

Docket No.: A.26-01-009
Exhibit No.: SC-20
ALJ: Jamie Ormond
Witness: Tyson Siegele

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Southern California Gas
Company (U904G) in Compliance with
Ordering Paragraph 6 of Decision 24-12-076.

Application 26-01-009
(Filed January 15, 2026)

**PREPARED REBUTTAL TESTIMONY OF TYSON SIEGELE
ON BEHALF OF SIERRA CLUB**

OCTOBER 8, 2026

TABLE OF CONTENTS

1. Introduction.....	1
2. Forward and current gas prices are low and support reducing Aliso Canyon inventory.....	2
2.1. Forward prices overstated actual winter prices and are now the lowest in five years.....	3
2.2. Current gas prices are lower than the historical average.	7
2.3. SoCalGas storage has operated at least 10 Bcf below system capacity since Aliso Canyon’s capacity increased to 68.6 Bcf.	10
2.4. The Commission can order a reduction while preserving just and reasonable gas rates.	11
3. SoCalGas’s proposed modeling assumptions each shift the reliability threshold well beyond the Commission’s 1-in-10 Peak Day standard.....	12
3.1. SoCalGas exaggerates demand by stacking unlikely events to yield extremely unlikely scenarios far less likely than a 1 day -in-10 years event.	12
3.2. It is reasonable to assume 97% RPU to model system reliability because it reflects historical reality.....	16
3.3. The Biennial Assessment Process should consider whether SoCalGas’s nominal system capacity has decreased.	18
4. The 2025 Biennial Assessment and multiple recent STUDIES ALL support a 39.6 Bcf inventory.	20
4.1. The hydraulic analysis does not conflict with a 29 Bcf reduction.....	20
4.2. Reliability could have been maintained throughout Winter Storm Fern without Aliso inventory.....	23
4.3. Every independent study finds that Aliso inventory can be reduced.....	23
5. Data shows unscheduled storage withdrawal capacity throughout winters with high gas prices, demonstrating that neither the Aliso Canyon Withdrawal Protocol nor reduced Aliso Canyon inventory contributed to higher gas prices.	24
6. Storage withdrawals follow demand rather than price.	27
6.1. SoCalGas answers an 18-winter statistical analysis with one 14-day example that fails to control for demand variables.....	27
6.2. During Winter Storm Fern, pipeline capacity exceeded gas sendout every day.	29

6.3. SoCalGas’s analysis of withdrawals on highest-priced days does not hold up under scrutiny.	30
6.4. SoCalGas has not quantified or demonstrated with concrete examples that it operates Aliso Canyon to mitigate prices.	30
6.5. End-of-winter inventory demonstrates that Aliso Canyon inventory can be reduced.	31
7. The Commission can lower Aliso inventory by 29 Bcf without reducing firm UBS winter withdrawal capacity.	31
7.1. SoCalGas has acknowledged that the UBS program is unnecessary.....	32
7.2. UBS transaction volumes do not show that inventory is needed.....	33
8. SoCalGas proposed No Specific and actionable changes to the Biennial Assessment Economic Analysis.	34
9. The 2026 California Gas Report contains an erroneous 1-in-10 peak day gas demand FORECAST.	35
10. Comparing Winter Peak Electric Demand to Renewables, Storage, and Electric Imports Shows that The Full 68.6 BCF of Aliso Canyon Inventory is Unnecessary.....	38
11. Conclusion	40

LIST OF FIGURES

Figure 1: Winter Season (Dec–Feb) Average Daily SoCal Citygate Prices.....	8
Figure 2: SoCalGas Withdrawal Data in SoCalGas Winter Technical Assessment Scenarios vs. 2025 Biennial Assessment Minimum Required Withdrawal Rate.....	22
Figure 3: Daily prices during Winter Storm Fern (SoCal Citygate, Henry Hub, SoCal Border–Ehrenberg, SoCal Border–Needles, PG&E Citygate, Waha).....	28

LIST OF TABLES

Table 1: SoCal Citygate Prices for Winter Seasons (Dec–Feb) (\$/MMBtu).....	3
Table 2: Biennial Assessment Process price tests applied to Winter 2026-27	6
Table 3: SoCalGas All-Facility Storage: November Maximum Inventory Compared to SoCalGas’s Nominal Capacity, 2023–2025	11
Table 4: Event Probability for IS and SoCalGas Assertions	14
Table 5: Aliso Canyon Withdrawal Capacity at Selected Inventory Levels	21
Table 6: Aliso Canyon inventory during Winter Storm Fern (Bcf).....	23
Table 7: Days with unscheduled withdrawal capacity (customer basis, Nov–Mar).....	25
Table 8: Winter 2022-23, storage capacity scheduled and average daily gas price	26

Table 9: Receipt capacity vs. sendout, Jan 18–31, 2026 (MDth/d)	29
Table 10: CAISO, Key Statistics for December 2020-2025	39

1. INTRODUCTION

My rebuttal testimony responds to the testimonies of Southern California Gas Company (“SoCalGas”), Indicated Shippers (“IS”), and the Public Advocates Office (“Cal Advocates”). Those parties each ask the Commission to keep the Aliso Canyon maximum inventory at 68.6 billion cubic feet (“Bcf”). Nothing in their testimonies changes my recommendation that the Commission should accept the Biennial Assessment’s recommendation to reduce Aliso Canyon inventory and further reduce the maximum inventory at Aliso Canyon by a total of 29 Bcf, which results in a new maximum inventory of 39.6 Bcf.

The following is an overview of my findings:

- Historically low gas price data supports an inventory reduction. Forward prices for Winter 2026-27 are the lowest in five years, both the Commission’s price tests are well below the 50% threshold, and SoCalGas has left at least 10 Bcf of its storage capacity unfilled in each of the last three years.
- SoCalGas and IS reach their reliability concerns by stacking unlikely conditions on top of a 1-in-10 peak day, which describes events far rarer than the Commission’s standard requires SoCalGas to plan for.
- The 2025 Biennial Assessment and every independent study support a lower inventory.
- The 2025 Biennial Assessment’s gas balance analysis and hydraulic analysis show that the Commission can lower Aliso Canyon inventory.
- Withdrawal capacity went unscheduled on nearly every day before the Aliso Canyon Withdrawal Protocol was removed, so neither the protocol nor the lower inventory limit explains high gas prices prior to the 2023-2024 winter season.
- Storage withdrawals follow demand more than price, and SoCalGas has not identified specific measures nor quantified any price mitigation from Aliso Canyon.
- A 29 Bcf reduction to Aliso Canyon maximum inventory would not reduce the Unbundled Storage Program’s (“UBS”) firm winter withdrawal capacity.
- SoCalGas’s proposed overhaul of the Biennial Assessment Process’s economic analysis is vague and conflicts with D.24-12-076.
- SoCalGas’s 2026 California Gas Report’s 1-in-10 peak day demand forecast contains errors and omissions that make it unreliable.

1 **2. FORWARD AND CURRENT GAS PRICES ARE LOW AND SUPPORT REDUCING**
2 **ALISO CANYON INVENTORY.**

3 The 2025 Biennial Assessment recommends that the Commission reduce the storage
4 inventory at Aliso Canyon by the maximum amount that D.24-12-076 allows it to recommend.
5 The Commission has determined that it will make decisions regarding whether to lower the Aliso
6 Canyon maximum inventory level based on two factors: whether a lower inventory level
7 supports (1) reliable energy service and (2) just and reasonable rates (i.e. commodity gas
8 prices).¹ This section addresses the second factor, gas prices.

9 The 2025 Biennial Assessment recommended that the Commission reduce the Aliso
10 storage inventory by the maximum amount it could recommend: 10 Bcf. Then, the 2025
11 Biennial Assessment goes on to provide the following caveat to its recommendation:

12 However, given current forecasts for higher gas commodity prices in winter
13 2026-27, the CPUC *may* wish to consider a smaller incremental reduction.²

14 SoCalGas, Indicated Shippers (“IS”) and Cal Advocates each assert that this gas-price-
15 based caution is reason to keep gas inventory at 68.6 Bcf,³ and that the economic analysis is
16 insufficient to forecast gas prices.⁴ Below, in my detailed response to those concerns, I show that
17 (1) while no economic analysis accurately forecasts gas prices, gas prices are low and falling on
18 the measures Attachment A uses, (2) gas prices have remained at historically low levels for the
19 last three winter seasons; and (3) gas prices have remained low for the last 3 winter seasons at
20 actual inventory levels that align with the 2025 Biennial Assessment’s 10 Bcf inventory
21 reduction level.

¹ A.26-01-009, Assigned Commissioner’s Scoping Memo and Ruling, at 4 (July 8, 2026).

² California Public Utilities Commission (“CPUC”) Energy Division, Energy Resource Modeling, *2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076*, at 29 (Oct. 1, 2025), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/2025_aliso_canyon_biennial_assessment.pdf [hereinafter “2025 Biennial Assessment”] (emphasis added).

³ Prepared Direct Testimony of M. Michelle Dandridge, at MMD-6, footnote 28 (Jan. 15, 2026) [hereinafter “Dandridge Direct Testimony”] (Staff’s own caution that a smaller incremental or no reduction may be appropriate given the forward price outlook).

⁴ *Id.* at MMD-4; Direct Testimony of Brian C. Collins, at 15-16 (Aug. 20, 2026) [hereinafter “Collins Direct Testimony”]; Prepared Rebuttal Testimony of Stacy C. Chang, at SCC-15 (Sept. 17, 2026) [hereinafter “Chang Rebuttal Testimony”].

For these reasons and other reasons, the Commission should be comfortable lowering the Aliso Canyon maximum gas inventory by my recommendation of 29 Bcf.

2.1. Forward prices overstated actual winter prices and are now the lowest in five years.

In this section, I expand the gas price assessment and show that the most recent gas prices at SoCal Citygate are low and falling on the measures prescribed in D.24-12-076, Attachment A (“Biennial Assessment Process”) uses.

Forward SoCal Citygate prices regularly exceed winter actual prices due to the time-based risk premium that traders apply to forward pricing. The following table shows the ~22-month forward price for the last 5 years, the ~10-month forward price for the last 5 years, the actual daily average price for the last 4 years, and the difference between the daily average price and the forward price.

Table 1: SoCal Citygate Prices for Winter Seasons (Dec–Feb) (\$/MMBtu)⁵

Winter	~22-month forward	~10-month forward (Att. A window)	Actual Average of Daily Prices Dec–Feb	10-month forward vs actual
2022-23	4.72	9.23	18.77	–51%
2023-24	6.73	9.16	3.69	+148%
2024-25	8.46	7.33	4.07	+80%
2025-26	7.79	6.85	3.45	+99%
2026-27	7.35	5.55	—	—

First, typical winter seasons like the 2024-25 winter season and the 2025-2026 winter season, show that forward prices are higher than the resulting prices because they include the time-based risk premium, financing costs, and the physical carrying costs such as storage fees.⁶

⁵ Source data: NGI forward data using the publication windows specified in D24-12-076 Attachment A, and 2025 Biennial Assessment (22-month forward); The 2025 Biennial Assessment used trade dates, which gives \$7.37/\$6.86; the difference is 1–2 cents.

⁶ The normal state of the forward prices is contango in which near-term forward prices are lower than prices further out. Occasionally near-term forward prices are higher than those further out due to a near-term supply shortfall (backwardation). Ultimately forward prices converge with daily prices, the closer the settlement date is to the forward date.

1 Thus traders buy and sell forwards at prices higher than they forecast as the daily price of the
2 settlement date.

3 Second, winters like 2022-2023 show that regardless of the time-based risk premium,
4 forward prices tend to converge on the actual price as the forward price approaches the
5 settlement date. Infrastructure outages and other issues that increased gas prices continued to
6 appear as the 2022-2023 Winter approached. As a result, the forward price at ~10 months out
7 increased compared to the forward price ~22 months out.

8 Third, the 2023-2024 Winter shows the lingering impact on forward prices of price spikes
9 of the prior winter.⁷ The daily gas prices through two of the three months (March-May) that
10 make up the ~10-month forward window remained elevated. However, the 2022-2023 Winter
11 price spike had not yet occurred at the point of the ~22-month forward for the 2023-24 Winter.

12 Fourth, the table shows that forward prices are a poor predictor of actual prices. Large
13 gas traders have access to more and better information and prediction tools than the Commission
14 could replicate for gas price forecasting because gas price forecasting is the basis for their
15 businesses upon which tens of billions of dollars are at stake each month. Despite those
16 sophisticated tools and access to nearly unlimited data, gas traders' forward prices were off by at
17 least -51% and up to 148% each of the last 4 years, as shown in the fifth column in Table 1
18 above. This data supports the Commission's D.24-12-076 finding that "the economic analysis is
19 designed to be a simple and transparent way to identify conditions when gas prices are high
20 enough to significantly impact ratepayers' bills."⁸ This data is also a direct rebuttal to Witness
21 Chang's assertion that the Commission should dramatically increase the complexity of the
22 economic analysis.⁹ Forward prices shown in the table above demonstrate that complex analyses
23 – such as those completed by gas traders – do not accurately predict gas prices. Complex
24 economic analyses would only drain limited Commission resources with no additional accuracy
25 in predicting gas prices.

