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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation pursuant to Senate Bill 380 to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while still maintaining energy and electric reliability for the region.	Investigation 17-02-002

ADMINISTRATIVE LAW JUDGE'S RULING ENTERING INTO THE RECORD ALISO CANYON INVESTIGATION 17-02-002 PHASE 2: ADDITIONAL MODELING REPORT, REQUESTING COMMENT

This ruling enters into the record the February 2, 2022, Aliso Canyon Investigation 17-02-002 Phase 2: Additional Modeling Report (Phase 2 Additional Modeling Report) by Energy Division, for comment by the parties.

After receiving recommendations on additional Phase 2 modeling, on August 27, 2021, the assigned Administrative Law Judge ordered Energy Division to perform two additional simulations.[1] The Phase 2 Additional Modeling Report is affixed to this ruling as Attachment A.

Concurrent opening comments on the Phase 2 Additional Modeling Report must be filed and served by close of business March 1, 2022. Concurrent reply comments on the Phase 2 Additional Modeling Report must be filed and served by close of business March 15, 2022.

[1] Administrative Law Judge's Ruling Ordering Modeling by the Commission's Energy Division, August 27, 2021, at 3 – 4.

IT IS RULED that:

1. The February 2, 2022, Aliso Canyon Investigation 17-02-002 Phase 2: Additional Modeling Report by the Commission's Energy Division is entered into the record.

2. The February 2, 2022, Aliso Canyon Investigation 17-02-002 Phase 2: Additional Modeling Report by the Commission's Energy Division is affixed to this ruling as Attachment A.

3. Parties may file concurrent opening comments on the Report by close of business March 1, 2022.

4. Parties may file concurrent reply comments on the Report by close of business March 15, 2022.

Dated February 10, 2022, at San Francisco, California.

/s/ ZHEN ZHANG
Zhen Zhang
Administrative Law Judge

ATTACHMENT A

Aliso Canyon I.17-02-002 Phase 2: Additional Modeling Report

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
February 2, 2022

Khaled Abdelaziz, PhD, PE, Utilities Engineer
Lisa Cosby, Analyst

Donald Brooks – Supervisor, Energy Resource Modeling Section

Table of Contents

List of Figures

List of Tables

Executive Summary

This report provides two new sets of modeling results. Firstly, two additional reliability assessment scenarios of the gas system in 2030 provide new results for comparison with the results provided in Aliso Canyon I.17-02-002 Phase 2: Modeling Report (Phase 2 Modeling Report).[2] Secondly, a feasibility assessment of the gas storage levels in 2027 and 2035 provides insight on the inventory, and therefore the withdrawal rates, for comparison with the inventory levels used as inputs in these modeling scenarios and in the FTI Consulting, Inc. (FTI) study of future portfolios without the Aliso Canyon natural gas storage facility.

Pursuant to the administrative law judge's (ALJ) ruling issued on August 27, 2021,[1] Energy Division Staff performed two additional sensitivity scenarios to assess the reliability of the SoCalGas natural gas system. The first scenario is a sensitivity on simulation 5 (S05) from Phase 2 Modeling Report.[2] It models a winter 2030 1-in-10 cold day, which has a forecasted demand of 4,821 MMcfd, using an increased receipt point utilization of 95 percent (S05b). The second scenario is a sensitivity on simulation 9 (S09) and models a winter 2030 1-in-35-year cold day with minimum local generation, which has a forecasted demand of 3,370 MMcfd, with a lower receipt point utilization of 55 percent for the Northern and Southern Zones (S09b).

The previous simulation of scenario 5 (S05) met the demand and restored linepack, but only with the use of 520 MMcfd of withdrawals from Aliso Canyon. In the sensitivity (S05b), interstate supplies were increased from 3,115 MMcfd to 3,457 MMcfd, resulting in an incremental gain of 342 MMcfd. A 24-hour hydraulic transient simulation of S05b indicates that withdrawals from Aliso Canyon are still needed to maintain reliability, albeit at a lower minimum rate of 52 MMcfd. Staff notes, however, that the assumptions of S05b are very optimistic. In particular, the assumption of 90 percent inventory levels in the non-Aliso storage fields is infeasible as demonstrated by the feasibility assessment presented in Energy Division's Phase 2 Modeling Report, independent analysis conducted by FTI in Phase 3 (CPUC's contractor), and further validation by Energy Division Staff in this additional modeling report. Furthermore, the assumption of 95 percent receipt point utilization leading to the 3,457 MMcfd of available interstate supplies is inconsistent with historical data and does not take into account multi-state cold weather events or out-of-state outages that might jeopardize the availability of natural gas at the Southern California border.

The previous simulation of scenario 9 (S09) succeeded without the use of withdrawals from Aliso Canyon, owing to the lower demand requirement on a 1-in-35 extreme peak day resulting from curtailing all noncore customers except a small set of electric generation customers required to maintain local reliability. Sensitivity S09b (55% RPU on the Northern and Southern zones) lowered the interstate supplies from 3,115 MMcfd to 2,375 MMcfd, resulting in an incremental loss of 740 MMcfd of interstate supplies to simulate a loss of interstate supplies similar to — but not as severe as — that experienced in February 2021 during Storm Uri. A 24-hour hydraulic transient simulation of S09b indicates that withdrawals from Aliso Canyon are still not needed to meet the 1-in-35

[1] August 27, 2021, Ruling: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M403/K094/403094525.PDF
[2] Phase 2 Modeling Report: i_1702002_phase2modelingreport_3-8-21_unredacted.pdf (ca.gov)

reliability standard. However, Staff encountered modeling challenges supporting the Southern Zone using supplies from the Northern Zone. Staff note that a minimum local generation scenario degrades the reliability of the electrical grid. While S09b does not represent an acceptable level of electric reliability due to extensive generation curtailments leading to high loss of load, sensitivity S09b should be used to assess the reliability of the natural gas system to serve its core customers, rather than its noncore and electrical generation customers. This is true for all scenarios from the Phase 2 Modeling Report aiming to assess the 1-in-35 reliability standard, i.e., scenarios six to nine.

Although not ordered in the ALJ's ruling, Energy Division Staff conducted more feasibility assessments of gas storage inventory levels for years 2027 and 2035, which are the time horizons considered in Phase 3[3] of the OII. These assessments were performed to validate FTI's findings regarding the seasonal availability of natural gas from the non-Aliso fields in 2027 and 2035, and the natural gas shortfall should Aliso be retired in 2027 or 2035. Using a daily pipeline capacity of 2,756 MMcfd, the maximum withdrawal and injection curves provided by SoCalGas, and assuming that Aliso Canyon is retired, FTI conducted a monthly gas balance analysis and reported that the inventory level in the non-Aliso fields in 2027 and 2035 would drop to **54 percent and 82 percent**[4] respectively, and that the natural gas shortfall on a peak day would be **395 MMcfd and 323 MMcfd**[5] in 2027 and 2035 respectively.

To validate the amount of SoCalGas underground storage available at the end of the winter season, as calculated by FTI, Energy Division Staff used the same set of assumptions related to pipeline capacity and withdrawal and injection curves but a more conservative daily mass balance methodology which introduced some variation around the daily and yearly forecasts of the 2020 California Gas Report. Energy Division Staff found that the non-Aliso inventory levels would drop to **46 percent and 71 percent** in 2027 and 2035, i.e., a slightly higher need for underground storage compared to the FTI's findings. Therefore, Energy Division Staff concludes that the inventory levels calculated by FTI are reasonable but may be overstated due to inaccurate forecasts or future wells abandonments or outages.

