Summer 2024 Southern California Gas Reliability Assessment

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
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Table of Contents

List of Tables

List of Figures

Executive Summary

The summer 2024[1] reliability outlook for the Southern California Gas Company (SoCalGas) system is favorable, with expected pipeline capacity stable, and natural gas storage field inventory on target to fill by mid-August[2] or earlier if favorable conditions persist. Due to a mild winter in California and across the country, SoCalGas exited winter with its storage fields at least 80 percent full,[3] which contributed to low natural gas prices in the region.[4]

With the current natural gas assets, maximum inventory limits imposed, and sufficient interstate gas supplies, the model predicts no curtailments or emergency flow orders in summer 2024. The SoCalGas pipeline network should be able to meet average summer demand as well as the summer high sendout day, which is forecasted to be 2,306 million cubic feet per day (MMcfd) by the 2022 California Gas Report,[5] 2,891 MMcfd by the 2020 California Gas Report,[6] and 3,269 MMcfd by a 2020-2022 hybrid forecast.[7]

To estimate summer risk, California Public Utilities Commission (CPUC) staff (Staff) modeled supply and demand using a method that was developed during the Alison Canyon Investigation (I.) 17-02-002. The method combines aspects of two previously used analyses. The model uses assumptions about pipeline capacity for each month and randomly selects a demand value for each day of that month that is within the expected probability distribution. Thus, the model includes some days with higher or lower demand than the monthly average.[8] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. Thus, the model both evaluates the potential increase in storage inventory over the course of the summer and the system's ability to meet peak day demand.

Staff modeled three main scenarios based on variations in forecasts and planned outages for maintenance reported on SoCalGas' ENVOY electronic bulletin board.[9] The average daily pipeline capacity varies from 2,707 million cubic feet per day (MMcfd) for the worst-case scenario to 3,266 MMcfd for the best-case scenario. All three scenarios assume a cold and dry hydro year; high

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[1] The gas summer is from April through October. This report covers May through October, since April actuals were available when the assessment began, i.e., the entire analysis was shifted one month.

[2] SoCalGas Envoy: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.

[3] SoCalGas Envoy. Percentage in text is based on a total storage capacity of 119 billion cubic feet (Bcf). Using the lower Aliso Canyon maximum capacity of 59 Bcf, storage was 87 percent full on March 31, the last day of the gas winter.

[4] According to Natural Gas Intelligence, the average price of gas sold for delivery to the SoCal Citygate on March 31, 2024, was $1.695 per million British thermal units (MMBtu) compared to $8.365/MMBtu for gas delivered on March 31, 2023.

[5] *2022 California Gas Report*, p. 182: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

[6] *2020 California Gas Report*, p. 141: https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.

[7] The hybrid forecast combines the core demand and the noncore, non-EG demand from the 2022 California Gas Report with the noncore, EG demand from the 2020 California Gas Report. *Southern California Gas Company Summer 2024 Technical Assessment,* April 1, 2024, p. 1: summer-2024-socalgas-tech-assessment.pdf.

[8] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.

[9] SoCalGas ENVOY: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.

demand variability; no supplies from Otay Mesa, a less-used gas receipt point on the Mexican border; and no restrictions on the maximum inventory level of underground gas storage fields. Furthermore, a 20 percent reduction in withdrawal and injection rates was assumed to account for required field shut-ins and unplanned storage outages. Unplanned outages account for anomalies that may be detected during well testing, which may extend the duration of the outages. Unplanned outages also account for outages of above-surface facilities such as dehydrators or compressors. Another 30 percent reduction in withdrawal and injection rates was applied to La Goleta to account for extended pipeline outages in the coastal area that may impact the availability of excess gas in this area.

There are at least three factors not captured by the model that could cause the summer's trajectory to differ from the modeled outcomes. First, high gas prices could cause gas customers to inject less or use withdrawals from storage to manage costs as well as reliability, leading to higher withdrawals than forecasted. Second, any additional out-of-state disruptions to supply, such as an outage on an interstate pipeline, would not be captured. Finally, local transmission limitations could result in lower flow rates and hence lower injection rates into nearby storage. For example, a localized high demand from any customer (e.g. commercial or electric generation) near or upstream of a storage field will decrease the volume of gas available for injection. Similarly, the withdrawal rate may be limited by nearby Maximum Allowable Operation Pressure (MAOP) of pipelines. Such details are not captured by this model as they necessitate modeling the energy balance, not just the mass balance.

Introduction

This report aims to assess the summer 2024 reliability of the SoCalGas natural gas network using a stochastic daily mass balance model. This model was developed by CPUC Staff and presented in Workshop #4 of Phase 2 of I.017-02-002 on October 15, 2020.[10] The model is based on the mass conservation law[11] and provides valuable insight into the natural gas system without being overly computationally expensive. The model has been slightly modified to perform further studies on short-term winter and summer reliability. The model has been previously used to assess summer 2023 reliability, and its results were published on the Aliso Canyon Well Failure webpage on August 18, 2023.[12] The model has been also used to assess the reliability of winter 2022-2023 and winter 2023-2024.

In earlier Reliability Assessments, Staff used a monthly mass balance combined with a summer high sendout day. The monthly mass balance was conducted to see how storage inventory filled up over the course of the summer. In that analysis, average demand and supply were assumed for every day of each month. This was coupled with a summer high sendout day analysis, which evaluated whether a peak summer day could be met in each month given assumed pipeline and storage withdrawal capacity. The storage inventory used in the peak day analysis was determined by the monthly mass balance.

The new stochastic daily mass balance combines elements of two previously used analyses. The model uses assumptions about pipeline capacity for each month and randomly selects a demand value for each day of that month that is within the expected probability distribution. Thus, the model includes some days with higher or lower demand than the monthly average.[13] If needed, the model injects excess supply into storage or withdraws from storage to resolve a deficit. All days throughout the summer are modeled in this manner. The model is then repeated 100 times (iterations) to create a probabilistic analysis that includes a spectrum of variations in demand. Thus, the model both evaluates the potential increase in storage inventory over the course of the summer, like the monthly mass balance, and the system's ability to meet peak day demand, like the summer high sendout day analysis.

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[10] CPUC Workshop on Aliso Canyon Hydraulic Modeling, Workshop #4 (Oct. 15, 2020) (youtube.com)

[11] In very simple terms, the law of conservation of mass states that for any closed system, the mass of the system cannot be created or destroyed, i.e., the mass of the system must remain constant or conserved over time. In natural gas pipelines, this means that supplies must equal demand, with supplies being interstate supplies, California production, or withdrawals from underground storage, and demand being actual customer demand (sendout), or injection into underground storage. In this formulation, the time rate of change of mass within the pipelines is assumed to be zero, which means that the linepack returns to its initial value by the end of the day. Violation of the law of conservation of mass in the pipelines directly translates to an actual problem in the system that will result in either curtailments, over-pressurization, under-pressurization or may even indicate leakage in the system.

[12] *Summer 2023 Southern California Gas Reliability Assessment*, July 12, 2023: socalgas_summer_reliability_2023_daily_stochastic_mass_balance_final.pdf

[13] Less than half the days of the month will be higher than average due to the right skewness of the Gamma Distribution.

