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High Natural Gas Prices in Winter 2022-23: Part III (~~Updated~~Revised)

A STAFF WHITE PAPER SUPPORTING CPUC INVESTIGATION (I.) 23-03-008

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Thanks to:

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Executive Summary

This Staff White Paper continues the California Public Utilities Commission's (CPUC) investigation of the factors contributing to extremely high natural gas prices in winter 2022-23 in Investigation (I.) 23-03-008. It builds on findings presented in the Staff White Paper *High Natural Gas Prices in Winter 2022-23: Part I* (*White Paper Part I*), issued on July 2, 2024, and the Staff White Paper *High Natural Gas Prices in Winter 2022-23: Part II (White Paper Part II)*, issued on June 5, 2025.

The focus of this expanded analysis includes the following topics: 1) hedging by the gas utilities' core procurement departments in winter 2022-23; and 2) an evaluation of the utilities' core gas procurement incentive mechanisms, including how they performed over a 10-year period[1] and how they performed during winter 2022-23. Because of differences in the timing of the utilities' incentive mechanism reports, Staff are able to discuss the winter 2022-23 performance of SoCalGas' core gas procurement mechanism in more detail than that of PG&E.[2]

White Paper Part I addressed two issues identified for consideration in the proceeding:[3]

1. What factors caused or contributed to observed gas price increases beginning on November 1, 2022? This includes market fundamentals as well as other applicable factors.
2. Did any of the entities under the Commission's regulatory jurisdiction play a role in causing or contributing to the gas price increase in California border prices between November 1, 2022, and March 31, 2023 (gas price spikes)?

White Paper Part II further developed the record on those issues and addressed the following additional scoping memo issues:

5. In addition to the information currently in the record, is there any additional information that the Commission should collect or examine to further understand market dynamics that caused or contributed to the gas price spikes?
6. What are the gas and electric market interactions that affected, during the gas price spikes, and affect, currently, costs to consumers that the Commission should examine and/or investigate?

This *White Paper III* aims to further develop the record regarding winter 2022-23 and to seek answers to the issue below:

4. What actions should the Commission and/or other entities take to mitigate the harm to ratepayers if such gas price spikes do recur?

For the hedging section, Energy Division staff (Staff) describe what happened in 2022-23, with Staff finding that hedging resulted in gains for both utilities' ratepayers. For the section on core gas procurement

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[1] The 10-year periods reviewed differ between the utilities for two reasons: 1) SoCalGas submits its incentive mechanism performance reports more promptly than PG&E, thus Staff have access to the data for more recent years; and 2) the utilities' reporting periods cover different months.
[2] See the Sources and Methodologies section below for more information.
[3] Assigned Commissioner's Scoping Memo and Ruling for I.23-03-008, issued September 5, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M519/K776/519776476.PDF.

incentive mechanisms, Staff provide an in-depth study with the goal of identifying changes the CPUC could consider that may mitigate the harm to ratepayers should gas price spikes recur. Staff suggest three changes that could be made in this proceeding that we believe could increase transparency, alignment, and stakeholders' understanding of how the incentives operate, which could mitigate harm to ratepayers should gas price spikes recur. Staff also identify broader possible improvements to the core procurement incentive mechanisms that could potentially be considered in a future proceeding. While these improvements could increase oversight and the share of savings allocated to ratepayers, these broader changes are beyond the scope of this proceeding. Staff thus present these suggestions here for general consideration.

It is worth noting at the outset, however, that core procurement incentive mechanisms are not intended to, and cannot, prevent price spikes in the deregulated natural gas commodity market. Rather, they provide incentives for the utilities to respond effectively to market conditions and to procure gas for core customers at a reasonable cost.

The CPUC received comments on *White Papers Part I* and *II* from nine parties. Some parties requested additional analysis related to hedging and the performance of the core gas procurement incentive mechanisms. For example, in its Opening Comments on *White Paper I,* Small Business Utility Advocates (SBUA) recommended that the CPUC "[e]xplore the use of financial hedging instruments to protect against extreme price fluctuations."[4] The Sierra Club, in all of its comments, argued that the core gas procurement incentive mechanisms, and particularly that of SoCalGas, are "broken and should be replaced."[5] Staff address those concerns here.

Hedging for Winter 2022-23

The gas utilities' core procurement departments, known as SoCalGas Gas Acquisition and PG&E Core Gas Supply, purchase natural gas for the utilities' "bundled" core gas customers, i.e., for those core customers who opt to take gas procurement service from the utility.[6,7] To protect core customers from having to pay the full cost of gas price spikes, Gas Acquisition and Core Gas Supply purchase physical and/or financial hedges. Hedging is a form of insurance in which the utility takes offsetting financial positions that limit both potential losses and potential savings from market movements.[8]

Staff found that PG&E Core Gas Supply and SoCalGas Gas Acquisition employed different hedging strategies heading into winter 2022-23. PG&E Core Gas Supply procured only financial hedges, which are purely financial transactions (or contracts) with no actual gas molecules delivered. In contrast, SoCalGas

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[4] SBUA Opening Comments on *White Paper I*, p 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K061/537061689.PDF.