Consistent with FTI's findings, the feasibility assessment indicates that Aliso Canyon would not be needed on an average demand winter day in 2027 or 2035. However, the absence of Aliso Canyon would lead to a gas shortfall on a peak day. To validate FTI's determination of that gas shortfall, Energy Division Staff conducted a parametric study to further evaluate the need for Aliso Canyon in 2027 and 2035 and if needed, what would be its minimum required inventory level. Using the daily mass balance methodology, Energy Division Staff found that the minimum inventory level needed from Aliso Canyon in 2027 and 2035 is 10 percent and 5 percent respectively. This translates to about **586-672 MMcfd and 500-586 MMcfd** of withdrawal capacity needed from Aliso Canyon in 2027 and 2035 respectively compared to **395 MMcfd and 323 MMcfd for 2027 and 2035** obtained

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[3] Now merged with Phase 2

[4] FTI Workshop #3 Nov 3, 2021, page 18, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-presentation-workshop-3-revised.pdf

[5] FTI Workshop #3, Nov. 3, 2021, page 20, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-presentation-workshop-3-revised.pdf

by FTI. In other words, based on the daily mass balance methodology, the withdrawal rate required from Aliso Canyon in 2027 and 2035 is higher than the contractor's shortfall by 177-277 MMcfd.

Additional 1-in-10 Scenarios Modeling

In response to requests from parties for additional modeling runs to supplement the Phase 2 modeling report, the CPUC issued the above-mentioned ruling on August 27, 2021, directing Energy Division to perform two additional modeling sensitivities.[6] Energy Division performed an additional sensitivity with RPU (Receipt Point Utilization) at 95%, based on Simulation 5 (S05), a 1-in-10 peak day in winter 2030. Secondly, Energy Division staff performed a sensitivity with RPU at 55% based on Simulation 9 (S09), a 1-in-35 extreme winter peak day in 2030. These scenarios can be viewed as book ends, with the first at the optimistic end of the spectrum and the second reflecting very difficult, but not unprecedented conditions, where interstate supplies are low. The original Simulations 5 and 9 were included in the Phase 2 Modeling Report issued March 8, 2021.[7]

Scenario 5b: Winter 2030 1-in-10 Peak Day with Higher Interstate Supplies

The CPUC directed Energy Division to perform a sensitivity based on S05 (Winter 1-in-10 2030) modified to have 95% of RPU for all zones. This sensitivity is referred to in this report as S05b.

Baseline Scenario: Scenario 5

Simulation S05, which was performed in Phase 2, aimed to determine the extent to which Aliso Canyon withdrawals would be needed on a 2030 1-in-10 cold winter day with RPU of 85% in the Southern Zone, 85% plus two outages in the Northern Zone (pressure reductions on L235 and L4000), and 100% in the Wheeler Ridge Zone. A summary of Aliso Canyon withdrawal rates needed for a successful simulation is shown in Table 1.

Table 1: Summary of Non-Aliso Inventory Levels and Aliso Canyon Withdrawal Rates for Scenario 5 Baseline and Phase 2 Sensitivities (Winter 2030)

Baseline or Sensitivity	Non-Aliso Inventory Level	Aliso Canyon Withdrawal Rate (MMcfd)
Baseline	90%	520
Sensitivity 1	70%	830
Sensitivity 2	50%	1,010
Sensitivity 3	37%	1,160

Sensitivity Scenario: Scenario 5b

S05b keeps all assumptions of S05, except that the interstate supplies from Wheeler Ridge, Northern, and Southern Zones are modified to flow at 95% of their nominal capacities. S05b assumes 90% inventory levels at the non-Aliso storage fields, similar to S05 baseline.[8] S05b also

[6] August 27, 2021, Ruling: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M403/K094/403094525.PDF
[7] Phase 2 Modeling Report 369286397.PDF (ca.gov)
[8] Although 90% inventories were used for the non-Aliso fields for the baseline simulation 5 in the Phase 2 Modeling Report, the Feasibility Section of the Phase 2 Report showed that this would be an unrealistic assumption over multiple cold days. 369286397.PDF (ca.gov), Section V, pp 84-85

assumes the same customer demand and profiles as the baseline S05. Table 2 below summarizes the supply and demand assumptions of S05 and S05b.

Table 2: 1-in-10 Peak Day Pipeline Receipts, Maximum Storage Withdrawals, and Demand for S05 and S05b

1-in-10 Peak Day Pipeline Receipts, Max Storage Withdrawals, and Demand			
Receipt Points (MMcfd)	**Baseline S05**	**Sensitivity S05b**	**Different**
Pipeline Receipts			
Wheeler Ridge	**765**	**724**	**Yes**
Wheeler Ridge RPU	**100%**	**95%**	**Yes**
Blythe Ehrenberg	980	1,095	Yes
Otay Mesa	50	50	No
Total Southern Zone	**1,030**	**1,145**	**Yes**
Southern Zone RPU	**85%**	**95%**	**Yes**
Kramer Junction	420	520	Yes
North Needles	430	599	Yes
South Needles	400	400	No
Total Northern Zone	**1,250**	**1,518**	**Yes**
Northern Zone RPU	**79%**[9]	**95%**	**Yes**
California Producers	**70**	**70**	**No**
Total Pipeline Receipts(a)	**3,115**	**3,457**	**Yes**
Total Receipts RPU	**86%**	**95%**	**Yes**
Maximum Storage Withdrawals			
Honor Rancho	802	802	No
La Goleta	228	228	No
Playa Del Rey	299	299	No
Subtotal Non-Aliso	1,329	1,329	No
Aliso Canyon (b)	1,265	1,265	No
Max Storage Withdrawals (c)	**2,594**	**2,594**	**No**
Total Available Supplies (d) (a+c)	**5,709**	**6,051**	**Yes**
Avail. Supplies without Aliso (d-b)	**4,444**	**4,786**	**Yes**
Total Demand	**4,821**	**4,821**	**No**

[9] Lower than 85% due to assumed pressure reductions on L235 and L4000.

The total available supplies in Table 2 include pipeline receipts and maximum storage withdrawal rates. Without Aliso Canyon, the total available supplies in S05 would be 4,444 MMcfd, which is lower than the total demand of 4,821 MMcfd. Similarly, in S05b without Aliso Canyon, the total available supplies of 4,786 MMcfd, are lower than the total demand of 4,821 MMcfd.

The total nominal pipeline receipt capacity is 3,635 MMcfd, and with a 95% RPU used in S05b, the total pipeline receipts are 3,457 MMcfd. This is 342 MMcfd, or 11%, higher than the total pipeline receipts of 3,115 MMcfd used in S05.

For S05b, the non-Aliso storage inventories of 90%, along with pipeline RPU of 95%, are representative of a system operating at nearly maximum capacity, with no planned or unplanned outages. While Non-Aliso storage inventories can be 90% full at the beginning of winter, they are unlikely to stay that high as the winter progresses and inventories are drawn down.

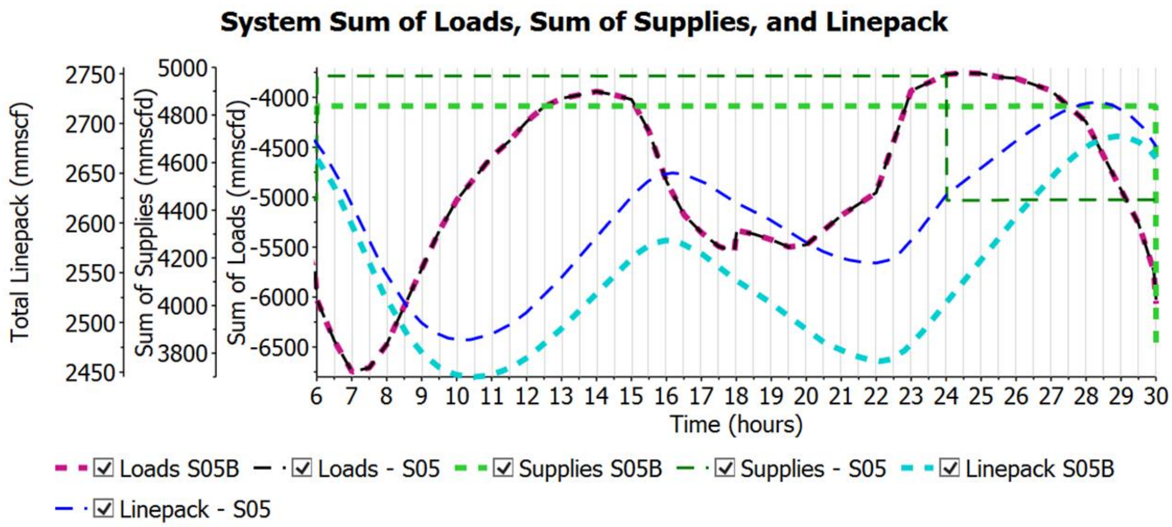
Results of Sensitivity Scenario 5b

S05b resulted in an Aliso Canyon withdrawal rate of 52 MMcfd for a 24-hour period, from 6:00 AM one day until 6:00 AM the next. This result would be possible only if the system operators knew in advance exactly what the demand would be. If the system operators knew in advance that a withdrawal rate of 52 MMcfd would meet the demand, they could withdraw at this rate, but in the absence of this knowledge, they would use a higher withdrawal rate to ensure that a potentially higher demand would be met. To avoid loss of linepack, the pipeline system would be run at a higher withdrawal rate for the first hours of the day to maintain a higher linepack, and then reduced later in the day. In S05, Aliso Canyon withdrawals were needed from 6:00 AM to midnight. If S05b used a similar withdrawal pattern (6:00 AM to midnight) over an 18-hour period, the withdrawal rate from Aliso Canyon withdrawal would be 71 MMcfd.