Winter 2023-2024 Lookback

Winter 2023-2024 began with relatively high natural gas commodity prices[14] and a large number of High operational flow orders (OFOs).[15] These conditions were in part due to customers bringing in gas to fill the additional storage capacity made available by the August 31, 2023, CPUC Decision (D.) 23-08-050.[16] The decision increased the maximum Aliso Canyon inventory from 41.16 to 68.6 Bcf, which allowed noncore customers[17] to regain access to storage capacity through the Unbundled Storage Program for the first time since the 2015 Aliso Canyon leak. Gas prices and the number of High OFOs began to fall once the Aliso Canyon field reached its seasonal peak of 59 Bcf on November 26, 2023.[18] On December 8, 2023, SoCalGas notified customers that injection capacity at Aliso Canyon would be reduced as the field neared the maximum pressure limit authorized by the California Geologic Energy Management Division (CalGEM, formerly known as DOGGR).[19,20]

Winter 2023-2024 was mild both nationally and in California. Low demand and high gas production kept storage fields full and prices low despite record natural gas exports.[21,22] In Southern California, gas prices for December 2023 were the lowest for that month since 2015 when adjusted for inflation.[23] At the end of winter 2023-2024, U.S. storage was 39 percent higher than the five-year average, and 23 percent higher than in 2023. In the Pacific region—which includes California, Oregon, and Washington[24]—storage was 52 percent higher than the five-year average and 211 percent higher than in 2023.[25] SoCalGas' exited winter with its fields 80 percent full if an Aliso Canyon maximum of 68.6 Bcf is assumed and 87 percent full if the actual winter 2023-2024 maximum inventory of 59 Bcf is used. SoCalGas and its noncore customers are thus well positioned to fill storage this injection season. However, such high storage levels early in the injection season

14 The average daily spot price for November at the SoCal Citygate was $6.31/MMBtu compared to $3.72/MMBtu in December (Source: NGI).
15 A High OFO is called if more gas is scheduled to be delivered to the gas system than can be safely managed by the pipeline system and injections into storage. SoCalGas called a High OFO on all but one day between November 2 and 26, 2023, compared to nine days during the same period in 2022 and 11 days in December 2023 (Source: SoCalGas ENVOY).
16 D.23-08-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.PDF.
17 Noncore customers are large commercial and industrial customers who procure their own gas or used a third party to procure it for them.
18 SoCalGas ENVOY.
19 On July 17, 2017, CalGEM/DOGGR issued its Updated Comprehensive Safety Review Findings (p.2), which authorized a maximum pressure of 2,926 pounds per square inch (psi) at Aliso Canyon: https://www.conservation.ca.gov/calgem/Documents/Aliso/Enclosure1_2017.7.19_Updated%20Comprehensive%20Safety%20Review%20Findings.pdf. According to calculations done by CalGEM staff at the time and shared with the CPUC, that pressure would be reached at an inventory of 68.6 Bcf.
20 SoCalGas, ENVOY Critical Notice, December 8, 2023.
21 EIA. "The United States Exported a Record Volume of Natural Gas in 2023," April 15, 2024: https://www.eia.gov/todayinenergy/detail.php?id=61823.
22 EIA. "Mild winter weather may lead to persistently high natural gas inventories through 2025," April 11, 2024: Mild winter weather may lead to persistently high natural gas inventories through 2025 - U.S. Energy Information Administration (EIA).
23 EIA, "December natural gas price in Southern California was the lowest since 2015," March 25, 2024: https://www.eia.gov/todayinenergy/detail.php?id=61644.
24 EIA, Notes and Definition: Natural Gas Storage Regions: Notes and Definitions (eia.gov).
25 EIA figures for March 29, 2024: https://ir.eia.gov/ngs/ngs.html.

may result in an increase in the number of High OFOs compared to recent years since there will be limited room to inject excess pipeline supplies.

Input Data and Assumptions

Withdrawal curves, injection curves, and initial inventory level

In the earlier analyses, Staff have used the same withdrawal and injection curves regardless of the calendar month. However, maintenance and other factors cause withdrawal and injection curves to vary over time. Therefore, Staff requested that SoCalGas submit forecasted monthly withdrawal and injection curves based on well availability and planned maintenance outages. SoCalGas submitted these curves for the period from April to August 2024 for all storage fields and for the period from September to October 2024 for some storage fields.[26] These curves were submitted to Staff under a confidentiality agreement and are not available to the public.[27] They are used extensively by the model to calculate the daily available withdrawal and injection capacities.[28] If any monthly data is missing, Staff uses the withdrawal and injection rates corresponding to the preceding month.

The initial inventory level of all four storage fields on April 1, 2024, was obtained from SoCalGas' ENVOY. The model allows the storage fields to fill to their maximum working gas inventories, which are as follows: Playa del Rey, 1.9 billion cubic feet (Bcf); La Goleta, 21.5 Bcf; Honor Rancho, 27 Bcf; Aliso Canyon, 68.6 Bcf.[29] While the model allows Aliso Canyon to be filled to 68.6 Bcf as approved by the CPUC, in 2023 the field reached the maximum field pressure allowed by the California Geologic Energy Management Division (CalGEM) at an inventory of roughly 59 Bcf. Due to this discrepancy in the inventory limit, Staff continues to use 68.6 Bcf as the maximum allowed inventory level of Aliso Canyon. Should the field properties result in the same pressure-volume relationship this summer, Staff will start to limit Aliso Canon inventory level to 59 Bcf in future assessments, most importantly the upcoming winter 2024-2025 assessment.

In order to account for seasonal shut-ins and unplanned outages of underground storage facilities, such as compressors or dehydrators outages, or outages due to anomalies detected during well testing, staff is assuming 80 percent utilization of Aliso Canyon, Honor Rancho, and Playa Del Rey. Furthermore, to account for ongoing outages in the North coastal system, staff is assuming 50 percent utilization of La Goleta underground storage. The percentage is simply used to scale down all the withdrawal and injection curves (flow rates).

Supply outlook and assumptions

Unlike previous assessments, staff relied only on publicly available planned outage data that are posted on ENVOY.[30] SoCalGas indicated that planned outages that are published on the

[26] Missing data could be due to testing schedules not finalized yet or just omission.
[27] Storage curves are market sensitive, and if released, could cause market actors to game the system
[28] Closed-form integration was performed on the linearly regressed storage curves to obtain accurate inventory volumes
[29] Based on the U.S. Energy Information Agency's Field Level Storage Data for all fields except Aliso Canyon. https://www.eia.gov/naturalgas/storagecapacity/ The model uses the Aliso Canyon maximum set by the CPUC in Decision (D.) 23-08-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.PDF.
[30] In previous assessment, staff requested this data from SoCalGas as they may have not been published yet.

Maintenance Schedules page are finalized and should occur as planned. Other outages summarized in the Maintenance Outlook[31] on ENVOY are preliminary and may or may not occur due to issues such as a lack of necessary construction permits or labor resource conflicts. Therefore, Staff elected to include the finalized planned outages in the first scenario and both finalized and preliminary planned outages in the second and third scenarios as described below.

1. Scenario 1: Planned and finalized outages that last fewer than seven days are ignored. Planned and finalized outages that last seven days or longer are included, and their duration is rounded to the nearest number of months. The duration of the outages is rounded to full calendar months due to current modeling limitations, but this practice could also account for some of the uncertainty associated with the duration of planned outages, their start dates, and their end dates. This scenario represents an upper bound or a best-case scenario for the summer season. This scenario includes ongoing L235 East remediation in the Northern System and ongoing L2001 remediation and L5000 repair in the Southern System.
2. Scenario 2: A Line (L) 4000 hydrotest and L235 remediation restrict the Northern Zone capacity to 955 MMcfd for the entire study period. Both the Southern and the Wheeler Ridge Zones operate at full capacity for the study period. In addition, 90 percent receipt point utilization is assumed, except for California Production. This scenario matches the flowing supplies assumed by SoCalGas in their own summer 2024 assessment.
3. Scenario 3: Same outages assumptions as in Scenario 2. In addition, the average monthly demand values are obtained from the 2020 CGR instead of the 2022 CGR, since the latter underestimated electric generation demand in summer 2022.

