41	69	69	69

Source: CEC staff

CEC staff tracks injections and withdrawals daily from SoCalGas gas storage facilities. Furthermore, SoCalGas reports daily operational data and working gas totals to the CEC.

During winter 2023–2024, the maximum daily net withdrawal (accounting for injections) from these fields totaled 1.9 Bcf, which occurred January 13, 2024. When 1.9 Bcf of gas was withdrawn January 13, 2024, storage inventories were an estimated 92 Bcf, demonstrating that staff's assumed maximum withdrawal capacity of 2 Bcf is reasonable. In its 2024–2025 winter assessment, SoCalGas estimated that the maximum storage withdrawal capacity is 2.4 Bcfd with the caveat that as inventory levels decline through the winter, the maximum may not be available.[35] In its gas balances presented below, CEC staff projects storage inventories will remain at between 110 and 120 Bcf in January 2026.

As of early September 2025, SoCalGas estimated working gas inventory is about 102 Bcf, and CEC staff expects that it will increase to the full capacity of 120 Bcf by November 1. Inventory at SoCalGas underground gas storage facilities would not reach 120 Bcf if systemwide demand will average more than 2,400 MMcfd from early September 2025 through October 2025. From late-July 2025 through early September 2025, demand on the SoCalGas has averaged about 2,400 MMcfd.

SoCalGas Gas Balance

Staff analyzed monthly average demand, monthly 1-in-10 demand, and two levels of peak-day demand for this assessment: a 1-in-10 core and noncore day and a 1-in-35-core and 1-in-10 noncore day.[36] Table 12 and Figures 8 and 9 show the monthly gas balance for the 2025-26 winter months using the CEC's forecast for average demand. Based on the projected average demand for those months, staff concludes that pipeline supply plus storage withdrawals are sufficient to meet that demand.

---

35 *Southern California Gas Company Winter 2024–25 Technical Assessment,* https://stage.socalgas.com/sites/default/files/2024-11/WINTER-2024-25-TECHNICAL-ASSESSMENT.pdf.

36 Appendix A describes the method used to develop the CEC demand projections. In the average demand case, the CEC is a little lower than the California Gas Report and a little higher in the high-demand case on average over the winter months November through March.

Table 13 and Figures 10 and 11 show a monthly cold demand and dry hydro scenario. CEC staff projects that at those demand levels for winter 2025–2026, storage withdrawals will be needed from November through February. Based on the projected average demand for those months, staff concludes that pipeline supply plus storage withdrawals are sufficient to meet that demand.

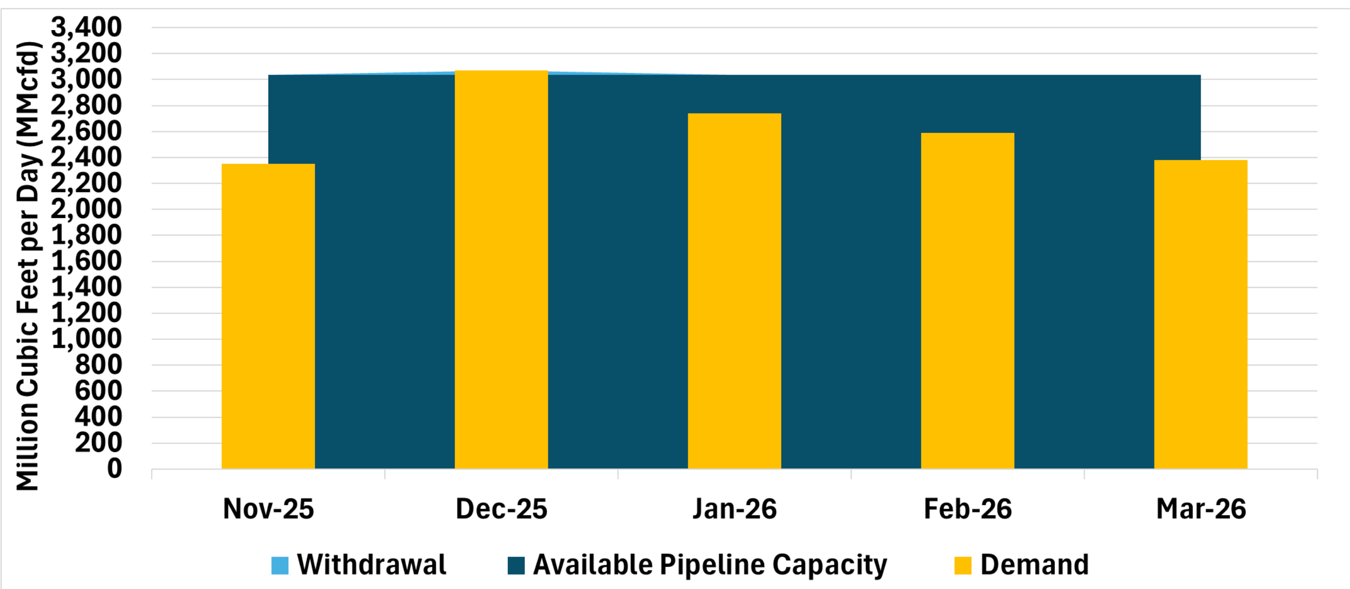
The winter ending inventory in the winter cold case is estimated to be 112 Bcf compared to 119 Bcf in the average demand case.

Table 12: SoCalGas Monthly Gas Balance Average Demand

Average Demand	Nov 2025	Dec 2025	Jan 2026	Feb 2026	March 2026
Demand (MMcfd)	2,352	3,071	2,741	2,591	2,380
Available Pipeline Capacity (MMcfd)	3,035	3,035	3,035	3,035	3,035
SoCalGas Injection/(Withdrawal) (MMcfd)	0	(36)	0	0	0
SoCalGas End-of-Month Inventory (Bcf)	120	119	119	119	119

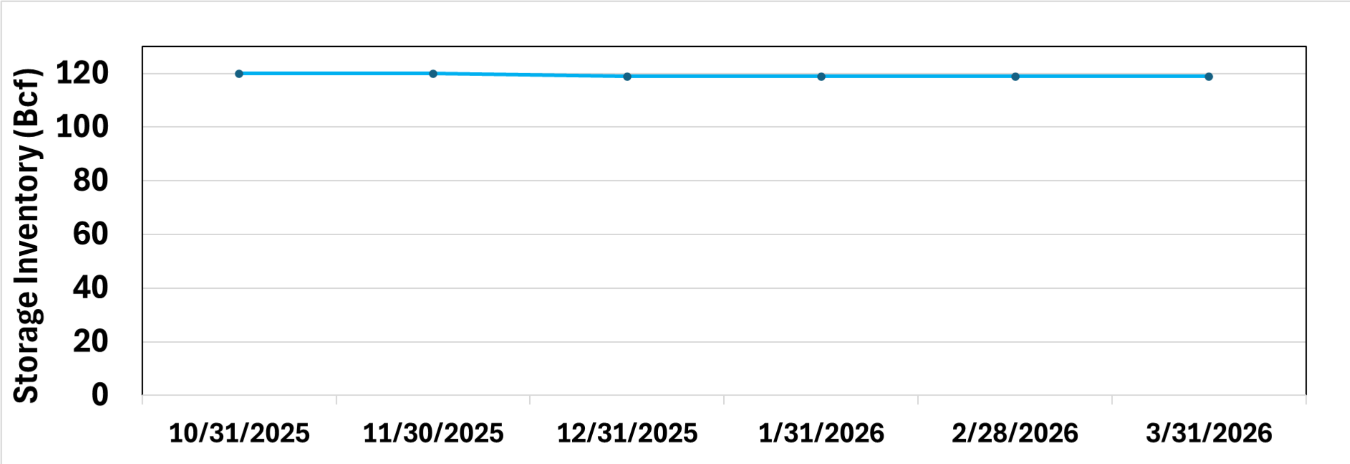
Source: CEC staff

Figure 9: SoCalGas Available Pipeline Capacity, Needed Withdrawals, and Demand (Average Temperature Demand)