⁷ See Table 1 above.

⁸ D.24-12-076, Decision Adopting Biennial Assessment Process, at 58 (Dec. 19, 2024),
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K009/551009286.PDF> [hereinafter
"D.24-12-076"].

⁹ Chang Rebuttal Testimony at SCC-15.

1 While D.24-12-076 allowed for future updates to the economic analysis,¹⁰ the
2 Commission designed its economic analysis “to be a simple and transparent way to identify
3 conditions when gas prices are high enough to significantly impact ratepayers’ bills”¹¹ and
4 rejected more complicated analyses that parties previously proposed.¹² My recommendation to
5 update the economic analysis based on average daily prices conforms to D.24-12-076’s direction
6 and is grounded in historical data.

7 Fifth, Table 1 shows that SoCalGas’s and other intervenors’ price concerns are
8 misplaced. While the 2025 Biennial Assessment allowed for the fact that future prices are
9 unknown, it also showed data that futures prices are decreasing,¹³ stated that “gas prices
10 expected in Southern California for winter 2025-26 do not exceed the threshold levels set by
11 D.24-12-076[.]”¹⁴ and stated that “expected prices [for Winter 2026-27] are still well below
12 recent highs.”¹⁵ My table above expands the analysis by Energy Division and shows that the
13 ~10-month forward price has *dropped every year since at least the 2022-2023 winter season*
14 despite the future “conditions and risks” that SoCalGas lists as potential concerns.¹⁶ The drop in
15 forward prices established by gas traders account for future conditions and risks.

16 The disconnect between forward prices and actual gas prices suggests the actual gas
17 prices, not forward prices, should be used to assess whether it is reasonable to reduce Aliso
18 Canyon storage inventory. The forward prices are inaccurate predictors of what the actual prices
19 will be, undermining the accuracy of assessing whether and how much gas storage at Aliso
20 Canyon is needed to maintain reliability.

21 Forward prices ~10 months away from the settlement date are the basis for the two
22 economic analyses that D.24-12-076 requires for the Biennial Assessment Process. The 2025
23 Biennial Assessment completed the ~10 month forward economic analysis for the 2025-26

¹⁰ D.24-12-076 at 59 (“The implementation process in the following section provides opportunities to update the economic analysis.”); D.24-12-076, Attachment A, Biennial Assessment Report Input and Methods, at A1, <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M551/K129/551129840.PDF> [hereinafter “D.24-12-076 Attachment A”].

¹¹ D.24-12-076 at 58.

¹² *Id.* at 55-59.

¹³ 2025 Biennial Assessment at 26, Table 11.

¹⁴ *Id.* at 25.

¹⁵ *Id.* at 26.

¹⁶ Prepared Rebuttal Testimony of Andrew J. Sawin, at AJS-3 (Sept. 17, 2026) [hereinafter “Sawin Rebuttal Testimony”].

Winter. It also completed a ~22 month forward economic analysis, which D.24-12-076 does *not* require, and which showed that the ~22-month analysis would have exceeded the threshold that was established for a ~10-month forward. The results were summarized in 2025 Biennial Assessment Tables 7 and 10.¹⁷ That analysis found the ~22-month SoCal Citygate forward price to be 57% above Henry Hub forwards (above the +50% threshold for ~10-month forwards) and 36% below SoCal Citygate bidweek prices of the prior three years (well below the threshold of +50%).¹⁸

On the basis of the ~22-month forward economic analysis, the 2025 Biennial Assessment stated that “given current forecasts for higher gas commodity prices in winter 2026-27, the CPUC may wish to consider a smaller incremental reduction [than 10 Bcf].”¹⁹

The Biennial Assessments are not required to review off-year winters such as 2026-27 and did not adopt a threshold for ~22-month forwards. Moreover, any analyses completed should be considered on an apples-to-apples basis. Because March-May of 2026 have passed, I am able to complete the ~10-month forward analysis for the 2026-2027 Winter with data that was not available to Energy Division in 2025 when the assessment was published. The table below shows the results of the two economic analyses updated for the 2026-2027 Winter using the methodology required in D.24-12-076 Attachment A (forwards published March 1–May 31, 2026). The results show no price conditions that would bar a reduction to the Aliso Canyon maximum inventory, and both results (i.e. 24% and 12%) are well below the 50% threshold that restricts inventory reduction.

Table 2: Biennial Assessment Process price tests applied to Winter 2026-27

Test (D.24-12-076, Att. A)	SoCal Citygate forward, Dec–Feb 2026-27	Comparator	SoCal premium	Threshold
SoCal Citygate vs Henry Hub forward	\$5.55	\$4.49 (Henry Hub forward, same window)	+24%	50%
Historical vs prior three	\$5.55	\$4.97 (SoCal Citygate)	+12%	50%

¹⁷ 2025 Biennial Assessment at 25-26, Tables 7 and 10.

¹⁸ *Id.*

¹⁹ *Id.* at 29.

winters' bidweek		bidweek avg, 2023-24 to 2025-26)		
---------------------	--	--	--	--

In summary, Table 1 shows that ~10-month forward gas prices are decreasing. Table 2 shows that both economic tests of the Biennial Assessment Methodology, when applied to Winter 2026-2027, produce results well below the 50% threshold established in D.24-12-076. Tables 1 and 2 update the information supplied by now outdated economic analyses in the 2025 Biennial Assessment and demonstrate that the Biennial Assessment’s caution regarding “current forecasts for higher gas commodity prices in winter 2026-27” no longer applies.²⁰

I discuss historical daily gas prices in the following section.

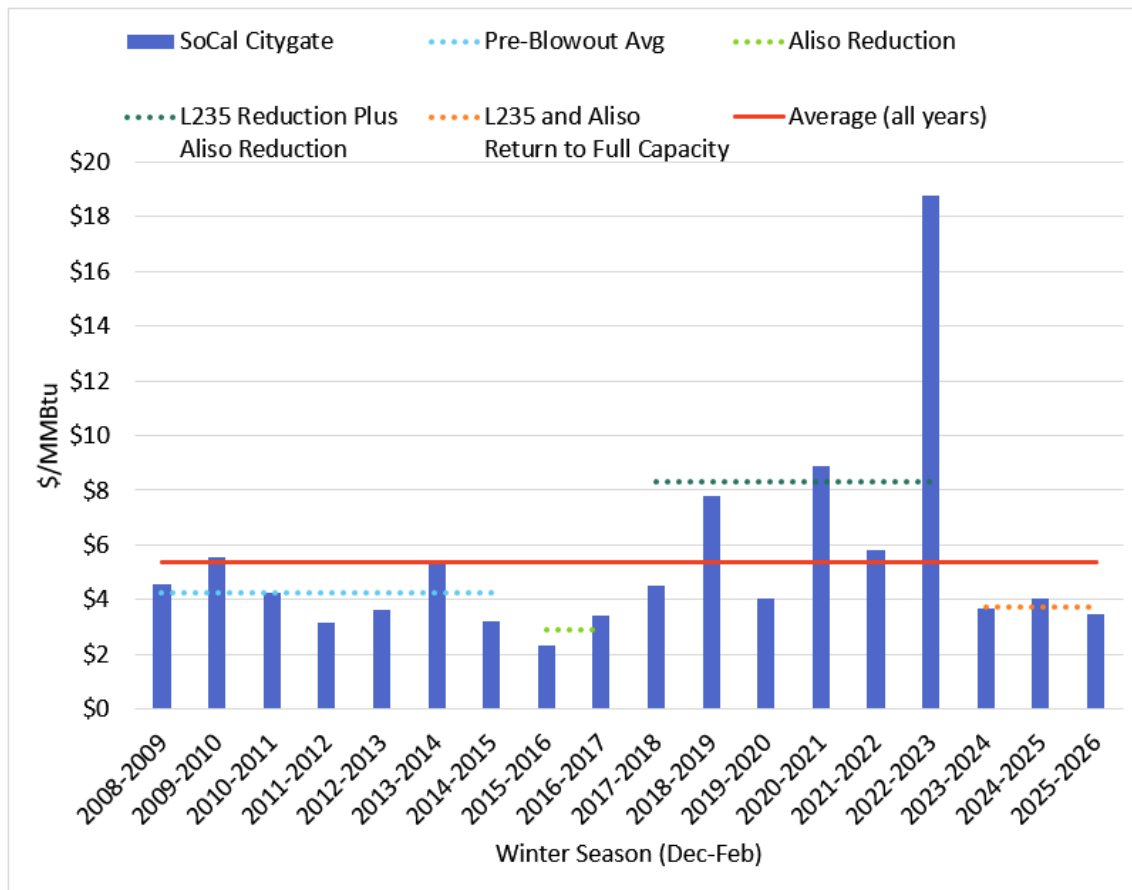
2.2. Current gas prices are lower than the historical average.

In this section, I report the historical gas prices for every winter season in the NGI daily gas price database, show that recent prices have been historically low, and provide insights as to why gas prices can remain low even if the Commission reduces Aliso Canyon inventory capacity.

The average winter gas prices over the most recent three years are lower than the long-term average and lower than gas prices prior to the Aliso Canyon blowout.

²⁰ *Id.* at 29 (“However, given current forecasts for higher gas commodity prices in winter 2026- 27, the CPUC may wish to consider a smaller incremental reduction.”).

Figure 1: Winter Season (Dec–Feb) Average Daily SoCal Citygate Prices²¹



In 2015-16 and 2016-17, when Aliso Canyon inventory was most restricted (injections halted after the blowout), winter prices averaged \$2.90/MMBtu, below the pre-blowout average of \$4.24/MMBtu.

The higher-priced years align with the Line 235/4000 outages (October 1, 2017) and Aliso storage reduction (October 23, 2015), not Aliso Canyon on its own. The Commission's Safety and Enforcement Division found that SoCalGas's actions were responsible for both the Line 235 rupture and the Aliso Canyon Blowout.²² While Aliso was in service throughout the time shown, the inventory limit was raised to 68.6 Bcf (Aug 2023). However, it is impossible to determine the impact of that on its own because Line 235 returned to full pressure at the end of

²¹ Data Source: NGI data, SoCal Citygate daily prices.

²² Exh. SC-09: Safety and Enforcement Division Line 235 Final Report – Redacted, Released Pursuant to CPUC Resolution L-571, at PDF p. 28 (Oct. 25, 2018) (filed as Attachment A to A.26-01-009, Sierra Club Comments in Response to Prehearing Conference Ruling (Mar. 27, 2026)), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K483/603483126.PDF>.

1 2023 as well.²³ Moreover, electric load serving entities have significantly increased the
2 renewable energy and electricity storage capacity over the last 4 years.²⁴ Gas demand required to
3 serve electric generation is 25% of 1-in-10 peak day gas demand forecast in the 2026 California
4 Gas Report,²⁵ which is more than double the reduction needed to close Aliso Canyon.²⁶ As gas
5 demand for gas fired generators decreases to meet the targets established in Public Utilities
6 Code, § 454.53 (a),²⁷ gas demand reductions for electric generation will eliminate the need for
7 Aliso Canyon even if there are no changes to any other category of gas demand.

8 Figure 1 above shows data that is consistent with my expectation that renewable energy
9 growth, energy efficiency and widespread electrification will keep reducing California gas
10 demand and in turn keep gas commodity prices at low levels compared to historical prices. The
11 confluence of events between the 2022-23 and 2023-24 winter season makes it inaccurate to
12 assign low gas prices in recent years only to the increase in Aliso Canyon inventory capacity to
13 68.6 Bcf. Moreover, I show in subsequent sections that during the 2022-23 Winter the storage
14 withdrawal capacity was only fully scheduled on two days, and on the two days when it was
15 fully scheduled, the scheduled capacity was not fully used. Thus, customers had access to gas
16 storage that they did not use every day of the 2022-2023 winter season, throughout the time of
17 record-high prices.

²³ CPUC, *Winter 2023-2024 Southern California Gas Reliability Assessment*, at PDF p. 4 (Sept. 15, 2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/2023_winter_reliability_daily_stochastic_mass_balance_model.pdf (“The Northern Zone of the pipeline system is set to regain 175 million cubic feet per day (MMcfd) of receipt capacity in November 2023 when Line (L) 235 west remediation is scheduled to end.”).

²⁴ See generally CPUC, *IRP Procurement Track*, <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track> (last visited Oct. 6, 2026) (detailing recent CPUC procurement orders, timelines for LSE contracting, and procurement compliance summaries).

²⁵ Calculation: $1,201 \text{ MMcfd} / 4,758 \text{ MMcfd} = 0.2524 = 25\%$.

²⁶ 2025 Biennial Assessment at 7, Table 1.