The average daily gas supply varies significantly between Scenario 1 (3,266 MMcfd) and Scenarios 2 and 3 (2,707 MMcfd[32]) with a 559 MMcfd average difference between them. All three scenarios assume no supplies from Otay Mesa, which is a receipt point in the Southern Zone that is rarely used. In other words, the capacity reduction resulting from the planned outages occurring in the Southern Zone is subtracted from the El Paso-Ehrenberg/North Baja-Blythe subzone. Depending on outages, the Southern Zone supplies vary from 560 (L5000 repair) to 1210 MMcfd, while the Northern Zone supplies vary from 955 (L235 remediation and L4000 hydrotest) to 1,590 MMcfd. Supplies from Wheeler Ridge are assumed to be 765 MMcfd, and California Production is 60 MMcfd for Scenario 1, and 70 MMcfd for Scenarios 2 and 3.[33]

The resulting monthly capacity based on the assumptions listed above is summarized in Table 1. The last row in the table is the sum of available pipeline supplies in Bcf.[34] Noteworthy is that these supplies are only "available," which means they may or may not be used fully depending on the daily demand and the injection capacity available on that day. The last two columns of the table list the

[31] SoCalGas ENVOY (socalgas-envoy.com)
[32] The average is weighted by the number of days in the calendar months.
[33] 60 MMcfd is what Staff has been using in previous assessments. 70 MMcfd is chosen to match SoCalGas assumptions in their own Summer 2024 Assessment.
[34] Daily supply multiplied by the number of days in a month, summed over the seven-month period divided by one thousand.

average daily demand by month forecasted by the 2022 California Gas Report (CGR) and the 2020 CGR for a cold temperature year with dry hydro conditions. For all three scenarios, the total available supplies (700 Bcf, 579 Bcf, and 579 Bcf) are higher than the forecasted demand for a cold and dry hydro year (454-473 Bcf) over the study period.

Table 1: System receipt capacity by month for the three scenarios and total gas requirement per the 2020 and 2022 California Gas Reports

	System Receipt Capacity[15] (MMcfd) for Scenario			**Cold Temperature and Dry Hydro Daily Demand [16] (MMcfd)**	
	1	**2**	**3**	**CGR 2022**	**CGR 2020**
Month					
April	2,355	2,707	2,707	2,385	2,245
May	3,000	2,707	2,707	2,090	1,915
June	3,005	2,707	2,707	2,021	1,864
July	3,625	2,707	2,707	2,058	2,270
August	3,625	2,707	2,707	2,102	2,508
September	3,625	2,707	2,707	2,100	2,399
October	3,625	2,707	2,707	2,086	2,259
Average Daily	**3,266**	**2,707**	**2,707**	**2,120**	**2,209**
	Total Available Supplies			**Total Forecasted Demand**	
April-October (Bcf)	**699.68**	**579.30**	**579.30**	**453.59**	**472.75**

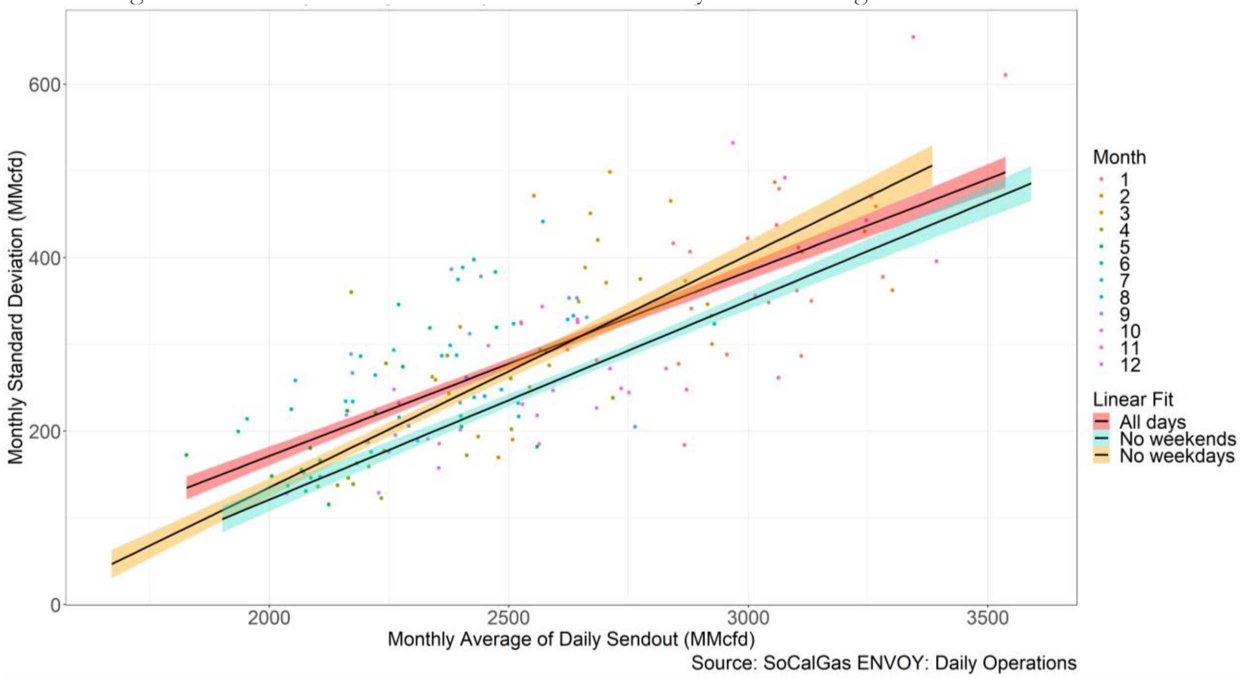
Apart from April in Scenario 1, the average daily system receipt capacity is higher than the average daily demand of the cold temperature, dry-hydro demand forecasts indicating no seasonal or average need for withdrawals from underground storage in order to preserve reliability.

Demand variability

To obtain the Gamma distributions used for the daily random draws,[35] three distributions per calendar month corresponding to three standard deviations (SD) were derived from historical data. These three standard deviations correspond to the predicted value and the 95 percent confidence intervals arising from the linear regression of the historical average daily demand with historical standard deviation for a given month. They can be thought of as a proxy for the degree of weather variability or any other variability inherent to the natural gas system such as customer decisions, customer outages, outages, and electric generation dispatch. Higher standard deviation is typically associated with higher mean daily volume as shown in Figure 1.

[35] The model uses a Gamma distribution which is a right-skewed distribution. Gamma distributions can be obtained by using a mean value and a standard deviation. The mean values are obtained from published natural gas demand forecasts such as the California Gas Report, while the standard deviation is obtained using a linear regression model of historical data.

Figure 1: Historical standard deviation vs. mean daily volume using 2010-2023 sendout data



To derive the linear regression model between the monthly average of the daily sendout and the monthly standard deviation of the daily sendout, historical data of daily sendout was used. In previous assessments, the historical data ranged from January 2010 to October 2018. For this assessment, the historical data range was extended to April 2023. The inclusion of additional data in the regression model did not result in a better correlation between the two variables but resulted in a negligible decrease in the standard deviation.[36] Furthermore, attempting to correlate the two variables during just weekdays or just weekends did not enhance the regression model nor decrease the confidence intervals of the predicted values of the standard deviation. Figure 1 illustrates the linear regression model for the extended dataset range for weekends alone, weekdays alone, or the entire dataset.