Figure 1 below shows the system sum of loads, sum of supplies, and linepack for the baseline simulation S05 and for the sensitivity S05b. Since the demand in the baseline and sensitivity is identical (winter 2030 1-in-10), the loads curves for both simulations are also identical. These are shown by the dash-dot black and dashed red lines. As for the linepack, it was restored by hour 30 in S05b as in the baseline simulation S05, as shown by the light and dark dotted blue lines, respectively. However, in S05b, more linepack was used during the evening ramp.

Figure 1 below shows the sum of supplies (interstate and storage withdrawals), in the dashed green lines. In the baseline simulation S05, shown by the dark green dashed line, supplies were constant up to hour 24, at which point storage withdrawals from Aliso Canyon ceased. In S05b, the storage withdrawals started lower and remained constant throughout the day, as shown within the light green dotted line. The total S05b supplies are lower than the total S05 supplies, because S05b used an Aliso Canyon withdrawal rate of 52 MMcfd, while S05 used an Aliso Canyon withdrawal rate of 520 MMcfd. Although the pipeline receipts were higher in S05b than S05, the higher pipeline receipts were more than offset by the lower withdrawal rate from Aliso Canyon, making the overall supply in S05b lower over the course of the gas day. A detailed figure of storage withdrawals by field follows.

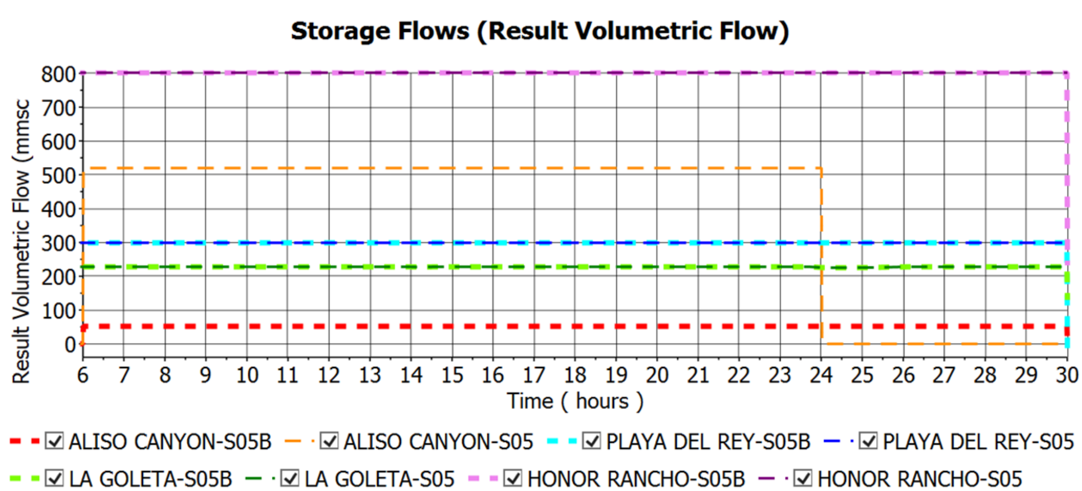
Figure 1: System Sum of Loads, Sum of Supplies, and Linepack for S05 and S05b



The storage withdrawals by field are shown in Figure 2. For the baseline S05 and sensitivity S05b, the withdrawals from the non-Aliso fields are identical and at their maximum capacity. The Aliso Canyon withdrawal rate of 520 MMcfd for the baseline is shown by the orange dot-dashed line. The Aliso Canyon withdrawal rate of 52 MMcfd for S05b is shown by the red dotted line.

No Maximum Operating Pressure (MOP) violations occurred. However, similar to the baseline simulation S05, several Minimum Operating Pressure (MinOP) violations occurred at nodes in the San Joaquin Valley, but the MinOP violations all resolved back to normal later in the simulation.

Figure 2: Storage Flows for S05 and S05b



In conclusion, as shown in Table 3, S05b results in an Aliso Canyon withdrawal rate of 52 MMcfd from 6:00 AM until 6:00 AM the next day in order to meet the Winter 2030 1-in-10 demand, with non-Aliso fields 90% full and a pipeline RPU of 95%. This result is based on an optimistic scenario of storage inventories for the non-Aliso fields, pipelines operating with no outages and "perfect foresight" accurate forecasting of the demand over the course of a 1-in-10 winter day. Additionally, this sensitivity does not take into account what would happen during a multiple cold day event, which was analyzed in the Feasibility Assessment of the Phase 2 Modeling Report.[10]

Table 3 Summary of Aliso Canyon Withdrawal Rates in Baseline S05 and Sensitivity S05b

Baseline or Sensitivity	Non-Aliso Inventory Level	Pipeline RPU	Aliso Canyon Withdrawal Rate (MMcfd)
Baseline S05	90%	86%	520
Sensitivity S05b	90%	95%	52

Scenario 9b: Winter 2030 1-in-35 with Lower Interstate Supplies and MLG

Energy Division staff were directed to perform a second sensitivity with 55% RPU on a 1-in-35 day, to assess whether core demand would be curtailed without the use of Aliso Canyon. Parties originally requested many sensitivities with RPUs lower than 85 percent. However, Energy Division decided to run the lowest requested RPU level of 55% because if a successful simulation is obtained, then levels above 55% would likely succeed.

Baseline Scenario: Scenario 9

S09 modeled a 1-in-35 peak demand day (also termed extreme peak) in winter 2030, with Minimum Local (electric) Generation (MLG) from gas-fired power plants. As mentioned in the original hydraulic modeling report,[11] curtailing all noncore customers, as allowed when modeling a 1-in-35-year reliability standard, is an extreme measure impacting all refineries, enhanced oil recovery, a portion of commercial and industrial customers, as well as all Southern California thermal electric generation power plants. Therefore, Energy Division staff investigated the reliability of the natural gas system under a MLG scenario, where thermal electric generation in the SoCalGas system was curtailed down to the minimum needed to meet the local reliability criteria according to FERC, rather than full curtailment. All other noncore demand is assumed to be curtailed. Production Cost Modeling has shown that an MLG scenario degrades the reliability of the electrical grid. Specifically, the MLG scenario results in an unacceptable frequency and duration of outages as well as unserved energy.[12]

Based on the 2018 California Gas Report, the core demand for this scenario is projected to be 3,038 MMcfd, while the wholesale demand is projected to be 127 MMcfd. In addition, Production Cost Modeling of the MLG scenario of winter 2030 showed a demand of 205 MMcfd from gas-fired power plants. Therefore, the total demand for Scenario 9 was 3,370 MMcfd.

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[10] Phase 2 Modeling Report issued March 8, 2021, Section V p. 68 369286397.PDF (ca.gov)
[11] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF
[12] Phase 2 Modeling Report issued March 8, 2021, i_1702002_phase2modelingreport_3-8-21_unredacted.pdf (ca.gov), p. 24

As for supplies, the interstate supplies resulting from 85% RPU and outages on L235 and L4000 were 3,115 MMcfd including 70 MMcfd from California Production. The maximum combined withdrawal rate available from the non-Aliso fields was assumed at 1,329 MMcfd based on 90% inventory levels.