²⁷ Cal. Pub. Util. Code § 454.53(a) (“It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035, 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040, 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045...”), https://leginfo.ca.gov/faces/codes_displaySection.xhtml?sectionNum=454.53.&lawCode=PUC

1 While SoCalGas claimed that “the historical data suggests Aliso Canyon inventory has an
2 impact on prices[,]”²⁸ the data it provided excluded most of the 2015-16 and 2016-17 winter
3 seasons that occurred immediately after the blowout. Those two winters included two of the
4 lowest average prices on record. Further, SoCalGas failed to explain why the Commission
5 should ignore the numerous confounding factors and provide no additional context such as the
6 L235 restrictions, L235 return to full capacity, the rapid ramp up of renewables and battery
7 storage, or any other event that coincided with the Aliso Canyon inventory changes that may
8 have influenced gas prices.

9 The average daily gas prices for the 2022-2023 through 2025-2026 winter season are
10 lower than the gas prices prior to the Aliso Canyon blowout, as noted in Figure 1 above. When
11 accounting for inflation, the difference is even greater. The low gas prices in recent years are
12 consistent with my expectation that renewable energy growth, energy efficiency and
13 electrification will keep reducing California gas demand and will keep gas prices low in future
14 years as well.

15 **2.3. SoCalGas storage has operated at least 10 Bcf below system capacity since Aliso**
16 **Canyon’s capacity increased to 68.6 Bcf.**

17 SoCalGas and IS recommend that the Commission retain the current inventory at Aliso
18 Canyon, claiming all of it is needed,²⁹ yet SoCalGas has ample storage on its system that it is not
19 fully using. Currently there is 119.5 Bcf of storage capacity across all SoCalGas storage fields
20 including 68.6 Bcf at Aliso Canyon. Even though Aliso Canyon inventory has been capped at 41
21 Bcf or lower for much of the last decade, more than 34 Bcf across SoCalGas storage fields has
22 remained in inventory at the end of winter every year for the last 10 years.³⁰ As stated in my
23 opening testimony, much of this end of winter gas inventory is not needed, and the data below
24 demonstrates another reason why.

25 Not only has SoCalGas had tens of Bcf of gas in system inventory at the end of every
26 winter for the last 10 years, but since the Commission increased Aliso capacity to 68.6 Bcf in
27 August 2023, SoCalGas has been at least 10 Bcf short of filling its system-wide storage capacity

²⁸ Chang Rebuttal Testimony at SCC-2.

²⁹ Sawin Direct Testimony at AJS-13; Collins Direct Testimony at 5, 11.

³⁰ SoCalGas Envoy, Gas Storage Data, <https://www.socalgas-envoy.com/> (last visited Oct. 1, 2026).

before each winter season. SoCalGas leaving at least 10 Bcf of unfilled capacity each year shows that a 10 Bcf reduction at Aliso Canyon is feasible and should be the minimum reduction considered.

Table 3: SoCalGas All-Facility Storage: November Maximum Inventory Compared to SoCalGas’s Nominal Capacity, 2023–2025³¹

Year	November Max Inventory (Bcf)	SoCalGas nominal 119.5 Bcf capacity minus November Max Inventory (Bcf)
2023	106.1	13.4
2024	106.4	13.1
2025	108.9	10.6

The historically low gas prices from the previous Figure 1 were achieved while SoCalGas’s storage was operating with at least 10 Bcf of storage unfilled each winter. This shows the impact on gas prices of a 10 Bcf reduction is effectively already known because SCG has been operating its system 10 Bcf below capacity for three years. If the Commission orders a 10 Bcf reduction, it will effectively memorialize SoCalGas’s current operational practices. This again shows that my recommendation to reduce inventory levels beyond a 10 Bcf reduction is reasonable and supported by data.

2.4. The Commission can order a reduction while preserving just and reasonable gas rates.

D.24-12-076 states that “[a]s forecast peak day natural gas demand declines, reduction to the maximum storage level at Aliso Canyon can be considered, provided that just and reasonable rates are preserved.”³² Current gas prices are lower than both the long-term average and the pre-blowout average. The 2025 Biennial Assessment found that the current price environment does not preclude an Aliso Canyon storage reduction and recommended the maximum reduction that D.24-12-076 allows Energy Division to make. The 10-month forward price has fallen in each of the last four years, from \$9.23 to \$5.55, and both Biennial Assessment Process’s price tests for winter 2026-27 are well below their thresholds. Each of these data points supports the

³¹ Data Source: SoCalGas Envoy, Gas Storage Data, <https://www.socalgas-envoy.com/> (last visited Oct. 1, 2026).

³² D.24-12-076 at 50.

Commission’s ability to lower the Aliso Canyon storage inventory while preserving just and reasonable rates. SoCalGas, IS and Cal Advocates’ arguments to the contrary are unsupported. I recommend that the Commission follow the 2025 Biennial Assessment’s recommendation and order a reduction in the Aliso Canyon storage inventory.

3. SOCALGAS’S PROPOSED MODELING ASSUMPTIONS EACH SHIFT THE RELIABILITY THRESHOLD WELL BEYOND THE COMMISSION’S 1-IN-10 PEAK DAY STANDARD.

3.1. SoCalGas exaggerates demand by stacking unlikely events to yield extremely unlikely scenarios far less likely than a 1 day -in-10 years event.

SoCalGas’s methodology to identify a 1-in-10 peak day estimate fails to account for recent warming trends and includes unlikely inputs that result in SoCalGas reliability proposals aligned with 1-in-500-year events instead of 1-in-10-year events. SoCalGas sets its 1-in-10 design temperature, 42.3°F, from the coldest day of each year from 1950 through 2023, weighting 1950s temperatures equal to more recent temperatures and holding the value constant through 2040. Dr. Berardi showed that the same calculation using 2004–2023 temperatures gives 44.4°F, 2.1°F warmer than SoCalGas’s value and 3.3°F warmer than using 1950–1969, a statistically significant difference.³³ Regardless, the 2026 California Gas Report selected a 42.3 degree temperature to represent a 1-day-in-10-year demand event.

Once a variable has been selected that corresponds to a 1-in-10 peak day demand – in this case the temperature corresponding to a 1-in-10 peak demand – all other variables (e.g., pipeline availability or storage availability) must be set at average values for such a day and not be set at levels that are below average. Assuming values lower than average will produce an event less frequent than 1-in-10 and values higher than average will produce even more frequent than 1-in-10. Either would result in testing a different reliability level than the Commission’s 1-in-10 reliability standard.

If multiple low probability events are layered into a model, the likelihood of both occurring at the same time – assuming no correlation – is the product of the likelihood of each event on their own. For example, the likelihood of two uncorrelated 1-in-10 events occurring at

³³ Exh. SC-02: Direct Testimony of Vincent Berardi, at 10, Table 1 (Aug. 20, 2026).

1 the same time is 1-in-100.³⁴ I described this in opening testimony when I showed that just one of
2 SoCalGas’s unlikely inputs, when combined with a 1-in-10 peak demand event, aligns with a 1-
3 in-500-year event rather than a 1-in-10-year event.³⁵

4 SoCalGas Witness Sawin claims 97% receipt point utilization (“RPU”) is unreasonable to
5 assume and instead suggests that the Commission assume an RPU of 85% after accounting for
6 outages (addressed in Section 3.3, below).³⁶ However, even if we assume SoCalGas’s proposed
7 RPU of 85%, the 1-in-10 peak day event would result in a 1-day-in-68-year event as calculated
8 in Table 4. The 1-in-68 example rests on available capacity (2,760 million cubic feet per day
9 (“MMcfd”) or less which occurs on 14.8% of winter days).³⁷ Thus, the scenario of an 85% RPU
10 *simultaneous to* SoCalGas’s 1-in-10 peak demand is rarer than even the 1-in-35 extreme peak
11 day that defines SoCalGas’s core reliability standard, and far rarer than the 1-in-10 cold day
12 standard for core and firm noncore service. The Commission’s standards do not require
13 SoCalGas to plan for the overlap of low RPU during a 1-in-10 peak day demand.

³⁴ $1/10 \text{ years} \times 1/10 \text{ years} = 1/100 \text{ years}$.

³⁵ Exh. SC-01: Direct Testimony of Tyson Siegele, at 52-53 (Aug. 20, 2026) [hereinafter “Siegel Direct Testimony”].

³⁶ Sawin Rebuttal Testimony at AJS-29.

³⁷ Calculation: $10 \text{ years} / 14.8\% = 68 \text{ years}$. Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (posted receipt capacity was at or below 2,760 MMcfd on 286 of 1,926 December–February days, 2004–2025).

Table 4: Event Probability for IS and SoCalGas Assertions³⁸

Example	Assertion	Cite	Share of winter days	Layered over a 1-in-10 day
1	Available receipt capacity of 2,760 MMcfd after SoCalGas's modeled outages	Sawin R 13–14; Sawin D 14	≤2,760 on 14.8% of days	~1 in 68 yrs
2	Outage sized to observed 650–655 MMcfd reductions (3,286 – 650 = 2,636)	IS 28, 47; Sawin R 28	≤2,636 on 3.8%	~1 in 260 yrs
3	Receipt point utilization based on event days: 47% / 38% / 25%	IS 27–28, 34, 47; Sawin D 6; Sawin R 9–10	4.2% / 1.2% / 0.1% of days	~1 in 240 / 800 / 9,600 yrs
4	Stacking: constrained upstream supply plus an intrastate outage plus colder weather ("Nothing, however, would prevent...")	Sawin R 14–15	#2 × #3 (47%) if independent	~1 in 6,300 yrs
Notes: <u>Example 1:</u> This example uses 2,760, not 2,416. In opening testimony I compared SoCalGas's 2,416 MMcfd (after its 85% utilization cut) to posted capacity: 1.9% of days, resulting in a 1 in 500 year event when layered on a 1-in-10 demand day. Mr. Sawin asserts that my analysis mixes two different measures (Sawin Rebuttal at 13-14). I continue to support my original analysis because SCG has stated that it has no data to support its conclusion that an RPU below 100% results from supply outages. However to demonstrate that my analysis continues hold up even when selecting Mr. Sawin's, own 2,760 MMcfd available-capacity figure, I calculated that percentage in this example. This scenario produces a 1-in-68 year event. <u>Example 3:</u> My independence assumption is reasonable. The 2021 low-utilization day fell on a 3rd-percentile demand day (see §2.4.4 of my opening testimony), so low utilization and peak demand tend not to happen together. The data runs through December 2025, so Winter Storm Fern isn't in it; the 25% figure is based on only two earlier days.				

The other examples in the table above demonstrate how rapidly the stacking of scenarios changes the likelihood of events. For example, Example 4 from the table aligns with the following SoCalGas statement:

Recent events demonstrate that these risks can occur concurrently. On December 27, 2025, during the December-through-January peak demand period, a force majeure event on Line 225 significantly reduced available capacity in the Wheeler Ridge Zone. Weeks later, Winter Storm Fern affected upstream supply conditions and RPU declined to approximately 25 percent, while Line 225 was still out of service. Southern California avoided more severe consequences because local weather and demand were comparatively mild and 8.2 Bcf of natural gas was withdrawn from storage during the storm. Nothing, however, would prevent similarly constrained

³⁸ If the events are correlated, then the likelihood of SoCalGas's or IS's proposed modeling scenarios would be adjusted based on the strength of the correlation.

1 upstream supplies from occurring at the same time as colder weather in
2 Southern California or while an intrastate pipeline outage is in effect.³⁹

3 I agree with SoCalGas when it says that nothing would prevent a scenario of that type
4 from occurring (i.e. two major pipeline outages, low RPU, low temperatures, and high gas
5 demand). In fact, based on historical data, it will occur at a frequency of approximately once
6 every 6,300 years as I calculated in Table 4 above. The Commission's reliability standard
7 requires meeting the peak demand that occurs on one day every ten years, and the Commission's
8 reliability standard is reasonable. The Commission's planning standard does not require the 1-in-
9 10 peak demand to be met at the same time as multiple rare infrastructure outages.

10 IS's witness makes the same mistake of stacking unlikely events when it states that Sierra
11 Club "concludes that 44% of maximum inventory capacity suffices for system balancing and
12 reliability, even though that capacity level holds in only 19 of the 27 scenarios modeled by Staff.
13 In nearly 30% of Staff's scenarios, more than 44% of inventory capacity is required."⁴⁰
14 SoCalGas's data show that posted total receipt capacity at or below 3,200 MMcfd on only 36%
15 of December–February days from 2004 to 2025, and on 35% of those days since the Line
16 235/4000 restoration (Dec 2023–Dec 2025).⁴¹ Each of the cited eight scenarios in the 2025
17 Biennial Assessment assumes 3,200 MMcfd or less of pipeline supply combined with reduced
18 storage well utilization.⁴² That means each of the 8 scenarios describes overlapping events each
19 with a below-average likelihood. A below-average-likelihood event layered on a 1-in-10
20 temperature produces a scenario far rarer than 1 day in 10 years. The very conservativeness and
21 unlikelihood of those eight scenarios directly support the Biennial Assessment's
22 recommendation that the Commission can safely reduce the inventory at Aliso Canyon while
23 maintaining system reliability.