In the feasibility studies performed in Phase 2 of I.17-02-002, staff concluded that the high standard deviation (corresponding to the upper 95 percent confidence interval) of a cold temperature and dry hydro year forecasted data best mimicked the historical 2013 cold year.[37] Hence, it was used to

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[36] R-squared for the extended dataset is 0.5254 compared to 0.5606 for the previous dataset. p-values are extremely small for both datasets. Simply put, an R-squared of 0.52-0.56 means that only 52 -56 percent of the variance in the monthly standard deviation can be explained by the monthly average of the daily demand. This is probably due to variations in weather across multiple years. A year can have a consistently hot or average August (which would yield low SD), while another year could have an average August with a heat wave that lasts a week (hence higher SD). Electric generation demand will also contribute to variability.

[37] Year 2013 had 12 days with sendout higher than 4 Bcfd, while the Gamma distribution for a cold 2022-2023 with the upper standard deviation yielded 7.09 days with sendout higher than 4 Bcfd. In comparison, the predicted and lower standard deviations for a cold 2022-2023 yields only 2.67 and 0.27 days respectively. Furthermore, year 2013 had only 1,206 HDDs. A 1-in-10 cold year will have 1,398 HDDs and a 1-in-35 will have 1,476 (CGR 2022).

perform multiple feasibility assessments. For the 2024 summer reliability assessment, Staff continues to use the high standard deviation of a cold temperature and dry hydro year.

Table 2 and Table 3 summarize the Gamma distributions[38] of the daily demand for the period from April 1, 2024, to October 31, 2024, for a cold and dry hydro year using forecasts from the 2022 and 2020 California Gas Reports respectively. For example, for a cold and dry year using the 2022 CGR, there are 12.28 and 27.39 days of demand ranging from 2.5 billion cubic feet per day (Bcfd) to 3.0 Bcfd using the normal and high standard deviation respectively. Similarly, there are no days with demand ranging from 3.0 Bcfd to 3.5 Bcfd using the low standard deviation, but 0.35 and 2.96 days using the normal and high standard deviation respectively for a cold and dry hydro year.

In comparison with the demand distributions summarized in Table 2 and Table 3, the 2022 CGR predicts a summer high sendout of 2,306 MMcfd in September 2024 under 1-in-10-year dry hydro conditions. Furthermore, the 2020 CGR predicts a summer high sendout of 2,891 MMcfd for September 2024 under 1-in-10-year dry hydro conditions, which is about 25 percent higher than that forecasted by the newer forecasts in the 2022 CGR. Finally, a 2020-2022 hybrid forecast used in SoCalGas' Summer 2024 Technical Assessment[39] predicts a peak summer forecast of 3,269 MMcfd, which is 42 percent higher than that forecasted by the 2022 CGR.

Table 2: Demand distribution for April-October for low, normal, and high standard deviation (variability) of a summer 2024 cold temperature and dry hydro forecast from CGR 2022

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 3.5	Negligible	Negligible	0.19
3.0 to 3.5	Negligible	0.35	2.96
2.5 to 3.0	4.49	12.28	27.39
2.0 to 2.5	196.31	134.56	99.63
Lower than 2.0	13.19	66.81	83.62
Total	**214**	**214**	**214**
September days above 2,306 MMcfd	**Negligible**	**4.42**	**8.02**
Total days above 2,306 MMcfd	**23.56**	**40.33**	**61.25**
Total days above 3,269 MMcfd	**Negligible**	**Negligible**	**0.78**

[38] The model uses a Gamma distribution which is a right-skewed distribution. Gamma distributions can be obtained by using a mean value and a standard deviation. The mean values are obtained from published natural gas demand forecasts such as the California Gas Report, while the standard deviation is obtained using a linear regression model of historical data.

[39] The hybrid forecast was introduced in SoCalGas Technical Assessment of summer 2024. It uses the 2022 CGR forecasts for core and noncore, non-EG, but 2020 CGR forecasts for Electric Generation in addition to the oncethrough cooling demand for summer 2023.

Table 3: Demand distribution for April-October for low, normal, and high standard deviation (variability) of a summer 2024 with cold temperature and dry hydro forecast from CGR 2020

	Expected Number of Days		
	Low SD	**Normal SD**	**High SD**
Demand Range (Bcfd)			
Higher than 3.5	Negligible	Negligible	0.82
3.0 to 3.5	Negligible	1.91	8.03
2.5 to 3.0	21.83	36.68	41.64
2.0 to 2.5	131.10	114.26	91.83
Lower than 2.0	61.06	61.13	71.67
Total	**214**	**214**	**214**
September days above 2,891 MMcfd	**Negligible**	**1.04**	**3.51**
Total days above 2,891 MMcfd	**0.13**	**4.24**	**13.87**
Total days above 3,269 MMcfd	**Negligible**	**0.21**	**2.71**

Noteworthy is that in summer of 2022, SoCalGas experienced 21 days where the demand was higher than the summer high demand predicted by the 2022 CGR.[40] The highest recorded demand during that period was 3.2 Bcfd on September 6, much higher than the forecasted high sendout value of 2.579 Bcfd for summer 2022. During those 21 days, the average demand was 2.8 Bcfd.

Given the uncertainty in the CGR forecasts described above, Staff will continue to use the high variability of a cold and dry hydro forecast to generate the monthly distributions of daily gas demand, which would generate, on average, 8.02 days of demand higher than 2,306 MMcfd and 3.51 days of demand higher than 2,891 during the study period using the 2022 and 2020 CGRs respectively. The daily gas demand distributions based on the CCG 2020 generate about three days of demand higher than 3,26 9MMcfd, which is the 2020-2022 hybrid summer peak demand forecast. The results of the model are discussed in the next section.

Stochastic Daily Mass Balance Results

The main advantage of the stochastic daily mass balance model compared to a monthly mass balance is that it creates daily data such as the daily imbalance volume. Other metrics have been derived such as the number of imbalance days, which may lead to Emergency Flow Orders, the Expected Unused Supplies (EUS), and the Expected Unserved Volume (EUV). All metrics may be averaged by month or over the whole study period to summarize the results. Aside from the daily inventory tracking, further analysis of the daily data (e.g., distributions or outliers) is usually not needed unless peculiar results warrant doing so. In other words, aside from daily inventory tracking, reporting averaged results of the different metrics is sufficient. In the following subsections, the results of the different metrics and inventory tracking are presented for all four scenarios.

[40] Two days in July, nine days in August, and 10 days in September

Number of imbalance days

The most important metric or outcome for the stochastic daily mass balance model is the number of imbalance days that occur during the simulation. An imbalance day means that the natural gas system could not meet the demand using the supplies available on that day (interstate supplies + California production + available withdrawal capacity). The total number of imbalance days is divided by the number of iterations[41] to obtain the expected number of imbalance days, which can be disaggregated by month. For all scenarios, the model predicts negligible imbalance days, even under the high demand variability assumption and using the higher summer demand forecasts of the 2020 CGR. In other words, based on the model inputs and assumptions, SoCalGas' natural gas network should be able to meet customers' demand every day during the entire 2024 summer season, with up to eight days of demand above 2,306 MMcfd or three days of demand above 2,891 MMcfd, or even three days of demand above 3,269 MMcfd. The natural gas network can likely support much higher demand.