Without Aliso Canyon, the total available supplies were more than 1 Bcf in excess of demand, which hinted towards a successful simulation. Indeed, a 24-hour simulation using Synergi Gas indicated that Scenario 9 will succeed without the use of withdrawals from Aliso Canyon. The peak combined non-Aliso fields withdrawal rate was ~470 MMcfd between the hours of 10 and 15 (10:00AM to 3:00PM).

Sensitivity Scenario: Scenario 9b

S09b keeps all the assumptions of S09, except the interstate supplies to the Northern and Southern Zones (i.e., North Needles, Topock, Kramer Junction, Blythe Ehrenberg, and Otay Mesa), which are lowered to reduce the Northern and Southern Zones capacities to 55% of their nominal capacity. Scenario 9b simulates a situation similar to — but not as severe as — that of Winter Storm Uri in 2021, when outages upstream of California prevented gas from being delivered. During that event, actual pipeline receipts and non-Aliso withdrawal capacity were significantly lower than assumed in S09b.[13] Table 4 shows that the demand in S09b (3,370 MMcfd) exceeds the pipeline receipts (2,375MMcfd). However, withdrawal rates available from the non-Aliso fields result in excess supplies of 334 MMcfd.

Table 4: Summary of Interstate Receipts, Withdrawal Capacity Available, and Demand for Scenario 9 Baseline and Sensitivity

	1-in-35 Peak Day Demand with MLG		
Receipt Points (MMcfd)	Baseline S09	Sensitivity S09b	Different
Wheeler Ridge	**765**	**765**	**No**
Wheeler Ridge RPU	**100%**	**100%**	**No**
Blythe Ehrenberg	980	665.5	Yes
Otay Mesa	50	0	Yes
Total Southern Zone	**1,030**	**665.5**	**Yes**
Southern Zone RPU	**85%**	**55%**	**Yes**
Kramer Junction	420	100	Yes
North Needles	430	335.5	Yes
South Needles	400	439	Yes
Total Northern Zone	**1,250**	**874.5**	**Yes**

[13] Between February 13 and 17, 2021, actual pipeline receipts ranged from 1,314 MMcfd to 1,807 MMcfd — up to 1,061 MMcfd lower than assumed in S09b. The non-Aliso storage fields entered Storm Uri on February 13 with 40.1 Bcf in inventory and 887 MMcfd of available withdrawal capacity, 447 MMcfd less than assumed in S09b. [Sempra - SoCalGas ENVOY]

Northern Zone RPU	**79%**[14]	**55%**	**Yes**
Total Pipeline Receipts[15]	3,115	2,375	Yes
Total Receipts RPU	**85.7%**	**65.3%**	**Yes**
Non-Aliso Max W/D	1,329	1,329	No
Honor Rancho Max W/D	802	802	No
La Goleta Max W/D	228	228	No
Playa Del Rey Max W/D	299	299	No
Aliso Max W/D	0	0	No
Storage Max W/D	**1,329**	**1,329**	**No**
Total Available Supplies	**4,444**	**3,704**	**Yes**
Total Demand	**3,370**	**3,370**	**No**

Results of Sensitivity Scenario 9b

Simulation of S09b in Synergi Gas was successful without using withdrawals from Aliso Canyon, although S09b required multiple attempts in order to support the Southern Zone and SDG&E area by flowing gas from the Northern Zone to the Southern Zone. A detailed description of the results follows.

Since Scenario 9b assumes low interstate supplies to the Northern and Southern Zones, Staff maintained the same outages on the Northern Zone as in the baseline Scenario 9 (L235 and L4000 west of Newberry operating at reduced pressure). In addition, staff reduced pressure on L2000 consistent with ongoing pressure reductions on the pipeline since 2015. This set of outages does not reduce the capacity of either zones below 55 percent of their nominal capacity, though it can restrict their operation.

Initial attempts to simulate scenario 9b barely restored the total system linepack. In addition, the initial attempts of the simulation failed to maintain the linepack in the Southern Zone while resulting in an increase in linepack in the Northern Zone. A detailed review of the demand configuration showed that the total daily demand in SDG&E and the Southern Zone upstream of SDG&E (Moreno compressor station) exceeded the supplies. Specifically, the interstate supplies at Blythe were set to 665.5 MMcfd, which represents 55% of the nominal capacity of the Southern Zone of 1,210 MMcfd. On the other hand, the total demand, which includes core, wholesale, and MLG on SDG&E and the Southern Zone upstream of Moreno is 757.5 MMcfd. Therefore, without additional supplies to the Southern Zone, a linepack loss of ~92 MMcf is expected (supplies subtracted from demand).

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[14] This is lower than 85% due to assumed outages on Lines 235 and 4000

[15] Includes California Production of 70MMcfd

To resolve the southern supply issue, different regulator stations had to be reconfigured starting at midnight before the morning peak, primarily by changing their downstream set pressure. This was done in order to allow the flow of natural gas from the Northern Zone, through the "crossovers" (two major regulator stations between the Northern and Southern Zone east of the LA basin) into the Southern Zone, then east on Lines 2000 and 2001 and then into Moreno compressor station through L2001. Because L2001 is operating at a higher pressure compared to L2000, it was used to supply SDG&E from the Northern Zone. Supplies from the Northern Zone still flowed east to L2000 but only to meet the demand between the LA basin and Moreno compressor.

Once the supply issue was resolved, the 24-hour transient simulation was successful using a few more operational actions as summarized below:

1) Increasing withdrawals from PDR (Play Del Ray) to 250 MMcfd throughout the whole 24-hour simulation.
2) Increasing withdrawals from HR (Honor Rancho), with a peak of 680 MMcfd between 6:00AM and midnight.
3) Increasing the flow from the Northern Zone to the Southern Zone between the hours of 6:00AM and 2:00PM and 6:00PM and 2:00AM to meet peak demand and prevent excessive loss of the Southern Zone linepack.
4) Decreasing the flow from the Northern Zone to the Southern Zone between the hours of 2:00PM and 6:00PM and 2:00AM and 6:00AM to avoid over-packing the Southern Zone and violating MAOP[16] limits.
5) Other changes to other regulators set pressures and compressor discharge pressures.

The following three figures illustrate the transient simulation of scenario 9b summarized above and compare it to the baseline simulation of S09. All three figures show transient simulation results from hour 6 (6:00AM) to hour 30 (6:00AM the next day).

Figure 3 shows the system sum of loads, sum of supplies, and linepack for the baseline simulation S09 and the sensitivity simulation S09b. Since the demand in the baseline and sensitivity is identical (winter 2030 extreme peak with MLG), the loads curves for both simulations are also identical. For the supplies (S09: Orange dash dot, S09b: Green dot), jumps in curves signify changes in withdrawal rates from storage (because interstate supplies and California production are held constant). For S09b, withdrawals were constant from hour 6 to hour 24, then withdrawals from HR were decreased to avoid MAOP violations in the Northern Zone. For S09, multiple adjustments to withdrawals occurred at hours 8, 10, and 15.[17] As for the total linepack, it was recovered in both S09 and S09b although S09b has a lower average linepack.

Figure 3: System Sum of Loads, Sum of Supplies, and Linepack for S09 and S09b

[16] MAOP is the Maximum Allowable Operating Pressure of the pipeline. Exceeding this value may result in pipeline rupture immediately.
[17] In S09, SoCalGas elected to use a constant pressure with variable supply from La Goleta, which resulted in continuously variable supplies instead of horizontal lines with jumps as illustrated by the orange dash dot curve.