[5] For example, Sierra Club, Reply Comments on *White Paper I*, p. 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M538/K617/538617449.PDF.

[6] Core customers include residential and small commercial and industrial customers. Core gas customers have the option to take their procurement service from non-utility gas suppliers known as core transport agents. Noncore customers are responsible for their own procurement of gas supplies. For more information, see: www.cpuc.ca.gov/industries-and-topics/natural-gas/retail-gas-markets-and-core-transport-agent.

[7] SoCalGas Gas Acquisitions conducts gas procurement and hedging on behalf of SDG&E's bundled core gas customers per D.07-12-019: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/76171.PDF

[8] D.10-01-023, pp 12-14: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.

Gas Acquisition procured only physical hedges, where there is at least the option to have gas molecules delivered.

Staff's review of confidential reports on PG&E Core Gas Supply's financial hedges found that they ended winter "in the money." A financial hedge can be considered in the money if it generates a positive financial settlement, meaning the contract payoff is favorable relative to the market price at the time of execution. Hedging revenue helped reduce PG&E Core Gas Supply's overall gas procurement cost and **significantly** reduced core customers' utility bills. The exact amount of that reduction is not available publicly because of the still-pending California Public Advocates Office (Cal Advocates)[9] and CPUC review of PG&E's recently submitted *Core Procurement Incentive Mechanism (CPIM) Annual Performance Report* covering winter 2022-23. This paper thus relies on, but does not disclose, information that PG&E provided confidentially.[10]

SoCalGas Gas Acquisition's portfolio of physical hedges also ended winter 2022-23 in the money. A physical gas hedge is in the money if it creates value compared to the benchmark price for that delivery month. Gas Acquisition's net physical hedges resulted in about $10.1 million in savings relative to the associated benchmark costs, **modestly** reducing core customers' utility bills.

As noted in *White Papers Part I and II*, PG&E and SoCalGas faced differing market conditions in winter 2022-23. Outages on the El Paso interstate transmission line had a more significant impact on the SoCalGas system than that of PG&E. There was also considerably more overall gas storage capacity in the PG&E service territory than that of SoCalGas. Having sufficient gas storage and pipeline capacity can contribute to more "liquid" markets,[11] both for spot gas purchases and hedging contracts. The fact that PG&E's gas market was more liquid than that of SoCalGas may have contributed to the utilities' differing hedging decisions.

Core Gas Procurement Incentive Mechanisms

Overview

Prior to the adoption of the core gas procurement incentive mechanisms, the CPUC conducted after-the-fact reasonableness reviews in formal proceedings to determine whether the utilities' core procurement departments had purchased gas at a reasonable cost. These proceedings could be lengthy and contentious. For example, in Decision (D.) 94-03-050, the CPUC reviewed PG&E's Canadian gas procurement costs for the years 1988 through 1990 and ordered disallowances of $90 million plus interest. The CPUC required 54 days of hearings between June 1 and October 31, 1992, as well as extensive staff and party involvement to reach that decision.[12] In Rulemaking (R.) 90-02-002, the CPUC noted that some parties were concerned that

[9] Cal Advocates is the independent consumer advocate at the CPUC.

[10] PG&E filed its *CPIM Annual Performance Report for Year 30 (November 1, 2022 – October 31, 2023)* on July 29, 2025 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/ng-prices/pge-annual-cpim-202211-thru-202310-year-30.pdf.

[11] A "liquid" market is a market with many available buyers and sellers and comparatively low transaction costs. See Investopedia definition: Liquid Market: Definition, Benefits in Trading, and Examples.

[12] D.94-03-050 pp 2 and 5: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/decisions-rulemakings/d9403050_a9104003.pdf.

the reasonableness review process provided only negative incentives to minimize core procurement costs, which encouraged the utilities to be risk averse.[13]

Beginning in the mid-1990s, the CPUC adopted incentive mechanisms to provide California gas utilities with a financial incentive to lower procurement costs relative to market-based benchmark costs. These incentives rewarded or penalized utility shareholders for the core procurement departments' performance in procuring gas at below-benchmark prices. The CPUC's goals for the incentive mechanisms included:

- Reducing regulatory burden and complexity for parties,
- Providing the utilities with clear incentives to minimize gas costs to ratepayers and adjust to changing circumstances without micromanagement,
- Encouraging the utilities to develop innovative methods for improving performance, and
- Aligning ratepayer and shareholder interests.[14]

In general, these incentive mechanisms compare the utility's actual gas procurement costs to market-based benchmark costs to determine if the utility's costs were reasonable. Costs are reasonable if actual costs are within a specified range, called the deadband, relative to benchmark costs. If actual costs are lower than the range, utility shareholders get a financial reward. If actual costs are higher than the range, shareholders refund a percentage of the overage to customers. The reward or penalty is a certain percentage of the savings or excess costs below or above the deadband.

