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STAFF REPORT

Winter 2024-2025 California Gas Reliability Assessment

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California Energy Commission

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ABSTRACT

The California Energy Commission (CEC) presents this Winter 2024–2025 California Gas Reliability Assessment (Winter Assessment) to assess the risk of curtailment of Pacific Gas and Electric (PG&E) and Southern California Gas (SoCalGas)/San Diego Gas and Electric (SDG&E) gas service to gas-fired power plants and other noncore customers such as factories and large commercial facilities. The risk of curtailment of gas service to core customers (generally residential and small commercial customers) is lower as reliability standards for them have been designed to ensure that even under the most extreme cold conditions, gas service is maintained without interruption. Staff developed monthly demand and peak day demand forecasts for Winter 2024-25 and incorporated them into gas balance models, stochastic models, gas system simulations in the form of hydraulic models to assess how the PG&E and SoCalGas will meet demand in average months, cold months, and under two peak day scenarios.

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 (ISPs), 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 ISPs and issuing an Operational Flow Orders (OFO) 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: Natural gas, reliability, system, peak, extreme, balance, demand, Synergi, curtailment, interruption, risk, improved, pipeline, capacity, storage, hydraulic, modeling

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EXECUTIVE SUMMARY

The California Energy Commission (CEC) presents this Winter 2024–2025 California Gas Reliability Assessment (Winter Assessment) that focuses on gas service curtailment risk to gas-fired power plants and other noncore customers such as factories and large commercial facilities. This assessment does not focus on core customers (generally residential and small commercial customers) because reliability standards ensure that even under the most extreme cold conditions, their gas service is maintained without interruption. For the gas utilities, curtailment of core customers is a measure of last resort. Outages to core customers take a long time to restore — from several days to weeks — and involve tremendous manpower. Safety requires that utilities bring gas mains back on-line individually and sequentially and restore service to each home or building. 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.

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 mainly driven by the increased space and water heating needs of core customers. Nearly 37 percent of the electricity used in California is produced by natural gas; therefore, curtailment of gas service to power plants can jeopardize electricity system reliability. This report assesses the risk of gas system curtailments to noncore customers on the Pacific Gas and Electric (PG&E) and the Southern California Gas (SoCalGas)/San Diego Gas & Electric (SDG&E) systems.

While gas reliability standards set by the California Public Utilities Commission (CPUC) generally require gas utilities meet a high peak winter demand under very cold conditions for core customers (mainly residential and small commercial customers), service to noncore customers is not subject to this stringent level of reliability. However, when these reliability standards were established, many noncore customers such as power plants and factories had alternatives to burning gas in their facilities, such as diesel fuel. Largely because of air quality regulations, noncore customers no longer have dual-fuel capabilities.

PG&E Analysis

For its assessment of the PG&E system, CEC staff evaluated the following peak day demand scenarios which include demand scenarios for all customer classes for winter 2024–2025 and made the following findings:

Cold Day (Case 1) — A 1-in-10 cold day (demand that has a 1-in-10-year probability of occurrence that roughly corresponds to a 35-degree day in Northern California) for core and noncore customers. Based on CEC demand forecasts, CEC estimates of PG&E system pipeline capacity and PG&E estimates of the withdrawal capacity of its storage facilities in winter 2024–2025, CEC staff projects a net shortfall of 441 million cubic feet (MMcf) for a 1-in-10 day (Table 1). The net shortfall is a comparison of demand under this scenario and PG&E pipeline and PG&E storage withdrawal capacity. Withdrawals by independent storage providers (ISPs) are not included. As discussed further below, the 441 MMcf shortfall would impact noncore customers and can be addressed without curtailment of service via actions by noncore customers, ISPs, and PG&E. Withdrawals from ISPs for noncore customers (electric generators, large commercial, and industrials) can reduce or zero out the net shortfall estimates above and are feasible based on the withdrawal capacities of independent storge providers and pipeline capacity. However, the ISPs conduct these transactions independently of PG&E under terms not made available to the public. This means that CEC staff cannot produce an estimate of withdrawals from individual ISPs along with not knowing how much gas can be withdrawn from these facilities on a cold day. In the event of high or low pipeline inventory (for example, when linepack is threatened because customers did not nominate for delivery into the gas system enough gas to meet their demand), gas utilities can issue Operational Flow Orders (OFOs). Under a low OFO when pipeline inventory is low, noncore customers including power plants are required to limit their gas use to the amount they nominated within a tolerance band. In this example, a power plant would not be able to burn more gas than what they nominated for delivery plus a tolerance band to generate more electricity.

Abnormal Peak Day Plus (Case 2) — 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. Based on CEC demand forecasts, CEC estimates of PG&E system pipeline capacity, and PG&E estimates of the withdrawal capacity of its storage facilities in winter 2024–2025, CEC staff projects a net shortfall of 951 MMcf for an abnormal peak day plus day. The net shortfall is a comparison of demand under this scenario and PG&E pipeline and PG&E storage withdrawal capacity. ISP withdrawals are not included. The 951 MMcf net shortfall would impact noncore customers and can be addressed by withdrawals from ISPs or in the event of system imbalances, Operational Flow Orders (OFOs). A brief discussion of these measures is included in the previous bullet.

The electric generation forecast in Table 1 represents a dry hydroelectric year in which electric generation from hydroelectric resources is significantly lower than historical averages. During dry hydroelectric years, demand from gas-fired power plants increases. Also the forecast in Table 1 may not account for the increased use of central station and distributed battery storage systems interconnected to the grid to help meet electricity demand, which may reduce power plant gas demand. As California is not coming off a dry hydro year and with the increased use of battery storage, the estimate for peak-day gas demand for electricity generation may be conservative for Winter 2024-25 considering available resources.

In addition to the above, there are risks including potential impacts of scheduled and unscheduled maintenance events on PG&E’s key mainlines and storage facilities.

Table 1: PG&E Peak Demand Day Gas Balances

Demand, Withdrawal, and Net Shortfall	Case 1: Cold Day Core + Noncore 1-in-10* (MMcfd)	Case 2: Abnormal Peak Day Plus 1-in-90 Core + Noncore 1-in-10** (MMcfd)
Demand		
Core	2,429	2,939
Noncore-NonEG	496	496
EG	1,157	1,157
Off System	80	80
TOTAL Demand	4,162	4,672
Available Pipeline Capacity***	2,927	2,927
Needed Withdrawal	1,235	1,745
Assumed Available Withdrawal (PG&E Storage)****	-794	-794
Net Shortfall -Does Not Include ISP Withdrawals	441	951

Source: CEC staff

***Jan Peak**

**** Dec Peak**

***Staff developed estimate of capacity based on the maintenance outlook on the PG&E Pipe Ranger website.

****PG&E estimate of storage capacity for Winter 2024-25 in facilities it owns in CPUC Application 24-07-020.

SoCalGas Analysis

For its assessment of the SoCalGas system, CEC staff evaluated the following scenarios for winter 2024–2025 and made the following findings:

- **Cold Day (Case 1) —** A 1-in-10 cold day (demand that has a 1-in-10 year probability of occurrence that generally corresponds to a 44°F day in Southern California) for both core and noncore customers. Based on CEC demand forecasts, CEC estimates of SoCalGas system pipeline capacity, and CEC estimates of the withdrawal capacity of its storage facilities in winter 2024–2025, CEC staff projects no net shortfall for a cold day (Table 2).
- **Extreme Peak Day Plus (Case 2)** — 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 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. Based on CEC demand forecasts, estimates of SoCalGas system pipeline capacity, and estimates of the withdrawal capacity of its storage facilities in winter 2024–2025, CEC staff projects no "net shortfall" for an extreme peak day. (Table 2)

Due to the restoration of some pipeline capacity over the last two years on the SoCalGas system and the increased working gas capacity of Aliso Canyon, CEC staff estimates that SoCalGas can meet cold day and extreme peak-day demands without curtailment of noncore customers (Table 2). However, there are risks including potential impacts of scheduled and unscheduled maintenance events on SoCalGas's key mainlines and storage facilities. SoCalGas also can issue Operational Flow Orders to its customers in instances of low or high pipeline inventory.

Table 2: SoCalGas Peak Demand Day Gas Balances

Demand, Withdrawal, and Net Shortfall	**Case 1: Cold Day Core + Noncore 1-in-10* (MMcfd)**	**Case 2: Extreme Peak Day Plus 1-in-35 Core + Noncore 1-in-10** (MMcfd)**
Demand		
Core	2,834	2,987
Noncore-NonEG	595	595
EG	1,080	1,080
TOTAL Demand	4,509	4,662
Available Pipeline Capacity	3,035	3,035
Needed Withdrawal	1,474	1,627
Assumed Available Withdrawal ***	1,900	1,900
Net Shortfall	0	0

***Jan Peak**

**** Dec Peak**

***** Estimated withdrawal based on maximum withdrawal observed during winter 2023–2024.**

Source: CEC staff

Market Prices

Looking ahead to this winter, as pipelines on the PG&E and SoCalGas systems are operating at normal capacity and storage levels currently elevated, prices are expected to remain relatively stable, though they will likely rise with increased winter demand. Unforeseen factors such as severe weather or unexpected pipeline outages that greatly affect gas supplies or demand or both could have a significant impact on prices.

The EIA's Short Term Energy report forecasts natural gas prices will remain relatively flat in the upcoming shoulder season during September and October before generally rising in 2025. The EIA expects the Henry Hub spot price will rise from less than $2.00 per million British thermal units (MMBtu) in August 2024 to around $3.10/MMBtu next year.

CHAPTER 1: Introduction

The California Energy Commission (CEC) has prepared or taken a leading role in several seasonal gas system reliability assessments since April 2016, with a focus on the Southern California Gas Company (SoCalGas) territory. The CEC's effort was necessitated after the 2015 well leak at the Aliso Canyon underground gas storage field located near the Porter Ranch neighborhood in Los Angeles. The well leak at the SoCalGas-owned facility severely limited the use of the storage field. The CEC published those assessments as stand-alone reports. However, the CEC's recent gas system reliability assessment for summer 2024 was included as part of the *California Energy Resource and Reliability Outlook, 2024,* which provided assessments of both electricity and natural gas system reliability. In addition to the reliability outlook of the SoCalGas system, that report included a high-level analysis of the PG&E system.