Source: CEC staff

Figure 10: SoCalGas Storage Inventory (Average Temperature)



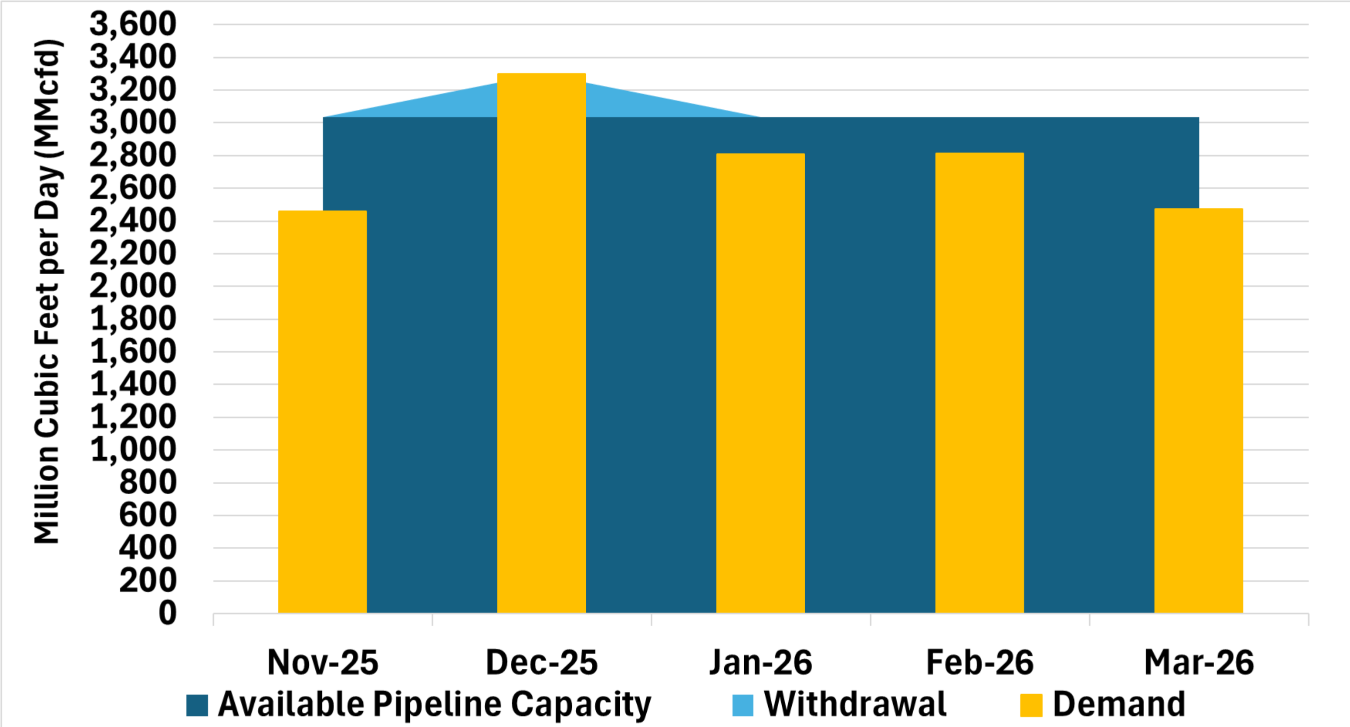
Source: CEC staff

Table 13: SoCalGas Monthly Gas Balance Cold Temperature/Dry Hydro Demand

Average Demand	Nov 2025	Dec 2025	Jan 2026	Feb 2026	Mar 2026
Demand (MMcfd)	2,460	3,297	2,807	2,814	2,472
Available Pipeline Capacity (MMcfd)	3,035	3,035	3,035	3,035	3,035
SoCalGas Injection/(Withdrawal) (MMcfd)	0	(262)	0	0	0
SoCalGas End-of-Month Inventory (Bcf)	120	112	112	112	112

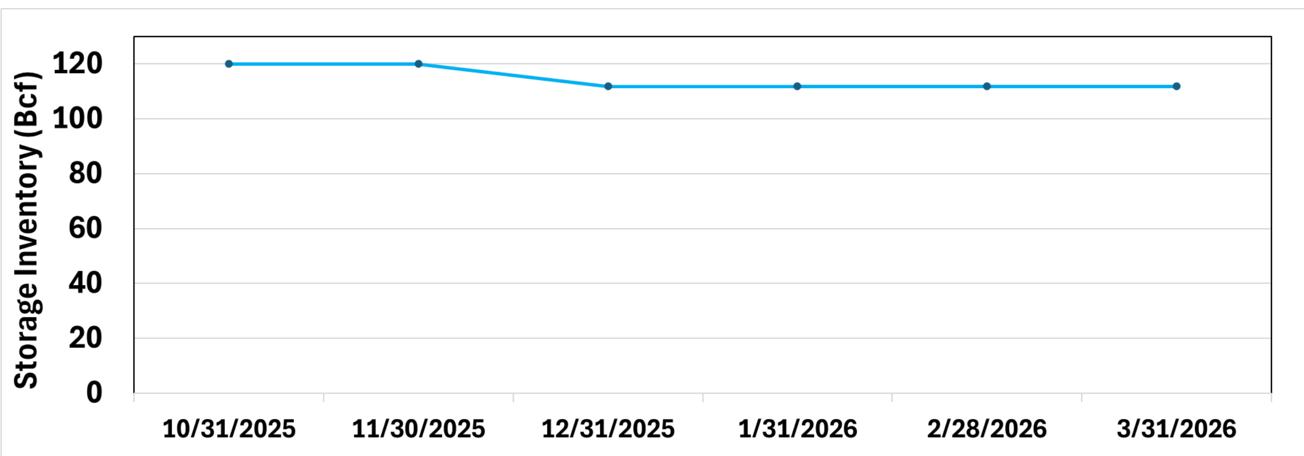
Source: CEC staff

Figure 11: SoCalGas Available Pipeline Capacity, Needed Withdrawals, and Demand (Cold Temperature/Dry Hydro Demand)



Source: CEC staff

Figure 12: SoCalGas Storage Inventory (Cold Temperature/Dry Hydro Demand)



Source: CEC staff

SoCalGas Peak-Day Analysis

Staff evaluated two peak-day cases for winter (Table 14 and Figure 12). Case 1 looked at a 1-in-10 peak temperature cold day for core and noncore load. Case 2 looked at the more extreme 1-in-35 peak temperature cold day for core plus 1-in-10 peak temperature cold day for noncore. A 1-in-35 peak temperature cold day correlates to a system average temperature of 40.6 degrees Fahrenheit for SoCalGas' service area and 43.5 degrees Fahrenheit for SDG&E's service area. A 1-in-10 peak temperature cold day correlates to a system average temperature of 42.3 degrees Fahrenheit for SoCalGas' service area and 44.9 degrees Fahrenheit for SDG&E's service area. CEC staff projects that SoCalGas storage fields will be at full capacity by the start of the winter 2025–2026 gas season in November.