This report provides an in-depth comparison of the two major gas utilities' core gas procurement incentive mechanisms: SoCalGas' Gas Cost Incentive Mechanism (GCIM) and PG&E's Core Procurement Incentive Mechanism. While the goals of these mechanisms are the same (to incentivize low-cost gas procurement), there are many differences in how the mechanisms operate. Some of the major differences are summarized in the table below.

Table 1: Major Differences between the GCIM and CPIM

	GCIM	CPIM
CPUC process	Application	Tier 2 Advice Letter
Deadline for Utility Annual Report/Application	Annual report and Application by June 15	No set deadline
Deadline for Cal Advocates Report	10/15	None
Reporting Year	April-March	November-October
Preliminary Statement Description	Describes calculations for benchmark costs (except for physical hedges), actual costs, and determination of reward	Does not describe calculation of benchmark or actual costs
Includes Storage?	No	Yes, as a pass-through cost
Transportation	Pass-through cost	Includes an incentive to reduce transportation reservation costs;

[13] R.90-02-002, p 15: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/decisions-rulemakings/r9002008.pdf.

[14] Ibid, pp 14.

	GCIM	CPIM
		impacts rewards/penalties
Commodity Benchmark: Volume	Based on actual Gas Acquisition purchases	Benchmark volume and sequence are based on the CPIM methodology
Commodity Benchmarks Prices	Benchmark prices are based on first-of-month indices at relevant Mainline trading points and the SoCal Border and Citygate	Monthly or daily index prices for sequenced locations calculated to citygate delivery point
Winter Financial Hedge Benchmark Costs	Gains/losses not included	80% of gains/losses included
Winter Financial Hedge Actual Costs	25% of gains/losses included	100% of gains/losses included
Winter Physical Hedge Benchmark Costs	25% of applicable commodity benchmark price included	n/a
Winter Physical Hedge Actual Costs	25% of actual net hedging cost included	n/a
Ratepayer/Shareholder Sharing Below Benchmark	Between 1% and 5% below benchmark: 75% ratepayers/25% shareholders More than 5% below benchmark: 90% ratepayers/10% shareholders	80% ratepayers/20% shareholders
Ratepayer/Shareholder Sharing Above Benchmark	50% ratepayers/ 50% shareholders	50% ratepayers/ 50% shareholders

Findings

In addition to describing the utilities' core gas procurement incentive mechanisms, Staff evaluated their performance over a 10-year period. Staff found that the utilities were consistently able to beat the benchmarks, generate ratepayer savings, and reap shareholder rewards. They did so through procurement of supplies priced near or below benchmark prices on average and strategic sales of core gas and other transactions.

After reviewing the topic in depth, Staff did not find the core gas procurement incentive mechanisms to be "broken" as asserted by the Sierra Club, despite finding some aspects of the mechanisms that could be improved.[15] These programs still advance the CPUC's original goals of reducing regulatory burden, providing clear incentives, allowing for innovation, and aligning ratepayer and shareholder interests. Between 2015 and 2024, SoCalGas' Gas Acquisition procured gas at an annual cost that was, on average, $114.6 million below the benchmark, saving ratepayers an average of $101.9 million per year and earning

[15] Sierra Club, Reply Comments on *White Paper I*, p. 2: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M538/K617/538617449.PDF.

average shareholder rewards of $12.7 million per year.[16] Between 2013 and 2023, PG&E's Core Gas Supply procured gas at an annual cost that was, on average, $47.9 million below the benchmark, saving ratepayers an average of $41.5 million per year and earning average shareholder rewards of $6.3 million per year.[17] In addition, formal CPUC review of incentive mechanism rewards resulted in a significant reduction to SoCalGas' GCIM reward for winter 2022-23 and provides a safety valve through which the CPUC can reduce outsize rewards when appropriate.

While Staff acknowledge this consistent record of ratepayer savings, we put forth several recommendations for improving the incentive mechanisms. The CPUC may wish to consider three of these modifications in this proceeding to increase transparency, alignment, and stakeholders' understanding of how the incentives operate, which could mitigate harm to ratepayers should a gas price spike occur again. These changes include requiring: 1) the utilities to provide complete descriptions of their incentive mechanisms in their Preliminary Statements; 2) all utilities to follow the same process for receiving CPUC approval of the shareholder award; and 3) PG&E to submit its Annual CPIM Report by a set deadline. Staff also propose other changes the CPUC could consider in a new proceeding to improve oversight of the incentive mechanisms and increase the share of savings allocated to ratepayers.