The winter assessments help provide directional information on potential risks to the reliability of service under normal and extreme conditions in the winter. For reference, the gas system defines winter as November 1 to March 31. During these months. gas utilities can often meet demand through pipeline supplies but may need to withdraw from storage during colder periods or to support the system during pipeline outages or maintenance.

The CEC conducted this assessment independently and prepared monthly and peak-day forecasts of the PG&E and SoCalGas systems. Staff analyzed these scenarios by simulating these conditions using PG&E and SoCalGas system hydraulic models.[1] Furthermore, staff prepared a stochastic hourly gas balance for the SoCalGas system as enough data is available to map out changes in intraday demand on that system. Staff does not have this level of data for PG&E but will explore preparing a stochastic hourly gas balance in future assessments.

This assessment provides an independent analysis of the expected reliability of service in winter 2024–25 for the PG&E and SoCalGas systems.

CEC Winter Analysis of the PG&E System

This is the first CEC assessment that includes a winter analysis of the PG&E system. This analysis allows CEC to provide a more complete picture of the state's gas systems and how reliability of these systems impacts service to core (residential and small commercial) and noncore customers (electric generators, large commercial, and industrial). While stringent reliability standards make curtailment of core customers a last resort, high demand by core customers and the associated increases in the use of available pipeline and storage capacity can impact the reliability of gas service to noncore customers. For the gas utilities, curtailment of core customers is a measure of last resort. Outages to core customers take a long time to restore — from several days to weeks — and involve tremendous manpower. Safety requires that utilities bring gas mains back on-line individually and sequentially and restore service to

1 Hydraulic models use system parameters including pipeline characteristics, such as pipeline lengths and diameters, storage withdrawals, and demand scenarios to calculate system pressures and flows.

each home or building. 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. Further, analyzing the ability to serve electric generator customers strengthens the understanding of the nexus between California's gas and electricity systems. To support this assessment, the CEC prepared forecasts of monthly peak-day forecasts of the PG&E system and incorporated these into a gas balance. CEC staff inputted its peak-day demand forecasts into the hydraulic models submitted by PG&E to simulate PG&E backbone transmission operations under the demand conditions forecasted by the CEC.

While the CEC previously has not prepared a winter analysis of the PG&E system, CEC staff collects and analyzes PG&E hydraulic models and storage facility operational data yearly; collaborates with the California Public Utilities Commission (CPUC) and the California Geologic Energy Management Division (CalGEM) on assessing the impacts of new CalGEM regulations on PG&E gas storage operations; and analyzes demand forecasting and system information submitted by PG&E to the CEC for the 2021 and 2023 Integrated Energy Policy Reports. These activities have laid the groundwork for this winter assessment.

The PG&E and SoCalGas gas systems purchase gas and provide transportation and storage services for core customers (residential, small commercial) under stringent reliability standards. However, each system has some unique characteristics that influenced the analyses.

The PG&E system includes ISPs in which noncore customers independently arrange for injection and withdrawal services, while PG&E ensures adequate pipeline inventory capacity levels. The ISPs provide gas withdrawal capacity to PG&E customers but are not responsible for supporting PG&E system reliability. Also, as the terms of transactions and the volume of gas that can be withdrawn from ISPs on a cold day are not public, CEC cannot estimate ISP withdrawals on a peak day. Noncore customers (electric generators, industrial customers, large commercial) have the option to purchase storage services from the gas utility or from ISPs, but the gas utility has no obligation to provide storage services for noncore customers.[2] PG&E's backbone transmission system and high diameter pipes run through much of the length of California (from Topock, Arizona, to Malin, Oregon), providing 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 system inventory even on high demand days.

Storage is an integral part of both utilities' gas systems, and a combination of storage and pipeline flows is needed to meet the peak winter heating demand of core customers. Without storage, the utilities would need more pipeline capacity to meet peak demand.[3] The reverse is also true. For example, PG&E's Redwood system is constrained near Delevan, California, to a maximum flow of 2,700 MMcfd. This means that system cannot accept all the potential gas

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2 Jones, Melissa, Jennifer Campagna, Catherine Elder, and Stephanie Bailey. 2022. *Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System.* California Energy Commission. Pg. B-3.

3 Jones, Melissa, Jennifer Campagna, Catherine Elder, and Stephanie Bailey. 2022. *Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System.* California Energy Commission. Pg. 18.

withdrawable from independent storage when supply is flowing from out-of-state at 100 percent of capacity at Malin (Northern California border).[4]

The SoCalGas system experiences challenges in managing inventory, as its gas system is a little more than half as large of PG&E's. These challenges are exacerbated on high-demand days, when system operators have to figure out how to maintain acceptable inventories while not overpressurizing their systems. SoCalGas uses transient hydraulic modeling to support transmission system analyses related to inventory management. The transient model can assess intraday changes in pipeline inventory (that is, linepack) under certain conditions. Also, for SoCalGas, the CEC has developed a stochastic model that estimates intraday peak-day trends. Staff may incorporate modeling tools that assess intraday operations for PG&E in future seasonal assessments.

Temperature Outlook for Winter 2024-25

In October 2024, the National Weather Service released a seasonal temperature outlook for December 2024 through February 2025.[5] They predict La Nina conditions throughout the continental United States that will leave the southern tier of the country (including Southern California and much of Central California) with higher temperatures during those months. (See Figure 1) The National Weather Service concludes that Northern California (including the Bay Area, the Sacramento Valley, and North Coast) have equal chances for above normal and below normal temperatures.

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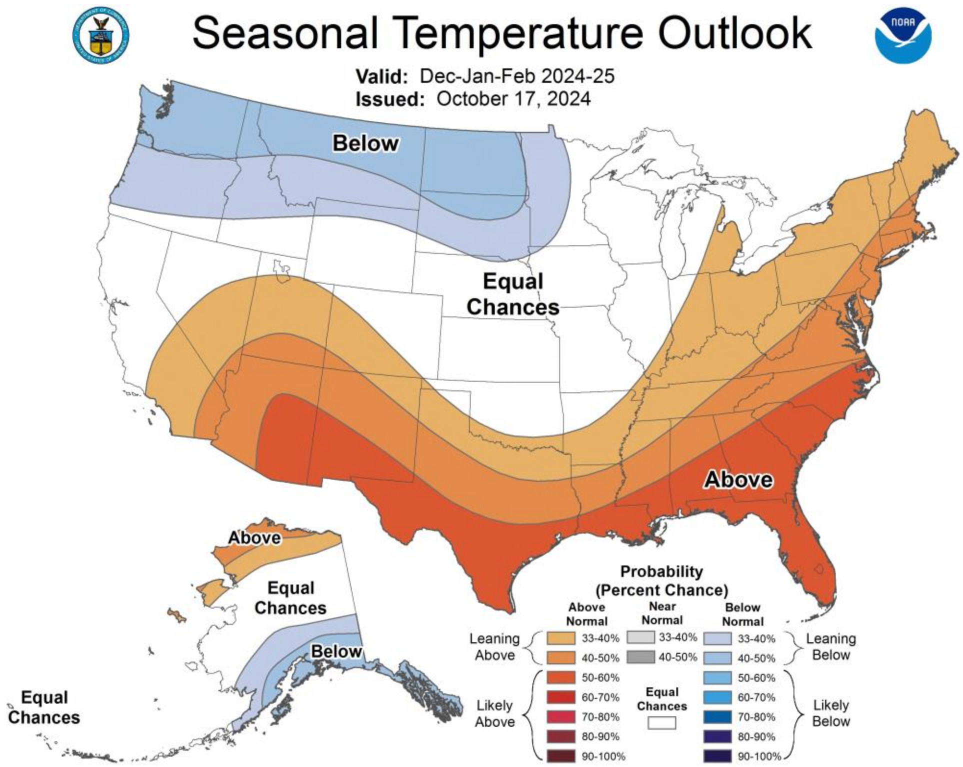
4 In such a case, PG&E can withdraw some gas from ISPs to bypass their backbone transmission system for direct delivery to their local transmission systems.

5 National Weather Service, *U.S. Winter Outlook: Warmer and Drier South, Wetter North*, October 17, 2024, https://www.noaa.gov/news-release/us-winter-outlook-warmer-and-drier-south-wetter-north.

Figure 1- National Weather Service Seasonal Temperature Outlook (December 2024- February 2025)



Source: National Weather Service.

Modeling Tools

The CEC compares its demand forecasts with CEC estimates of supply using the following information:

- Pipeline supplies
- Storage field working gas capacity, which is the volume of natural gas in an underground gas storage project available to be withdrawn.
- Storage withdrawal capacities

Staff incorporates these forecasts and estimates above in the following tools:

- Gas balances- Tables that compare estimated supply capacity and forecasted demand.
- Hydraulic models- Computer models that calculate pressures and flows at various points on a gas system resulting from the simulation of its operation under inputted conditions.
- Stochastic models- An hourly gas balance that uses historical data to forecast hourly demand on peak day scenarios.

Staff uses these tools to make assumptions on the timing and location of demand on the system to help understand the ability of the system to meet reliability. This is a rigorous analysis of both gas utilities, but the tools cannot account for certain risks (e.g. potential impacts of scheduled and unscheduled maintenance events) on each utility’s key mainlines and storage facilities.

CHAPTER 2: CEC PG&E Gas System Analysis

This section provides the CEC's findings of how the PG&E gas transmission system will meet demand in winter 2024–2025. The CEC developed its own demand projections as inputs to the analytical tools used in this assessment. Staff prepared a monthly and peak-day gas balance analysis to assess supply and demand. To capture how the PG&E gas transmission infrastructure will be able to meet demand on a peak day, staff analyzed a hydraulic model of the PG&E gas transmission system.

Gas Demand Forecast

Tables 3 and 4 present CEC's findings from the monthly average, cold peak-day, and abnormal peak demand forecast for the PG&E system. Compared to the California Gas Report,[6] CEC staff forecasts of the 1-in-10 cold day[7] and the Abnormal Peak Day Plus (a 1-in-90 core[8] plus 1-in-10 noncore day) are slightly lower than PG&E's. The 1-in-10 cold day demand is 4.2 Bcf and the abnormal peak is 4.7 Bcf. For comparison, the highest daily sendout[9] on the PG&E gas system in the last 10 years was 3.8 Bcf, which occurred February 5, 2019. Just outside the 10-year window, PG&E delivered 4.9 Bcf on December 9, 2013, a similar figure to the CEC staff forecast of abnormal peak-day demand for winter 2024–2025 as shown in Table 4.