Expected Unserved Volume (EUV)

Another simple metric was calculated using the stochastic daily mass balance, which is termed the Expected Unserved Volume (EUV). EUV is the sum of all the imbalance volumes averaged over the number of iterations of the study period. EUV can be reported as a total or disaggregated by month. EUV is negligible[42] for all three scenarios since the number of imbalance days is also negligible. In other words, no curtailments are expected this summer as long as the model's assumptions hold.

Expected Unused Supplies (EUS)

Another metric was calculated using the stochastic daily mass balance, which is termed the Expected Unused Supplies (EUS). EUS is the sum of supplies that couldn't be injected into storage due to injection limitations or inventory levels reaching their maximum allowed level, averaged over the number of iterations of study period. Similar to the previous metrics, EUS can be reported as a total or can be disaggregated by month. Table 4 shows EUS for Scenarios 1-3. The high EUS during many months of the study period indicates that additional supplies at the California border will not result in faster filling of underground storage due to injection limitations and near full underground storages by mid-summer. These supplies are not needed to meet the forecasted daily demand either. Therefore, a high EUS could also be interpreted as a margin available at the borders to meet a demand that is higher than forecasted.

Comparing EUS across different scenarios for the same month can illustrate the system constraints. For example, in June, Scenario 1 has 23.0 Bcf of additional supplies (EUS) compared to 14.4 Bcf for Scenario 2, while the daily supplies in June for Scenario 1 are 3,005 MMcfd compared to 2,707 MMcfd for Scenario 2. This shows that the additional supplies in Scenario 1 did not result in any

[41] Recall that the study period is simulated n=100 times. So, if the model reports 500 EFOs for the study period, this translates to five EFOs per study period on average.

[42] Out of the 100 iterations of each of the three scenarios, only Scenario 1 had one negative imbalance (i.e. available supplies did not meet the demand for one day out of 21,400 days). This day occurred in April, when supplies were assumed to be 2,355 MMcfd, and the random demand was 4,232 MMcfd. Even under these conditions, the amount of imbalance was negligible (15 MMcf).

additional injections compared to Scenario 2.[43] It will be shown later that Honor Rancho and Playa Del Rey are already full in June, so the injections in June are limited to La Goleta and Aliso Canyon. A high EUS could also indicate that some additional planned outages could be scheduled without diminishing the system's ability to fill underground storage or meet the forecasted daily demand. For example, July in Scenario 2 could sustain another planned outage with an impact of about 500 MMcfd (16.4*1,000/31).[44]

Table 4: Expected Unused Supplies (Bcf) for Scenarios 1-3

		Scenario		
		1	**2**	**3**
Month	**April**	0.15	1.90	4.48
	May	15.8	12.4	18.0
	June	23.0	14.4	19.2
	July	42.4	16.4	12.3
	August	46.4	18.5	6.98
	September	45.3	18.3	8.85
	October	47.0	19.1	13.2
	April-October Total	**219.98**	**101.01**	**82.98**

The EUS can also be used to calculate monthly receipts as opposed to the assumed monthly receipts that were summarized in Table 1. The calculated receipts are obtained by subtracting the EUS spread over a full month[45] from the assumed receipt capacity for each month. The calculated average monthly receipts for Scenarios 1 and 2 are approximately the same, since the demand over this period is the same (CGR 2022). The calculated receipts in Scenario 3 are higher owing to the higher demand forecasted by the CGR 2020. The difference in the average calculated receipts between the three scenarios is approximately the same difference in the average demand between CGR 2022 and CGR 20220 over the study period (78-83 vs 89 MMcfd).

Furthermore, the Receipt Point Utilization (RPU) can be calculated as shown in Table 5. The RPU is calculated by dividing the calculated receipts by the assumed receipt capacity summarized in Table 1. Based on Table 5, one may also conclude that the inventory levels would reach their maximum allowed capacity by the end of October as long as the RPU is within 73-86 percent on average during the April-October period.

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[43] The additional supplies (3,005-2,707=298 MMcfd) multiplied by the number of days in June (30) is 8.94 Bcf, which is approximately the EUS difference between Scenario 1 and Scenarios 2 in June (23.0-14.4=8.6Bcf).
[44] The more conservative approach would be to run the model with this outage included. However, this estimate is obtained without tapping into withdrawals from underground storage, so it is already conservative.
[45] The EUS is divided by the number of days in a month then subtracted from the assumed daily receipt capacity.

Table 5: Calculated Receipts and Receipt Point Utilization for Scenarios 1-3

		Calculated Receipts (MMcfd) for Scenario			RPU (percent) for Scenario		
		1	**2**	**3**	**1**	**2**	**3**
Month	**April**	2,350	2,644	2,558	100	98	94
	May	2,490	2,307	2,126	83	85	79
	June	2,238	2,227	2,067	74	82	76
	July	2,257	2,178	2,310	62	80	85
	August	2,128	2,110	2,482	59	78	92
	September	2,115	2,097	2,412	58	77	89
	October	2,109	2,091	2,281	58	77	84
	April-October Average	2,241	2,236	2,319	73	84	86

Inventory tracking

The stochastic daily mass balance tracks the daily inventory level of each storage field. In this section, inventory tracking plots for the three scenarios are shown. Each plot contains four subplots, one subplot for each storage field; Aliso Canyon (AC) on the top left, Honor Rancho (HR) on the top right, La Goleta (LG) on the bottom left, and Playa Del Rey (PDR) on the bottom right.

Because of the random draws performed by the model, the daily storage inventory level is not a deterministic value, but rather a probabilistic one, i.e., a distribution.[46] Therefore, each subplot contains five curves that represent the 5th, 25th, 50th (median), 75th, and 95th percentiles of the inventory level of one of the storage fields.

Figure 2, Figure 3, and Figure 4 show the inventory tracking plots for Scenarios 1, 2, and 3, while Table 6, Table 7, and Table 8 show the month-end storage inventories of Scenarios 1, 2, and 3. As summarized in Table 1, Scenarios 1, 2, and 3 have total available interstate supplies (and CA production) of 700 Bcf, 579 Bcf, and 579 Bcf compared to a forecasted demand of 454-473 Bcf over the study period for a cold and dry year. Scenario 1 represents, on-average, the best-case scenario, while Scenarios 2 and 3 match the supply assumptions assumed by SoCalGas in their own summer assessment. For all three scenarios, the total available supplies are higher than the total demand. In addition, all three scenarios assume a high demand variability (high standard deviation) within a cold temperature and dry hydro year and no supplies scheduled at Otay Mesa. All three scenarios assume 80 percent utilization of wells for Aliso Canyon, Honor Rancho, and Playa Del Rey, and 50 percent utilization of wells for La Goleta. Furthermore, all three scenarios withdraw and inject from all four storage fields using Aliso Canyon last in the sequence.

[46] Since each study period is simulated 100 times, it follows that each day in the study period is also simulated 100 times. In other words, the storage inventory levels on July 1st have 100 values for each scenario and statistics must be drawn to illustrate the results.

Figure 2, Figure 3, and Figure 4 show that all storage fields are filled to their maximum allowed inventory limit no later than by mid-August for all three scenarios. For Scenarios 2 and 3, all four storage fields are full by the end of July. Despite having the third injection priority in the model, PDR is always the first to reach its maximum inventory limit owing to its small capacity. Historically, PDR's inventory level fluctuates frequently during the summer in response to hourly variation in demand. As for La Goleta, it is either last or second-to-last to reach its maximum inventory limit despite having the highest priority. This is due to its low injection rate combined with an assumed 50 percent utilization of its wells to account for ongoing north coastal pipeline outages. Furthermore, Aliso Canyon is either last or second-to-last last to reach its maximum inventory limit owing to its large capacity and its low injection priority in the model.