Summary of Staff Recommendations

Staff used the following guiding principles in our evaluation of the incentive mechanisms:

- Transparency: Are all components of the incentive mechanism clearly described in the utility's tariffs?
- Simplicity: Does the methodology consist of straightforward processes that customers, staff, and stakeholders can understand?
- Alignment: Are the mechanisms and performance review processes consistent across California utilities where possible?
- Effectiveness: Does the mechanism provide the utility with an incentive to procure core gas supplies at below-benchmark costs while appropriately balancing risks and rewards for ratepayers and shareholders?

Staff provide a simplified list of our proposed changes below because a baseline knowledge of the incentive mechanisms is needed to understand some of the recommendations. A complete list can be found in the Staff Recommendations section at the end of the report. Staff recommend that the CPUC consider authorizing relatively simple changes in this proceeding to make the incentive mechanisms more transparent and better aligned. Better stakeholder understanding and participation may improve oversight and accountability during periods of market volatility, thereby potentially mitigating ratepayer harm should gas price spikes recur. These simple changes could also lay the groundwork for a possible future proceeding in which the CPUC could consider further changes to increase the simplicity, alignment, and effectiveness of the incentive mechanisms in order to improve oversight and increase the share of savings allocated to

[16] See Table 13~~Table 13~~ below.
[17] See Table 24 below.

ratepayers. Because these additional changes would be outside the scope of this proceeding, the CPUC may wish to consider these changes in a new proceeding.

Transparency

One of the first steps Staff took in preparing this report was to review the sections of the utilities' Preliminary Statements pertaining to the GCIM and CPIM.[18] Improving the description of these programs in the Preliminary Statements would increase transparency and stakeholders' ability to understand how they operate. Increasing transparency has the potential to mitigate harm to ratepayers by improving oversight should future gas price spikes occur.

At a high level, Staff found that SoCalGas provides a relatively clear description of the GCIM in its Preliminary Statement. However, SoCalGas could improve in a few areas, particularly in its description of how physical hedges are handled. In contrast, PG&E provides little description of how its very complex CPIM mechanism is structured in its Preliminary Statement.

To increase transparency and improve stakeholder participation and, thereby, potentially mitigate harm to ratepayers should gas price spikes recur, Staff recommend that the CPUC in this proceeding:

1. Require the utilities to submit Tier 1 advice letters updating their Preliminary Statements to thoroughly describe all aspects of their core procurement incentive mechanisms as set out in the Staff Recommendations section at the end of this report.

Simplicity

There are trade-offs between simple and complex programs. Simpler programs are easier for staff, parties, and the public to understand. Also, it is easier to maintain a shared understanding of a simpler program as time passes and the people who shaped the policy move on. That said, there are circumstances in which greater complexity leads to such significant gains in effectiveness that the trade-off between simplicity and complexity is worthwhile.

Staff found that PG&E's CPIM is significantly more complex than SoCalGas' GCIM. To potentially improve the functioning and oversight of the incentive mechanisms, Staff recommend that the CPUC gain a better understanding as to whether the benefits of the CPIM outweigh its burden of added complexity compared to the GCIM.

Alignment

There are differences between the SoCalGas and PG&E pipeline systems, the markets they access, and how they operate, which may justify some differences in how they are regulated. However, Staff recommend that

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[18] Preliminary Statements are a part of utility tariffs. They typically include a description of the services provided, a summary of rates, a description of balancing accounts, or a description of ratemaking mechanisms. The Preliminary Statement for the SoCalGas GCIM can be found in Part VIII of the link below (scroll down): https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM. The Preliminary Statement for PG&E's CPIM can be found in section C(9) here: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

similar programs be aligned across the utilities whenever possible to allow straightforward comparison of utility performance and to reduce the burden on staff and stakeholders who must spend time mastering the nuances of differing utility programs to oversee them effectively.

Therefore, Staff recommend that the CPUC consider bringing the utilities' core procurement incentive mechanisms into closer alignment where possible. Some of Staff's recommendations are procedural and could be considered in this proceeding. Others are more substantive and may benefit from consideration in a new proceeding.

In this proceeding, Staff recommend that the CPUC consider the following measures to streamline stakeholder participation and, thereby, potentially mitigate harm to ratepayers should gas price spikes recur:

2. Require all utilities to follow the same process for receiving CPUC approval of the shareholder award, either via an application or a Tier 2 or 3 advice letter.
3. Require PG&E's Annual CPIM Report and advice letter/application to be submitted by a set annual deadline.

Staff also recommend that the CPUC consider more substantive changes to improve the oversight and functioning of the incentive mechanisms in a new proceeding. Such changes could include requiring both utilities to follow similar procedures for calculating benchmark and actual costs; including incentives for both utilities to reduce transportation costs; and requiring both utilities to follow the same procedures, with the same percentages, for incorporating hedging into actual and benchmark costs.