24 The Commission has established that SoCalGas must serve the 1-in-10 peak day demand.
25 It does not require SoCalGas to maintain an excessive and oversized infrastructure to serve

³⁹ Sawin Rebuttal Testimony at AJS-14-15.

⁴⁰ Collins Direct Testimony at 30.

⁴¹ Exh. SC-07 (posted receipt capacity was at or below 3,200 MMcfd on 692 of 1,926 December–February days from 2004 to 2025 (35.9%), and on 75 of 212 such days from December 2023 through December 2025 (35.4%)).

⁴² 2025 Biennial Assessment at 12, Table 5.

1 scenarios less likely than the 1-in-10.⁴³ I base my analyses on probabilities that correspond to
2 Commission reliability requirements, and I recommend the Commission reject SoCalGas and
3 IS's proposals that would require reliability planning that conflicts with the Commission's 1-in-
4 10 standard.

5 **3.2. It is reasonable to assume 97% RPU to model system reliability because it**
6 **reflects historical reality.**

7 SoCalGas again claims, without evidence, that "upstream supply availability" is a factor
8 influencing RPU.⁴⁴ When Sierra Club asked SoCalGas for data quantifying upstream supply
9 constraints, SoCalGas stated that it had none.⁴⁵ In rebuttal SoCalGas claims that "RPU can be
10 influenced by a combination of factors, including upstream supply availability, transportation
11 constraints, commercial decisions, customer scheduling practices, and prevailing market
12 conditions."⁴⁶ Again, SoCalGas provides no data to support that upstream supply constraints
13 justify a lower RPU assumption.

14 SoCalGas claims that "Sierra Club's analysis repeatedly conflates three distinct concepts:
15 nominal capacity, available capacity, and flowing supply, and the factors impacting RPU."⁴⁷
16 That is inaccurate. My analyses use the same definition that SoCalGas uses for nominal capacity,
17 available capacity, and flowing supply.

⁴³ The 1-in-35 peak day demand requirement only requires service of core customers and thus is a less stringent standard than the 1-in-10 peak day demand standard.

⁴⁴ Sawin Rebuttal Testimony at AJS-7-8.

⁴⁵ Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026) ("SoCalGas objects to this request to the extent that it seeks information that is not within SoCalGas knowledge or control. Subject to and without waiving the foregoing objection, SoCalGas responds as follows. The 'actual availability' of gas supply at receipt points on the SoCalGas system is determined by the actions and decisions of third-party shippers, producers, marketers, and upstream pipeline operators, not by SoCalGas. SoCalGas does not possess information to disaggregate the volumes that were 'available' to be delivered from the volumes that were actually delivered based on third-party 'customer behavior,' as the request contemplates."). *See also*, Exh. SC-12: SoCalGas Response to Sierra Club Data Request 3-22, subparts (c) and (d) (Aug. 10, 2026) (SoCalGas was unable to quantify out-of-state supply unavailability in MMcf/d.).

⁴⁶ Sawin Rebuttal Testimony at AJS-8.

⁴⁷ *Id.* at AJS-11.

1 In my opening testimony, I provide data showing available capacity offered by SoCalGas
2 and that 97% of available capacity was regularly used for multiple winter seasons.⁴⁸ Grounded
3 on that historical data, I recommend modeling inputs for RPU be set to 97%.⁴⁹

4 SoCalGas objects to my recommendation on the basis that customers do not typically
5 schedule all available capacity,⁵⁰ despite acknowledging that SoCalGas does not have data to
6 demonstrate unavailability of unscheduled capacity.⁵¹

7 SoCalGas claimed that my recommendation to use a 97 percent RPU assumption “is
8 unrealistic.”⁵² However, SoCalGas’s own data shows otherwise. In the winters of 2018-19, 2019-
9 20 and 2020-21, SoCalGas reported RPU of 97% or more on 133 of 271 days (49%).⁵³

10 Days with RPU lower than 97% include days of low gas demand. This is the same reason
11 that RPU is lower in summer months despite the higher operational outages due to off-peak
12 maintenance activities. In recent winters, RPU has been lower than winters of 2018-19, 2019-20
13 and 2020-21 because renewable energy continues to replace gas demand and flowing supply
14 offered by SoCalGas has been higher in recent years. Both factors reduce RPU percentages and
15 show that low RPU is not a reflection of available capacity, but rather actual use of capacity
16 offered. The decrease in RPU in recent years reflects the ongoing energy transition in alignment
17 with California’s decarbonization policies and programs.

⁴⁸ Siegle Direct Testimony at 52, 60.

⁴⁹ *Id.* at 3, 61.

⁵⁰ Sawin Rebuttal Testimony at AJS-13 (“Thus, actual interstate supplies were approximately 1,160 MMcf below available receipt capacity. Whether that difference resulted from customer scheduling decisions, upstream supply limitations, market conditions, or some combination of those factors does not change its significance for reliability planning. The supplies did not enter the SoCalGas system and therefore were not available to serve customer demand on that day.”).

⁵¹ Exh. SC-06: SoCalGas Response to Sierra Club Data Requests 2-13 and 2-14 (May 28, 2026) (“SoCalGas objects to this request to the extent that it seeks information that is not within SoCalGas knowledge or control. Subject to and without waiving the foregoing objection, SoCalGas responds as follows. The ‘actual availability’ of gas supply at receipt points on the SoCalGas system is determined by the actions and decisions of third-party shippers, producers, marketers, and upstream pipeline operators, not by SoCalGas. SoCalGas does not possess information to disaggregate the volumes that were ‘available’ to be delivered from the volumes that were actually delivered based on third-party ‘customer behavior,’ as the request contemplates.”); *See also*, Exh. SC-12: SoCalGas Response to Sierra Club Data Request 3-22, subparts (c) and (d) (Aug. 10, 2026) (SoCalGas was unable to quantify out-of-state supply unavailability in MMcf).

⁵² Sawin Rebuttal Testimony at AJS-1.

⁵³ SoCalGas reports RPU rounded to two decimals; computed from its unrounded capacity and scheduled volumes, the count is 120 days (44%).

1 Winter Storm Fern adds a current example: on Jan 23–28, 2026 customers brought in
2 only 35–42% of available receipt capacity while SoCal Border prices ranged from \$3.6 to \$13.2
3 (peaking at \$9–13 on Jan 24–26) (see Section 6.2). Mid-level prices and low RPU demonstrate
4 RPU results tracking customers’ scheduling choices, not unavailable supply.

5 In rebuttal testimony, SoCalGas added a new claim regarding RPU. It states that
6 “[w]hether gas was unavailable upstream or available but not scheduled by customers, the
7 operational result is the same: that gas supply did not enter the SoCalGas system and was not
8 available to serve customer demand.”⁵⁴ That is like saying food is not available if a person
9 refuses to put it in their mouth.

10 Available resources should be included as available in the Commission’s Biennial
11 Assessment modeling. Based on substantial historical data, the Commission should increase the
12 Receipt Point Capacity percentage to 97%.⁵⁵

13 **3.3. The Biennial Assessment Process should consider whether SoCalGas’s nominal**
14 **system capacity has decreased.**

15 In opening testimony, I recommended that the Commission consider historical receipt
16 capacity when establishing modeling criteria. Modeling inputs that assume lower available
17 receipt capacity produce results showing a greater need for Aliso Canyon. SoCalGas disagrees
18 that gas reliability modeling should consider historical capacity, stating:

19 Sierra Club is proposing using the historical nominal receipt capacity of the
20 system, 3,875 MMcfd, as the basis for RPU calculations. This should be
21 rejected for several reasons. The total nominal receipt capacity includes
22 capacity for the local CA producers of 310 MMcfd. This was reduced by
23 100 MMcfd to 210 MMcfd in 2018, and the current nominal receipt
24 capacity is 3,775 MMcfd. Local California production has also been
25 declining for years, and both the Energy Division and SoCalGas use recent
26 production levels as inputs for analysis.⁵⁶

27 At any given time, the ability of the SoCalGas system to deliver gas suggests the used
28 and useful percentage of the system. In response to a Sierra Club data request, SoCalGas

⁵⁴ Sawin Rebuttal Testimony at AJS-8.

⁵⁵ D.24-12-076, Attachment A at A5, Row 10 (Receipt point capacity).

⁵⁶ Sawin Rebuttal Testimony at AJS 26.

1 reported its historical available receipt capacity excluding California production.⁵⁷ The highest
2 availability was recorded on December 30, 2014, at 3,864 MMcfd, less than one year before the
3 Aliso Canyon blowout.⁵⁸ The highest recent availability without California production was 3,643
4 MMcfd on January 15, 2024.⁵⁹ Unless there were no outages on that day, the 2014 number and
5 2024 number represented less than the nominal capacity.

6 System capacity before the blowout was 221 MMcfd higher than today.⁶⁰ That represents
7 almost half the difference between the difference that Energy Division calculated between Aliso
8 Canyon closure threshold and the SoCalGas 1-in-10 peak demand.⁶¹

9 The Biennial Assessment assumed 2,800 MMcfd in its gas balance analysis for 2025-26
10 and 3,215 MMcfd for 2030-31, with each including 70 MMcfd of California production.⁶² Both
11 are conservative compared with the capacity SoCalGas posts as available. For example, 2,800
12 MMcfd is just 73% of the available capacity – not nominal capacity – that SoCalGas posted less
13 than a year before the blowout; available capacity has decreased 27%. Even if the 2014 number
14 represents nominal capacity (i.e., no outages on the reported day), that would still be a difference
15 of 7.7% compared to the 3,635 MMcfd nominal capacity assumed in the 2025 Biennial
16 Assessment.⁶³ A 7% gas supply difference produces significantly different modeling outputs.

17 If 2,800 MMcfd is the assumed available capacity of the current gas system, the
18 remaining 27% of capacity that was used and useful in 2014 may no longer qualify as used and
19 useful today. Alternatively, if more than 2,800 MMcfd of capacity is used and useful, then more
20 than 2,800 MMcfd of capacity should be assumed to be available on a 1-in-10 peak day demand.

⁵⁷ Exh. SC-07: SoCalGas Supplemental Response to Sierra Club Data Request 2-8 (July 6, 2026) (“SoCalGas interprets ‘Total Receipts’ to mean total system receipt capacity excluding California production, and ‘Total Deliveries’ to mean total system scheduled volumes excluding California production.”); Exh. SC-07 reports total receipt capacity and total scheduled volumes in dekatherms; I have converted to MMcfd using the conversion factor 1,029.3 Dth/MMcf.

⁵⁸ *Id.*

⁵⁹ *Id.*

⁶⁰ Calculation 3,864 MMcfd – 3643 MMcfd = 221 MMcfd.

⁶¹ 2025 Biennial Assessment at 7, Table 1.

⁶² *Id.* at 11, 14.

⁶³ Calculation: $1 - ((3,635 \text{ MMcfd} - 70 \text{ MMcfd of CA production}) / 3,864 \text{ MMcfd (no CA production)}) = 0.07738 = 7.7\%$.

1 **4. THE 2025 BIENNIAL ASSESSMENT AND MULTIPLE RECENT STUDIES ALL**
2 **SUPPORT A 39.6 BCF INVENTORY.**

3 **4.1. The hydraulic analysis does not conflict with a 29 Bcf reduction.**

4 In opening testimony, I recommended the Commission reduce Aliso inventory by 29 Bcf,
5 which corresponds to an Aliso Canyon inventory of 39.6 Bcf.⁶⁴

6 Mr. Sawin states:

7 For winter 2025-26, hydraulic modeling showed that a withdrawal rate of
8 550 MMcfd from Aliso Canyon is needed on a peak day to maintain gas
9 system reliability. Without Aliso Canyon withdrawals, the simulation
10 failed: linepack fell from 2,618.6 MMcf to 2,071.5 MMcf, a loss of 547.1
11 MMcf... This hydraulic result directly contradicts Sierra Club's suggestion
12 that only 30.2 Bcf of inventory is needed.

13 Importantly, Energy Division did not interpret the 30.2 Bcf result as
14 supporting a 38.4 Bcf reduction.⁶⁵

15 Mr. Sawin characterizes my testimony as treating 30.2 Bcf as “the total amount of Aliso
16 Canyon inventory required”⁶⁶ and compares it to a 38.4 Bcf reduction. I proposed neither. My
17 recommendation is a 39.6 Bcf Aliso inventory and a 29 Bcf reduction. This is an additional
18 buffer above the reliability need found in the 2025 Biennial Assessment's gas balance analysis
19 and the gas balance analysis was conservative. The gas balance analysis was completed using a
20 set of assumptions so rare that the scenario has never occurred.⁶⁷

21 Mr. Sawin did not provide any data or analysis showing that Aliso Canyon combined
22 with non-Aliso storage inventory would be unable to successfully meet the Energy Division's
23 conservative hydraulic modeling scenario. Instead, he asserted that even less likely events should
24 be assumed.⁶⁸

25 Neither SoCalGas nor the Biennial Assessment identifies an Aliso inventory below which
26 the 550 MMcfd withdrawal rate requirement could not be met. Thus, there is no data showing
27 what that level of inventory is. Staff used the gas balance analysis's February 15 inventories to

⁶⁴ Siegle Direct Testimony at 3.