Table 3: CEC Forecast of PG&E Monthly Demand

Demand Scenario	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Average Demand (MMcfd)[10]	1,932	2,188	2,865	2,677	2,338	1,916
1-in-10 Demand (MMcfd)[11]	2,073	2,357	3,062	2,818	2,389	1,927

Source: CEC staff

6 Prepared in compliance with California Public Utilities Commission Decision (D.) 95-01-039, the California Gas Report (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years. The supply and demand projections in California Gas Reports are used for long-term gas system planning.

7 Demand that has a 1-in-10- year probability of occurrence that correlates to a 35-degree day in Northern California.

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

9 Sendout includes a total of gas delivered to customers and injected into storage.

10 Average daily demand by month in a normal year.

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

Table 4: CEC Staff Forecast — PG&E Cold Day and Abnormal Peak-Day Plus Demand

Demand by Category	Case 1: Cold Day Core + Noncore 1-in-10* (MMcfd)	Case 2: Abnormal Peak Day Plus Core 1-in-90 + Noncore 1-in-10** (MMcfd)
Core	2,429	2,939
Noncore — Non-Electric Generation	496	496
Noncore — Electric Generation	1,157	1,157
Off System	80	80
TOTAL Demand	4,162	4,672

*** January peak**

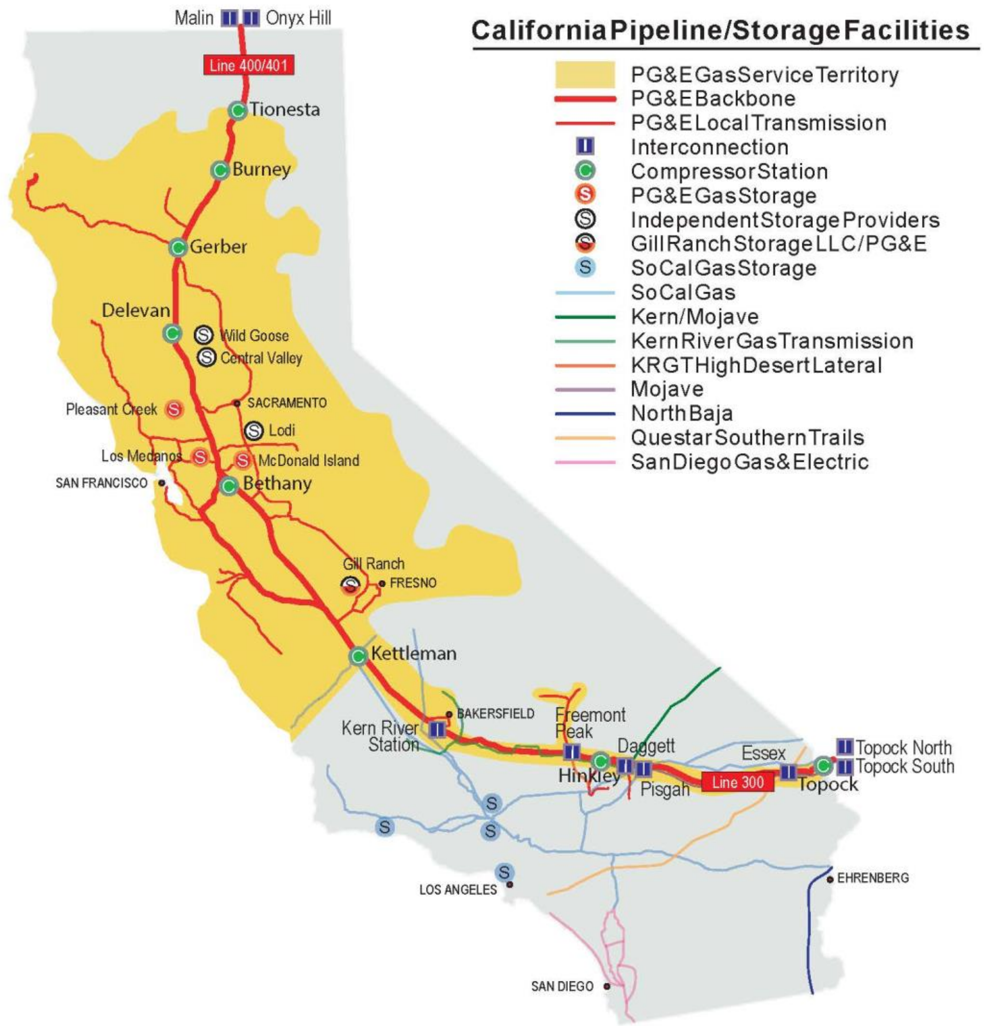
**** December peak**

Source: CEC staff

PG&E Pipeline Capacity and Storage Inventory

For the Winter Assessment, staff estimated available pipeline capacity and storage inventory on the PG&E system, which was designed to meet winter demand with flowing pipeline supply and storage withdrawals. (Figure 2)

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



Source: PG&E

Staff took a conservative approach in estimating pipeline capacity for winter 2024–2025. The PG&E Pipe Ranger website reports the capacity available to its customers for scheduling and maintenance and outage events that impact the capacity. Per Pipe Ranger, PG&E is scheduled to undertake maintenance on its Redwood system in Northern California, which will reduce capacity by roughly 10 percent on some days in December and January. For each month, CEC staff assumes the lowest percentage of available maximum capacity in the maintenance outlook reported on Pipe Ranger. This planned maintenance accounts for staff using the slightly reduced pipeline capacity for 2024–2025. As noted earlier, PG&E can withdraw from its significant pipe inventory to meet demand and maintain operating pressures on the gas system.

PG&E owns the Los Medanos, McDonald Island, and Pleasant Creek[12] gas storage facilities, but ISPs are also connected to PG&E's system. The ISPs are Wild Goose, Central Valley Gas Storage, Lodi, and Gill Ranch (partially owned by PG&E). Storage is an integral part to of the utilities' gas systems, and a combination of storage and pipeline flows is needed to meet the peak winter heating demand of core customers. Without storage, the utilities would need more pipeline capacity to meet peak demand. The reverse is also true, as PG&E's Redwood system is constrained near Delevan to a maximum flow of 2700 MMcfd. This means it cannot accept all of the potential gas withdrawable from independent storage at the same time supply flowing in from out-of-state is at 100% of capacity at Malin. However, some gas withdrawn from ISPs can bypass the PG&E backbone transmission system by getting delivered directly to PG&E local transmission systems. Noncore customers have the option to purchase storage services from the gas utility or from ISPs. On a daily basis, CEC staff tracks injections and withdrawals from California's underground gas storage facilities. Moreover, utility and ISPs report daily operational data and working gas totals to the CEC quarterly.[13] 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 2024–2025 season (Table 5). As the ISPs have no obligation to support reliability standards for core customers, Table 5 does not include estimates of their storage inventory levels for the upcoming and previous winters. However, under PG&E's Natural Gas Storage Strategy, which was approved by the CPUC, PG&E can procure storage services from ISPs to meet reliability standards.

Table 5: PG&E Winter Supply and Storage Comparison

Capacity and Inventory	Winter 2021–2022	Winter 2022–2023	Winter 2023–2024	Winter 2024–2025
Pipeline Capacity (MMcfd)	3,226	3,225	3,230	2,927*
Total PG&E Storage Inventory (Bcf)	~17	~9	~23	~35
Percentage Full (Total PG&E Storage Inventory)	49%	26%	66%	100%

*An average of minimum capacity available in December 2024 and January 2025 based on the PG&E maintenance outlook reported on Pipe Ranger.

Source: CEC staff

12 Pleasant Creek is no longer in operation. In July 2023, PG&E, Pleasant Creek Gas Storage Holdings, LLC, and eCorp Natural Gas Storage Holdings, LLC, filed a joint application with the CPUC for the approval of PG&E's sale of the Pleasant Creek Gas Storage Field to the latter two companies. A-23-07-007- https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M514/K599/514599766.PDF.

13 *Instructions for Form CEC-1314 – Underground Gas Storage Data.* California Energy Commission, https://efiling.energy.ca.gov/GetDocument.aspx?tn=249063&DocumentContentId=83621.

PG&E Winter 2024–2025 Gas Balance

Staff analyzed monthly average demand, monthly cold winter demand, and two levels of peak-day demand for this assessment.[14] Table 6 shows the monthly gas balance for the 2024–2025 winter months using the CEC's forecast for average demand. With average daily demand (Table 6) in December 2024 and January 2025 around 2,900 MMcfd and 2,700 MMcfd respectively, staff concludes that pipeline supply plus storage withdrawals from PG&E-owned storage facilities are sufficient to meet that demand. In both cases, PG&E needs storage withdrawals in December 2024, January 2025, and March 2025. CEC staff assumed withdrawals even in months in which pipeline capacity exceeds demand in order to create a reserve of 10 percent. Under the average demand scenario, storage withdrawals are assumed in some months in which available pipeline capacity exceeds demand in order to maintain a reserve of pipeline capacity.

While forecasted demand is expected to be lower in March relative to the earlier winter months, scheduled maintenance on the Baja system in Southern and Central California would necessitate storage withdrawals during that month. In both the average and high demand cases (Tables 6 and 7), CEC staff assumes there will be no injections into the PG&E-owned storage fields during the winter months. The combined winter ending inventory for PG&E in the high-demand case is 12 Bcf compared to 23 Bcf in the average demand case.

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

Table 6: PG&E Monthly Gas Balance Average Demand

Average Demand	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Demand (MMcfd)	1,932	2,188	2,864	2,677	2,338	1,917
Available Pipeline Capacity (MMcfd)	2,496	2,782	2,967	2,887	2,957	1,992
PG&E Injection/(Withdrawal) (MMcfd)	0	0	(170)	(70)	0	(109)
PG&E End-of-Month Inventory (Bcf)	34	34	29	27	27	23

Source: CEC staff

Table 7: PG&E Monthly Gas Balance 1-in-10 Demand

Average Demand	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Demand (MMcfd)	2,073	2,357	3,062	2,818	2,389	1,927
Available Pipeline Capacity (MMcfd)	2,496	2,782	2,967	2,887	2,957	1,992
PG&E Injection/(Withdrawal) (MMcfd)	0	0	(386)	(199)	0	(129)
PG&E End-of-Month Inventory (Bcf)	34	34	22	16	16	12

Source: CEC staff

PG&E Peak-Day Analysis

Staff evaluated two peak day cases for winter. One case looked at a 1-in-10 peak-temperature cold day for core and noncore load. The second looked at the abnormal 1-in-90 peak-temperature cold day for core plus 1-in-10 peak-temperature cold day for noncore.[15] With 2.9 Bcf available in pipeline capacity in winter 2024–2025, 1.5 Bcf and 2.0 Bcf in storage withdrawals are needed to meet demand on the cold day and abnormal peak day plus scenarios, respectively (Table 8).