Effectiveness

While Staff support the idea of providing an incentive to gas utilities to procure reliable gas supplies for core customers at the lowest possible cost, the incentive should balance risk and reward for both ratepayers and shareholders. Shareholders have consistently received rewards under these mechanisms for decades throughout many different market conditions. Shareholders' consistent wins and almost non-existent losses raise the question: could the rules of these incentive mechanisms be modified to preserve the benefits of performance-based ratemaking while allocating more of the savings to ratepayers?

Answering these questions would require broad changes to the CPIM and GCIM. Staff, thus, recommend that the CPUC consider the following in a future proceeding:

- Reduce the shareholder reward cap for both the GCIM and CPIM from its current level of 1.5 percent of commodity costs to 1 percent.
- Limit the shareholder reward to no more than 15 percent of the overall savings for both the CPIM and GCIM.
- Reduce the upper tolerance band for both the GCIM and the CPIM from the current level of 2 percent of benchmark commodity costs to no more 1 percent.
- Include a higher percentage of the actual and benchmark costs for physical hedges into the GCIM and use the same percentage for the CPIM.
- Consider a cap on hedging costs.

Sources and Methodologies

While this report looks into two topics, utility hedging and core procurement incentive mechanisms, Staff relied on many of the same sources for both. Since gas hedging costs are recovered in part through the utility's core procurement incentive mechanisms, Staff relied on the various reports, advice letters, and proceedings that provide information about the utilities' core procurement efforts for both sections of this report. Much of this information is confidential because it involves market-sensitive information. Making such information public could make it more difficult for the utilities' core procurement departments to negotiate good deals for ratepayers. However, some of this information is discussed publicly in the *Monitoring and Evaluation Reports* that Cal Advocates issues for each year to verify the utilities' penalties or rewards based on whether they purchased gas at prices above or below their established benchmarks.[19] In this document, Staff rely heavily on the publicly available information in Cal Advocates' reports.

SoCalGas's winter 2022-23 GCIM has already been reviewed by Cal Advocates and approved by the CPUC, with modifications.[20,21] However, PG&E did not submit its report for the period including winter 2022-23 until July 29, 2025.[22] Cal Advocates thus has not had time to evaluate the PG&E report and issue a *Monitoring and Evaluation Report* for that year, and the CPUC's disposition of PG&E's CPIM request is pending.

Staff have access to the same confidential information as Cal Advocates but cannot disclose information that has been labeled confidential. For this reason, there is more information that Staff can discuss publicly regarding SoCalGas' hedging and core procurement decisions in winter 2022-23 than there is for PG&E.[23] Cal Advocates has recently taken roughly a year to complete *Monitoring and Evaluation Reports* for PG&E, and Staff could not delay this investigation until the report for winter 2022-23 comes out. In addition, Staff will formally review the advice letter requesting PG&E's CPIM reward after Cal Advocates issues its *Monitoring and Evaluation Report*. For these reasons, Staff discuss PG&E's winter 2022-23 actions in this White Paper at a higher level than those of SoCalGas.

Lastly, it is important to note that Staff's recommendations in this report focus on the structure of the GCIM and CPIM mechanisms themselves and not on whether the utilities should receive their awards for specific years. Those awards are based on the incentive mechanism rules in effect during the year in question.

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[19] Cal Advocates, *SoCalGas GCIM Monitoring and Evaluation Reports*: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/monitoring-and-evaluation-report-of-southern-california-gas-company-gas-cost-incentive-mechanism. Cal Advocates, *PG&E CPIM Monitoring and Evaluation Reports*: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/monitoring-and-evaluation-report-of-pacific-gas-and-electric-core-procurement-incentive-mechanism.

[20] Cal Advocates, *GCIM Year 29 Monitoring and Evaluation Report:* https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/sce-natural-gas-gcim-reports/240314-caladvocates-scg-gcim-report-year-29-a2307005.pdf.

[21] D.24-10-007: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K267/544267180.PDF. Cal Advocates was the only party to protest SoCalGas' GCIM application for winter 2022-23.

[22] PG&E Year 30 CPIM Report (Public Version), November 2022 – October 2023: pge-annual-cpim-202211-thru-202310-year-30.pdf.

[23] Winter 2022-23 (November-March) is the subject of SoCalGas' GCIM Year 29 and PG&E's CPIM Year 30 reports.

Below is an overview of the evaluation process for the core procurement incentive mechanisms with a description of the documents that are provided in each step.

Informal Staff Updates

Prior to every winter, SoCalGas' Gas Acquisition and PG&E's Core Gas Supply provide Staff with a confidential winter hedging plan. These utility divisions also provide confidential updates about hedging at biweekly (SoCalGas) or monthly (PG&E) meetings attended by ratepayer representatives and Staff.