⁶⁵ Sawin Rebuttal Testimony at AJS-2-3.

⁶⁶ *Id.* at AJS-2.

⁶⁷ Siegle Direct Testimony at 7-8.

⁶⁸ See table above “Event Probability for IS and SoCalGas Assertions”.

set the non-Aliso withdrawal rates⁶⁹ and, having considered all four analyses, recommended a 58.6 Bcf maximum inventory.⁷⁰

Outside of the 2025 Biennial Assessment and outside of SoCalGas’s testimony, there is data showing Energy Division’s hydraulic modeling coordinates with its 30.2 Bcf inventory need determination in its gas balance analysis. SoCalGas’s own winter Technical Assessments show Aliso can deliver more than 550 MMcfd at inventories far below my recommended 39.6 Bcf: 1,164 MMcfd at 41.16 Bcf and 695 MMcfd at 16.9 Bcf in winter 2022-23, and 919 MMcfd at 33.4 Bcf and 710 MMcfd at 16.5 Bcf in winter 2021-22.⁷¹ The figure and table below display this data.

**Table 5: Aliso Canyon Withdrawal Capacity at Selected Inventory Levels
(SoCalGas Winter Technical Assessments, 2021-22 and 2022-23)⁷²**

SoCalGas Storage Inventory (Bcf)	Withdrawal Capacity (MMcfd)
41.16	1,164
33.4	919
16.9	695
16.5	710

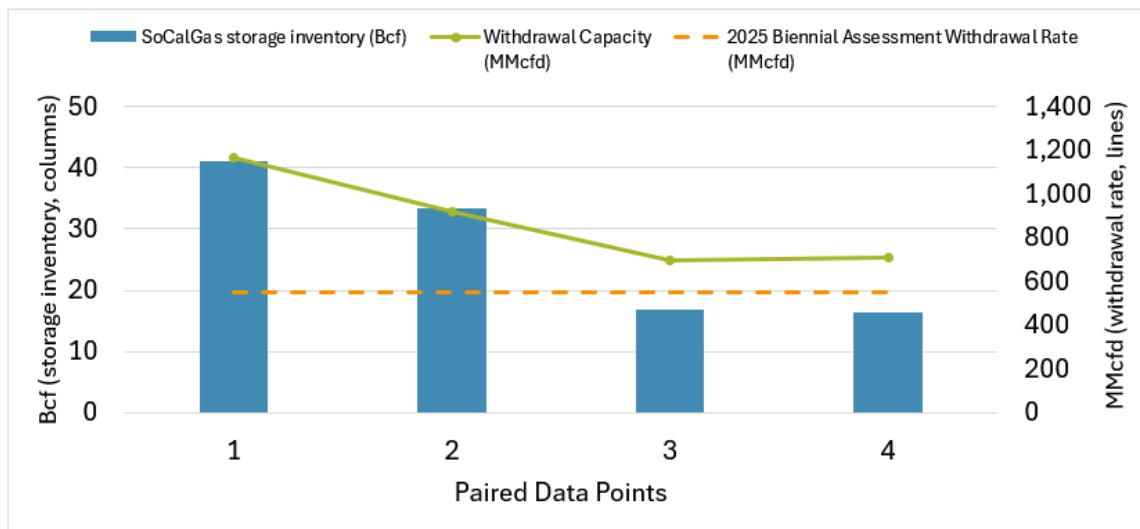
⁶⁹ 2025 Biennial Assessment at 13, 16.

⁷⁰ *Id.* at 5, 29.

⁷¹ SoCalGas, *Winter 2022-23 Technical Assessment*, at 6, Table 3 (Oct. 26, 2022), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=246873> [hereinafter “SoCalGas Winter 2022-23 Technical Assessment”]; SoCalGas, *Winter 2021-22 Technical Assessment*, at 6, Table 3 (Oct. 21, 2021), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/socalgas-winter-2021-22-technical-assessment.pdf> [hereinafter “SoCalGas Winter 2021-22 Technical Assessment”].

⁷² SoCalGas Winter 2022-23 Technical Assessment at 6, Table 3; SoCalGas Winter 2021-22 Technical Assessment at 6, Table 3.

Figure 2: SoCalGas Withdrawal Data in SoCalGas Winter Technical Assessment Scenarios vs. 2025 Biennial Assessment Minimum Required Withdrawal Rate



The gas balance analysis found 44% (30.2 Bcf) to be the minimum Aliso Canyon inventory using a 2,800 MMcfd pipeline supply assumption.⁷³ My recommendation retains a 39.6 Bcf storage inventory, 58% of current capacity and 9.4 Bcf above the 30.2 Bcf requirement determined in the Biennial Assessment.

For comparison, across all four SoCalGas storage facilities, the current maximum storage inventory is 119.5 Bcf. During the record-high-price 2022-2023 winter there was 51.1 Bcf withdrawn from the combined SoCalGas storage facilities, from the November maximum inventory to the March minimum inventory.⁷⁴ My recommendation for Aliso Canyon inventory reduction of 29 Bcf would lower the current 119.5 Bcf four-facility capacity to 90.5 Bcf. That 90.5 Bcf capacity is 39 Bcf greater than the amount of gas withdrawn from storage during the highest-price winter gas season ever.

In summary, SoCalGas's discussion of the gas balance and hydraulic modeling misstates my recommendation and makes inaccurate assertions about the 2025 Biennial Assessment. My recommendation is that the Commission reduce Aliso Canyon inventory to 39.6 Bcf. This recommendation is 9.4 Bcf above the 30.2 Bcf figure that Mr. Sawin attributes to Sierra Club. The hydraulic modeling cited by Mr. Sawin does not conflict with my recommendation.

⁷³ 2025 Biennial Assessment at 12, Table 4.

⁷⁴ Envoy storage data (last visited Oct. 1, 2026).

4.2. Reliability could have been maintained throughout Winter Storm Fern without Aliso inventory.

IS (citing SoCalGas’s May 2026 workshop reply comments at 1–2) asserts that Aliso’s highest daily withdrawal during Winter Storm Fern “required at least 40.6 Bcf of inventory...”⁷⁵ SoCalGas offered no withdrawal curve, calculation or data for that figure, and no SoCalGas witness repeats it. During Winter Storm Fern, Aliso’s largest daily drawdown was about 0.9 Bcf (Jan 25–26) (Table 6). SoCalGas’s own 2021-22 Technical Assessment reported 919 MMcfd of Aliso withdrawal capacity at 33.4 Bcf. Moreover, the peak Aliso withdrawal was not needed for reliability: on January 26, receipt capacity exceeded sendout by 452 MDth/d and customers used only 36% of available receipt capacity (Table 9).

Table 6: Aliso Canyon inventory during Winter Storm Fern (Bcf)

Date	Actual Aliso (Bcf)	Aliso daily change	Total system (Bcf)	Total daily change	Aliso under 39.6 Bcf cap
1/20	63.6	+0.0	107.7	+0.1	39.6
1/21	63.4	−0.2	107.3	−0.4	39.4
1/22	62.9	−0.5	106.6	−0.7	38.9
1/23	62.3	−0.6	105.5	−1.1	38.3
1/24	61.6	−0.7	104.3	−1.2	37.6
1/25	60.7	−0.9	102.9	−1.4	36.7
1/26	59.8	−0.9	101.3	−1.6	35.8
1/27	59.2	−0.6	100.1	−1.2	35.2
1/28	58.7	−0.5	99.1	−1.0	34.7
1/29	58.5	−0.2	98.8	−0.3	34.5
1/30	58.4	−0.1	98.7	−0.1	34.4
1/31	58.5	+0.1	98.8	+0.1	34.5

4.3. Every independent study finds that Aliso inventory can be reduced.

In opening testimony, I referenced four independent reviews of the reliability need for Aliso Canyon: the 2025 Biennial Assessment, a CAISO study, an Energy Division consultant’s study, and an evaluation by Southern California Edison.⁷⁶ I also highlighted the criticisms of

⁷⁵ Collins Direct Testimony at 40.

⁷⁶ See SC-01 Siegel Direct at 6-11, 17 (reviewing and discussing the 2025 Biennial Assessment, the 2022-2023 CAISO Transmission Plan, the FTI Phase 3 Report, and Southern California Edison’s testimony in Investigation 17-02-002 reviewing the FTI Phase 3 Report).

1 these studies and noted an instance in which an additional study could help evaluate a reasonable
2 date to consider beginning Aliso Canyon closure activities.

3 SoCalGas's rebuttal similarly highlighted each study and its criticisms.⁷⁷ However, it
4 failed to address their central theme: every one of them, on its own terms or updated with current
5 resource data as in my opening testimony, shows that Aliso Canyon inventory can be reduced
6 while maintaining energy reliability.

7 Studies are not perfect; in that regard I agree with SoCalGas. For example, my opening
8 testimony highlighted CAISO's concern with its own study.⁷⁸ However, I also listed several
9 ways in which the studies excluded inputs that would have produced more accurate results,
10 results that would have reduced any finding of need for Aliso Canyon.

11 Regardless of whether the studies are criticized as overly conservative or not conservative
12 enough, the fact remains that all four independent studies show that Aliso Canyon inventory can
13 be reduced without impacting gas or electric system reliability. It is reasonable for the
14 Commission to follow these recommendations.

15 **5. DATA SHOWS UNSCHEDULED STORAGE WITHDRAWAL CAPACITY**
16 **THROUGHOUT WINTERS WITH HIGH GAS PRICES, DEMONSTRATING THAT**
17 **NEITHER THE ALISO CANYON WITHDRAWAL PROTOCOL NOR REDUCED**
18 **ALISO CANYON INVENTORY CONTRIBUTED TO HIGHER GAS PRICES.**

19 SoCalGas and IS claim that prior to 2023 two conditions limited storage withdrawals and
20 increased gas prices: lower inventory levels at Aliso Canyon,⁷⁹ and the Aliso Canyon
21 Withdrawal Protocol.⁸⁰ They use these assertions as a basis for retaining 68.6 Bcf in Aliso
22 Canyon storage inventory.

⁷⁷ Sawin Rebuttal at AJS-2-6 (discussing 2025 Biennial Assessment, the FTI Phase 3 Report, SCE's review of the FTI report, and CAISO's 2023 reliability study).

⁷⁸ Siegle Direct Testimony at 10-11 (detailing CAISO's identified limitations of its study).

⁷⁹ Collins Direct Testimony at 40 ("price spikes ... occurred while Aliso Canyon was capped well below its current 68.6 Bcf inventory level and while Line 235 remained at reduced pressure. That history demonstrates the cost to ratepayers of constrained storage coinciding with pipeline outages.").

⁸⁰ Sawin Rebuttal Testimony at AJS-17 ("Sierra Club's analysis also fails to account adequately for the ACWP. During much of the historical period on which Sierra Club relies, withdrawals from Aliso Canyon were restricted by the protocol. Inventory remaining at the end of those winters may therefore reflect restrictions on access to Aliso Canyon rather than a determination that the inventory was unnecessary.").

In this section I provide data showing that SoCalGas and IS's assertions are false. Neither a lower inventory level nor the Aliso Canyon Withdrawal Protocol limited customer withdrawals. Thus, neither condition could have been responsible for high prices, and neither can be used as a basis for retaining Aliso's current inventory levels.

SoCalGas claimed that the Aliso Canyon Withdrawal Protocol limited gas storage use prior to its removal.⁸¹ IS claimed that limited inventory capacity coinciding with the 2022-2023 price spike "demonstrates the cost to ratepayers of constrained storage coinciding with pipeline outages."⁸² The data below shows SoCalGas's and IS's claims are inaccurate. The data covers the three winters before the Protocol was lifted (2020-21, 2021-22 and 2022-23), which include the 2020-21 and 2022-23 winters, which are the two highest-priced winters in NGI's SoCal Citygate daily index prices (2008-09 through 2025-26).⁸³

The table below shows the number of days each winter that had unscheduled withdrawal capacity. At least 10% of withdrawal capacity went unused on 98.5% of days (446 of 453), and at least 20% went unused on 97.1% of days (440 of 453).

Table 7: Days with unscheduled withdrawal capacity (customer basis, Nov–Mar)

Winter	Days	≥5%	≥10%	≥20%	≥30%	≥40%	≥50%
2020-21	151	150	150	150	147	143	134
2021-22	151	151	151	151	150	149	146
2022-23	151	146	145	139	130	121	107
Total	453	447	446	440	427	413	387
Share		98.7%	98.5%	97.1%	94.3%	91.2%	85.4%

The table above excludes withdrawal capacity reserved for balancing. There were only 7 days across the three winters when customers scheduled more than 90% of available storage withdrawal capacity. Envoy's net storage withdrawal capacity, which I used to build this table, excludes Aliso Canyon storage on the days when Aliso Canyon was not available due to the Withdrawal Protocol, which means the table accounts for the impact of the Aliso Canyon Withdrawal Protocol.