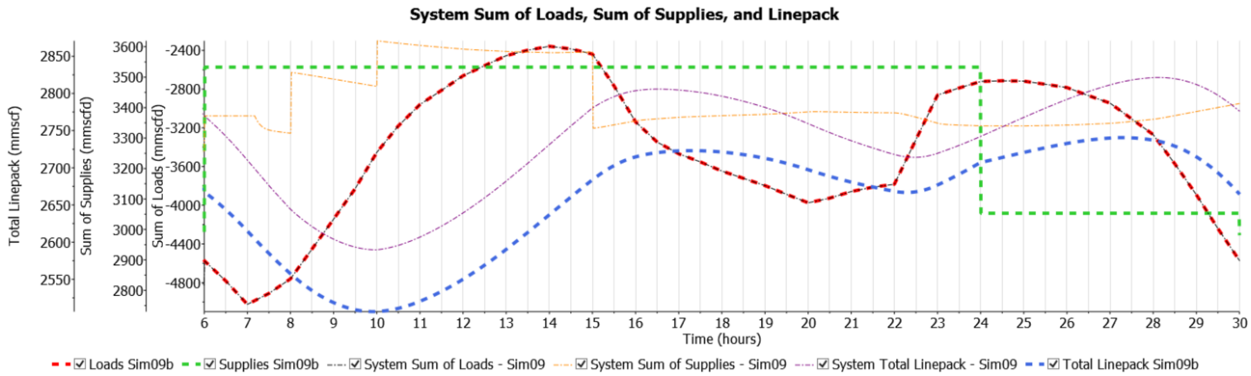


Figure 4 shows the storage withdrawal rate for S09b, which is constant for La Goleta and Playa Del Rey but is decreased for Honor Rancho at hour 24 to avoid MAOP violations in the Northern Zone. In addition, Figure 4 shows that not all the non-Aliso fields have been used at their maximum withdrawal capacity and that additional withdrawal capacity of 371 MMcfd from Honor Rancho and Playa Del Rey remains.

Figure 4: Storage Withdrawals for S09b

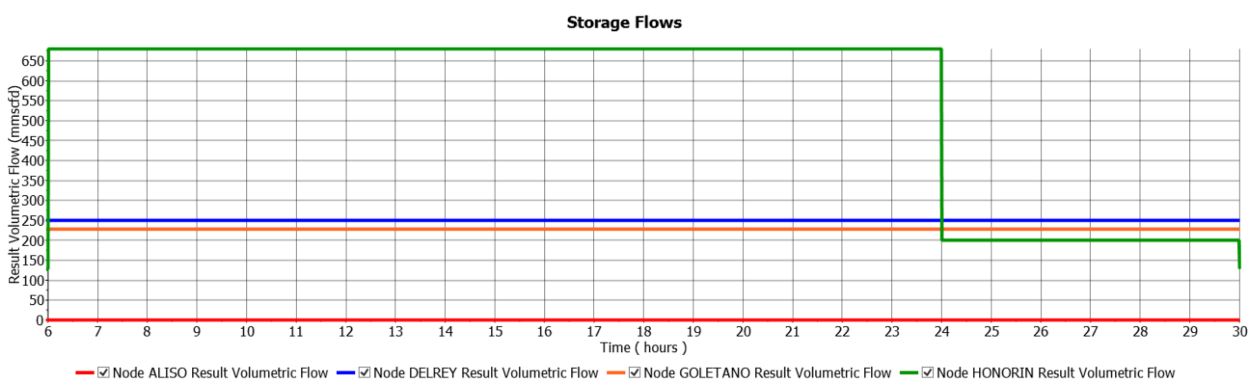
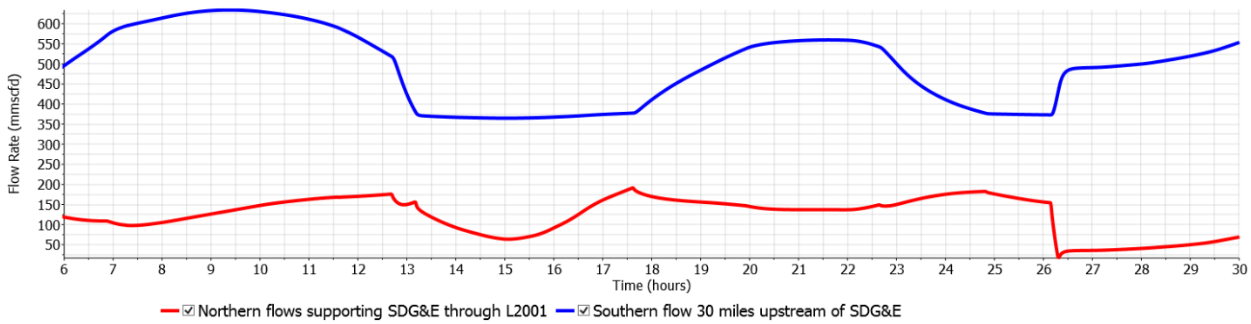


Figure 5 shows how much gas flow rate was needed from the Northern Zone to support the demand in the SDG&E area. The flow rate from the Northern Zone was highest during the hours from 6:00AM to 1:00PM, then from 5:30PM to 2:00AM, at which time the flow rate was reduced as evidenced by the sharp drop in the red curve. This drop is the result of an operational action that reduced the set pressure of one of the crossover regulators at 2:00AM. The average flow rate used to support SDG&E from the Northern Zone is approximately 124 MMcfd. The average flow rate through both crossover regulators is 338 MMcfd which supports the demand in SDG&E and meets the demand on lines 2000 and 2001 between the western city gates and the Moreno compressor station.

Figure 5: Chart Showing Supplies to SDG&E from the Southern and Northern Zones



While there could be many combinations of operational actions that could lead to a successful simulation, the simulation of scenario S09b was characterized by lower pressures in the basin. Both S09 and S09b maintained the operating pressures in LA above the MinOP, but S09b exhibited sharper drops during the morning peak. For example, during the morning peak, a node in the southern part of the LA basin reached a minimum pressure of 135% of the MinOP in S09b but reached a minimum pressure of 175% of the MinOP in S09. Lower pressures in Scenario S09b indicate higher risk of pressure dropping below MinOP levels

During talks with SoCalGas' transmission planning group, it was pointed out that the System Operator, acting in real time and without perfect foresight, would take actions in anticipation of further pressure drops rather than "waiting" for the operating pressures to reach or get close to the minimum operating pressures. In other words, the Operator will resort to (voluntary) curtailments or more storage withdrawals when the pressure drops to, for example, 150% of the minimum operating pressure with continuous loss of linepack. When modeling, this is not taken into account. Therefore, in the model it is possible to let the pressure drop as long as it is stays above the minimum operating pressure because the model can be re-run over and over until a successful simulation is obtained. This simply means that the modeler is more risk tolerant compared to the pipeline operator.

A back of the envelope calculation suggests that if the Wheeler Ridge Zone RPU drops to 55% (similar to the Northern and Southern Zones) or if the RPU of the Southern and Northern Zones drops further to 45%, withdrawals from Aliso Canyon will be needed to preserve Core reliability on a 1-in-35 day with MLG. In addition, the Southern Zone would require higher flow rates from the Northern Zone, which may not be easily available. Reducing the use of Aliso Canyon increases system risk by increasing the risk of pressures dropping below the minimum operating levels..

Additional Feasibility Assessment for 2027 & 2035

In Phase 1 of this investigation (OII-17-02-002), the scenarios framework outlined a feasibility assessment but only for calendar year 2020 or the short-term. In contrast, the reliability assessment was outlined for years 2020, 2025, and 2030. Comments provided by some stakeholders indicated that the feasibility assessment should be conducted before the reliability assessment in order to determine the correct non-Aliso storage inventory levels during a peak day reliability assessment. However, LANL (Los Alamos National Lab, the CPUC's contractor during that period), proposed using 100% inventory levels at the non-Aliso fields. Based on stakeholders' comments, Energy Division Staff lowered the inventory assumption of the non-Aliso fields to 90% for all three time horizons.

Subsequently, during Phase 2 and after concluding the reliability assessment, Energy Division developed its own methodology to conduct the feasibility assessment. The feasibility assessment showed that consistently maintaining a 90% inventory level at the non-Aliso fields throughout the winter is not possible (not feasible) without Aliso Canyon, and much lower inventory levels will occur, especially during cold years. Shutting down or minimizing the use of Aliso Canyon will result in more use of the non-Aliso storage fields to meet daily demand rather than maintaining a 90% inventory level, which did not occur historically.

In Phase 3,[18] FTI consulting (CPUC's contractor during the 2020-2021 period) conducted their own feasibility assessment of the monthly usage of the non-Aliso fields for winters 2027 and 2035. FTI's analysis showed that if Aliso Canyon is retired in winter 2027 or 2035, the minimum level of the non-Aliso fields by the end of a cold winter season would be 54% and 82% respectively,[19] well below the 90% assumption used in Phase 2 despite lower gas demand forecasts in 2027 and 2035.