15 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 an abnormal peak day. Including the noncore load in this calculation allows us to understand how much of the noncore load might be curtailed.

Table 8: PG&E Peak Demand Day Gas Balances

	Demand, Withdrawal, and Net Shortfall	Case 1: Cold Day Core + Noncore 1-in-10*(MMcfd)	Case 2: Abnormal Peak Day Plus 1-in-90 Core + Noncore 1-in-10** (MMcfd)
	Demand		
	-Core	2,429	2,939
	-Noncore-NonEG	496	496
	-EG	1,157	1,157
	-Off System	+80	+80
	TOTAL Demand	**4,162**	**4,672**
	-Available Pipeline Capacity	-2,927	-2,927
	Needed Withdrawal	**1,235**	**1,745**
	-Assumed Available Withdrawal (PG&E Storage)****	-794	-794
	Net Shortfall (Does Not Include ISP Withdrawals)	441	951

***January peak.**

****December peak**

*******PG&E estimate of storage capacity for winter 2024–2025 in facilities it owns in CPUC Application 24-07-020.**

Source: CEC staff

The forecast in Table 8 may not account for the increased use of central station and distributed battery storage systems interconnected to the grid to help meet electricity demand, which may reduce power plant gas demand. As California is not coming off a dry hydro year and with the increased use of battery storage, the estimate for peak-day gas demand for electricity generation may be conservative for Winter 2024-25 considering available resources.

The CEC estimates a 2.9 Bcf pipeline capacity for PG&E in winter 2024–2025. This, combined with PG&E's estimate of a storage withdrawal capacity of 794 MMcf for that period, yields CEC's estimated net shortfall of 441 MMcf for Case 1 and 951 MMcf for Case 2 (Table 8). The net shortfall is a comparison of demand under this scenario and PG&E pipeline and PG&E storage withdrawal capacity. There are options to meet this demand before any curtailment of service, but the net shortfall estimate can be viewed as a worst-case scenario. This report lays out options below to address estimated shortfalls, but staff cannot quantify how much each of them would be used.

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. The CEC recognizes that these withdrawals are not used to meet reliability standards but are based on the economic needs 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 the terms are 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 both.[16]

PG&E Hydraulic Analysis

CEC staff used the Synergi Gas hydraulic modeling platform to assess PG&E gas system operations.[17] PG&E's hydraulic model for its Baja and Redwood transmission systems is a steady-state model that estimates system capacity using demand scenarios inputted by a user. The Bay Area Loop (portions of the East Bay and the South Bay) requires steady-state and transient modeling. The hydraulic analysis 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 was done for the gas balances. Staff assumed pipeline supply of 2,927 MMcfd from the gas balances and available withdrawal capacities as reported by PG&E in CPUC Application 24-07-020. As mentioned in the previous section, analysis of PG&E's hydraulic models shows that receipts of natural gas from interstate pipelines combined with storage withdrawals from PG&E- and ISP-owned facilities can eliminate the shortfalls estimated in Table 8. Appendix C describes the method.

Conclusion

While the CEC estimates a 2.9 Bcf pipeline capacity for PG&E in winter 2024–2025 and PG&E estimates a storage withdrawal capacity of 794 MMcf for that period, CEC predicts a net shortfall of 441 MMcf for Case 1 and 951 MMcf for Case 2 (see Table 8). There are options to meet this demand before any curtailment of service to noncore customers, but the net shortfall estimate can be viewed as a worst-case scenario. While it is hydraulically feasible for ISPs to meet this shortfall, staff cannot estimate the 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 geographic length of California, so there is significant pipe inventory to support the system. While the gas balances in this chapter show examples that maximize pipeline capacity, there are other permutations of quantities of pipeline deliveries and storage withdrawals to meet demand. As mentioned earlier, those supply options will be determined by the operational needs of the PG&E system and the economic considerations of market participants.

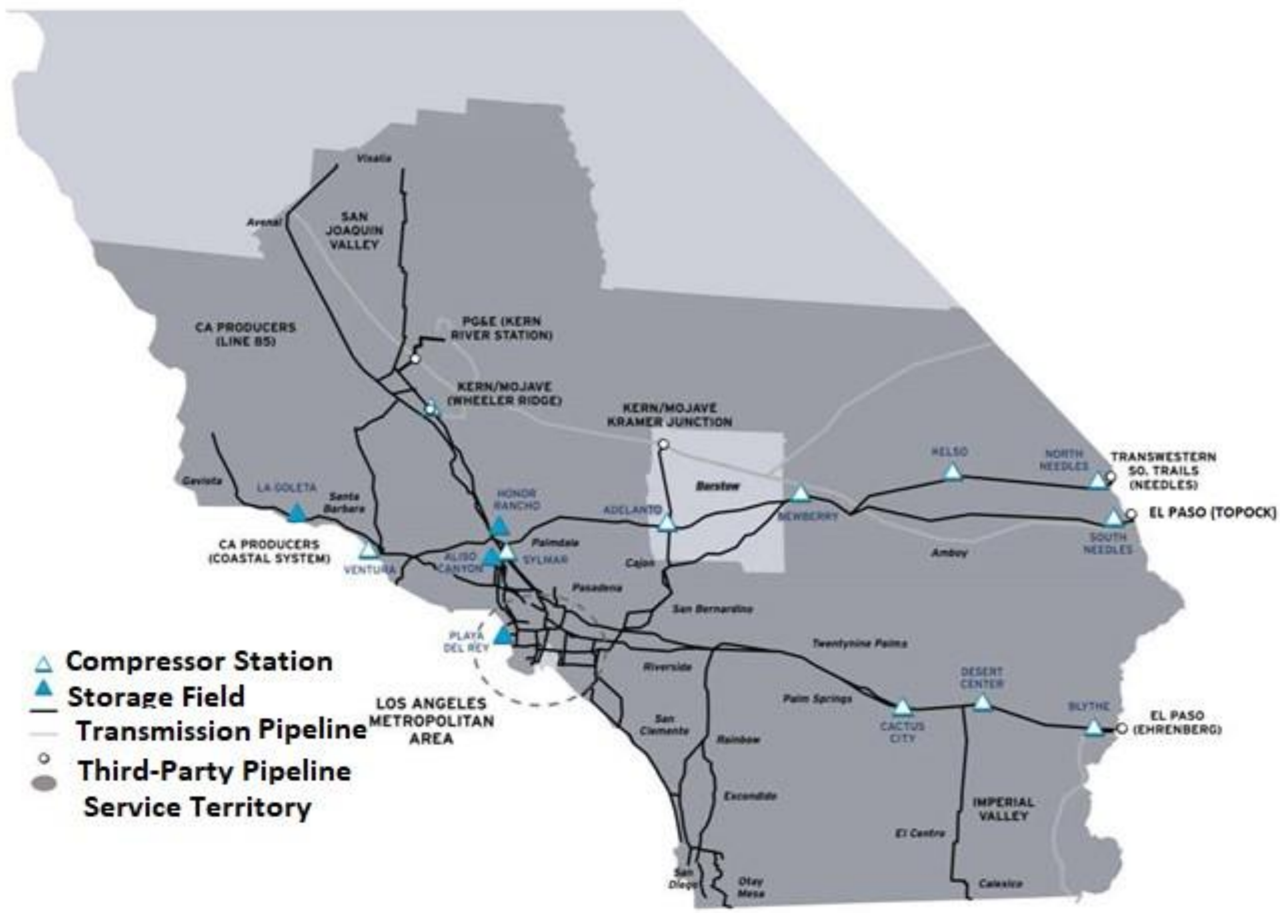
16 PG&E may issue an EFO if deliveries to end-use customers are threatened due to supply and/or capacity shortages. An EFO would normally follow an OFO but may be invoked without a preceding OFO. EFOs do not apply to oversupply (high inventory) situations. This information on EFOs is attributed to PG&E.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

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

CHAPTER 3: CEC SoCalGas Gas System Analysis

The following section provides the CEC's independent assessment of how the SoCalGas gas transmission system (Figure 3) will meet demand in Winter 2024-25. The CEC developed its own demand projections, which served as inputs to the analytical tools. To assess supply and demand, staff prepared a monthly and peak day gas balance analysis. Staff also developed an hourly stochastic gas balance of the peak day to highlight the hourly changes to demand on the peak day and the needed storage withdrawals. To capture how the SoCalGas gas transmission infrastructure will be able to meet demand on a peak day, staff analyzed a hydraulic model of the SoCalGas gas transmission system.

Figure 3: Map of SoCalGas/SDG&E Transmission System



Source: California Energy Commission Docket 21-IEPR-05

Gas Demand Forecast

Tables 9 and 10 present the findings from the monthly average, cold-peak-day, and extreme-peak-demand forecasts for the SoCalGas system. Compared to the California Gas Report, CEC forecasts of the 1-in-10 cold day[18] and the 1-in-35 core[19] plus 1-in-10 noncore day are slightly lower than SoCalGas forecasted values. The highest daily sendout on the SoCalGas system in the last 10 years was 3.8 Bcf, which occurred February 5, 2019, the same day observed on the PG&E system (as reported in the Chapter 2). Just outside the 10-year window, deliveries on the SoCalGas system totaled 4.9 Bcf on December 9, 2013, which is slightly higher than the CEC staff forecast of extreme peak day plus demand for winter 2024–2025.

Table 9: CEC Forecast of SoCalGas Monthly Demand

Demand Scenario	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Average Demand (MMcfd)[20]	1,975	2,538	3,007	2,702	2,686	2,240
1-in-10 Demand (MMcfd)[21]	1,976	2,465	3,164	2,859	2,986	2,524

Source: CEC staff

18 Demand that has a 1-in-10 year probability of occurrence that generally 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.