⁸¹ *Id.*

⁸² Collins Direct Testimony at 40 ("price spikes ... occurred while Aliso Canyon was capped well below its current 68.6 Bcf inventory level and while Line 235 remained at reduced pressure. That history demonstrates the cost to ratepayers of constrained storage coinciding with pipeline outages.").

⁸³ See Figure 1 for the average daily winter season gas price at SoCal Citygate.

I completed a further analysis of the 2022-23 Winter, the highest-priced winter in NGI's SoCal Citygate daily index. The table below shows the average daily gas price and the average share of storage withdrawal capacity scheduled each month.

Table 8: Winter 2022-23, storage capacity scheduled and average daily gas price⁸⁴

Month	Avg SoCal Citygate (\$/MMBtu)	Avg share of capacity scheduled
Nov 2022	8.88	41%
Dec 2022	30.67	50%
Jan 2023	17.96	15%
Feb 2023	7.63	34%
Mar 2023	8.70	20%

This table shows that during December 2022, the month with the highest prices in NGI's SoCal Citygate daily index, 50% of storage withdrawal capacity went unscheduled. Across all three winters, customers scheduled 100% of available capacity on only two days, December 2 and 17, 2022. On both, Envoy-reported capacity was about half that of surrounding days, consistent with Aliso's exclusion under the Protocol. On those two days, the net withdrawals left 7% and 14% of total capacity unused.

The analysis above shows that the Aliso Canyon Withdrawal Protocol limited storage scheduled for withdrawals on two days from Winter 2020-21 through Winter 2022-23.

My analysis shows that the Protocol appears to have had no impact on customer-scheduled withdrawals on 99.5% of winter days.⁸⁵ Because customers could have scheduled more withdrawals on 99.5% of winter days, the analysis also shows that the reduced inventory level at Aliso Canyon during the 2022-2023 winter season does not explain the price spikes of the 2022-2023 winter season.

⁸⁴ Table 8 uses flow-date (delivery) averages. On an issue-date basis, the December 2022 average is \$30.09 rather than \$30.67.

⁸⁵ Calculation: $1 - (2 \text{ days} / 453 \text{ days}) = 0.995584 = 99.5\%$

1 **6. STORAGE WITHDRAWALS FOLLOW DEMAND RATHER THAN PRICE.**

2 **6.1. SoCalGas answers an 18-winter statistical analysis with one 14-day example**
3 **that fails to control for demand variables.**

4 Dr. Berardi completed a rigorous statistical analysis showing that “the strength of the
5 relationship between demand and withdrawal is over four times as large as the relationship
6 between price and withdrawal.”⁸⁶ Gas demand explains more of the variation in storage
7 withdrawals than price in 17 of 18 winters from 2008-09 to 2025-26 (the exception, 2020-21,
8 includes Winter Storm Uri, when both were low). On average, demand explained 72.5% of the
9 variation and price explained 17.9%.⁸⁷ SoCalGas responds to Dr. Berardi’s 18-year regression
10 analysis with a 14-day comparison of prices and storage withdrawals during Winter Storm Fern
11 from which it concluded “Sierra Club’s reasoning that ‘demand is a stronger predictor of
12 withdrawal than price’ does not follow.”⁸⁸ SoCalGas’s price and storage analysis should be
13 rejected for three reasons.

14 First, Dr. Berardi’s results show the price-withdrawal relationship strengthened beginning
15 in winter 2023-24 , the first winter after the Commission opened I.23-03-008, its 2022-2023 gas
16 price spike investigation. Even so, demand remained the stronger predictor in each of those
17 winters.⁸⁹

18 Second, the 14-day analysis does not evaluate demand, nor does it show any demand
19 data. Without controlling for demand, SoCalGas’s analysis fails to address the core of Dr.
20 Berardi’s analysis: comparing the strength of the relationship between demand and withdrawal
21 against the strength of the relationship between price and withdrawal.

22 Third, the 14-day analysis compares SoCal Citygate to Henry Hub, a Louisiana price
23 index. Henry Hub is the national benchmark Attachment A uses, but it cannot show whether
24 Aliso storage moderated Southern California prices during Winter Storm Fern. Western prices
25 can. At the storm’s peak (Jan 24–26), Henry Hub averaged \$28.28; Waha (western Texas)
26 \$14.47; SoCal Border–Ehrenberg \$13.21; SoCal Border–Needles \$9.18; SoCal Citygate \$7.23;

⁸⁶ Exh. SC-02 (Berardi) at 24-25.

⁸⁷ *Id.* at 21-22.

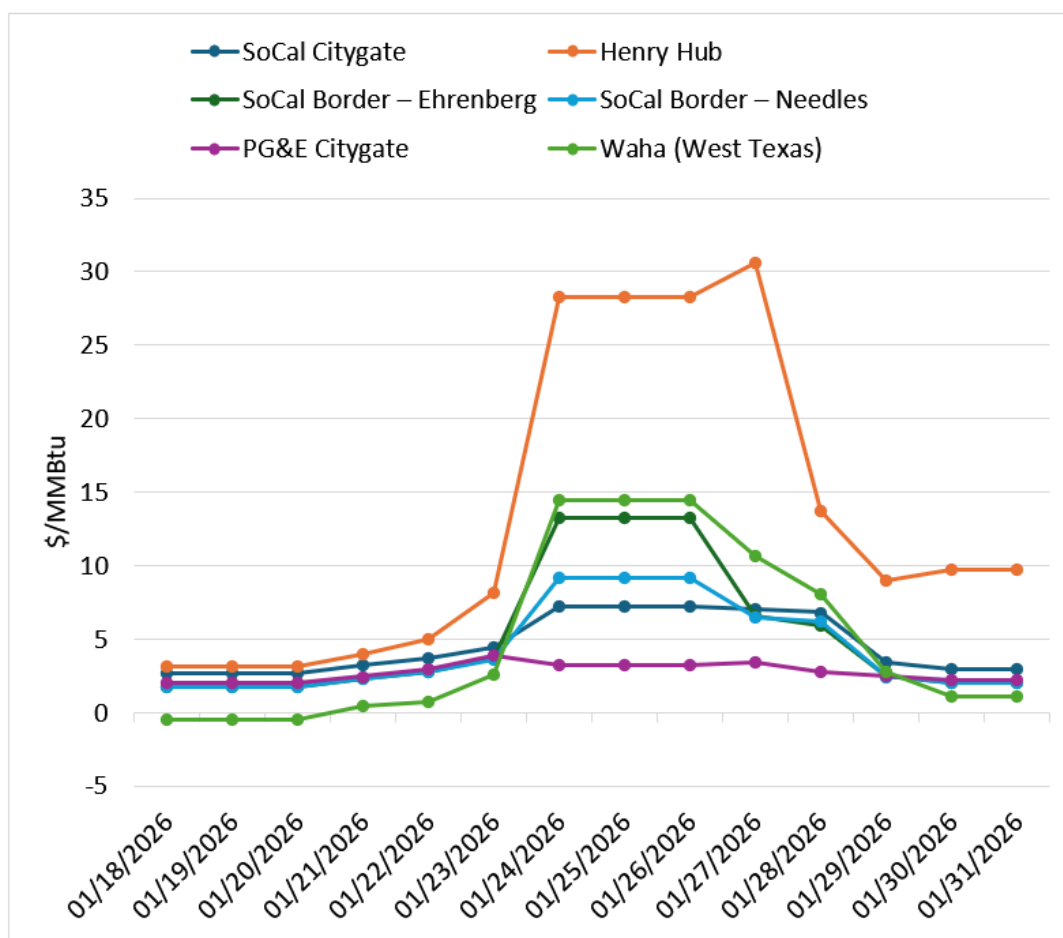
⁸⁸ Chang Rebuttal Testimony at SCC-3-4, Figure 2.

⁸⁹ Exh. SC-02 (Berardi) at 22, Figure 2.

Pacific Gas and Electric Company (“PG&E”) Citygate \$3.26. PG&E Citygate stayed between \$2.00 and \$3.87 throughout Jan 18–31.

IS claims that during Winter Storm Fern stored gas “substituted for spot market gas priced near \$30 per dekatherm.”⁹⁰ No Southern California market traded anywhere near \$30 as shown in the figure below. SoCal Citygate averaged \$7.23 at the peak (highest reported trade \$8.00), and the highest SoCal Border trade was \$17.50. Only Henry Hub, in Louisiana, approached \$30.⁹¹

Figure 3: Daily prices during Winter Storm Fern (SoCal Citygate, Henry Hub, SoCal Border–Ehrenberg, SoCal Border–Needles, PG&E Citygate, Waha)



Most of the gap to Henry Hub existed at the border before gas entered SoCalGas’s system; storage can account at most for the \$2–6 border-to-citygate difference for three days.

⁹⁰ Collins Direct Testimony at 26.

⁹¹ Source: NGI daily data.

PG&E Citygate was the lowest price point and PG&E sources gas from some of the same gas supply basins as SoCalGas.

6.2. During Winter Storm Fern, pipeline capacity exceeded gas sendout every day.

Reliability during Fern was not an issue because system receipt capacity exceeded customer demand (sendout) on each of the 14 days of SoCalGas’s analysis. SoCalGas states that storage became “the primary source of natural gas for customers, supplying nearly 60 percent of system demand at the storm’s peak.”⁹² The data show that storage use was because customers chose not to schedule available pipeline capacity, not because of a lack of flowing supply. SoCalGas’s own witness acknowledges that Southern California “local weather and demand were comparatively mild” during Fern.⁹³

Table 9: Receipt capacity vs. sendout, Jan 18–31, 2026 (MDth/d)⁹⁴

Date	Receipt capacity	Sendout	Capacity – sendout	Actual receipts	Physical Receipts/ Capacity
1/18	2,914	1,982	932	2,179	75%
1/19	2,924	2,185	739	2,173	74%
1/20	2,949	2,170	779	2,169	74%
1/21	3,117	2,306	811	1,937	62%
1/22	3,122	2,402	720	1,720	55%
1/23	3,086	2,259	827	1,251	41%
1/24	3,082	2,435	647	1,138	37%
1/25	3,147	2,557	590	1,104	35%
1/26	3,245	2,793	452	1,178	36%
1/27	3,192	2,519	673	1,258	39%
1/28	3,113	2,374	739	1,293	42%
1/29	3,096	1,908	1,188	1,700	55%
1/30	3,091	1,994	1,097	1,908	62%
1/31	3,056	1,851	1,205	1,902	62%

⁹² Chang Rebuttal Testimony at SCC-3.

⁹³ Sawin Rebuttal Testimony at AJS-15.

⁹⁴ Source: SoCalGas Envoy, Capacity Utilization (Jan. 2026, final cycle) and Daily Operations; SoCalGas’s RPU of 25% on Jan 24-25 uses scheduled volumes rather than physical receipts.

1 **6.3. SoCalGas’s analysis of withdrawals on highest-priced days does not hold up**
2 **under scrutiny.**

3 SoCalGas claims that Dr. Berardi’s analysis should be disregarded and that its own
4 Figure 3 “provides a more direct assessment by comparing average scheduled withdrawals of
5 each winter season with scheduled withdrawals on the highest-priced day of each winter
6 season.”⁹⁵ However, SoCalGas’s analysis reviews a handful of days, which do not represent
7 typical withdrawal activity and do nothing to inform the Commission as to SoCalGas storage
8 operations during the more than 2,000 other days included in Dr. Berardi’s analysis.

9 SoCalGas’s Figure 3 reviews 11 days over 11 winters with no statistical analysis and
10 without controlling for demand. A list of 11 winter days does not respond to a comprehensive
11 analysis of every winter day over 18 years. Figure 3 sets withdrawals on peak-priced days
12 against the winter average but does not control for demand. The figure shows that withdrawals
13 typically rise on cold, high-demand days, which is not in dispute. It does not show whether
14 customers used the withdrawal capacity available.

15 Its own figure also undercuts its claim in multiple ways. For example, in winter 2019-20,
16 scheduled withdrawals on the highest-priced day were near zero and below that winter’s average
17 withdrawals. On the highest-priced day of 2022-23 (Dec 14, 2022, \$49.67; Chang’s 2022-23 bar,
18 about 1.34 million Dth), customers scheduled 1,336,000 Dth/d of storage withdrawals against
19 1,590,000 Dth/d of available system withdrawal capacity, leaving 16% (about 254,000 Dth/d)
20 unused. Aliso was included in Envoy’s capacity that day. Moreover, on the second highest-
21 priced day (Dec 22, \$48.74), customers left 30% of system capacity unused. Finally, over the 55
22 above-average-price days that winter, customers used on average only 34% of available system
23 withdrawal capacity.⁹⁶

24 **6.4. SoCalGas has not quantified or demonstrated with concrete examples that it**
25 **operates Aliso Canyon to mitigate prices.**

26 Despite having many opportunities, SoCalGas has yet to demonstrate that Aliso Canyon
27 storage mitigates gas prices for California customers. SoCalGas failed to quantify price

⁹⁵ Chang Rebuttal Testimony at SCC-5.