During winter 2023–2024, the maximum daily net withdrawal (accounting for injections) from these fields totaled 1.9 Bcf, which occurred January 13, 2024. When 1.9 Bcf of gas was withdrawn January 13, 2024, storage inventories were an estimated 92 Bcf, demonstrating that an assumed maximum withdrawal capacity of 2 Bcf is reasonable.

Table 14: SoCalGas Peak-Demand-Day Gas Balances

Demand, Withdrawal, and Net Demand Type, Available Pipeline Capacity, and Needed Withdrawal	Case 1: Core + Noncore 1-in-10*	Case 2: 1-in-35 Core + Noncore 1-in-10**
Core Demand	2,843	2,991
Noncore-NonEG Demand	594	594
EG Demand	1,067	1,067
Total Demand	**4,504**	**4,652**
Available Pipeline Capacity	3,035	3,035
Needed Withdrawal	(1,469)	(1,617)
Assumed Available Withdrawal ***	2,000	2,000
Net Shortfall	0	0

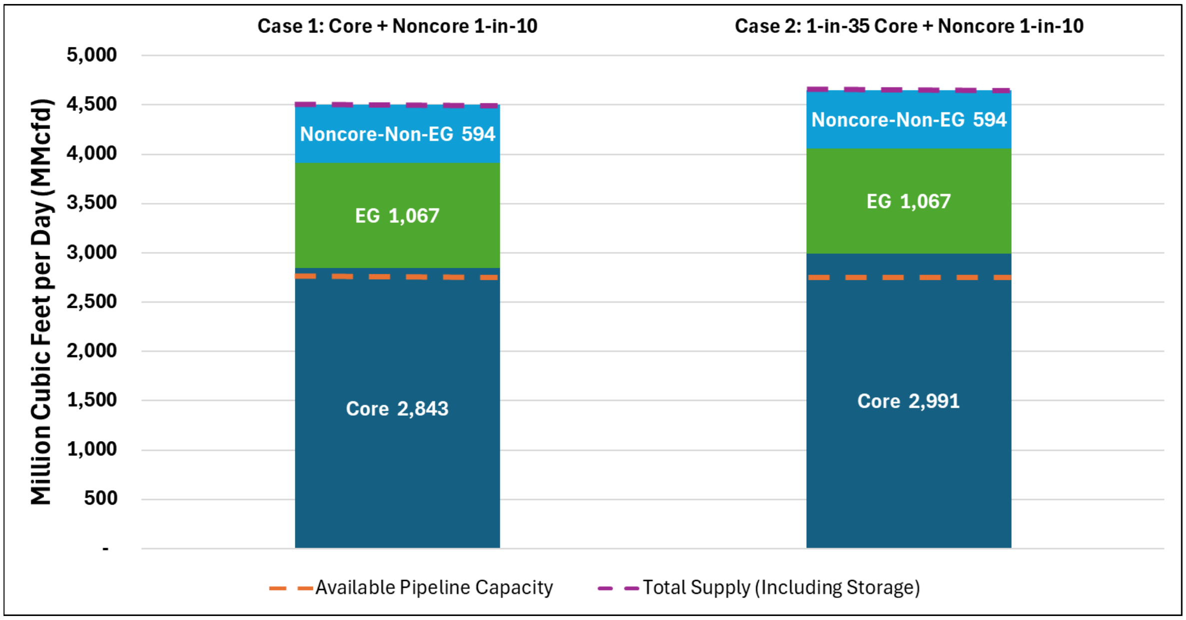
***Jan Peak**

**** Dec Peak**

***** Estimated withdrawal based on CEC staff analysis of historical gas withdrawal data.**

Source: CEC staff

Figure 13: SoCalGas Peak-Demand-Day Supply and Demand



Source: CEC staff

Based on the above assumed conditions, staff finds that supply can meet demand in Cases 1 and 2.

SoCalGas Stochastic Analysis

Staff performed an additional gas balance analysis for the upcoming 2025–2026 winter. It allows hourly demand to vary stochastically. This refined analysis simulates demand fluctuations within a historical range derived from 15 years of hourly gas demand data by day. This approach provides a more detailed picture of gas demand dynamics, capturing the hourly demand patterns that the conventional demand analysis does not.

Staff used the same method as in prior assessments to craft the hourly stochastic demand.[37] The key difference relative to staff's prior analyses is the availability of one more year's observations CEC staff has been able to add to the data set. Another difference is that staff also allowed receipts to vary stochastically. This variance demonstrates receipts fluctuating by about 5 MMcfd from average over a day. For the stochastic analysis, staff has also estimated withdrawal curves for SoCalGas. These curves were developed based on observed historical withdrawals and storage inventory levels from 2017 to 2024. As such, they are not an engineering estimate of what the fields could do but indicate what the data show SoCalGas has been observed to withdraw at a given inventory. The resulting withdrawal curves offer a baseline for available storage withdrawal to meet demand during the summer peak day.

---

37 Wong, Lana, Jason Orta, and Miguel Cerrutti. 2022 [Winter 2022–2023 SoCalGas Reliability Assessment.](https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment) *California Energy Commission*. Publication Number: CEC-200-2022-007, https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment. Appendix B of this report offers detailed documentation of the stochastic gas balance method.

With these refined inputs, staff compared supply to demand in a gas balance for each hour of the day and the necessary gas withdrawals for each hour within the simulated peak day for both the 1-in-10 cold day demand and the 1-in-35 core plus 1-in-10 noncore extreme peak day.

Tables 15 and 16 and Figure 13 illustrate the resulting gas balances. They highlight the critical midday ramping period, the morning and afternoon peak-demand hours, and the corresponding withdrawal requirements. The variability band around the average load profile demonstrates hourly variations, with peak hours exhibiting greater fluctuation. Demand peaks at 8 a.m. in both the cold-day and extreme peak-day cases, while supply is relatively flat hour over hour. The results show withdrawals required in all hours of the day, but no estimated curtailments, even under extreme peak-day conditions.