19 Demand that has a 1-in-35 year probability of occurrence that generally correlates to a system average temperature of 40.6 degrees Fahrenheit for the SoCalGas' service area and 43.5 degrees Fahrenheit for SDG&E's service area.

20 Average daily demand by month in a normal year.

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

Table 10: CEC Staff Forecast — SoCalGas Cold Day and Extreme Peak Day Demand

Demand by Category	Case 1: Cold Day	Case 2: Extreme Peak Day Plus
Core and Noncore	**Core + Noncore 1-in-10* MMcfd**	**Core 1-in-35 + Noncore 1-in-10** MMcfd**
Core	2,834	2,987
Noncore- Non-Electric Generation	595	595
Noncore- Electric Generation	1,080	1,080
TOTAL Demand	4,509	4,662

*** January Peak**

**** December Peak**

Source: CEC staff

SoCalGas Pipeline Capacity and Storage Inventory

For the winter assessment, staff estimated available pipeline capacity and storage inventory on the SoCalGas system 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.

Staff took a conservative approach in estimating pipeline capacity for winter 2024–2025. Envoy reports the capacity available to its customers from scheduled maintenance or outage events. Staff observed that SoCalGas pipeline capacity is similar to that of last year. The slight reduction in pipeline capacity in winter 2024–2025 is due primarily to the impact of unplanned maintenance on a line that receives gas produced in the Central Valley (Table 11).

In recent years, SoCalGas has recovered some pipeline capacity. In October 2021, Line 4000 in the SoCalGas Northern Zone returned to service at a higher operating pressure, which increased capacity from 800 MMcfd to 1,250 MMcfd.[22] Also, in February 2023, the El Paso pipeline near Phoenix returned to service. This upstream outage had reduced the capacity in the Southern Zone of the SoCalGas system during an 18-month period.

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. Winter 2023–2024 was the first winter since CPUC Decision 23-08-050 increased the working gas limit at Aliso Canyon to 68.6 Bcf. This decision and the elimination of the Aliso Canyon Withdrawal Protocol essentially removed all operating restrictions at Aliso Canyon. The recovery of pipeline capacity (discussed in previous paragraph) and the additional withdrawal

22 Pg. 141, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Long Beach Energy Resources Department, and Southern California Edison Company, 2022. *2022 California Gas Report*.

capacity at Aliso Canyon can help SoCalGas meet demand on peak days without curtailment, thereby reducing risk to system reliability.

Based on CEC tracking and analysis, staff estimates that Aliso Canyon and the other SoCalGas underground gas storage facilities — Playa del Rey, Honor Rancho, and La Goleta — will be at or near full capacity by winter 2024–2025 (Table 11). During winter 2023–2024, the maximum daily net withdrawal (accounting for injections) from these fields totaled 1.9 Bcf, which occurred January 13, 2024.

Table 11: SoCalGas Winter Supply and Storage Comparison

Capacity and Inventory	Winter 2021–2022	Winter 2022–2023	Winter 2023–2024	Winter 2024–2025
Pipeline Capacity (MMcfd)	2,835	2,815	3,065	3,035
Total Storage Inventory (Bcf)	~81	~90	~90	~119
Percentage Full (Total Storage)	96%	97%	75%	100%
Allowed Aliso Inventory (Bcf)	34	41	69	69

Source: CEC staff

SoCalGas Winter 2024–2025 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.[23] Table 12 shows the monthly gas balance for the 2024–2025 winter months using the CEC's forecast for average demand. With average daily demand (Table 12) in December at an estimated 3,000 MMcfd, staff concludes that pipeline supply plus storage withdrawals are sufficient to meet that demand. For December 2024, under the average scenario, withdrawals are expected to be needed even as available pipeline capacity exceeds demand in order to create a 10 percent reserve. Subsequently, as average daily demand in January 2025 will be an estimated 2,700 MMcfd, pipeline supplies alone are sufficient to meet that demand.

Table 13 shows a monthly cold demand scenario. CEC staff projects that at those demand levels for Winter 2024-25, storage withdrawals will be needed from the months of November through February. Under the cold demand scenario, withdrawals are expected to be needed even as available pipeline capacity exceeds demand in November 2024, January 2025, and February 2025 in order to create a 10 percent reserve. However, pipeline supply plus storage withdrawals are sufficient to meet that demand.

The winter ending inventory in the winter cold case is estimated to be 93 Bcf compared to 111 Bcf in the average demand case.

Table 12: SoCalGas Monthly Gas Balance Average Demand

Average Demand	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Demand (MMcfd)	1,975	2,396	3,007	2,702	2,686	2,240
Available Pipeline Capacity (MMcfd)	2,515	2,675	3,035	3,035	3,035	3,035
Injection/(Withdrawal) (MMcfd)	0	0	-267	0	0	0

23 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.

Average Demand	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
End-of-Month Inventory (Bcf)	119	119	111	111	111	111

Source: CEC staff

Table 13: SoCalGas Monthly Gas Balance 1-in-10 Demand

1-in-10 Demand	Oct 2024	Nov 2024	Dec 2024	Jan 2025	Feb 2025	Mar 2025
Demand (MMcfd)	1,976	2,465	3,164	2,859	2,986	2,524
Available Pipeline Capacity (MMcfd)	2,515	2,675	3,035	3,035	3,035	3,035
Injection/(Withdrawal) (MMcfd)	0	-41	-445	-115	-250	0
End-of-Month Inventory (Bcf)	119	118	104	100	93	93

Source: CEC staff

SoCalGas Peak-Day Analysis

Staff evaluated two peak-day cases for winter. One case looked at a 1-in-10 peak temperature cold day for core and noncore load. The second looked at the more extreme 1-in-35 peak temperature cold day for core plus 1-in-10 peak temperature cold day for noncore.[24] As Table 13 shows, SoCalGas storage working gas capacities are essentially full as the 2024–2025 winter season approaches. The maximum feasible withdrawal from that inventory, however, remains unclear. Withdrawal capability depends on storage inventory, which typically declines over the winter as more gas is withdrawn.

As mentioned earlier, 1.9 Bcf of net storage withdrawals were observed January 13, 2024. For winter 2024–2025 peak days, 1.5 Bcf and 1.6 Bcf in storage withdrawals are needed to meet demand on the cold day and extreme peak day, respectively. Based on the availability of 1.9 Bcf of storage withdrawals, CEC staff estimates that demand on the SoCalGas system can be met without curtailment of noncore customers.

Table 14: SoCalGas Peak Demand Day Gas Balances

Demand, Needed Withdrawal, and Net Shortfall	Case 1: Cold Day Core + Noncore 1-in-10* MMcfd	Case 2: Extreme Peak Day Plus 1-in-35 Core + Noncore 1-in-10** MMcfd
Demand		

24 Noncore load is less temperature-sensitive, so adding its 1-in-10 probability estimate to the core 1-in-35 allows calculation of total system load that could need to be curtailed on an extreme peak day plus scenario.

Demand, Needed Withdrawal, and Net Shortfall	Case 1: Cold Day Core + Noncore 1-in-10* MMcfd	Case 2: Extreme Peak Day Plus 1-in-35 Core + Noncore 1-in-10** MMcfd
Core	2,834	2,987
Noncore-NonEG	595	595
EG	1,080	1,080
TOTAL Demand	4,509	4,662
Available Pipeline Capacity	3,035	3,035
Needed Withdrawal	1,474	1,627
Assumed Available Withdrawal ***	1,900	1,900
Net Shortfall	0	0

***Jan Peak**

**** Dec Peak**

***** Estimated withdrawal based on maximum withdrawal observed during winter 2023-2024.**

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 prepared an hourly gas balance using a stochastic forecast for demand in each hour of a 1-in-10 cold day and a 1-in-35 core plus 1-in-10 noncore extreme peak day plus. This forecast uses the same modeling method used in the CEC's 2022 winter assessment.[25] This analysis allows demand to vary randomly based on the hourly demand distribution observed over the 12 years of recorded hourly and daily demand data. This variation captures a greater range of variation in gas demand, especially hourly demand patterns that are not reflected in the standard peak-day demand analysis shown in Table 10. The hourly demand data are trained on a subset of winter demand days representing the highest demand levels in the dataset, specifically the top 5 percent of daily demand days in the SoCalGas territory.

25 Wong, Lana, Jason Orta, and Miguel Cerrutti. 2022. *Winter 2022-2023 SoCalGas 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

The stochastic model simulates random draws for each hour of demand given the CEC's daily 1-in-10 and 1-in-35 peak day forecasts. This yields a stochastic hourly load shape for a winter peak day, summing to the total forecast cold peak day demand of 4,508 MMcfd and 4,662MMcfd for the extreme peak day plus used in Table 10. The stochastically determined load shape then feeds into the hourly gas balance, which uses the same assumptions as the peak-day analysis for pipeline capacity (3,035 MMcfd). The supply-and-demand balance during each hour of the day yields the required withdrawals in each hour.