⁹⁶ SoCalGas Envoy, Capacity Utilization (Nov. 2022–Mar. 2023, final cycle); NGI daily SoCal Citygate prices.

1 mitigation through gas storage withdrawals but rather argues that there was unquantified price
2 mitigation.⁹⁷ Moreover, SoCalGas fails to separate price-mitigation withdrawals from planned
3 withdrawals. SoCalGas asserts that its withdrawal data demonstrates cost benefits, but the only
4 way to show price mitigation during a price spike is to quantify it, which SoCalGas has failed to
5 do. SoCalGas cannot claim price-mitigation benefits without evidence.

6 **6.5. End-of-winter inventory demonstrates that Aliso Canyon inventory can be**
7 **reduced.**

8 SoCalGas states: “End-of-winter inventory is influenced by numerous factors, including
9 weather, operational needs, customer inventory management strategies, and market conditions
10 throughout the withdrawal season.”⁹⁸ I agree that multiple factors impact end-of winter
11 inventory. For example, over the past decade SoCalGas service territory has experienced
12 multiple major infrastructure outages, historically cold winters, and a winter with the highest
13 average gas price on record. Yet throughout the decade SoCalGas storage inventory has ended
14 each winter season with more than 34 Bcf of gas in storage. Thus, the end-of-season inventory is
15 an ideal metric for the Commission to use to confirm the reasonableness of reducing Aliso
16 Canyon storage inventory.

17 **7. THE COMMISSION CAN LOWER ALISO INVENTORY BY 29 BCF WITHOUT**
18 **REDUCING FIRM UBS WINTER WITHDRAWAL CAPACITY.**

19 SoCalGas, IS, and Cal Advocates opposed a reduction because they inaccurately claimed
20 it would impair the UBS program’s ability to withdraw gas during high prices.⁹⁹ My opening
21 testimony (Section 3.4) shows that Aliso storage could be reduced by 29 Bcf before the UBS
22 program could drain its full firm withdrawal capacity during the winter withdrawal months
23 (Nov–Mar).

24 After I filed opening testimony, SoCalGas stated that it had provided Sierra Club
25 erroneous UBS data in response to a Sierra Club data request.¹⁰⁰ The data correction does not
26 change the UBS program’s firm withdrawal capacity. My evaluation of firm withdrawal capacity

⁹⁷ Chang Rebuttal Testimony at SCC-6.

⁹⁸ *Id.* at SCC-4-5.

⁹⁹ Dandridge Direct Testimony at MMD-6-9; Collins Direct Testimony at 22-24.

¹⁰⁰ Exh. SC-22: SoCalGas Amended Supplemental Response to Sierra Club Data Request 1-19 (Sept. 28, 2026).

1 relied only on D.24-07-009 and continues to support my conclusion that UBS can still withdraw
2 its maximum firm capacity during the winter peak if the Aliso limit is lowered by 29 Bcf.

3 SoCalGas's supplemental data request response claims that Park and Loan injections and
4 withdrawals should also be counted as UBS inventory. SoCalGas's Schedule G-PAL (Park and
5 Loan, "PAL") and Schedule G-TBS (Transaction Based Storage, "TBS") define the two
6 Operational Hub programs. While both operate under the SoCalGas Operational Hub, PAL
7 effectively operates with unallocated UBS capacity that is not contracted to TBS customers.
8 Schedule G-PAL states that "[g]as parking is the temporary storage of gas on the Utility's system
9 and gas loaning is the temporary lending of gas from the Utility's system."¹⁰¹ G-PAL defines the
10 service as "temporary" and "interruptible."¹⁰² It is a way for SoCalGas to market storage for
11 which UBS customers have not signed firm TBS contracts. Advice Letter 5650, which closed G-
12 PAL, tacitly acknowledged that PAL is operated with unused UBS capacity: "[w]ith the
13 temporary suspension of the Unbundled Storage Program, the Operational Hub no longer has
14 capacity available to it to offer these parking and loaning services."¹⁰³ It does not state that PAL
15 is suspended because it is a component of the Unbundled Storage program. This calls into
16 question whether PAL is truly an Unbundled Storage program component or a separate entity
17 dependent on unallocated UBS capacity. However, I agree that if UBS is closed in the future that
18 PAL would be forced to close as well.

19 **7.1. SoCalGas has acknowledged that the UBS program is unnecessary.**

20 Regardless of how the Commission defines the UBS program in this proceeding (TBS
21 only, or TBS plus PAL), two facts remain.

- 22 • First, despite asserting in this proceeding that UBS is a key price-mitigation tool,
23 SoCalGas proposed in A.18-07-024 to "eliminate the Unbundled Storage Program"; the

¹⁰¹ SoCalGas, Schedule G-PAL, *Operational Hub Services*, Sheet 1, CPUC Sheet No. 61214-G, at Sheet 1 (eff. Oct. 15, 2023),

<https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS§Id=G-SCHEDS>.

¹⁰² *Id.*

¹⁰³ SoCalGas, Advice 5650, *Modification of Schedule No. G-PAL and Rule No. 41 Pursuant to Decision (D.) 20-02-045* (Triennial Cost Allocation Proceeding), at 2 (June 24, 2020) (approved by Energy Division and effective July 24, 2020),

<https://tariffsprd.socalgas.com/scg/filings/content/?utilId=SCG&bookId=GAS&flngStatusCd=Approved>.

Commission denied that request in D.20-02-045.¹⁰⁴ SoCalGas’s proposed elimination of UBS suggests its witnesses overstate UBS’s importance as a price-mitigation tool.¹⁰⁵

- Second, UBS’s assigned withdrawal capacity is only 2.1% of firm withdrawal capacity; 97.9% is assigned to other customer categories.¹⁰⁶ Moreover, on a 1-in-10 peak day, UBS firm withdrawal capacity is only 1.1% of demand. This demonstrates that UBS has minimal if any impact on gas prices on high demand days.

These facts support my opening testimony analysis that a 29 Bcf reduction to Aliso Canyon maximum inventory can be ordered because the impact to the UBS program’s withdrawals and injection will not be significantly impacted.

7.2. UBS transaction volumes do not show that inventory is needed.

SoCalGas asserts “substantial customer activity” in the UBS program.¹⁰⁷ Under D.24-07-009, UBS has 50 MMcfd of firm withdrawal rights; withdrawing at that rate every day of the 151-day winter changed the UBS inventory level by 7.55 Bcf, which equates to about 30% of the 25 Bcf UBS allocation.¹⁰⁸ SoCalGas’s corrected data show UBS winter drawdowns, including interruptible activity, peaked at 8.5 Bcf in 2024-25 and 7.8 Bcf in 2025-26 (34% and 31% of the allocation). Because these inventory changes are similar to the 7.55 Bcf that I calculated in opening testimony, SoCalGas’s testimony does not effectively rebut the evidence that UBS will be minimally impacted by a 29 Bcf reduction.

SoCalGas states: “These transaction volumes greatly exceed any single observed inventory balance and demonstrate that customers repeatedly cycled gas into and out of storage

¹⁰⁴ D.20-02-045, Decision Addressing San Diego Gas & Electric Company and Southern California Gas Company Triennial Cost Allocation Proceeding Application, at 6, 74 (Feb. 28, 2020), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M328/K289/328289863.PDF> (describing SCG’s request to eliminate the Unbundled Storage Program and denying that request).

¹⁰⁵ Dandridge Direct Testimony at MMD-8 (“Given the high prices that occurred when storage was constrained, and the equally demonstrated benefits following reinstatement of the UBS Program, the Commission should exercise caution before reducing or eliminating a program that has proven effective at mitigating price volatility and protecting ratepayers.”).

¹⁰⁶ Siegele Direct Testimony at 39-41, Table 5; D.24-07-009, Decision Adopting All-Party Settlement Agreement and Granting San Diego Gas & Electric Company and Southern California Gas Company Authority to Revise Their Natural Gas Rates and Implement Storage Proposals, Attachment A, at 6 (July 23, 2024), <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K491/536491449.PDF> (50 of 2,400 MMcfd).

¹⁰⁷ Chang Rebuttal Testimony at SCC-9.

¹⁰⁸ Siegele Direct Testimony, Section 3.4.

1 as a procurement and risk management tool rather than maintaining static inventory
2 positions.”¹⁰⁹

3 Volume cycled does not directly equate to needed inventory. D.24-07-009 allocates UBS
4 50 MMcfd of firm injection and withdrawal rights; activity above that is interruptible, as-
5 available service, and imbalance trades require no injection or withdrawal rights. That customers
6 can cycle large volumes on an interruptible basis while holding only a fraction of the 25 Bcf
7 allocation shows that cycling does not depend on the inventory that a 29 Bcf Aliso Canyon
8 inventory reduction would remove. Even including interruptible activity above firm rights, UBS
9 inventory fell by only 5.5 Bcf in 2024-25 (17.3 to 11.8 Bcf) and 4.5 Bcf in 2025-26 (23.0 to 18.4
10 Bcf) between November 1 and March 31.

11 SoCalGas also states that UBS “[i]nventory levels may not appear ‘full’ precisely
12 because customers are actively cycling gas into and out of storage in response to changing
13 market conditions and pricing opportunities.”¹¹⁰ Cycling explains turnover of a *portion* of
14 capacity. For example, 1 Bcf of gas cycled into and out of storage 4 times equates to 4 Bcf of
15 injection and 4 Bcf of withdrawals, but that activity only used 1 Bcf of storage inventory.
16 Records of cycling, such as in Witness Chang’s Figures 4 and 5, display activity but fail to
17 quantify inventory use, inventory need or UBS economic value.

18 **8. SOCALGAS PROPOSED NO SPECIFIC AND ACTIONABLE CHANGES TO** 19 **THE BIENNIAL ASSESSMENT ECONOMIC ANALYSIS.**

20 SoCalGas recommends a major overhaul to the Biennial Assessment Process’s economic
21 analysis. SoCalGas asserts that:

22 [r]ather than modifying individual inputs, the Commission should
23 adopt the broader enhancements recommended by SoCalGas, including (1)
24 reconsidering the 50% price-premium threshold and developing a
25 methodology that more directly evaluates customer and ratepayer cost
26 impacts; (2) incorporating summer-winter price spread analyses as a
27 measure of storage demand and value; (3) comparing SoCal Citygate
28 pricing metrics to western supply basin benchmarks; and (4) conducting

¹⁰⁹ Chang Rebuttal Testimony at SCC-9.

¹¹⁰ *Id.* at SCC-8.

1 predictive price-impact, storage-behavior, and price-volatility analyses to
2 evaluate the broader market consequences of inventory reductions.¹¹¹

3 SoCalGas’s proposal is not a modification to the Biennial Assessment Process it is a
4 wholesale rejection of the economic analysis that the Commission adopted in D.24-12-076. The
5 Commission specifically rejected complexity, instead opting for a simple approach to evaluating
6 the economics of Aliso Canyon storage inventory. D.24-12-076 states:

7 [T]he economic analysis is a simple approach, which does not quantify the
8 impact of Aliso Canyon on gas prices. However, the economic analysis is
9 not designed to quantify the impact of Aliso Canyon. The economic
10 analysis is designed to be a simple and transparent way to identify
11 conditions when gas prices are high enough to significantly impact
12 ratepayers’ bills. We conclude that the economic analysis is reasonable, and
13 in particular it is reasonable to compare the value of natural gas and storage
14 in Southern California to the general benchmark for the United States, i.e.
15 Henry Hub.¹¹²

16 Not only does SoCalGas propose a major overhaul that directly conflicts with D.24-12-
17 076, its proposal lacks sufficient detail to evaluate, much less implement, it. Without a specific
18 proposal, there is nothing for the Commission to evaluate. I recommend that the Commission
19 dismiss SoCalGas’s proposal because it would complicate the Biennial Process and drain
20 commission resources while failing to produce more actionable results than the Biennial
21 Assessment Process’s existing economic analysis. In contrast, the Commission should evaluate
22 and adopt Sierra Club’s proposed revisions to the Biennial Assessment process.

23 **9. THE 2026 CALIFORNIA GAS REPORT CONTAINS AN ERRONEOUS 1-IN-10**
24 **PEAK DAY GAS DEMAND FORECAST.**

25 Cal Advocates notes the difference in the 2024 California Gas Report (“CGR”) compared
26 to the 2026 CGR.¹¹³ Cal Advocates notes that the higher 2026 CGR peak demand estimates
27 “work directionally against the results of the 2025 Biennial Assessment...”¹¹⁴ I concur with that
28 assessment. Cal Advocates also states:

¹¹¹ *Id.* at SCC-15.

¹¹² D.24-12-076 at 57.

¹¹³ Prepared Testimony of Christian Lambert, at 1-7 to 1-10 (Aug. 20, 2026) [hereinafter “Lambert Direct Testimony”].

¹¹⁴ *Id.* at 1-8.