Monthly and Quarterly Reports

SoCalGas is required to provide the CPUC with monthly reports within 60 days of the end of each production month. These reports provide a summary of SoCalGas' GCIM procurement activities and the monthly and year-to-date benchmark budget and actual purchased gas costs.[24] SoCalGas marks these reports as confidential. PG&E's Core Gas Supply submits similar reports monthly and quarterly. However, since there is no set deadline by which these reports must be submitted, PG&E does not follow a regular schedule.[25]

Utility Annual Reports and Cal Advocates Evaluations

The CPUC requires SoCalGas to file an application and annual report by June 15 of each year summarizing the results of its core procurement activities over the previous 12 months and requesting its shareholder award.[26] SoCalGas includes some non-confidential tables as appendices to its application and submits a separate report with tables marked as confidential to the CPUC. This deadline is two-and-a-half months after the end of SoCalGas' GCIM Year, which runs from April 1 through March 31. The utility must either submit the application on time or request an extension from the CPUC's Executive Director.[27]

Because SoCalGas is required to file an application to receive its GCIM award, the utility submits the annual report along with its application. Cal Advocates then evaluates the utility's report in its *Monitoring and Evaluation Report,* which is due by October 15.[28] In the past three cycles, Cal Advocates has released its

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24 SoCalGas Preliminary Statement Part VIII (E)(1). Scroll down to find link to Part VIII: https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

25 PG&E's Preliminary Statement Part C (9) says only: "PG&E submits monthly and quarterly reports to the CPUC's Energy Division and California Public Advocates Office (Cal Advocates) in addition to an annual report outlining cost savings, rewards or penalties under the CPIM." GAS_PRELIM_C.pdf

26 D.02-06-023, Attachment A, p. 4: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/16315.PDF. See also, SoCalGas Preliminary Statement Part VIII (D) and (E)(3).

27 SoCalGas asked for, and received, an extension for its Year 29 (2022-23) GCIM Report, which was submitted on July 15, 2023. See A.23-07-005, p. 1: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M514/K477/514477140.PDF.

28 D.02-06-023, Attachment A, p. 4.

report within four to eight months of the utility's GCIM filing. The CPUC then considers the Cal Advocates report as part of the record for reaching a decision on the utility's GCIM award.[29]

The CPUC did not establish a deadline for PG&E to file its confidential annual CPIM reports. In the past three cycles, PG&E has filed its report between 16 and 20 months after the end of the incentive mechanism period, which runs from November 1 through October 31. Cal Advocates, in turn, has released its *Monitoring and Evaluation Report* within eight to 13 months of the utility's filing. After Cal Advocates issues its report, PG&E submits a Tier 2 advice letter for its CPIM award. Staff consider the Cal Advocates reports in our evaluation of the advice letter.[30]

Other Sources

In addition to the utilities' various confidential GCIM and CPIM reports and Cal Advocates' *Monitoring and Evaluation Reports*, Staff reviewed market data from sources such as the Energy Information Administration (EIA), Natural Gas Intelligence (NGI), and S&P Global Commodity Insights to assess the interaction of the core procurement departments' hedges with movements in the gas markets. Staff also consulted the 2001 *Evaluation Report on Southern California Gas Company's Gas Cost Incentive Mechanism*.[31]

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[29] The CPUC voted out the most recent GCIM decision, D.25-06-050, on June 26, 2025. The decision was for gas procured during GCIM Year 30 (2023-24): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K416/571416942.PDF.

[30] The CPUC's Energy Division approved the most recent CPIM advice letter, 4957-G, on October 4, 2024. This advice letter was for gas procured during CPIM Year 28 (2020-21): https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4957-G.pdf.

[31] Energy Division Staff, *Evaluation Report on Southern California Gas Company's Gas Cost Incentive Mechanism,* January 2001: myers_gcimreport2001.pdf.

Winter 2022-23 Hedging

This section explores the role of hedging in gas commodity procurement and utility price risk management. It begins with background on relevant CPUC decisions and a general overview of hedging practices, followed by an evaluation of hedging outcomes during winter of 2022-23, including hedging's effect on gas procurement rates for bundled core customers.[32]

Background

The CPUC requires the gas utilities' core procurement departments, namely PG&E's Core Gas Supply and SoCalGas' Gas Acquisition, to secure a reliable natural gas supply prior to winter for their bundled core customers. The utilities achieve this by injecting set amounts of gas into storage, either in their own storage fields or via independent storage providers (ISPs); acquiring specified amounts of interstate pipeline capacity; and making strategic gas purchases.[33,34] While storage inventory and firm indexed contracts for pipeline supplies[35] serve as a type of physical hedge to support reliability and insulate against gas price volatility, they are not the subject of this section of the report. Instead, the focus here is on transactions that are subject to the hedging cost allocation rules in the GCIM and CPIM, which are described below. These include financial hedges, which do not include physical deliveries of gas, as well as physical hedges, in which physical gas contracts are procured at fixed prices outside bidweek.[36]

Prior to 2005, the costs and benefits of financial hedges were shared between ratepayers and shareholders as part of the gas procurement incentive mechanisms.[37] Following the disruptions to natural gas supply caused by Hurricane Katrina in 2005, which triggered a surge in gas commodity prices nationally,[38] the CPUC approved emergency hedging plans to shield ratepayers from gas price spikes.[39] The CPUC allocated all the costs and benefits from these emergency hedges to core ratepayers.[40] By doing so, the CPUC sought to eliminate the disincentives for the utilities to hedge due to investor risk, which could leave core customers unprotected from potential price spikes.[41] In subsequent decisions, the CPUC refined hedging

[32] The utilities procure gas for bundled core customers.