Tables 15 and 16 give the hourly gas balance results for the average load shape scenario. They highlight the key ramping period in the middle of the day, the afternoon hourly peak demand, and the required withdrawals needed in certain hours. The stochastic assessment confirms the adequacy of supply to meet demand and no risk of potential curtailments under winter peak-day conditions for the cold and extreme peak-day demand cases.[26]

Table 15: Stochastic Hourly Gas Balance Results for the 1-in-10 Peak Day

Units in MMcf	Simulated 1-in-10 Winter Peak Day Hourly Gas Balance																								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	244	262	236	208	186	173	163	156	150	154	171	206	220	223	216	205	184	164	154	153	152	154	172	202	4508
Receipts	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	3035
Required Withdrawals	118	136	109	82	60	46	37	29	23	27	44	80	93	97	90	79	57	37	27	26	26	28	46	75	1473
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	0

*Minimum Curtailment Required in Each Hour

Source: Aspen Environmental Group

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

Units in MMcf	Simulated 1-in-35 plus 1-in-10 Noncore Winter Peak Day Hourly Gas Balance																								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	253	272	243	215	192	178	168	162	157	160	177	215	229	231	223	212	189	168	159	157	158	159	177	208	4662
Receipts	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	3035
Required Withdrawals	127	146	117	88	65	52	42	35	30	34	51	88	103	105	97	86	62	42	32	31	31	32	50	82	1627
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	0

*Minimum Curtailment Required in Each Hour

Source: Aspen Environmental Group

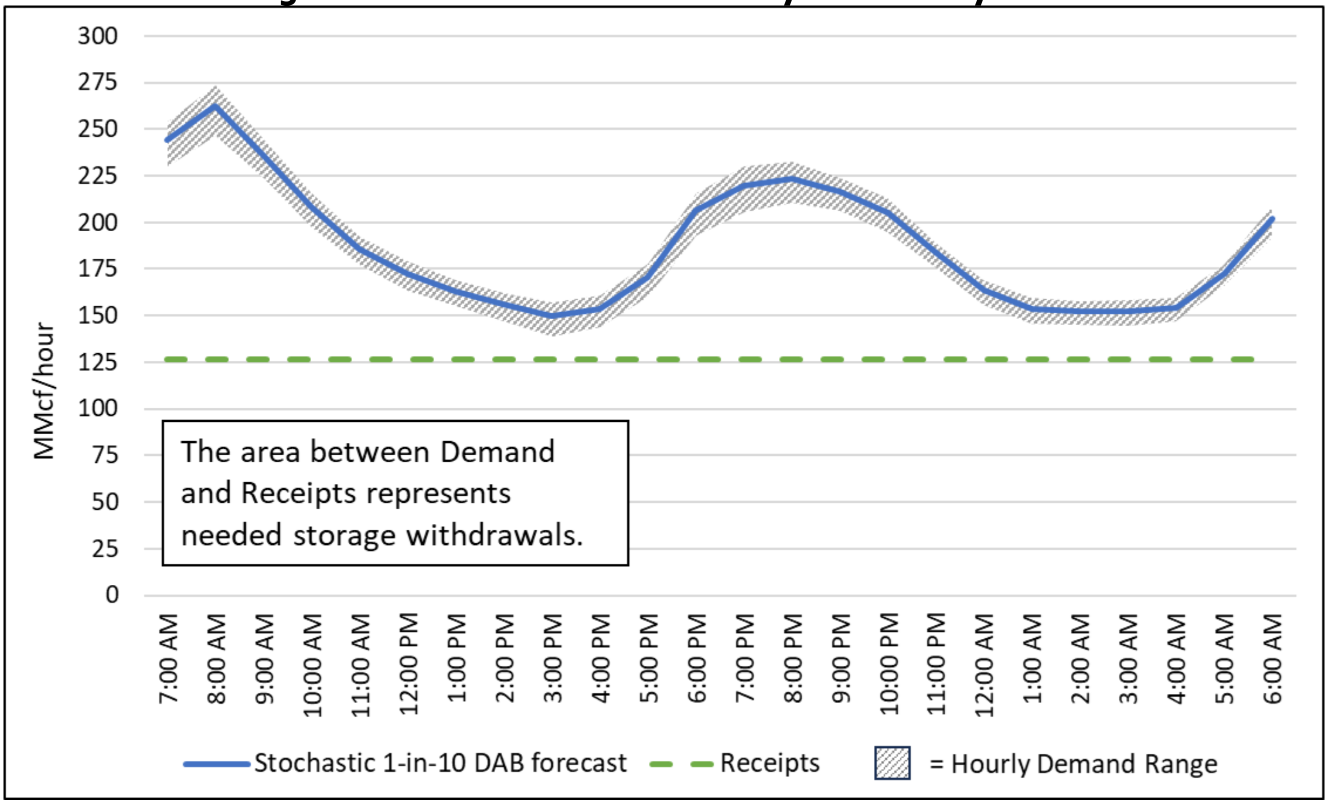
Figure 4 gives a range for the variation in demand for the 1-in-10 demand case. The shaded area shows the range of potential demand in each hour.[27] A dotted line shows fixed hourly receipts, consistent with pipeline operations and tariff requirements that call for flat hourly flows. A solid line represents the average 1-in-10 peak-day load shape scenario included in the hourly gas balance in Table 11. The hours where demand is above the receipts dotted line

26 The analysis estimates zero curtailment, provided SoCalGas is able to withdraw from storage to meet demand during the peak hours. The maximum hourly withdrawal estimated during the winter extreme peak-day is 144 MMcf and a total of 1606 MMcf over the entire gas day.

27 The variation in demand represented by the shaded area is relatively small since the distribution of demand is based on a small number of observations (the top 5 percent of demand days).

indicate storage withdrawals would be needed to meet that day's demand. Seeing the range of demand also helps staff understand the range of potential withdrawals on that peak day.

Figure 4: 1-in-10 Winter Peak Day Demand by Hour



Source: Aspen Environmental Group

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 line pack 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 C 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. The further restoration of some pipeline capacity on the SoCalGas system and storage withdrawal capacity at Aliso Canyon have lowered the risks to system reliability.

CHAPTER 4:
Market Prices

Natural Gas Prices and Winter Reliability in California

Natural gas prices can be higher and more volatile in winter, primarily due to higher demand during cold weather. For the first time, the CEC's Winter 2024–2025 Reliability Assessment includes an analysis of pricing trends. Staff compared annual average vs. winter month natural gas pricing trends over the past five years and found that prices in the winter months tended to be more volatile.

Looking ahead to this winter, natural gas supply infrastructure appears to be in good shape, with pipelines operating at normal capacity and storage levels currently elevated. As a result, prices are expected to remain relatively stable, though they will likely rise with increased winter demand. Unforeseen factors such as severe weather or unexpected pipeline outages that greatly affect gas supplies or demand or both could have a significant impact on prices. Weather is a source of uncertainty in the CEC's forecasts, so it is important to consider scenarios that assume colder and warmer winter weather.

The EIA's Short Term Energy report forecasted natural gas prices remaining relatively flat in the shoulder season (September and October) before generally rising in 2025. Natural Gas Intelligence data showed Henry Hub natural gas spot price rose by 15 percent to $2.28 per MMBtu in September 2024. EIA's Short Term Energy Outlook (STEO) expects the Henry Hub price to continue to rise to around $2.80/MMBtu in late 2024 and continue to increase to about $3.10/MMBtu on average in 2025 as liquefied natural gas exports increases with the addition of capacity.

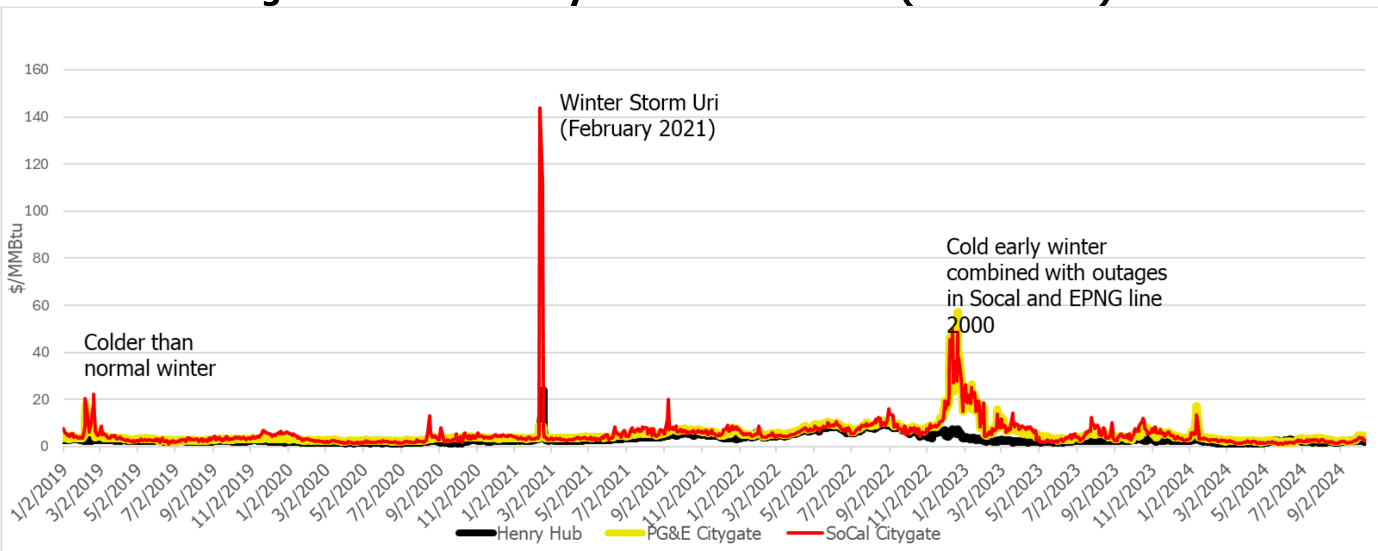
Natural Gas Prices: Recent Winter Trends vs. Five-Year Averages (Winter 2019–2020 Through Winter 2023–2024)

Over the last five years, average annual prices for natural gas in California have ranged from $3.01 to $8.89 per MMBtu. During the winter months, prices increase, reflecting the increased demand. For instance, in the winter of 2022 (November 2022–March 2023), natural gas prices averaged at $13.63 per MMBtu.

When comparing the winter prices to the five-year average, external factors such as extreme cold weather conditions can cause more significant fluctuations. For example, in mid-February 2021, prices jumped to nearly $90 per MMBtu during a storm that hit much of the United States. The plummeting temperatures led to skyrocketing demand for natural gas, widespread disruptions in both electricity and natural gas supply due to production loss and energy infrastructure shutdowns and rolling blackouts and outages. In California, this price surge had significant downstream effects, leading to higher costs for electricity generation and heating across the state, though not nearly as severe as in other parts of the United States such as Texas, Oklahoma, and some of the Midwest.[28]

Figure 5 shows the daily prices for each winter (months November–March) from 2019 until 2024 for the California Regional Average Hub. Here you can clearly see the weather-related winter price spikes.

Figure 5: Winter Daily Natural Gas Prices (2019–2024)



Source: NGI, EAD staff

The winter of 2023–2024 was mild across California and the nation, and natural gas prices remained relatively low, with winter prices averaging $3.9 per MMBtu — significantly lower than the previous winter's peak. This reduction in prices was further supported by high natural gas production levels and well-stocked storage facilities, which helped reduce the impact of increased demand during the colder months.

When comparing these figures to the five-year average, it becomes evident that while prices have generally remained within a predictable range, external factors such as weather conditions and storage levels can cause substantial year-to-year fluctuations.