1 Whereas the 2024 vintage forecasts decrease steadily over the forecast
2 horizon, the 2026 vintage forecasts *increase* from winter 2028-29 through
3 winter 2030-31. The 2026 California Gas Report electricity generation peak
4 day demand forecast for winter 2030-31 is 34% higher than the winter
5 2030-31 forecast in the 2024 California Gas Report.

6 If this higher winter 2030-31 peak day demand forecast materializes,
7 then a reduction in the Aliso Canyon maximum storage limit would also be
8 imprudent... ¹¹⁵

9 I disagree with Cal Advocates' assessment of a reasonable response to the 2026 CGR.
10 Cal Advocates appears to accept the 2026 CGR as neutral, however, D.24-12-076 establishes the
11 CGR's 1-in-10 peak demand forecast as the threshold for triggering the Commission's
12 consideration of Aliso Canyon retirement.¹¹⁶ Thus, SoCalGas's upward revision in the 2026
13 CGR should be viewed with skepticism. Dr. Berardi's Opening Testimony listed numerous
14 inconsistencies and methodological issues with the 2024 CGR and recommended that the
15 Commission update the source for the 1-in-10 gas demand forecast from the CGR to the forecast
16 produced by the California Energy Commission.¹¹⁷

17 When the 2026 CGR was released, Sierra Club requested additional data to understand
18 several idiosyncrasies in the 2026 CGR. The following are errors or omissions in the 2026 CGR
19 that I have found based on SoCalGas's response to Sierra Club's data request.¹¹⁸

- 20 • The 2026 CGR's 1-in-10 peak day demand does not account for gas demand changes
21 resulting from the South Coast Air Quality Management District's ("SCAQMD")

¹¹⁵ *Id.* at 1-9 to 1-10 (emphasis in original).

¹¹⁶ D.24-12-076 at 2-3 ("This decision finds that Aliso Canyon is necessary for natural gas and electric reliability and cost containment until the peak day natural gas demand forecast drops below 4,121 million metric cubic feet per day... When the peak day demand forecast for two years out decreases to 4,121 million metric cubic feet per day and the biennial review process shows that Aliso Canyon could be closed without jeopardy to reliability or just and reasonable rates, then the Commission will open an Order Instituting Investigation proceeding to review the conclusions of the biennial assessment, consider issuing any related orders and address any relevant issues related to permanent closure and decommissioning.").

¹¹⁷ Exh. SC-02 (Berardi) at 6-17, 25 (detailing four core methodological flaws in SoCalGas' demand forecasting methodology and recommending the Commission use the CEC's 1-in-10 gas demand forecasts instead).

¹¹⁸ Exh. SC-23: SoCalGas Response to Sierra Club Data Request 7 – First Set of Responses (Sept. 23, 2026); Exh. SC-24: SoCalGas Supplemental Response to Sierra Club Data Request 7-All Responses (Sept. 30, 2026).

1 Amended Rule 1146.2.¹¹⁹ SCAQMD’s board approved Amended Rule 1146.2 over two
2 years ago on June 7, 2024, and SCAQMD estimates it will impact over 1 million gas-
3 fired units requiring them to convert to zero-emissions.¹²⁰

- 4 • The 2026 CGR’s 1-in-10 peak day demand does not include any renewable energy or
5 battery storage resources ordered by the Commission after 2021.¹²¹
- 6 • SoCalGas was unable to explain the extreme year-to-year fluctuations (up to 17% year-
7 over-year differences) in its forecast gas demand for gas-fired electric generation.¹²² The
8 California Energy Commission (“CEC”) Integrated Energy Policy Report’s (“IEPR’s”)
9 year-over-year electricity demand forecast does not change by even close to 10% in any
10 year, much less 17%.¹²³ Moreover, because SoCalGas was unable to provide any
11 justification for the swings in demand in gas demand required to serve electric
12 generation, SoCalGas’s electric generation component of its 1-in-10 peak day demand
13 forecast is highly likely to be inaccurate.
- 14 • The 2026 CGR states that “[t]he base case assumes most of the CPUC adopted 2025
15 Preferred System Plan.” When asked which parts of the plan were excluded, SoCalGas
16 stated “CAISO capacity assumptions used in the model were based on the capacity
17 defined under the 2025–2027 Transmission Planning Process scenario.”¹²⁴ No such

¹¹⁹ Exh. SC-23: SoCalGas Response to Sierra Club Data Request 7 – First Set of Responses at 7 (Sept. 23, 2026) (“QUESTION 16: Does the 2026 California Gas Report Table 38 account for gas demand changes resulting from the South Coast Air Quality Management District’s Amended Rule 1146.2? If so, specify which categories of gas demand are impacted and quantify the impact. RESPONSE 16: No.”).

¹²⁰ SCAQMD, *South Coast AQMD Approves Rule to Accelerate the Transition to Zero-Emission for Water Heaters*, <https://www.aqmd.gov/home/research/pubs-docs-reports/newsletters/aug-sep-2024/water-heaters> (“On June 7, 2024, South Coast AQMD’s Governing Board approved updates to Rule 1146.2 that will require new and existing residential and commercial buildings to transition to zero-emission (ZE) water heaters... The amendments to Rule 1146.2 will impact about 1 million units across South Coast AQMD’s four-county jurisdiction, including approximately 710,000 natural gas-fired residential pool and spa heaters...”).

¹²¹ Exh. SC-23: SoCalGas Response to Sierra Club Data Request 7 – First Set of Responses at 6-7, (Sept. 30, 2026), (“QUESTION 18(b): Does the power market simulation include resources that the Commission ordered after D.21-06-035?... RESPONSE 18(b): No.”).

¹²² Exh. SC-24: SoCalGas Response to Sierra Club Data Request 7 – Supplemental at 3-5, (Sept. 30, 2026).

¹²³ See CEC, *2025 Integrated Energy Policy Report, CEC Integrated CED 2025 Baseline Forecast LSE and BAA Tables*, 25-IEPR-03 Docket, TN# 268727, at Sheet “Form 1.1c” (reference Column Average Annual Growth 2025-2050: SCE Service Territory = 1.30%, LADWP service territory = 1.30%), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=268722&DocumentContentId=105878>.

¹²⁴ Exh. SC-23: SoCalGas Response to Sierra Club Data Request 7 – First Set of at 6-7.

1 scenario exists. The Transmission Planning Process includes base cases each year and as
2 well as other portfolios. There is not a multi-year Transmission Planning Process
3 scenario. SoCalGas's vague and inaccurate assertion again calls into question the
4 rigorousness of the modeling that produced the erratic year-over-year results for its
5 electric generation gas demand forecast.

6 The list above is a partial collection of errors and omissions in the 2026 CGR. These significant
7 errors and omissions produce inaccurate inputs for the 1-in-10 peak gas demand forecast making
8 the forecast unreliable and unusable for Commission decision making.

9 **10. COMPARING WINTER PEAK ELECTRIC DEMAND TO RENEWABLES,**
10 **STORAGE, AND ELECTRIC IMPORTS SHOWS THAT THE FULL 68.6 BCF**
11 **OF ALISO CANYON INVENTORY IS UNNECESSARY.**

12 SoCalGas's rebuttal testimony argues that underground gas storage provides more energy
13 over longer periods than batteries and that the two are not interchangeable.¹²⁵ I agree that they
14 are not interchangeable. My opening testimony did not claim that they were. My testimony
15 showed that CAISO's battery capacity now exceeds the battery capacity that FTI's analysis
16 implied would be necessary to close the electric shortfall that FTI identified without Aliso
17 Canyon, and that battery capacity addresses the steepest three-hour electricity ramp.¹²⁶
18 SoCalGas's testimony does not address either point.

19 SoCalGas's main support for its claim is a statement by the President and CEO of the
20 North American Electric Reliability Corporation that, during the afternoon ramp, gas plants "are
21 pulling gas from the Southern California Gas system much faster than any pipeline can deliver
22 it," making Aliso Canyon "like a shock absorber on the system."¹²⁷ That statement dates from
23 November 2023. The table below shows the significant changes to the California electric system
24 since the end of 2023 as reported by CAISO.¹²⁸

¹²⁵ Sawin Rebuttal at AJS-20.

¹²⁶ Siegle Opening Testimony at 11, 16-19.

¹²⁷ Sawin Rebuttal at AJS-20.

¹²⁸ CAISO, Key Statistics Monthly Reports, <https://www.caiso.com/library/key-statistics> (last visited Oct. 8, 2026).

1

Table 10: CAISO, Key Statistics for December 2020-2025

December	Peak demand (MW)	Peak demand served by renewables (MW)	Peak net imports (MW)	Installed battery capacity (MW)	Peak demand minus renewables, imports, and batteries A - B - C - D = E
	A	B	C	D	E
2020	29,672	5,454	10,836	Not reported	13,382
2021	31,686	6,089	11,620	2,595	11,382
2022	30,283	10,008	9,207	4,614	6,454
2023	29,261	14,352	6,654	7,188	1,067
2024	30,581	16,360	9,260	11,454	-6,493
2025	31,455	19,592	11,078	15,810	-15,025
Notes: 1. Battery capacity date: each figure is "as of" about January 1 of the following year (December 31, 2022 for the 2022 report). The December 2020 report has no battery figure. 2. Different times: each column is a separate monthly peak at its own date and time, so column E represents a trend, not a point in time. 3. Renewables definition: the source notes define this column as "the highest amount of renewables serving peak electricity demand on any given day."					

2 CAISO reported that peak demand exceeded the combined totals of peak demand served
 3 by renewables, peak net imports, and installed battery capacity by 1,067 MW in the month of
 4 December 2023. By December 2025, the combined totals exceeded peak demand by 15,025
 5 MW. The other important factor to note about CAISO's data is that December peak electricity
 6 demand has remained between 29,000 MW and 31,500 MW every year between 2020 and 2025,
 7 while renewable generation and battery capacity have grown significantly every year. The table
 8 above demonstrates a strong trend showing that December gas demand from gas-fired generators
 9 will decrease each year. That trend is expected to continue for two decades because renewable
 10 generation capacity and storage capacity are forecast to grow every year between now and 2045
 11 to achieve California's 2045 carbon neutrality targets. Already in 2026, installed renewable
 12 capacity has grown by more than 5,000 MW, import capacity has increased by more than 2,000
 13 MW, and battery capacity has grown by more than 1,000 MW. Thus, for December 2026
 14 Column E will likely show a difference greater than 20,000 MW.

15 December is significant for two reasons. First, it is the month with the lowest solar
 16 generation production during the year. Even though solar production is low in December, the
 17 installed renewable capacity serves a significant portion of the winter peak demand. Second,

December is the month that SoCalGas uses as a basis for its 1-in-10 peak day gas demand.¹²⁹ The rapid increase in renewable production and battery capacity, plus the significant import capacity, should produce a corresponding rapid decrease in the California Gas Report's gas demand from electric generation (EG). However, the 2026 California Gas Report increased the 2026 EG forecast gas demand by 8% compared to the 2026 forecast reported in the 2024 California Gas Report, which conflicts with data in the table above.

Renewable capacity and battery capacity are increasing significantly faster than winter electricity demand. However, Energy Division staff in the IRP proceeding are already reviewing the potential for winter-peaking electricity demand after 2040. The IRP modeling that considers and plans for an eventual switch to winter-peaking electric demand ensures that renewable capacity will continue to meet electricity needs during the winter even when demand grows.

I draw two conclusions from the data above. First, the data in the table above shows that actual electric demand is consistent year to year, but renewables production and battery capacity continue to rapidly increase. That demonstrates SoCalGas' 1-in-10 peak day demand forecast is erroneously inflated. Second, the amount of gas used by electric generators will be lower on average in future years than it has been in past as additional renewable energy and storage come online, which will leave more gas in storage to be used in case of peak gas demand. These data show that the Commission can lower Aliso Canyon gas inventory while continuing to ensure energy reliability.

11. CONCLUSION

Aliso Canyon's current inventory can be reduced while maintaining energy reliability and just and reasonable rates. Gas commodity prices are low and falling on the Biennial Assessment Process measures, any reliability concerns rest on scenarios that are far less likely than a 1-in-10 peak day, and storage records show unused capacity at both the beginning and end of each winter season.

¹²⁹ 2026 California Gas Report, Table 38, note 6, ("Average daily December Noncore Non-EG demand for all market segments except Refinery and SoCalGas and SDG&E noncore Commercial; SoCalGas and SDG&E noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.").

1 I recommend that the Commission:

- 2 1. Approve the Biennial Assessment's recommendation to reduce Aliso Canyon inventory;
- 3 2. Reduce Aliso Canyon maximum inventory limit by 29 Bcf;
- 4 3. Reject modeling proposals that layer below-average supply conditions over top of 1-in-10
- 5 peak day assumptions;
- 6 4. Set receipt point capacity to 97% in future Biennial Assessment modeling;
- 7 5. Dismiss SoCalGas's proposed overhaul of the economic analysis; and
- 8 6. Replace the California Gas Report's 1-in-10 peak day forecast with the California Energy
- 9 Commission's forecast in the Biennial Assessment Process.

10 This concludes my testimony.