[33] *2024 California Gas Report*, p. 11: https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf.

[34] As noted in *High Natural Gas Prices in Winter 2022-23: Part II* at p. 13, the utility procurement departments purchase and store gas on behalf of core customers who are allocated storage inventory and injection and withdrawal capacity rights at the utilities' storage fields. Core Gas Supply also purchases additional storage from the ISPs: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M567/K955/567955443.PDF.

[35] An indexed contract is a supply agreement priced against a published market index such as Natural Gas Intelligence, allowing the price to track market conditions; it reduces price-guessing but may expose buyers to rising market prices.

[36] Gas customers purchase monthly gas contracts for the coming month during bidweek, which takes place during the first three of the last five gas trading days before the new month begins.

[37] D.10-01-023, FOF 7: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.

[38] SFGate, October 1, 2005: Natural gas bills expected to rise 71%, PG&E says / KATRINA & RITA: Utility blames hurricanes for enormous jump in home heating costs.

[39] D.05-10-015 for PG&E (2005), and D.05-10-043 for SoCalGas and SDG&E (2005), temporarily authorized the utilities to adjust to the gas shortage concerns caused by Hurricane Katrina.

[40] D.05-10-015, OPs 2-4. D.05-10-043, OPs 3-4.

[41] D.10-01-023, FOF 10.

authorizations, cost tracking, and regulatory oversight. D.06-08-027,[42] D.07-06-013,[43] and D.07-12-019[44] expanded hedging by authorizing long-term hedging programs, including allowing hedges outside the winter months, and imposing reporting requirements.[45] The CPUC further adjusted the utilities' core gas procurement incentive mechanisms to balance the risk of hedging between ratepayers and shareholders in D.10-01-023.[46] In that decision, the CPUC found that:

> Rather than a Commission-mandated program for hedging, the most effective regulatory treatment of hedging is to leave hedging strategies to the expertise of the utility, but also incorporate a system of incentives to hold the utility financially accountable for its decisions.[47]

D.10-01-023 ordered changes to how hedging costs and benefits would be allocated, but it did not do so consistently across the utilities. The CPUC required SoCalGas/SDG&E to include 25 percent of their hedging costs or gains in the GCIM, with the remaining 75 percent allocated to ratepayers.[48] For PG&E, the CPUC approved a settlement agreement in which 80 percent of hedging gains or losses are included in the CPIM benchmark while 100 percent are included in the actual costs.[49] These decisions still apply to winter hedging plans, and the core procurement departments of both utilities continue to provide hedging updates to Staff, Cal Advocates, and The Utility Reform Network (TURN).[50]

Based on Staff's review of the utilities' 2022-2023 hedging practices and outcomes, Staff does not see a need to prescribe certain hedging practices at this time.

Hedging Overview

When securing natural gas supplies, the gas utilities' core procurement departments[51] may attempt to manage the risk of volatile commodity prices by using contracts to lock in fixed prices, or fixed price ceilings, for a portion of future purchases. Because the primary goal is to reduce core customers' exposure to price swings, hedging typically involves taking offsetting positions that limit both potential losses and potential savings from market movements. These contracts, whether for physical gas delivery or financial

[42] D.06-08-027: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/59376.PDF.
[43] D.07-06-013: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/69051.PDF.
https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/69053.PDF.
[44] D.07-12-019: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/76171.PDF.
[45] The gas winter begins in November and ends in March of the following year.
[46] D.10-01-023: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.
[47] Ibid, FOF 4.
[48] Ibid, OP 4.
[49] D.10-01-023, Settlement Agreement, pp. 1-2:
https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/112578.PDF.
[50] The Settlement Agreement for D.10-01-023 requires that the CPUC's Energy Division, Cal Advocates, and TURN are to be notified of forecasted and tentative hedging amounts with documentation that is confidential due to market sensitivity:
https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/112578.PDF.
[51] Core gas procurement functions are structurally separated and separated by a "firewall" from the utility's transportation operations and are treated like any other transportation customer. However, for both operational and policy reasons, core customers retain transportation priority over noncore customers.

settlements based on price movements (derivatives), often involve costs, such as premiums. They are executed through instruments such as futures and options. Financial hedge premiums reflect market supply and demand, meaning they are typically less expensive in unconstrained markets without a recent history of price volatility. Financial hedges are also often more flexible than physical hedges, as they may be structured in varying volumes and durations, can be settled financially without requiring physical gas delivery, and are more easily adjusted or unwound as market conditions change.