Simple extrapolation of these numbers to a cold winter 2020 shows that the minimum levels of the non-Aliso fields in a cold 2020 winter should be around 29.5% (not 100% or 90%), which aligns roughly with Energy Division Staff findings in the Phase 2 feasibility assessment. In that assessment, Staff noted that 10%-30% is more likely by the end of a cold 2020 winter if Aliso Canyon use is to be minimized and used as an asset of last resort.

In order to corroborate staff findings in Phase 2 regarding the infeasibility of the 90% non-Aliso inventory level and to validate FTI findings in Phase 3 regarding the seasonal storage needs and the resulting shortfall if Aliso Canyon is retired, Energy Division Staff conducted a feasibility assessment for 2027 and 2035 using the methodology outlined in the second report[20] with a few modifications that will be described later.

Recap on Feasibility Assessment Methodology

The methodology developed by Energy Division Staff attempts a mass balance on each day of the study year rather than the conventional monthly mass balance approach and mass balance sheets. The model inputs are the forecasted daily demand using random draws from a known distribution, the assumed pipeline capacity, the maximum withdrawal and injection curves, and the working gas capacity of the storage fields. The model determines whether there is an excess or deficit in the gas supply, then injects or withdraws gas accordingly, while adhering to injection and withdrawal limits. If there is not sufficient supply to meet the demand (mass imbalance) on a given day, the model flags that day as an imbalance day or an emergency flow order (EFO) day. EFOs are used as a proxy

[18] Merged with Phase 2

[19] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-presentation-workshop-3-revised.pdf

[20] Final Phase 2 Modeling Report linked here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF

for an insufficient or excess supply (imbalance). An EFO due to a supply deficit could also be interpreted as a curtailment day or a curtailment event.[21]

The model uses average monthly demand obtained from the California Gas Report, and historical variability to build a distribution of daily demand around that monthly average. Three different variability scenarios have been tested in Phase 2 (lower 95% confidence interval (CI),[22] predicted value, and upper 95% CI), and it was concluded that using the upper 95% CI scenario provides a better match with a recent historical cold year.[23] After building a distribution for each month, the model attempts a daily mass balance and tracks the inventory levels and imbalance days for the whole calendar year. This calculation is repeated 50 to 100 times in order to calculate correct statistics for the inventory levels and number of curtailment days in a given calendar year. Further detailed information on the methodology is available in the final Phase 2 Modeling Report.[24]

Feasibility Assessment for 2027 and 2035 and Validation of Seasonal Storage Needs

To perform the feasibility assessment for 2027 and 2035 using Phase 3 assumptions, staff made one major change to the input data to align with the input data that was used in Phase 3, which is using the demand forecasts from the 2020 CGR (California Gas Report), instead of the 2018 CGR that was used in Phase 2. CGR 2020 includes climate warming assumptions which further reduces the average gas demand forecasts. This immediately translates to lower *seasonal* need of underground natural gas storage. Table 5 summarizes the number of expected days at a given demand range for the years 2020, 2027, and 2035 using average monthly values from the CGR, the high variability scenario (upper 95% CI), and Gamma distributions.

Table 5 Expected Number of Days by Demand Range

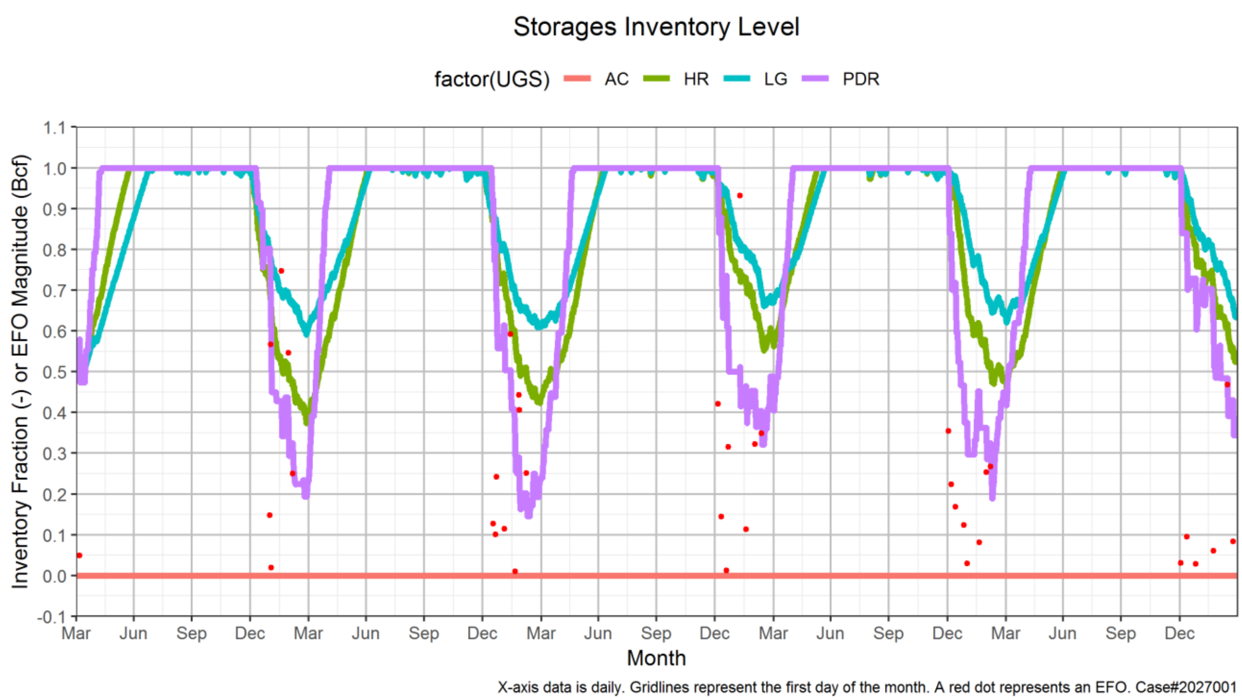
	Cold 2020 CGR 2018	**Cold 2027 CGR 2020**	**Cold 2035 CGR 2020**
	Expected Number of Days		
Demand Range (Bcfd)			
4.5 and higher	4.6	1.08	0.29
4.0 to 4.5	10.97	4.08	1.75
3.5 to 4.0	29.58	14.38	8.17
0.0 to 3.5	319.84	345.46	354.78

21 Similar to Loss of Load Expectation in Production Cost Modeling
22 Confidence Interval (i.e., confidence level in the predicted value)
23 The Feasibility Assessment model with high variability assumes 15.5 days with demand higher than 4 Bcfd. Year 2013 had 12 days with demand higher than 4 Bcfd and a total of 1216 HDD. A 1-in-10 cold year is predicted to have 1499 HDD (California Gas Report 2018). This prediction fell to 1434 HDD in California Gas Report 2020.
24 Final Phase 2 Modeling Report linked here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF

To further match Phase 3 assumptions, staff used 2,756 MMscf of daily available supplies, 100% well availability[25] throughout the year, 0% inventory level allowed at Aliso Canyon, 100% inventory level allowed at the non-Aliso storage fields, and 0% minimum inventory level allowed at the non-Aliso storage fields.

Figure 6 and Figure 7 show the model results for a cold 2027 year and a cold 2035 year. The x-axis represents the day of the year (showing only quarters for clarity). The plot is for five cycles or five repetitions of the study year albeit the actual model simulates the study year 100 times.[26] The y-axis represents the fraction of the inventory that is filled, where zero represents an empty storage field and 1 represents a full storage field. A red dot means an imbalance day or a curtailment day with its curtailment or imbalance volume shown on the y-axis in Bcf. One can immediately notice that Aliso Canyon is not being used in these scenarios (0% inventory throughout the study year), while the non-Aliso fields are being filled to 100% then used throughout the winter, dropping to different minimum levels. There are also a few curtailment days throughout the winter.