Based on the model results, withdrawals occur with varying magnitudes in the April-October period with a total of 5.04, 2.63, and 6.60 Bcf of withdrawn volume for Scenarios 1, 2, and 3 respectively. Withdrawals are neither high nor consistent enough to be noticeable on the inventory plots. However, one must note that modeled withdrawals are based on *daily* demand. Actual withdrawals are often caused by hourly demand and ramping needs, which vary significantly throughout the day. Therefore, actual withdrawals are likely to happen more frequently than indicated by the model. Table 9 shows a summary of the total withdrawn volume during the study period.

Figure 2: Inventory tracking for Scenario 1

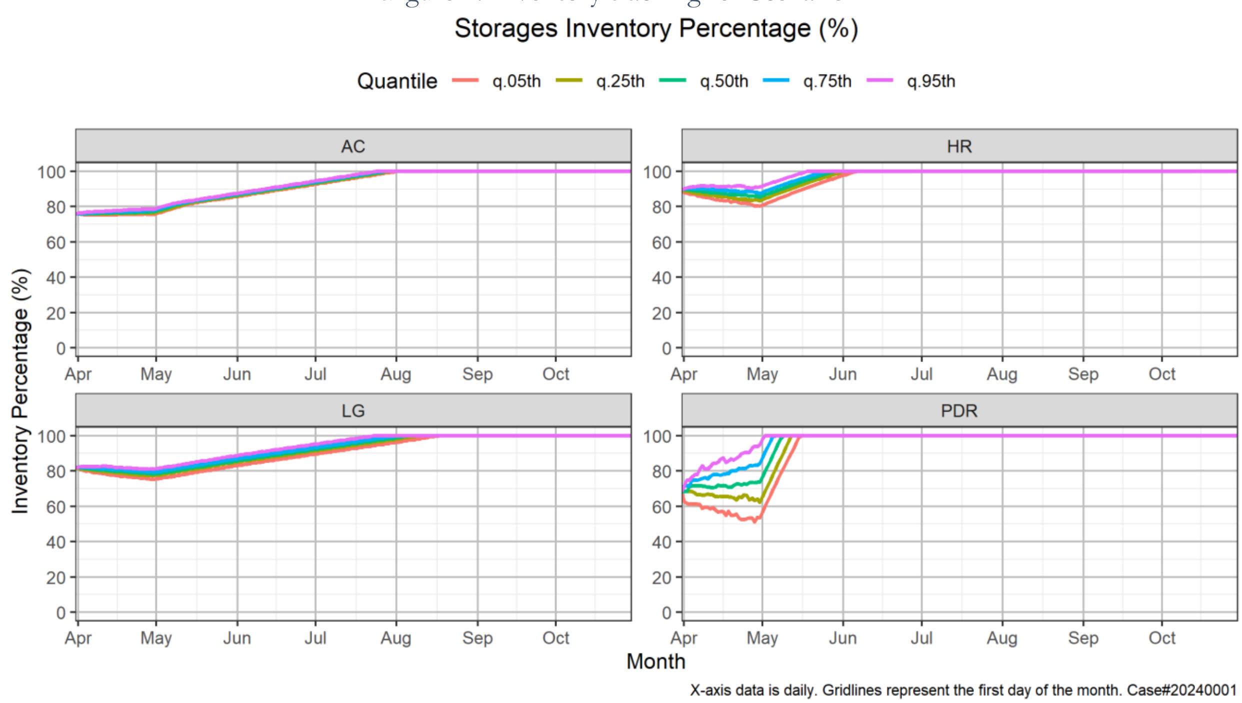
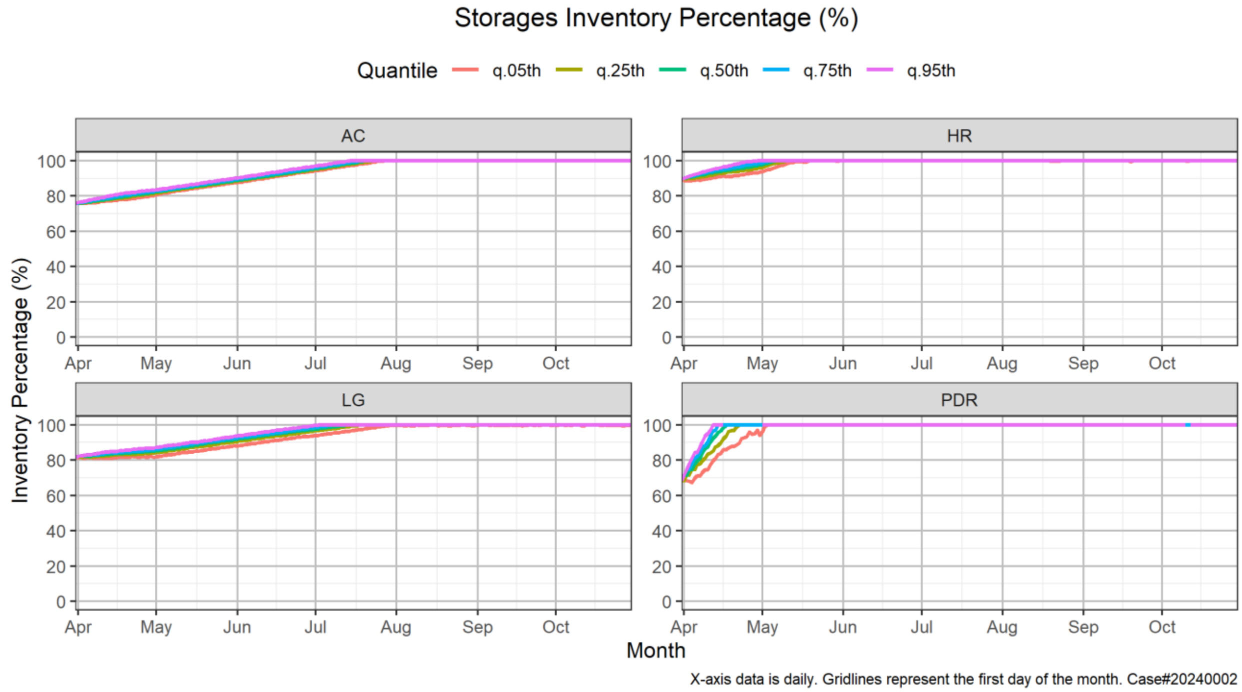
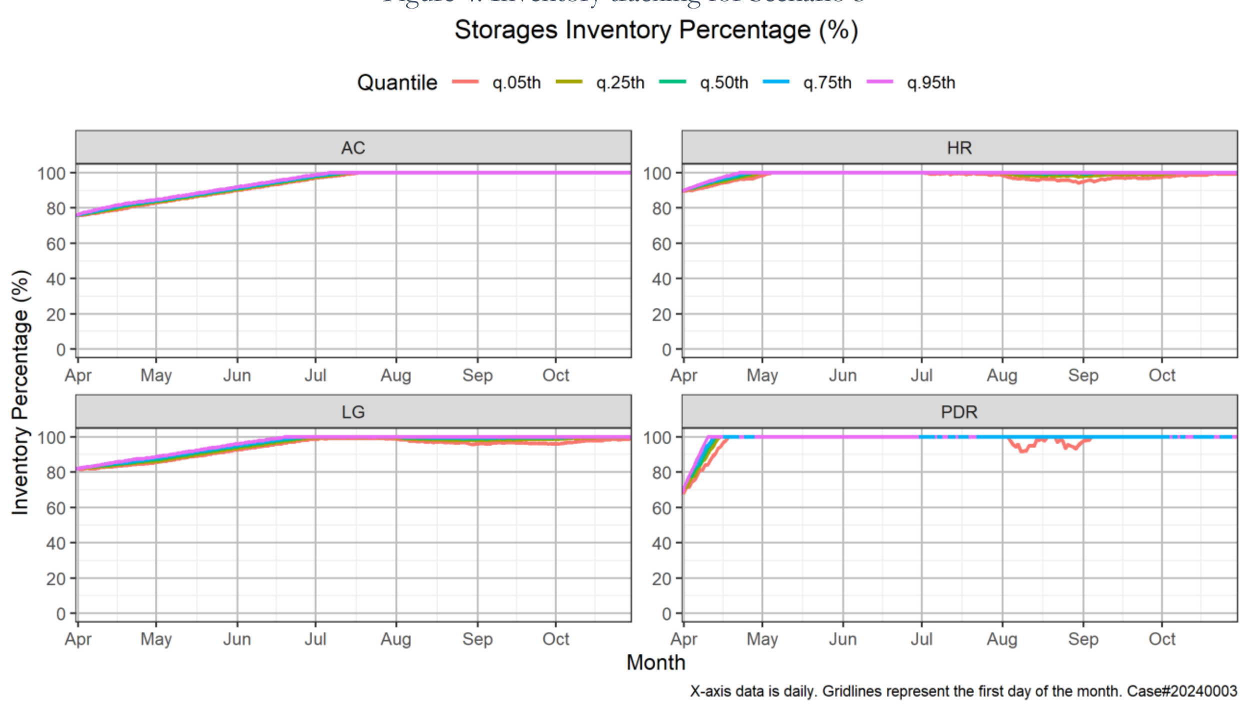