Table 15: Stochastic Hourly Gas Balance Results for the Cold Day

Units in MMcf	1-in-10 Winter Peak Day																							Total
Hour	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	
Demand	240	259	234	208	190	173	164	155	149	153	169	205	221	222	218	205	184	162	155	155	153	155	171	199	4,504
Receipts	127	127	126	126	125	125	125	125	126	126	126	126	126	126	126	127	126	127	127	128	128	128	128	128	3,035
Required Withdrawals	113	133	109	82	64	47	38	30	23	27	43	79	95	96	92	78	58	35	28	28	25	27	44	72	1,469
Curtailment*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

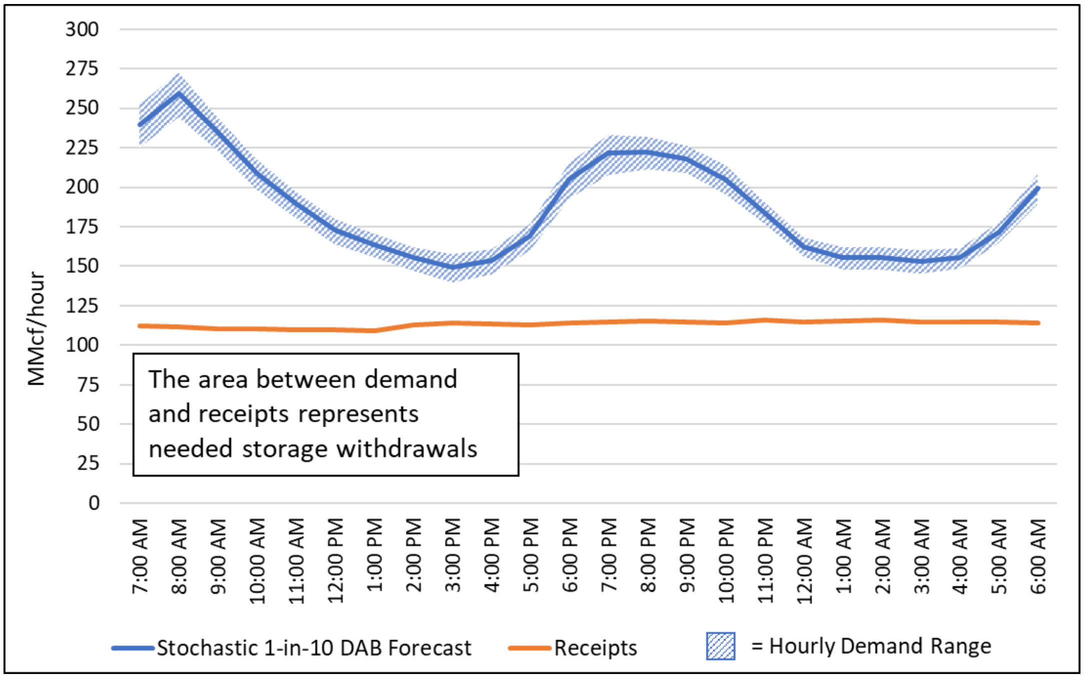
***Minimum curtailment required in each hour**
Source: Aspen Environmental Group

Table 16: Stochastic Hourly Gas Balance Results for the Extreme Peak Day

Units in MMcf	1-in-35 plus 1-in-10 Noncore Extreme Peak Day																							Total
Hour	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	0	1	2	3	4	5	6	
Demand	249	269	242	215	195	178	169	161	156	159	175	213	230	230	224	212	189	167	160	160	158	160	176	206	4,652
Receipts	127	127	126	126	125	125	125	125	126	126	126	126	126	126	126	127	126	127	127	128	128	128	128	128	3,035
Required Withdrawals	122	143	116	89	70	53	43	35	30	33	49	87	104	103	98	85	63	40	33	33	30	32	48	78	1,617
Curtailment*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-

***Minimum curtailment required in each hour**
Source: Aspen Environmental Group

Figure 14: Winter Peak-Day Demand Hourly Load Profile by Hour



Source: Aspen Environmental Group

The results of this stochastic assessment confirm the adequacy of supply to meet demand and no risk of potential curtailments under winter peak-day conditions and corroborate the results of the hydraulic modeling and other gas balances.

SoCalGas Hydraulic Analysis

CEC staff used the Synergi Gas hydraulic modeling platform to assess SoCalGas system operations. The hydraulic model simulates operations across the entire gas day, capturing changes in linepack that the peak-day gas balance cannot. It also identifies pressure violations and allows simulation testing of different operational solutions. Staff modeled the two peak-demand cases (Case 1 and Case 2) as in the gas balances. Staff used pipeline supply of 3,035 MMcfd assumed in the gas balances and used ratably, meaning the same quantity every hour. Storage withdrawals, in contrast, vary hourly to meet the difference between demand and supply flowing in from the interstate pipelines. The hydraulic modeling analysis confirms the analysis presented in the gas balances. On peak days, the SoCalGas system can meet demand without curtailments. Appendix B describes the method.

Conclusion

Based on the gas balance, stochastic analysis, and assessment of SoCalGas transmission system hydraulic models, SoCalGas can meet peak-day demands (the 1-in-10 and the extreme peak day plus) without curtailment of noncore customers. Meeting demand under these scenarios will require storage withdrawals in quantities below the assumed feasible withdrawal estimate on the SoCalGas system of 2,000 MMcfd.

CHAPTER 4: Qualitative Outlook of Fossil Gas Prices

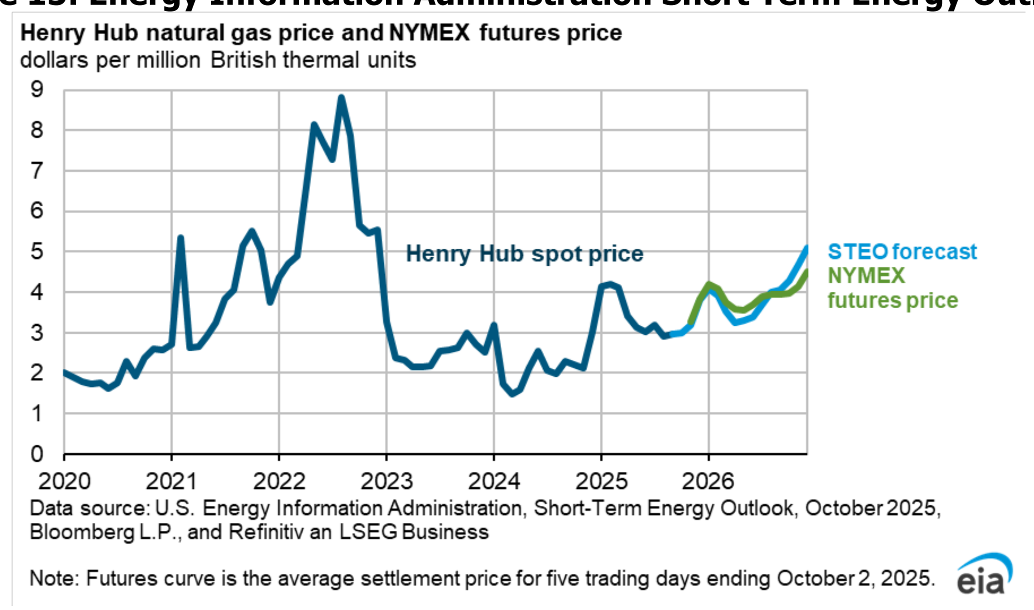
Winter Fossil Gas Prices

Fossil gas prices tend to be higher and more volatile during the winter months due to increased heating demand in the residential and commercial sectors, as well as some loss of supplies due to well freeze-offs that have occurred during extremely cold periods.

Looking ahead to the winter of 2025–2026, fossil gas supply infrastructure appears to be generally stable. As pipeline capacity for winter 2025-26 is expected to be like the previous winter, CEC staff expects prices to remain relatively stable. Overall prices are likely to rise with increased seasonal demand. Events such as severe weather or unplanned pipeline outages could significantly impact prices. Weather remains a major source of uncertainty, making it important to consider scenarios involving colder- and warmer-than-average winters.

According to the U.S. Energy Information Administration's (EIA) October 7, 2025, Short-Term Energy Outlook, Henry Hub fossil gas prices are projected to rise from an average of $2.97 per million British thermal units (MMBtu) in September to $3.80/MMBtu in 4Q25 and $3.90/MMBtu next year. EIA's October forecast shows lower prices for Q4 2025 and 2026 than their September forecast as higher than expected storage injection levels for late summer were observed combined with their revising forecasted production upward.