Figure 6: Inventory Tracking of all four storage fields during a cold 2027 year



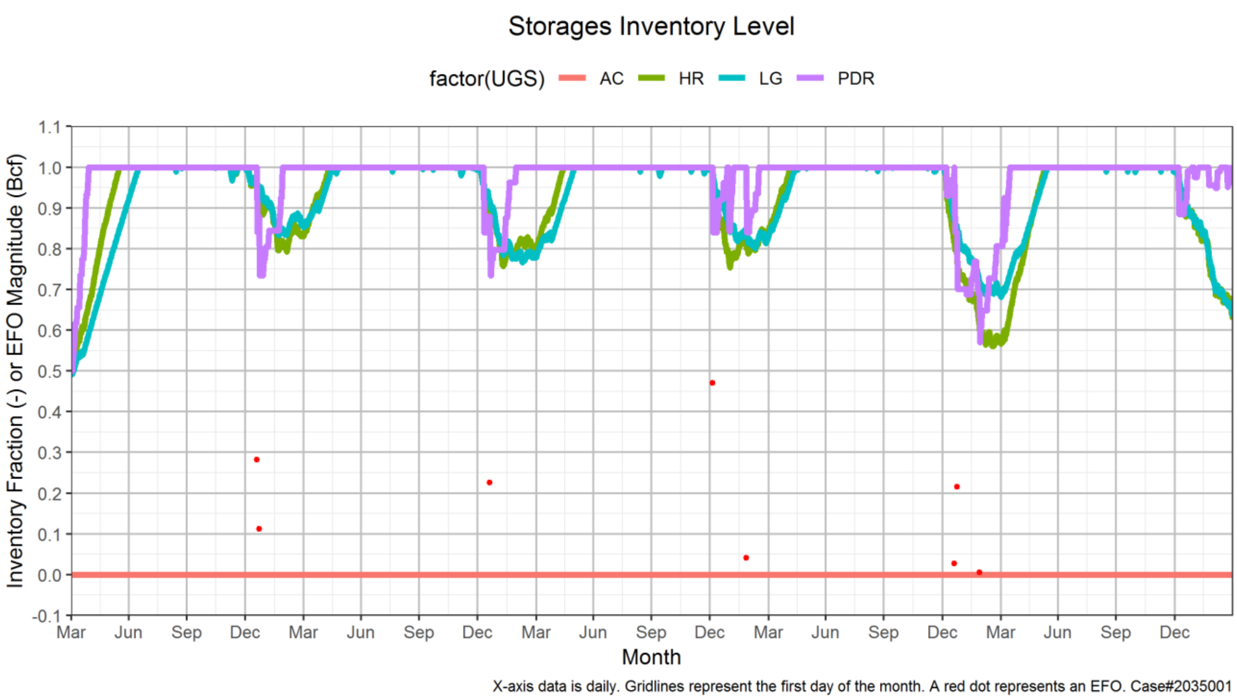
The average minimum inventory level of each storage field is obtained by averaging its minimum inventory level over the 100 repetitions of the study year. Once the average minimum level is obtained, the average range (maximum inventory level – minimum inventory level) can be calculated. Multiplying the range by the nominal capacity of the storage field yields the seasonal storage needed

[25] Based on November 2019 data request for maximum withdrawal and injection curves. Year-round well availability of 100% is an optimistic assumption because storage wells are subject to mandatory periodic safety inspections during which they must be taken out of service.

[26] The model actually simulates the study year 101 times, but the data of the first year is ignored to remove the effect of the assumed initial condition on the inventory levels (50%).

from that storage field. Summation over the three fields results is the total inventory needed throughout the winter season. For 2027, the seasonal storage needs from PDR, HR, and LG combined was 26.87 Bcf compared to 21.2 Bcf obtained by FTI. For 2035, the seasonal storage needs from PDR, HR, and LG combined was 14.18 Bcf compared to 7 Bcf obtained by FTI.[27] The storage needs from Energy Division Staff is higher than FTI's results owing to the inclusion of variability around the gas demand forecasts, which results in variability around the total yearly gas demand.[28] Staff is also using a more conservative approach in calculating the minimum inventory level of each field.[29] As for the average number of EFOs or curtailment days without Aliso Canyon, there were nine curtailment days per year for 2027 and about two curtailment days per year for 2035.

Figure 7: Inventory Tracking of all four storage fields during a cold 2035 year



Staff concludes that the seasonal needs from the non-Aliso storage derived by FTI using monthly balance sheets are reasonable but are likely underestimated by 5 to 7 Bcf due to the uncertainty in the gas demand forecasts not accounted for in the monthly balance sheets approach.

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27 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/fti-monthly-analysis-workpaper.xlsx

28 For example, the yearly demand for a cold 2027 year is forecasted at 875 Bcf in CGR 2020 but owing to the stochastic modeling in the daily balance model, the actual demand simulated ranges from 850 Bcf to 890 Bcf.

29 Energy Division staff is calculating the minimum level of each storage field individually then adding these levels, rather than calculating the total minimum inventory.

Full Parametric Study for 2027 and 2035 and Validation of Shortfall

To further evaluate the need for Aliso Canyon in 2027 and 2035 and the natural gas shortfall calculated by FTI, staff conducted a parametric study on both Phase 3 study years using the daily balance methodology. In other words, instead of running only one scenario or one set of assumptions on a study year as described in the previous section, different input parameters are varied within a certain range in order to determine if Aliso Canyon is needed or not and if needed, what would be the minimum required inventory level. The daily mass balance methodology attempts only a mass balance on the natural gas system without obeying energy conservation laws, unlike Synergi Gas, where both mass and energy conservation laws are obeyed. In other words, the daily mass balance methodology is a lower order modeling that requires less computational resources but nevertheless offers valuable insights.

The parametric space has four independent variables or parameters. These are pipeline capacity, utilization factor or well availability, the minimum inventory level at the non-Aliso fields, and the maximum allowed inventory in Aliso Canyon. The pipeline capacity is the assumed capacity or availability of interstate supplies, while the well utilization factor or availability represents the percentage of wells that are in-service and available for withdrawal and injection. For example, an 80% utilization factor means that, on average, 8 out of each 10 wells are in-service, while the other two are out-of-service. This parameter was primarily introduced to account for unplanned well outages and the uncertainty in current and future regulations from CalGEM,[30] which would in turn affect the duration of planned outages of wells. A detailed description of these parameters and how they have been used can be found in the final Phase 2 Modeling Report.[31]

Table 6: Table detailing the parametric space used in Phase 2 for 2020 and the parametric space used for 2027 and 2035

Parameter	Range in 2020	Range in 2027 & 2035	Parameter Increment
Pipeline Capacity (MMscfd)	2,700-3,100	2,700-3,500	100[32]
Well Availability (%)	60%-100%	60%-100%	20%[33]
Non-Aliso minimum inventory (%)	10%-70%	10%-70%	20%
Aliso maximum allowed inventory (%)	40%-100%	0%-100%	20% and 5%[34]
Number of repetitions (#)	50	101	-
Number of Scenarios per study year (#)	240	972	-

Table 6 shows a comparison between the parametric space used in the previous Energy Division report for Phase 2 and the expanded parametric space used to determine the minimum inventory of

30 Geologic Energy Management Division. https://www.conservation.ca.gov/calgem.
31 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF (Page 74)
32 i.e., capacities included in the study are 2,700, 2,800, 2,900, 3,000, 3,100, 3,200, 3,300, 3,400, and 3,500 MMcfd.
33 i.e., wells availability included in the study are 60%, 80%, and 100%.
34 Levels included are 0%, 5%, 15%, 20%, 40%, 60%, 80% and 100% for a total of 9 inventory levels.

Aliso Canyon for the time horizons used in Phase 3 (i.e., 2027 and 2035). In the parametric study for 2027 and 2035, staff increased the upper bound of the pipeline capacity from 3,100 to 3,500 MMcfd. In addition, with no reliability assessments available to determine the minimum inventory level in Aliso Canyon for 2027 and 2035,[35] staff decreased the lower bound of the Aliso Canyon maximum allowed inventory level from 40% to 0%, where 0% indicates no use of Aliso Canyon. Noteworthy is that even when Aliso Canyon inventory level is low, its nominal withdrawal capacity is higher relative to the other three fields when their inventories are low, hence the addition of 5%, 10% and 15% Aliso maximum allowed inventory in the parametric study for 2027 and 2035. The resulting parametric space simulates 972 scenarios per study year. For a given pipeline capacity and well utilization factor, there are 36 scenarios resulting from nine inventory levels considered at Aliso Canyon and four inventory levels considered for the non-Aliso storage fields.