Figure 3: Inventory tracking for Scenario 2



Apart from April in Scenario 1, withdrawals are occurring despite the average daily supplies being higher than the average daily demand. The withdrawn volume increases as the supply decreases. This, again, highlights the model's strength in predicting withdrawals despite average supplies being higher than average demand during each month in the study period even during the summer months.

Figure 4: Inventory tracking for Scenario 3



One of the advantages of the daily mass balance model is not only predicting withdrawals during months when the average supplies are lower than the average demand, but also predicting them during some months when the average supplies are higher than the average demand. This was very evident in the previous winter assessment and continues to be true in this assessment of summer 2024 as described above. Withdrawals did occur in the summer 2024 model to preserve reliability. Of note, is that in Scenarios 2 and 3, rarely more than two storage fields were needed to resolve a supply deficit on any day. However, Scenario 1 shows more frequent use of three and even four storage fields to resolve deficits, primarily in April when supplies are assumed to be low.

Table 6: Month-end inventory for Scenario 1 (median)

	Month						
	4	**5**	**6**	**7**	**8**	**9**	**10**
Aliso Canyon	52.94	59.23	63.95	68.60	68.60	68.60	68.60
Honor Rancho	23.19	27.00	27.00	27.00	27.00	27.00	27.00
La Goleta	16.86	18.37	19.76	21.17	21.50	21.50	21.50
Playa del Rey	1.4	1.90	1.90	1.90	1.90	1.90	1.90
Total	94.38	106.49	112.61	118.67	119.00	119.00	119.00

Table 7: Month-end inventory for Scenario 2 (median)

	Month						
	4	**5**	**6**	**7**	**8**	**9**	**10**
Aliso Canyon	56.17	60.71	65.27	68.60	68.60	68.60	68.60
Honor Rancho	26.29	27.00	27.00	27.00	27.00	27.00	27.00
La Goleta	18.27	19.67	20.91	21.50	21.50	21.50	21.50
Playa del Rey	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Total	102.63	109.29	115.08	119.00	119.00	119.00	119.00

Table 8: Month-end inventory for Scenario 3 (median)

	Month						
	4	**5**	**6**	**7**	**8**	**9**	**10**
Aliso Canyon	57.33	62.18	66.94	68.60	68.60	68.60	68.60
Honor Rancho	27.00	27.00	27.00	27.00	26.92	26.99	27.00
La Goleta	18.70	20.25	21.50	21.50	21.30	21.37	21.5
Playa del Rey	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Total	104.93	110.19	117.34	119.00	118.72	118.86	119.00

While the model shows that the most frequently used two storage fields are La Goleta and Honor Rancho because of the withdrawal sequence that is already prescribed in the model, historical data would likely show that those two storage fields are Honor Rancho (or Aliso Canyon if no restrictions are in place) and Playa del Rey owing to their proximity to the basin, electric generators, and load centers.

The results obtained by the daily stochastic mass balance model do not contradict previous results obtained from 24-hour transient modeling in Synergi Gas. In particular, in the Aliso Canyon Investigation, a summer 2030 simulation with a demand of 2,675 MMcfd and pipeline supply of 2,222 MMcfd used only two storage fields (La Goleta and Play del Rey) to meet the supply deficit.

It is worth noting that neither the industry-standard monthly balance sheets, nor the daily mass balance model take into account market decisions made by gas users comparing the price of gas from storage to that of pipeline gas. They also do not factor in the hourly changes in demand that frequently drive storage withdrawals. On the actual pipeline system, those market decisions and hourly surges in demand may lead to more storage being used than would be forecast based on daily reliability decisions alone.

In summary, inventory tracking shows relatively high inventory levels by mid-August and throughout August, September, and October, with few withdrawals and no imbalance days or curtailments. The inventory levels heading into winter 2024-2025 are forecast to be high and supportive of a reliable winter 2024-2025.

Table 9: Expected Withdrawal Volumes (Bcf) for Scenarios 1-3

		Scenario		
		1	**2**	**3**
Month	**April**	5.00	1.54	0.64
	May	0.02	0.21	0.02
	June	0.02	0.11	0.02
	July	0	0.15	0.73
	August	0	0.22	2.65
	September	0	0.21	1.70
	October	0	0.19	0.82
	April-October Total	**5.04**	**2.63**	**6.60**

Summary

The stochastic daily mass balance model was used to assess the reliability of SoCalGas natural gas network in Southern California for the upcoming summer of 2024. Three scenarios have been devised with varying preliminary and non-preliminary planned outages, which were obtained from SoCalGas' ENVOY. All three scenarios assume a cold and dry hydro year, high demand variability, no supplies from Otay Mesa, and no restrictions imposed on underground gas storage fields. In addition, all three scenarios assume 80 percent utilization of Aliso Canyon, Honor Rancho, and Playa del Rey to account for unplanned wells outages. Furthermore, all three scenarios assume 50 percent utilization of La Goleta to account for the north coastal outages.[47]

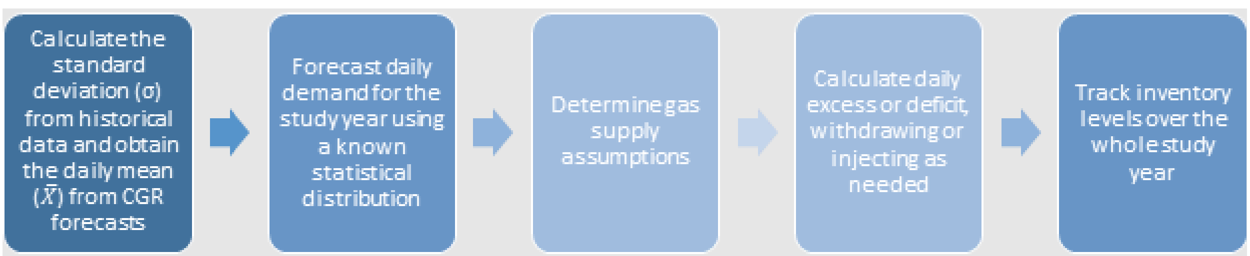
With the current natural gas assets in place and the maximum inventory limit of 68.6 Bcf set on Aliso Canyon, the model predicts no curtailments or emergency flow orders in the summer of 2024. Thus, the assessment predicts the system will be reliable during the upcoming summer.