To maintain winter reliability and stabilize natural gas prices, California has undertaken several strategic measures. One of the most critical steps was the CPUC decision to increase the maximum allowable inventory at Aliso Canyon from 41.16 Bcf to 68.6 Bcf. This increase allowed the facility to better manage the supply during peak winter months, ensuring that storage levels remained high enough to meet demand.

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28 Winter Storm Uri was polar vortex that caused natural gas prices to rise sharply across the country, including in California. In Southern California, the SoCal Border daily spot price peaked at $112.90/MMBtu on February 17, 2021. While the impacts of the storm were worst in Texas, the effects were felt through several regions of the United States, including California, underscoring the need for robust supply management and contingency planning. Winter Storm Uri is a reminder of the interconnectedness of national energy markets and the potential for distant events to affect reliability and local prices.

In addition to increasing the capacity at Aliso Canyon, SoCalGas partially restored pipeline capacity in its Northern Zone. Gas received in the SoCalGas Northern Zone can be delivered to the Southern Zone to support inventory levels on that portion of the SoCalGas and to the Los Angeles basin to meet demand or to be injected into storage fields.

The CPUC also employed a stochastic daily gas balance model to predict and manage supply and demand fluctuations during the winter. This model simulates various scenarios, including potential demand spikes, and allows for more precise management of natural gas storage and distribution. The effectiveness of this approach was demonstrated during the winter of 2023-2024, where the model successfully predicted minimal need for withdrawals from storage, even on days of higher-than-average demand.

Summary

The winter of 2023-2024 demonstrates how favorable conditions, such as mild temperatures and reduced demand, contribute to stable natural gas prices and help ensure a reliable supply. While increased storage capacity, improved pipeline infrastructure, and advanced modeling tools helped California manage potential disruptions, these factors alone did not drive prices. Instead, the combination of reduced demand for heating and moderate weather conditions played a key role in maintaining lower-than-average winter prices.

GLOSSARY

A ***billion cubic feet*** is a standard unit of measurement for natural 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 natural gas itself and the transportation services).

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

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

Henry Hub is a natural 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 natural gas*** is natural 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 natural 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 ***natural 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 natural gas to parts of Central and Northern California.

Southern California Gas Company (SoCalGas) is a utility company and primary provider of natural 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

This report presents a detailed method for modeling and forecasting Pacific Gas and Electric (PG&E) and Southern California Gas (SoCalGas) gas demand. It focuses on two types of demand forecasting: peak-day and monthly average demands for winter 2024–2025 across various customer classes and under different climate scenarios.

An initial exploratory analysis reveals that gas demand is nonlinearly driven primarily by temperature, showing trends, seasonality, and lagging temperature effects. Different customer classes have varying sensitivity to temperature changes. Given these data characteristics, a probabilistic approach is necessary to capture and account for them.

Datasets

CEC staff obtained thirty years (1994–2023) of historical daily maximum and minimum temperatures from NOAA. For temperature projections for 2023–2025, CEC staff used downscaled, bias-corrected climate data developed by CEC-funded Electric Program Investment Charge (EPIC)[29] grant recipients for use in the CEC's energy demand forecast.[30] Weighted average daily temperatures were computed for PG&E and SoCalGas service areas using weather station data, weighted by either population or proportion of the forecast zone associated with the weather station.[31]

PG&E provided aggregated daily gas data (MMcfd) from 1998 to mid-2022 that is partially disaggregated into major customer classes from 2005 to early 2022.SoCalGas provided daily gas demand data (MMcfd) disaggregated, or broken down, by customer classes from 2017 to 2022 as reported to the CEC and aggregated daily data from 2010 to 2023 sourced by CEC from the SoCalGas Envoy™ website.

29 Funded by California electric utility customers under the auspices of the California Public Utilities Commission. The California Energy Commission's Electric Program Investment Charge (EPIC) invests in scientific and technological research to accelerate the transformation of the electricity sector to meet the state's energy and climate goals. https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program.

30 The data use global climate model (GCM) output to drive the Weather Research and Forecasting (WRF) model simulations. The data consist of four downscaled GCM-WRF models based on one emission scenario. For more details, see Aydin, Mariko Geronimo and Aydin, Onur, December 19, 2023, "Presentation — Key Findings in Climate Data Analyses for Demand Forecast" at https://efiling.energy.ca.gov/GetDocument.aspx?tn=253658.

31 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.

Modeling Approach

Based on the initial exploratory analysis and the forecasting objectives, the Prophet modeling algorithm,[32] a Bayesian structural generalized additive time series model,[33] was chosen for the ability to decompose time series into three components: trend, seasonality, and holiday effects. The entire model consists of the sum of the components, each implemented separately, plus additional explanatory variables and residual error.

The trend function identifies breakpoints in the time series data and fits piecewise linear trends based on these breakpoints. Seasonality periodic functions capture repeating seasonal patterns using a Fourier series applied to the underlying trend. The holiday-specific function accounts for the holiday- or event-specific impacts.[34] The model includes a residual or error term accounting for unexplained variations not captured by the model and includes explanatory variables such as temperatures to improve accuracy. Decomposing a time series into trend, seasonality, holiday, and extra-regressors using additive or multiplicative adjustable components promotes a better understanding of the data characteristics and should yield more accurate forecasts.

Model calibration and evaluation include variable selection and hyperparameter optimization. Variable selection identifies the best predictive explanatory variables by exploring all possible combinations and interactions. Hyperparameter optimization uses Bayesian optimization[35] to fine-tune the learning process of the model, balancing overfitting and underfitting. Hyperparameters control trend flexibility, changepoint detection, and seasonality adjustment. They can be specified manually rather than estimated by default from the data, with the latter sometimes giving suboptimal results. Cross-validation splits the data to validate model accuracy. It helps compare and select the optimal combinations of variables and hyperparameters by splitting the data into subsets for training and testing. It fits the model using the training set and then compares and evaluates the testing set using the mean absolute percentage error[36] (MAPE) as a key performance metric.

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32 Facebook Prophet is an open-source time-series forecasting library built with its backend in STAN, a probabilistic coding language, released by Facebook's Core Data Science team -- Sean J. Taylor and Benjamin Letham. "Forecasting at Scale." *American Statistician*, Vol. 72, No. 1 (2018), pp. 37–45. https://www.researchgate.net/publication/344989540_Forecasting_at_scale

33 Bayesian probabilistic modeling is based on Bayes's Theorem, where available knowledge about parameters in a model is updated with the information in observed data. The background knowledge is expressed as a prior distribution and combined with observational data as a likelihood function to determine the parameters' posterior distribution used for making inferences.

34 Trend identifies breakpoints using a Laplacian or double exponential prior. A Fourier series expands a periodic function as a sum of sines and cosines. The holiday-specific function uses binary indicators.

35 Using the Gaussian process, Bayesian optimization builds a prior probabilistic objective function model based on the Bayes Theorem. Then, it uses an acquisition function (that is, a mathematical function) to consider the previously seen hyperparameter combinations, determine the next set of hyperparameter candidates to evaluate them, and locate the optimal objective value.

36 MAPE measures the accuracy of a forecast by expressing the difference between actual and forecast as a percentage.

Implementation Details

Temperature effects, as the primary driver of changes in gas demand, are quantified using weighted moving averages of average daily temperatures. This method assigns weights over three consecutive daily temperatures, with a weight of 0.6 assigned to the most recent day, 0.3 to the previous day, and 0.1 to two days earlier, and sums the resulting values.[37] The method requires resampling daily data to monthly frequency to compute the average daily data for each month. The datasets are then log-transformed to help normalize the data, make it more linear, reduce serial correlation, and manage extreme values.

Additional temperature-derived variables included third-degree polynomials, moving averages, and the magnitude and day-to-day variability of cooling degree days (CDDs) and heating degree days (HDDs) based on whether the average daily temperature is above or below either 65°F or 55°F temperature thresholds. The 55°F base temperature is added to adjust for changes in temperature over time.[38]

These temperature-derived variables are calculated using the 2015–2023 historical daily and corresponding monthly average values and then used to fit the models. In addition to these temperature-related variables, the modeling includes nonworking days as a binary dummy indicator for weekdays versus weekends and holidays and a binary indicator for winter (in other words, October to March) versus summer (that is, April to September).

The model calibration, optimization, and evaluation procedure consist of selecting the optimal variable and then selecting the hyperparameter values from more than a hundred combinations of variables and hyperparameters. Variable selection identifies the best variables to include by evaluating all possible combinations. Then, for the optimal variable values, each specific combination of hyperparameters is investigated to control the flexibility of the model regarding the trend, changepoints, and seasonality flexibility. MAPE, interpretability, handling data gaps and missing data points, and domain knowledge[39] are assessed for handling variable selection and hyperparameter optimization inconsistencies.

Forecasting Approach

Applying this method, the approach for PG&E and SoCalGas consists of training the models on peak-day and monthly average demand on historical data and then predicting future data points, including forecasts for customer classes, up to two years in advance (2024–2025).

The historical and predictive forecasting uses year-round data, but the reporting focuses only on the gas winter season, from October to March. Historical forecasting includes ex-post and

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37 This specific weighting scheme is commonly used in energy modeling and is meant to account for long-term adjustment to sustained cooling or warming.

38 Vitullo, Steven, Ronald H. Brown, George F. Corliss, and Brian M. Marx. 2009. "Mathematical Models for Natural Gas Forecasting." *Canadian Applied Mathematics Quarterly*, 807. https://epublications.marquette.edu/cgi/viewcontent.cgi?article=1291&context=electric_fac

39 *Domain knowledge* refers to applying the proper data analysis methods and judging the performance correctly. This implies expertise in probabilistic time series forecasting, ensuring the models interpret the data correctly and make meaningful predictions.

in-sample, and predictive forecasting, ex-ante. Ex-post forecasting splits historical data into two parts: one for training the model and another for validating the accuracy, helping assess the predictive performance of the model. After validating the model, in-sample forecasting fits the entire historical data, resulting in the final model incorporating all available data and optimizing the parameters for better accuracy. Then, using the final model, ex-ante forecasting makes predictions, relying on the future values of the regressors' and coefficients obtained from the in-sample forecasting.

While PG&E data cover 2015-2022, SoCalGas data span 2017–2023 (aggregated) and 2017–2022 (disaggregated). The method does not require an evenly distributed time series of data points (see footnote 3), making one-year imputation in the disaggregated data for the PG&E and SoCalGas datasets unnecessary.