To deem a scenario feasible, Energy Division Staff used the same criteria 1 outlined in the previous report.[36] Criteria 1 deemed a scenario feasible if no EFOs were triggered (i.e., no curtailments at all), or if all the EFOs that were triggered occurred on days when demand exceeded the 1-in-10 peak day demand.[37] Among all the feasible scenarios for a given pipeline capacity and well utilization factor (36 or fewer scenarios), the scenario resulting in the minimum inventory level at Aliso Canyon is selected. Table 7 summarizes the minimum inventory level in Aliso Canyon required to obtain a feasible solution for study years 2027 and 2035. The minimum inventory level is a function of the available pipeline capacity (2,700-3,500MMscfd) and well utilization factor or availability (60%, 80%, and 100%) and is shown as a percentage from the nominal capacity of 68.6 Bcf.[38]

For 2027, two scenarios have failed completely, which represent the worst-case scenarios (pipeline capacity lower or equal to 2,800 MMcfd with only 60% well availability). In both cases, the number of curtailment days was higher than one curtailment day per year even with the full use of Aliso Canyon (100% or 68.6Bcf) and no mitigations. Five other scenarios suggest that 100% of Aliso Canyon inventory is needed. However, the inventory level for these scenarios results in fewer than one curtailment day per year. Only one scenario in 2027 suggests that Aliso Canyon may not be needed, which is when the pipeline capacity is 3,500 MMcfd and all wells are available.

For 2035, none of the scenarios failed with the full use of Aliso Canyon. Five scenarios suggest that full use of Aliso Canyon is needed. However, these five scenarios result in fewer than one curtailment day per year. Twenty scenarios suggest different inventory levels for Aliso Canyon ranging from 5% to 60%. Only two scenarios in 2035 suggests that Aliso Canyon may not be needed, which is when the pipeline capacity is equal to or higher than 3,400 MMcfd and all wells are available.

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[35] Staff could use the shortfall calculation calculated by FTI consulting to calculate a minimum Aliso Canyon inventory level, but elected not to in order to maintain the independency of this report.
[36] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286397.PDF (Page 80).
[37] The 1-in-10 peak day demand is extrapolated from the 2020 California Gas Report. The 1-in-10 peak day demand for 2027 and 2035 is 4,910MMcfd and 4,815MMcfd respectively.
[38] This is the capacity deemed safe by the California Geologic Energy Management Division

Table 7: Minimum required Aliso Canyon inventory level for 2027 and 2035 (Percent of Nominal 68.6Bcf)

Study Year		2027			2035		
Wells Availability		60%	80%	100%	60%	80%	100%
Pipeline Capacity (MMCFD)	2,700	Fails	100%[39]	100%	100%[39]	100%[39]	40%
	2,800	Fails	100%[39]	40%	100%[39]	60%	20%
	2,900	100%[39]	60%	40%	100%[39]	40%	5%
	3,000	100%[39]	60%	15%	100%[39]	40%	5%
	3,100	100%[39]	40%	10%	60%	20%	5%
	3,200	60%	20%	5%	60%	5%	5%
	3,300	60%	10%	5%	40%	5%	5%
	3,400	40%	5%	5%	40%	5%	0%
	3,500	40%	5%	0%	10%	5%	0%

To calculate the shortfall if Aliso Canyon were to be eliminated, CPUC's contractor assumed 3,115 MMcfd of available capacity and 100% well availability. In Table 7, the scenario with assumptions closest to the contractor's assumptions is for a pipeline capacity of 3,100 MMcfd and a UF of 100 percent (i.e., the fifth row). The feasible scenario resulting from these assumptions is shaded in orange, which is 10% of Aliso Canyon inventory needed in 2027 and 5% needed in 2035. This translates to about 586-672 MMcfd and 500-586 MMcfd of withdrawal capacity needed from Aliso Canyon in 2027 and 2035, respectively, compared to the 395 MMcfd and 323 MMcfd for 2027 and 2035 calculated by CPUC's contractor.[40] Based on the daily mass balance methodology, the withdrawal rate required from Aliso Canyon in 2027 and 2035 is higher than the Contractor's shortfall by 177-277 MMcfd. The difference could be interpreted by reviewing Table 5 where the yearly distribution of demand is summarized. In Table 5, the expected number of days when the demand is higher than 4 Bcfd is about five days and two days in 2027 and 2035, respectively. This could explain the higher withdrawal capacity (and hence a higher shortfall) needed from Aliso Canyon if these high-demand days happen to occur by the end of the winter season. In other words, the daily balance methodology takes into account multiple cold days, rather than using only one peak day to calculate the shortfall. While the daily mass balance methodology does not obey energy

[39] EFO or curtailment days occurred but with a frequency lower than one day/year. 80% is also feasible but with a higher number of curtailment days per year. In some cases, 60% may also be feasible.

[40] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/aliso-canyon-2027-and-2035-shortfall-memo-revised.pdf

conservation laws, it offers the benefit of statistically modeling multiple cold days throughout the winter.

The daily mass balance methodology relies on many inputs, and one critical input is the underlying statistical distribution that is used to forecast daily demand throughout the study year. This distribution uses mean monthly gas demand values obtained from the California Gas Report and daily variability around that mean, which is derived based on historical daily demand data. This variability can be predicted using different confidence levels, where a higher confidence level results in more variability and hence more days with higher demand. For example, increasing the confidence interval in predicting the daily demand variability in 2027 from 95% to 99% increases the number of days when demand is higher than 4 Bcfd from 5.16 to 6.59 days, which in turn would require more frequent use of withdrawals from underground storage, but not necessarily higher seasonal needs. The variability included in this model is a proxy for weather variability, where the degree of weather variability in the future is uncertain due to climate changes. Another source of variability is the electric generation dispatch patterns, which are dependent on renewable penetration rates, their capacity factors, and local and temporal variations. The daily mass balance model would benefit the most if daily gas demand could be accurately forecasted a year ahead or at least the expected number of cold and extremely cold days with a certain demand range could be forecasted accurately.

The results of the feasibility assessment for 2027 and 2035 performed by Energy Division Staff are summarized and compared with FTI's findings in Table 8 below.

Table 8: Feasibility Assessment Results Summary and Comparison with CPUC's contractor

Year	2027	2035	2027	2035
Parameter	**FTI**		**Energy Division Staff**	
Non-Aliso Fields Minimum Inventory Level (Percent)	54%	82%	46%	71%
Gas Shortfall (MMcfd)	395	323	586-672	500-586

Energy Division staff agrees with FTI's findings regarding the non-Aliso fields minimum storage level by the end of Winter 2027 and Winter 2035 though Staff finds that the underground storage needs could be higher due to demand forecasting errors and unforeseen limitations on the injection capacity during the winter season. Staff also agrees with FTI's findings regarding the gas shortfall in 2027 and 2035 should Aliso Canyon be retired. However, FTI's shortfall calculation relies on simulating only one peak demand day and depending on which portfolio is selected to replace Aliso Canyon, this can become a crucial oversimplification. For example, if battery storage is selected, then more studies are needed to show that battery storage can sustain cold events longer than one day. Similarly, if noncore gas demand response is selected, then more studies are needed to show that these noncore customers can reduce their gas demand for longer than one day. Another source of discrepancy between FTI's shortfall calculation and Staff's daily balance methodology stems from the discrete nature of the parametric study performed by Staff. In particular, Staff considered the low levels of Aliso Canyon inventory of zero, five, 15, and 20 percent, but no other levels in between (e.g., 17.5 percent). For example, year 2027 requires 10 percent of inventory at Aliso Canyon, but this inventory level could be lower if other levels were considered (e.g., 9 or 8 percent), but not lower than 5 percent, which is the next lower inventory level considered in the parametric study. Adding additional Aliso Canyon inventory levels to the study would increase the computational cost exponentially and may provide a false sense of precision.

(END OF ATTACHMENT A)