Figure 15: Energy Information Administration Short Term Energy Outlook[38]

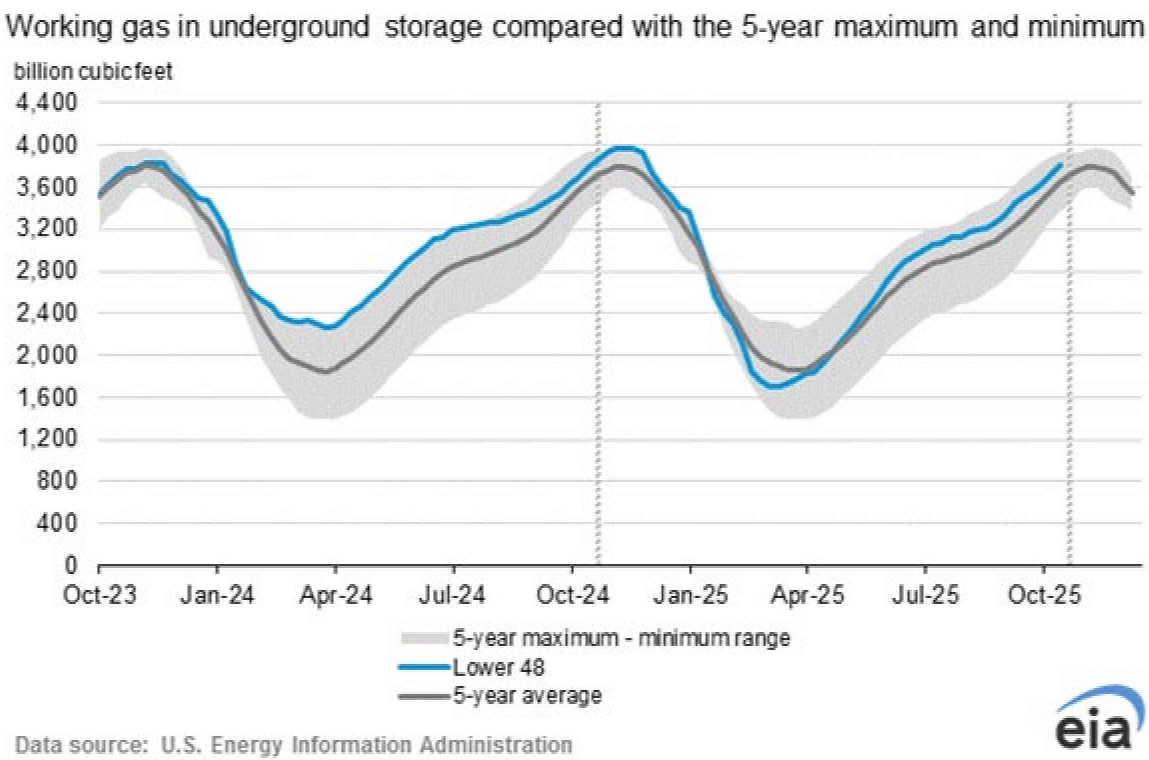


Storage inventory represents the difference in supply versus demand. Relatively small differences in storage inventories year-over-year sometimes have out-sized impacts on gas commodity prices as they indicate longer-term imbalances in the market. Thus, the fossil gas market collectively pays close attention to weekly changes in storage inventory.

38 Energy Information Administration, *Short Term Energy Outlook Report*, Figure 22, October 7, 2025.

The EIA projects U.S. storage to reach 3,978 Bcf by the end of the injection season in October, 186 Bcf above the five-year average of 3,792 Bcf.39 As of October 17, 2025, U.S. fossil gas inventories stood at 3,808 Bcf, 164 Bcf (5 percent) above the five-year average and 34 Bcf (0.1percent) above the level at this time last year.

Figure 16: EIA's U.S. Fossil Gas Storage[40]

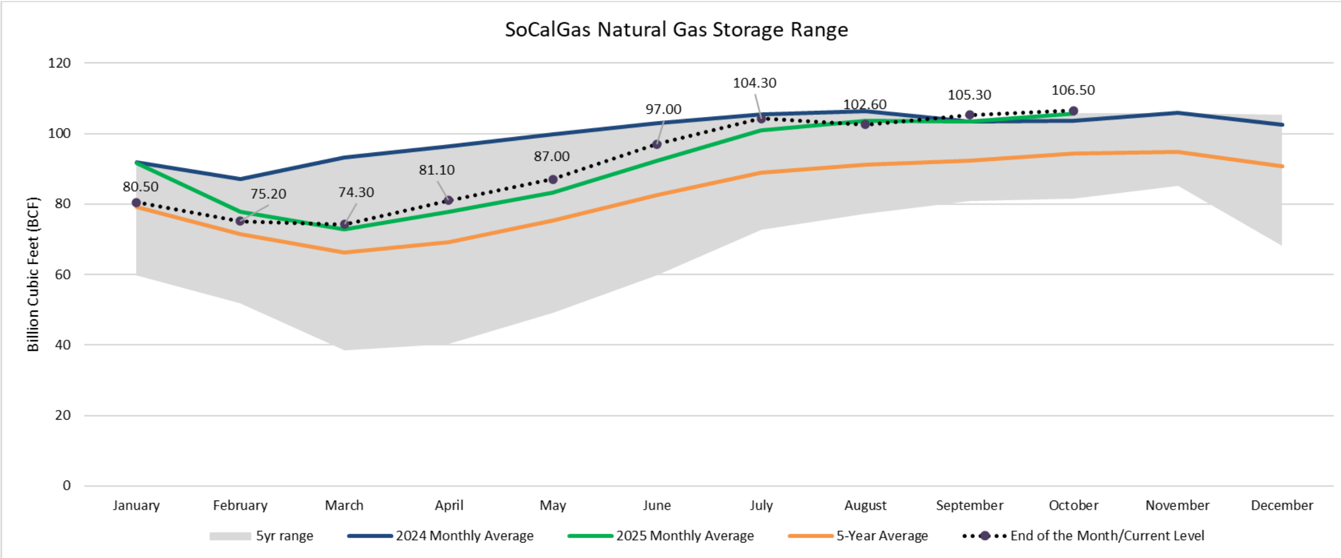


As of October 17 2025, SoCalGas has 106.5 Bcf of natural gas in storage. This is 1.3 Bcf more than the previous week and 2.3 Bcf more than this time last year. Overall, storage inventory for SoCalGas is 90 percent full.