Even with an assumed 20-50 percent of wells out-of-service, the SoCalGas natural gas network should be able to meet customers' demand every day during the 2024 summer, with up to 61 days of demand above 2,306 MMcfd, or 14 days of demand above 2,891 MMcfd, or three days of demand above 3,269 MMcfd, and possibly higher. The SoCalGas natural gas network should be able to meet the forecasted summer high sendout days forecasted by both the 2020 and 2022 CGR and SoCalGas' 2020-2022 hybrid forecast.

[47] In practice, the Aliso Canyon Withdrawal Protocol limits the use of the Aliso Canyon storage field. However, it may be used on days where a Stage 2 or higher Low Operational Flow Order (OFO) would have been called without its use. The model assumes that such a stage would have been reached on days with demand high enough to require the use of Aliso Canyon. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf.

Appendix: Review of the Stochastic Daily Mass Balance Model

The stochastic daily mass balance model attempts a mass balance on each day of the study year rather than the conventional and industry-standard monthly mass balance approach. This method provides an assessment of the system's ability to serve daily demand as a season progresses. The model inputs are the forecasted daily demand using random draws from a known distribution, the monthly assumed pipeline capacity, the storage withdrawal and injection curves, utilization factors[48] or well availability, the working gas capacity of the storage fields, and the maximum and minimum allowed inventory in the storage fields. The use of a distribution for daily demand makes it stochastic. The model outputs are mainly the expected average daily inventory levels and expected average frequency of Emergency Flow Orders (EFO) or imbalance days. Other metrics may be calculated such as the Expected Unused Supplies (EUS) and the Expected Unserved Volume (EUV). The model does not attempt to simulate customers' decisions on the natural gas network. In other words, if the pipeline operator issues an Operational Flow Order (OFO), which imposes a penalty for over- or under-delivering gas, customers may react to the OFO and make decisions that affect the amount of imbalance present in the system. Therefore, the model assumes a worst-case scenario, where customers decisions are unaffected by OFOs, and hence the natural gas system is inelastic. It is noteworthy that most of these outputs would not be available if monthly mass balance sheets were used. The model steps are illustrated in the Figure below.



Sequentially on each day of the study year, the model determines whether there is an excess or deficit in the gas supply, then injects or withdraws accordingly, while adhering to the withdrawal and injection limits imposed by the withdrawal and injection curves. If there is insufficient supply (i.e., interstate supplies, California production, and storage) to meet the demand (mass imbalance) on a given day, the model flags that day as an imbalance day or an EFO day. EFOs are used as a proxy for insufficient supply or imbalance and as a proxy for reliability events.

The model withdraws or injects the full daily available volume[49] from one storage field before switching to withdrawal or injection from another storage field. This approach was chosen for its simplicity. In addition, the model is currently set to withdraw from and inject into Aliso Canyon last

[48] The utilization factor or use factor is the ratio of the time that a piece of equipment is in use to the total time that it could be in use. For wells, these could be used to account for planned and unplanned outages. For example, if a well is scheduled for maintenance for one month, then its utilization factor would be 1/12. It is one simple way to incorporate outages.

[49] The model integrates the withdrawal and injection curves to get the total change in volume. In other words, the model takes into account the intraday change in withdrawal and injection capacity.

because one of the feasibility assessment goals was to minimize its use. Other, more sophisticated algorithms could involve optimizing withdrawals and the withdrawal sequence to maximize the withdrawal capacity throughout the withdrawal season or to maximize the injection capacity available on a day following withdrawals.

Specifically, for each day in the simulation, if there is an excess of supply (i.e., supplies are higher than the demand), then the injection sequence is initiated,[50] while always respecting the injection limits. For example, if the supplies are 3 billion cubic feet (Bcf) and the demand is 2.5 Bcf, then 500 million cubic feet (MMcf) needs to be injected on that day. If La Goleta is not full (i.e., inventory <100 percent), and the average injection capacity on that day is, for example, 100 million cubic feet per day (MMcfd), then 100 MMcf is injected into La Goleta as long as its inventory is not above 100 percent. The remaining 400 MMcf is injected to the other fields following a specified injection sequence and using the same logic. If all the fields are either full or have used their maximum injection capacity but there is still excess gas, then that day is flagged as a high EFO day. In actual operations, the pipeline operator will issue a high OFO or turn gas away at the California border in an attempt to return balance to the system. The EFO in the feasibility assessment model does not necessarily translate to an actual EFO since the operator can issue a high OFO and customers may attempt to voluntarily increase or balance their gas usage in order to avoid penalties.

Similarly, if there is a deficit in interstate supplies (i.e., supplies are lower than the demand), then the withdrawal sequence is initiated,[51] while always respecting the withdrawal limits. For example, if the supplies are 3 Bcf and the demand is 4 Bcf, then 1 Bcf needs to be withdrawn on that day. If La Goleta is above its minimum allowed inventory level (e.g., 0 percent if no restrictions are imposed), and the average withdrawal capacity on that day is, for example, 200 MMcfd, then 200 MMcf is withdrawn from La Goleta as long as its inventory does not dip below 0 percent. Otherwise, a smaller amount is withdrawn that brings the final inventory volume to 0 percent. The remaining 800 MMcf (or more if La Goleta withdrawal was less than 200 MMcf) must be withdrawn from the other fields following the sequence and the same logic. If all fields have either reached their maximum daily withdrawal or are below their allowed minimum inventory level (or a combination thereof), but there is still a deficit in gas, then that day is flagged as a low EFO day. In actual operations, if there aren't sufficient supplies and linepack to meet the demand, the pipeline operator will issue a low OFO with increasingly stringent stages in an attempt to balance the system. Again, the EFO in the feasibility assessment model does not necessarily translate to an actual EFO or curtailments, since the operator can issue a low OFO and customers may attempt to voluntarily decrease or balance their gas usage in order to avoid penalties.

Because of the statistical nature of the model, a study period must be simulated multiple times. Staff found that 50 iterations of a study period are enough to produce statistically convergent results. However, Staff continued to use 100 iterations in this report.

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[50] The injection sequence is currently set to La Goleta > Honor Rancho > Playa Del Rey > Aliso Canyon
[51] The withdrawal sequence is currently set to La Goleta > Honor Rancho > Playa Del Rey > Aliso Canyon

In essence, the daily demand is the only random input, which is being generated from a known right-skewed distribution. Other inputs remain deterministic, though these inputs may be varied to simulate different scenarios or perform sensitivities. For example, the assumed interstate supplies are deterministic, but they vary by month to account for planned outages and other scenarios. Similarly, the number of wells is allowed to vary by month to account for planned outages, but sensitivities can be performed on the availability of wells using utilization factors. Staff has previously conducted parametric studies that included 972 scenarios per study period in order to vary these deterministic inputs.[52]

[52] Aliso Canyon Investigation 17-02-002 Phase 2: Additional Modeling Report https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M449/K511/449511926.PDF