Each peak-day and monthly average historical fitted model undergoes variable selection, hyperparameter optimization, and cross-validation separately. Each combination of temperature-derived variables investigated is evaluated using MAPE, with hyperparameters optimized for trend flexibility and seasonality adjustment. As a result, CDDs and HDDs at 65°F base temperature, day-to-day change, and seasons are selected among the possibilities of several equally likely competing combinations of explanatory temperature-derived variables. In addition, in the daily analysis, holiday effects are replaced by nonworking-day dummies. No other variables are used to fit the models.

Historical Forecasting

The following outlines the CEC’s approach to historical forecasting:

- Bayesian hyperparameter optimization is conducted for the models with the selected variables and evaluated by using the most recent 12 months of data as the testing data and the first portion of the data as the training data to make predictions on the held-pack portion, a simulated out-of-sample forecast (ex-post forecast) and then running cross-validation and using MAPE. In cross-validation, a model is trained using progressively smaller fractions of the training set and evaluated on the testing set. Models are fitted on the training set and evaluated on the test set to ensure a fair evaluation of the performance of the model. The final cross-validation MAPE confirmed the accuracy of the historical fitted models.
- After cross-validation predictive performance evaluation, the models make in-sample forecasts on the historical dataset. The optimal variables apply to all models, but optimal hyperparameter values differ slightly across utilities and types of demand forecasting. Most importantly, the seasonality hyperparameter mode is additive to the peak-day modeling and multiplicative to the monthly average modeling. The additive model assumes a constant seasonal component value across time, whereas the multiplicative mode assumes a varying value over time. Both forecasting types include linear piecewise trends, but peak-day uses yearly, monthly, and weekly Fourier series functions, and monthly average modeling uses only annual functions.
- After variable selection and hyperparameter optimization, the performance metrics achieved a MAPE of 5.5 percent averaged over cross-validation for SoCalGas peak day, 3.3 percent for month average, and 7.8 percent and 5.4 percent for PG&E,

respectively. A MAPE of 5.5 percent indicates that the model predictions deviate from actual values by an average of 5.5 percent across all the predicted points.

- Descriptive statistics of models' residuals indicate that a one-standard-deviation or one-sigma event represents 182 MMcfd, or 7 percent, and 109 MMcfd, or 4.4 percent, of the peak day and monthly average demand for SoCalGas and 224 MMcfd, or 9.5 percent, and 155 MMcfd, or 6.6 percent, for PG&E, respectively.

Predictive Forecasting

The following outlines the CEC's approach to predicting future gas demand:

- To predict the gas demand data two years in advance (ex-ante forecast), the peak-day model uses the estimated trend, seasonality, and regressor coefficients from the historical fitted models. CEC staff uses these to extrapolate the latest linear trend into the two years ahead. The extrapolation incorporates yearly, monthly, and weekly seasonality and future values of selected regressors. Like the peak-day model, the monthly average model based on the in-sample forecast results extends the linear trend, focusing on yearly seasonality using future values of selected regressors, excluding the nonworking-days regressor. The future values of selected explanatory variables are derived similarly to historical temperature-derived variables using daily and monthly averages from climate change data for 2024–2025.
- The models are applied to predict future gas demand, focusing on winter peak demand scenarios under various probabilities of extreme cold weather events. Extreme HDD conditions are modeled using an ensemble of 204 daily meteorological forecasting variants to account for temperature variations and related impacts on gas demand. Gas demand forecasting framed in terms of 1-in-2, 1-in-10, 1-in-35, and 1-in-90 probabilities quantifies extreme HDD impacts.
- Descriptive statistics of detrended and moving average historical temperatures over 30 years (1994–2023), over the last 5-year period (2019–2023), and the previous year (2023) are compared to the detrended temperature forecast based on downscaled climate projections for 2023–2025. The comparison highlights the differences in short-term fluctuations and long-term trends between climate projections and historical temperatures, ensuring that adjusting HDD probabilities based on these differences produce reliable temperature forecasts.

Customer Classes — Historical and Predictive Forecasting

The following outlines the CEC's approach to historical predictive forecasting of peak-day and monthly average core and electric generation demand.

- Peak-day and monthly average core and electric generation profiles as a percentage of historical and predictive total demand are modeled and projected separately, following the probabilistic additive models described above. These two customer classes exhibit strong relationships with the selected explanatory variables. The projected profiles are then applied to the peak-day and monthly average to derive the projected demand by customer class. Customer-class profiles other than core and electric generation show less sensitivity to temperature and seasonality, and the projected portion of the demand is scaled based on core and electric generation values and daily and monthly growth rate by applying historical profiles to daily and monthly forecasts.

Results

Below are forecasted peak-day and month average demands for SoCalGas and PG&E over the forecast period.

Table A-1 shows PG&E winter peak day demand (MMcfd) (Oct.–Dec. 2024 to Jan.–Mar. 2025) by customer class for 1-in-10 and 1-in-90 cold temperatures.

Table A-1: PG&E as Winter Peak-Day Demand by Customer Class

Quantile	Year	Core	Industrial	Electric Gen	Off_System	Total
1 in 10	2024	2429	496	1157	80	4162
1 in 10	2025	2579	530	1057	80	4246
1 in 90	2024	2939	494	1151	80	4664
1 in 90	2025	3062	517	1030	80	4689

Source: CEC

Table A-2 shows SoCalGas winter peak day demand (MMcfd) (Oct.–Dec. 2024 to Jan.–Mar. 2025) by customer class for 1-in-10 and 1-in-35 cold temperatures.

Table A-2: SoCalGas Winter Peak-Day Demand by Customer Class

Quantile	Year	Core	SDG&E Core	Other Core	Noncore	Electric Gen	Total
1 in 10	2024	2414	284	136	595	1080	4508
1 in 10	2025	2390	279	135	586	1042	4432
1 in 35	2024	2544	293	150	587	1066	4641
1 in 35	2025	2557	295	154	593	1055	4654

Source: CEC

Table A-3: PG&E Monthly Average Demand (MMcfd) (2024–2025) by Customer Class and Winter Average Temperature

Year	Month	Core	Industrial	Electric Gen	Off_System	Total
2024	1	1377	475	838	111	2801
2024	2	1154	419	692	75	2341
2024	3	889	450	557	64	1961
2024	10	493	523	880	36	1932
2024	11	838	457	810	83	2188
2024	12	1309	504	944	107	2865
2025	1	1326	483	766	102	2677
2025	2	1178	448	641	71	2338
2025	3	859	464	533	61	1916
2025	10	466	514	825	33	1838
2025	11	830	463	781	78	2152
2025	12	1255	497	900	98	2750

Source: CEC

Table A-4: PG&E Monthly Average Demand (MMcfd) (2024–2025) by Customer Class and Winter Cold Temperature

Year	Month	Core	Industrial	Electric Gen	Off_System	Total
2024	1	1497	478	900	99	2973
2024	2	1248	421	785	65	2520
2024	3	957	452	736	54	2199
2024	10	498	505	1042	28	2073
2024	11	877	445	964	71	2357
2024	12	1401	497	1071	93	3062
2025	1	1429	482	819	88	2818
2025	2	1218	429	685	57	2389
2025	3	840	422	619	46	1927
2025	10	488	515	999	26	2028
2025	11	900	465	953	69	2387
2025	12	1374	500	1044	86	3004

Source: CEC

Table A-5: SoCalGas Monthly Average Demand (MMcfd) (2024–2025) by Customer Class and Winter Average Temperature

Year	Month	Core	Noncore	Others	SDG&E	Electric Gen	Total
2024	1	1244	433	28	296	673	2674
2024	2	1285	465	29	325	618	2722
2024	3	1081	468	26	297	579	2451
2024	10	621	416	21	161	756	1975
2024	11	960	446	26	235	729	2396
2024	12	1361	459	32	303	852	3007
2025	1	1257	447	28	304	666	2702
2025	2	1285	463	28	328	582	2686
2025	3	989	432	24	275	520	2240
2025	10	660	441	22	174	814	2111
2025	11	977	456	26	243	756	2458
2025	12	1238	421	29	280	793	2761

Source: CEC

Table A-6: SoCalGas Monthly Average Demand (MMcfd) (2024–2025) by Customer Class and Winter Cold (1-in-10) Temperature

Year	Month	Core	Noncore	Others	SDG&E	Electric Gen	Total
2024	1	1448	461	32	339	716	2996
2024	2	1449	480	32	358	637	2956
2024	3	1204	482	28	328	602	2644
2024	10	629	411	21	162	753	1976
2024	11	1018	446	26	247	728	2465
2024	12	1494	460	33	327	850	3164
2025	1	1385	449	30	325	670	2859
2025	2	1489	492	32	356	617	2986
2025	3	1163	470	27	293	571	2524
2025	10	698	457	23	186	847	2211
2025	11	975	428	25	247	710	2385
2025	12	1415	440	32	323	824	3034

Source: CEC

Conclusion

The trend indicates a slight overall decline in gas demand over time. The weekly component implies that the day of the week strongly affects the forecasts. The effects are more pronounced monthly and weekly since the portion of demand attributed to core and electric generation classes varies significantly among months and days of the week. Yearly seasonality also greatly influences the model's prediction. The predicted demand is consistent with peaks observed in colder winters and warmer summers. The monthly component indicates that demand is slightly higher on earlier days of the month.

Demand is somewhat lower on nonworking days and holidays than on working days. Winter versus summer effects are noticeable. As discussed previously, peaks in winter months and dips in summer months correspond to temperatures. Demand may spike in the summer due to increased electric generation for cooling needs, and heating needs make up a substantial fraction of the elevated demand for core customers during colder months.

APPENDIX B: Hydraulic Modeling

In 2017, the California Energy Commission (CEC) launched an initiative to conduct independent hydraulic modeling assessments of the state's natural 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, its consumption by end users, and the physical structure of the pipeline network.

Natural 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 inform 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 policymakers.

Hydraulic Modeling Platform and Data Integration

The CEC uses the DNV-GL Synergi Gas™ hydraulic modeling platform, a widely adopted tool in the U.S., 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 utilizes these inputs for its own 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 2024–2025 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's 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 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 both PG&E and SoCalGas systems as part of the 2024–2025 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 linpeack plays a critical role in these simulations. Line pack 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 2024–2025 reliability assessment confirmed that both 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 natural 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.