39 Energy Information Administration, *Weekly Natural Gas Storage Report For Week Ending October 17, 2025* Figure 27, https://ir.eia.gov/ngs/ngs.html

40 Energy Information Administration, *Weekly Natural Gas Storage Report For Week Ending October 17, 2025* https://ir.eia.gov/ngs/ngs.html

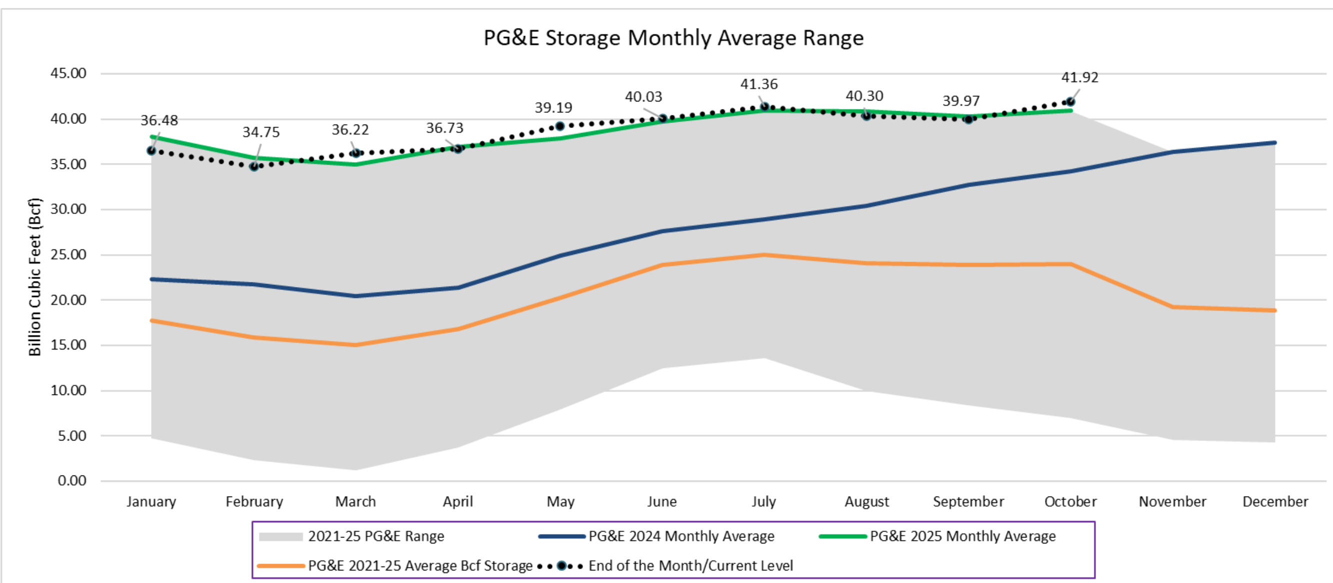
Figure 17: SoCalGas Fossil Gas Storage Inventory



Source: SoCalGas Envoy, CEC

As of October 17, 2025, PG&E has approximately 41.92 Bcf of natural gas in storage. This is 1 Bcf more than the previous week and 7.4 Bcf more than this time last year. The current storage inventory available is 82 percent of the total physical working gas capacity.

Figure 18: PG&E's Fossil Gas Storage Inventory



Source: PG&E Pipe Ranger, CEC

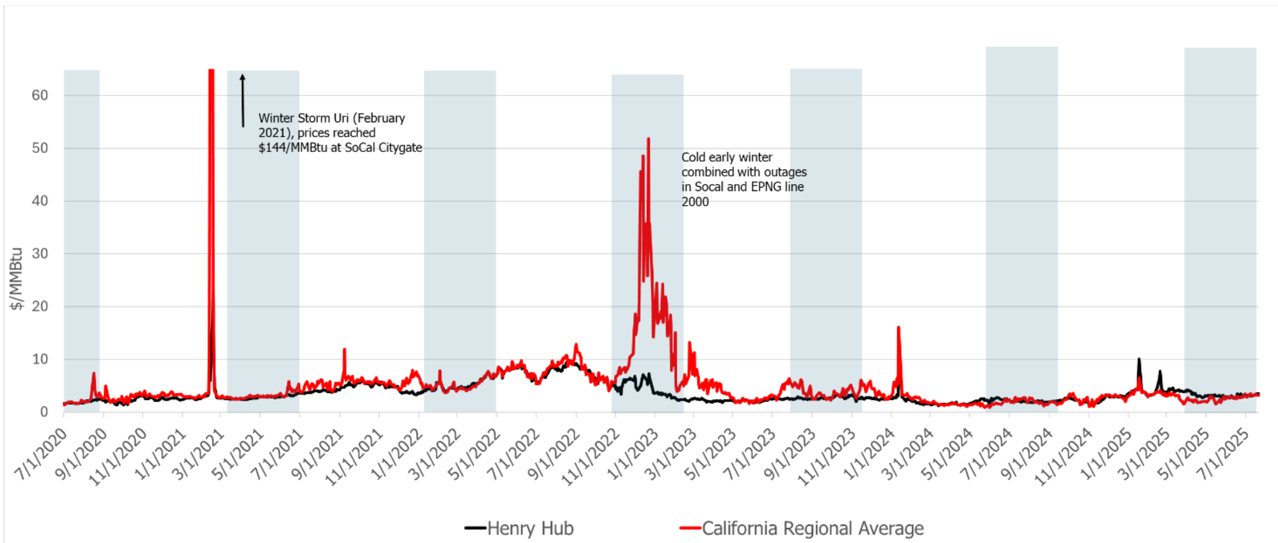
Fossil Gas Prices: Recent Winter Trends vs. Five-Year Averages (Winter 2020–2021 Through Winter 2024–2025)

Over the past five years (winter 2020–2021 through winter 2024–2025), California's average annual fossil gas prices have ranged from $3.01 to $8.89 per MMBtu. Prices typically increase during the winter months. For example, winter 2022–2023 saw an average price of $13.63/MMBtu, which included a significant price spike during a January cold snap.

Extreme weather can cause significant price spikes. During Winter Storm Uri in February 2021, prices surged to nearly $90/MMBtu because of surging demand, well freeze-offs, and infrastructure disruptions. While the price spikes of Winter Storm Uri did not impact California as severely as Texas or Oklahoma, California did experience notable increases in electricity and heating costs

Figure 14 shows daily Henry Hub and California regional average prices from July 2020 to July 2025, highlighting spikes from Winter Storm Uri and the early cold in winter 2022–2023.

Figure 19: Daily Fossil Gas Prices (2020-2025)



Source: NGI, CEC

The winter of 2024–2025 was mild across California and much of the United States, and fossil gas prices remained relatively low. Henry Hub prices averaged $3.35/MMBtu from November to March, up 32.7 percent from the previous winter. This increase reflects flat production and growing export volumes.

When compared to the five-year average, these data show that while prices generally fall within an expected range, factors such as weather and storage levels can lead to substantial fluctuations year to year.

To support reliability and price stability, California has taken strategic steps, including the CPUC's decision to increase the maximum allowable inventory of Aliso Canyon from 41.16 Bcf to 68.6 Bcf. This increase has enhanced the ability of the facility to meet peak winter demand.

Winter Storm Uri highlighted the vulnerability of interconnected energy markets. On February 17, 2021, the SoCal Border daily spot price peaked at $112.90/MMBtu. While the worst effects of the storm were centered in Texas, price spikes in California underscored the importance of strong supply management and contingency planning.

Summary

In summary, the mild winter of 2024–2025 illustrates how favorable conditions, such as lower demand and moderate weather (fewer freeze-offs), contribute to stable fossil gas prices and supply reliability. Though increased storage capacity and infrastructure improvements helped manage risks, the primary drivers of lower prices were weather-related and demand based.

GLOSSARY

A *billion cubic feet* is a standard unit of measurement for fossil gas supply/demand - 1,000,000 MMBtu = 1 Bcf.

A *British thermal unit* is the quantity of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at a specified temperature (such as 39 degrees Fahrenheit).

A PG&E *core customer* are all customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

A SoCalGas/SDG&E *core customer* are all residential customers; all commercial and industrial customers with average usage of 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 by procuring bundled service (both the fossil gas itself and the transportation services).

A *decatherm* is the quantity of heat energy equivalent to 1 million British thermal units.

An *end user* means any company that consumes electricity or fossil gas for its own use and not for resale.

(18)(22) "Energy storage system" means

The *Federal Energy Regulatory Commission* regulates fossil gas transportation in interstate commerce and construction of gas pipeline, storage, and liquefied fossil gas facilities.

Henry Hub is a fossil gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.

The *Independent Storage Providers* are the Lodi Gas Storage, Wild Goose Storage, Central Valley Storage, and Gill Ranch Storage underground gas storage facilities, which are connected to the PG&E gas system.

A *liquefied fossil gas* is fossil gas that has been cooled to a liquid state, about -260° Fahrenheit, for shipping and storage.

A *million British thermal unit* is a thermal unit of measurement for fossil gas.

A *million cubic feet per day* (MMcfd) is a unit of measurement used to express the amount of fluid (gas, water, and so forth) that is consumed, produced or traversed in a pipeline on any given day.

A *fossil gas* is a hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane, and other gases.

A *noncore load* is electric generators, industrial customers, commercial, and all other noncore customers based in Los Angeles and Southern California.

Pacific Gas and Electric Company is a utility company and primary provider of fossil gas to parts of Central and Northern California.

Southern California Gas Company (SoCalGas) is a utility company and primary provider of fossil gas to Los Angeles, Southern California, and parts of Central California.

Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

APPENDIX A: Gas Demand Forecast Method

Method for Gas Demand Forecasting (2025–2026)

This document details the method used to forecast fossil gas demand for Pacific Gas and Electric (PG&E) and Southern California Gas (SoCalGas) during the winters of 2025 and 2026. The approach combines time-series modeling with climate drivers, using Facebook's Prophet model. This model was selected for the ability to handle multiple seasonal patterns, nonlinear trends, and external variables such as temperature and climate change projections. These features are essential for modeling gas demand that varies because of environmental factors.

Data Collection and Preparation

The historical dataset covers 2017 to 2024 and provides daily fossil gas demand data by customer type. This segmentation enables the model to distinguish between how core and noncore customers respond differently to temperature changes.CEC staff collected temperature data from the National Oceanic and Atmospheric Administration (NOAA), which provided observations at weather stations.[41] Daily maximum and minimum temperatures were calculated using a weighted average by population across the stations in the service territories.

To anticipate the impact of climate change on gas demand, climate projections for 2025 and 2026 were incorporated into the analysis.[42] These projections guided adjustments in future-year temperature distributions while accounting for uncertainty in climate projections, without directly embedding them into the time-series model. Instead, historical and projected temperature data were analyzed over various time horizons (1 to 40 years), examining quantiles to estimate the range of warming and related effect on heating and cooling demand.

From these historical and projected temperature profiles, heating degree days (HDDs) and cooling degree days (CDDs) were derived using standard thresholds of 65°F and 55°F.[43] These metrics served as proxies for weather-dependent gas usage.

41 Burbank, Long Beach, Santa Barbara, Bakersfield, and Riverside in SoCalGas' service area and Fresno, Oakland, Red Bluff, Sacramento, San Jose, San Luis Obispo, and Ukiah in PG&E's service area.

42 Ongoing research supported by the Electric Program Investment Charge (EPIC) has delivered a suite of hybrid (statistical-dynamical) downscaled, bias-corrected projections over California at a 3 kilometer (km) by 3 km resolution which are then assigned to weather stations used by CEC for forecasting energy demand.

43 Degree days are calculated based on the difference between the average daily temperature and the thresholds.

Exploratory Data Analysis

Initial analysis revealed a nonlinear relationship between temperature and demand, particularly among core customers during the winter months. Their heating demand increased sharply as temperatures dropped.

To address daily fluctuations in temperature data and better reflect response lags, a three-day weighted moving average was applied to the temperature series. This average assigns weights of 0.6, 0.3, and 0.1, with the highest weight given to the most recent day, smoothing out day-to-day noise and more accurately capturing response delays.Time-related features, such as year, month, and week, were added to capture cyclical patterns. In addition, binary variables were created to distinguish between winter (November to March) and summer (April to October), as well as to indicate weekends and public holidays. No significant anomalies or outliers were found in the dataset.

Modeling Approach

The Prophet model analyzes time series data by additively breaking it down into basic components: trend, seasonality, and holidays. The trend appears as a piecewise linear function with change points, indicating shifts in demand behavior. Seasonality is modeled using a Fourier series,[44] which captures annual, weekly, and monthly patterns. Both additive and multiplicative seasonal components were tested, but staff ultimately chose the multiplicative one, as it better reflected that seasonal effects tend to scale in proportion to total demand.

Holiday effects were incorporated using binary indicators. The demand series was log-transformed to address heteroskedasticity and reduce the influence of outliers. This transformation also stabilized the variance and diminished serial correlation. Weather regressors (CDDs and HDDs) were included along with one-day lagged difference terms to account for customer response delays. Binary variables for nonworking days (weekends and holidays) and seasonal indicators were also incorporated.

Model hyperparameters, such as the changepoint prior scale, trend flexibility, and seasonal strength,[45] were optimized using Bayesian techniques,[46] improving forecasting performance and preventing overfitting.

Historical Performance Evaluation (2017–2024)

To validate the method, staff performed a rolling forecast evaluation over the historical period. The model was estimated iteratively using a rolling window approach. It was trained on fixed-size data windows and then used to produce 12-month out-of-sample forecasts. After each

---

44 Simply stated, a Fourier series is the output of a periodic function characterized by amplitudes and frequencies.

45 45The hyperparameters limit the number of potential changepoints included in the model, and modulate the strength of the trend and seasonal components. By adjusting these values, the model accommodate larger fluctuations in trends and seasonal patterns.

46 Garnett, Roman. 2023, *Bayesian Optimization*. Cambridge University Press.

iteration, the window was shifted forward by one month, and the model was re-estimated. Staff repeated this process until forecasts were generated for all available test periods.

Performance was assessed using the mean absolute percentage error (MAPE). Peak-day forecast errors ranged from 3.5 percent for SoCalGas to 4.2 percent for PG&E, with monthly average MAPE values between 1.5 percent and 1.7 percent. The residuals showed no systemic bias, and their distribution closely matched normality, indicating that the model effectively captured trends and seasonality.

Predictive Forecasting (2025–2026)

After validation, the model generated winter gas demand forecasts for 2025 and 2026. CEC staff made adjustments based on statistical downscaled climate change data, with a particular focus on the distribution of daily minimum temperatures to evaluate the impacts of HDDs on peak demand. Four peak-day scenarios were developed to analyze peak-day demand. Two represent weather conditions with a 90 percent occurrence (1-in-10) for both gas utilities, one with a 97.5 percent occurrence (1-in-35) for SoCalGas and one with a 98.8 percent occurrence (1-in-90) for PG&E. These scenarios were derived from historical minimum temperature data from the past 40 years and statistical downscaled climate projections for 2025–2026. They indicated a general decrease in HDDs due to long-term warming, which is expected to result in lower peak-day heating demand during future winters.

Staff created two monthly scenarios to examine the average monthly demand. One represents typical weather conditions with a 50 percent chance of occurring, while the other simulates slightly colder-than-average months with a 10 percent chance of occurring. Both scenarios follow the same statistical approach as the peak-day projections. These forecasts cover typical and cold climate variability cases.

In the coldest projected scenario (a one-in-35-year cold day), peak-day demand for SoCalGas is expected to reach 4,753 MMcfd in 2025 and 4,704 MMcfd in 2026, while PG&E's one-in-90 scenario forecasts peaks of 5,188 MMcfd and 5,069 MMcfd, respectively.

In December 2025 and with a 50 percent occurrence, SoCalGas is projected to have a total demand of 3,297 MMcfd, with 1,671 MMcfd coming from core customers. PG&E's forecast for December is 3,380 MMcfd, of which 1,341 MMcfd is linked to core demand. For December 2026, the projections stay fairly consistent: 3,232 MMcfd for SoCalGas and 1,646 MMcfd from core customers, while PG&E is estimated at 3,346 MMcfd, with 1,334 MMcfd from core customers, indicating a consistent but gradually shifting demand profile. These projections highlight the temperature sensitivity of core customers' gas demand, along with the regional variations in climate response.

Core and noncore segments were modeled separately to reflect the respective distinct consumption behaviors. Core demand was directly forecasted using the additive Prophet model, while noncore demand was inferred from historical ratios and trends. Growth rates were derived from projections in the California Gas Reports (CGR) of 2022 and 2024, as well as gas utility filings to the California Energy Commission's *2025 Integrated Energy Policy Report (IEPR)* docket.

Results

While this method emphasizes winter demand, it also considers full-year trends to ensure precise seasonal adjustment. Below are the projected peak-day demands and monthly average consumption for PG&E and SoCalGas for 2025–2026. (Tables A-1 and A-2)

Table A-1: Peak-Day Demand (MMcfd) for PG&E During Winter 2025–2026, Categorized by Consumer Class and for a 1-in-10 and 1-in-90-Year Peak Day

Strata	Year	Core	Industrial	Electric Gen	Off_System	Total
1-in-10	2025	2,524	521	1,016	368	4,429
1-in-10	2026	2,539	523	902	366	4,331
1-in-90	2025	3,065	563	1,137	423	5,188
1-in-90	2026	3,032	576	1,039	422	5,069

Source: CEC staff

Table A-2: Peak-Day Demand (MMcfd) for SoCalGas During Winter 2025–2026, Categorized by Consumer Class for a 1-in-10 and 1-in-35-Year Peak Day

Strata	Year	Core	SDGE Core	Other Core	Noncore	Electric Gen	Total
1-in-10	2025	2,425	279	139	594	1,067	4,504
1-in-10	2026	2,453	282	142	614	1,041	4,531
1-in-35	2025	2,532	301	158	651	1,112	4,753
1-in-35	2026	2,507	286	161	648	1,103	4,704

Source: CEC staff

APPENDIX B: Hydraulic Modeling

In 2017, the California Energy Commission (CEC) launched an initiative to conduct independent hydraulic modeling assessments of the state's fossil gas pipeline systems. These models simulate gas-flow dynamics, incorporating complex nonlinear equations that account for the behavior of a compressible fluid. The objective is to analyze the interactions between gas supply entering the system, the consumption by end users, and the physical structure of the pipeline network.

Fossil gas utilities, such as PG&E and SoCalGas, routinely use hydraulic models to simulate operations, assess system capacity, and determine when infrastructure expansions are necessary. These assessments guide decisions on pipeline diameter, length, and compressor requirements to meet future demand. The CEC's role in this process is to verify the utilities' results, run independent simulations, and provide analysis for policy makers.

Hydraulic Modeling Platform and Data Integration

The CEC uses the DNV-GL Synergi Gas™ hydraulic modeling platform, a widely adopted tool in the United States, employed by major utilities like PG&E and SoCalGas. California's regulatory framework mandates that gas utilities submit their hydraulic models to the CEC, alongside key operational data such as minimum and maximum allowable pressures, demand scenarios, and load profiles. The CEC uses these inputs for its modeling and analysis, as outlined in Title 20, Division 2, Chapter 3, Article 1, Section 1314 of the California Code of Regulations.

Utilities are also required to brief the CEC on model updates, ensuring transparency and collaboration between both parties. This ongoing exchange helps the CEC fully understand the operational data and model parameters provided by the utilities.

Winter 2025–2026 Reliability Assessment

For the upcoming winter reliability assessment, CEC staff analyzed hydraulic models submitted by PG&E and SoCalGas. The analysis involves both steady-state and transient simulations. A steady-state analysis offers a static view of the system, illustrating gas supply, demand, and pressure levels under specific conditions. In contrast, transient analysis simulates gas flow over time, capturing the system response to changing demand throughout the day.

Both models use detailed inputs, including pipeline lengths, diameters, compressor stations, regulators, valves, and storage facilities. PG&E and SoCalGas also provide operational constraints, such as minimum and maximum pressures, which the CEC uses to ensure the models simulate realistic operating conditions.

The CEC's transient simulations assess system behavior across a full day, including how pressures fluctuate during peak-demand periods and stabilize during off-peak hours. This simulation helps identify critical moments when the system approaches capacity limits and requires adjustments to maintain balance.

Key Scenarios and Case Studies

Two key scenarios were modeled for PG&E and SoCalGas systems as part of the 2025–2026 assessment:

- **1-in-10 Cold Day Scenario (PG&E and SoCalGas)**: A high-demand scenario based on weather extremes expected once every 10 years.
- **Abnormal Peak Day Plus Scenario (PG&E)**: A more severe scenario combining the 1-in-90 core customer demand with 1-in-10 noncore customer demand for PG&E.
- **Extreme Peak Day Plus Scenario (SoCalGas)**: A 1-in-35 core customer demand plus 1-in-10 noncore customer demand for SoCalGas.

In both scenarios, the models used steady-state and transient analyses to evaluate system performance under stress. Staff ensured that supply from interstate pipelines and California production was maintained at constant, ratable levels, in line with industry practices and regulatory requirements from the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC).

System Balance and Intraday Operations

During the simulations, the primary goal was to maintain system balance, ensuring all pressure regulators, valves, and meters operated within tolerance and that demand was consistently met. Transient analysis offered insights into intraday operations, highlighting how peak-hour demand impacts system pressures and the adjustments needed to maintain system stability.

The concept of linepack plays a critical role in these simulations. *Linepack* refers to the amount of gas stored within the pipeline network. If supply exceeds demand, the system enters packing mode, causing pressure to rise, while drafting mode occurs when demand exceeds supply, leading to pressure drops. Managing line pack is crucial to avoid both underpressure and overpressure, which can present safety risks.

The results of the 2025–2026 reliability assessment confirmed that PG&E and SoCalGas can meet demand under peak-day conditions. The findings closely aligned with each utility's gas balance projections, indicating that the CEC's independent assessments offer a reliable reflection of system behavior under the given conditions.

Conclusion

The hydraulic modeling assessments conducted by the CEC provide critical insights into the capacity and resilience of California's fossil gas pipeline systems. By simulating real-world scenarios and verifying the utilities' models, the CEC ensures that California's gas infrastructure can reliably meet demand while maintaining safety and operational efficiency. These assessments are instrumental in guiding policy decisions and infrastructure planning, ensuring that the state remains prepared for future energy challenges.