Core procurement departments may enter long positions when prices are expected to rise or short positions when a decline is anticipated. Commonly practiced hedging instruments include:

- Futures and forwards: Intended to lock in future prices;
- Options: Provide the right, but not the obligation, to buy or sell at a set price; and
- Swaps: Exchange fixed market prices for floating prices.[52,53]

Physical hedge contracts achieve similar goals to financial hedges but involve at least the option of receiving physical delivery of gas supplies under set contractual terms and pricing arrangements.

To illustrate, a long futures contract would lock in a fixed purchase price, which can provide protection if spot market prices rise above that level but may result in losses if spot prices fall below it. Options, by contrast, offer insurance, where the utility can exercise them if prices move higher but let them expire if market conditions are below the option price. Swaps function as a trade of fixed prices for floating prices and provide a flexible way to hedge.

PG&E's Core Gas Supply and SoCalGas' Gas Acquisition use diverse combinations of contracts to plan for a reliable gas supply and mitigate price risk for core customers. A portion of their hedging gains or losses are included in the actual and benchmark gas costs in the utilities core gas procurement incentive mechanisms: PG&E's CPIM and SoCalGas' GCIM.[54] These incentive mechanisms are described in detail in the Core Gas Procurement Incentive Mechanisms section below.

This section does not compare PG&E and SoCalGas directly, given their different operations, market positions, and procurement strategies. Instead, it evaluates the impact of each utility's hedging strategy on its core customers' 2022-23 rates. Staff examined the full value of all purchase and sales contracts executed by the utilities. For physical hedge transactions, performance was based on the price of delivered hedged gas compared to the monthly benchmark. For financial hedges, their performance was measured by whether they generated a positive financial settlement, meaning the contract payoff was favorable relative to the market price at the time of execution.

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[52] For more information on hedging, see: What is Hedging in the Oil and Gas Industry?.

[53] For more information on swaps, see: Financial Energy Swaps | EBF 301: Global Finance for the Earth, Energy, and Materials Industries.

[54] SoCalGas' application for GCIM Year 29 (2022-23) provides detail on gas purchases and benchmarks.

Winter 2022-23 Hedging Outcomes and Ratepayer Impact

Hedging natural gas, whether through physical purchases or financial instruments, is a form of price insurance designed to protect core customers from excessive volatility. In D.10-01-023,[55] the CPUC gave discretion to the utilities as to the manner and amount they hedge as long as it is done prudently.[56]

To meet forecasted core demand for winter 2022-23, both PG&E Core Gas Supply and SoCalGas Gas Acquisition purchased substantial volumes of core winter gas and hedged a portion of those purchases in advance of the winter heating season. While PG&E Core Gas Supply spent a substantial undisclosed total amount for all gas supplies,[57] SoCalGas Gas Acquisition spent approximately $3 billion for all gas supplies.[58] Both procurement departments purchased more gas than usual during winter 2022-23 due to higher-than-usual seasonal demand, and both incurred higher-than-usual average costs per million British therm units (MMBtu).

The two utilities adopted contrasting hedging strategies, and both lowered gas costs for ratepayers. However, PG&E's hedging strategy appears to have saved ratepayers considerably more than that of SoCalGas during winter 2022-23. For transactions covered by the CPIM hedging cost allocation rules, PG&E Core Gas Supply relied exclusively on financial hedges, which generated significant gains. These gains indicate that the market price of gas that winter was higher than the hedged price. PG&E's ~~Since PG&E Core Gas Supply had no physical hedges during this period, its~~ financial hedges did not increase the volume of gas purchased. SoCalGas Gas Acquisition, in contrast, relied exclusively on physical hedges. These physical hedges added a net volume of 1,204,100 MMBtu,[59] or about 1.16 billion cubic feet (Bcf), of gas supply and resulted in an additional cost of roughly $38.6 million.[60] This strategy supported supply reliability and resulted in about $10.1 million in savings[61] relative to the associated benchmark costs.

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55 D.10-01-023: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF. Appendix A to D.10-01-023 is found at https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/112578.PDF; Appendix B at https://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/GRAPHICS/112485.PDF.

56 D.10-01-003, pp 14, 39, 45, and 58: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.

57 CPIM Annual Performance Report Year 30 ("Public Version"), p. 2. Though the document is public facing, the material has not yet been published; therefore, it could not be disclosed in this report.

58 Summarized winter totals from SoCalGas GCIM Year 29 Annual Report Workpapers.

59 Cal Advocates *GCIM Year 29 Monitoring and Evaluation Report,* see Tables 2-14 and 2-15, pp. A-23-A-24. For benchmark measuring purposes, Cal Advocates reports 1,275,000 MMBtu in total hedged purchases, which is 75 percent of the 1,700,000 MMBtu in total hedged purchases. Similarly, Cal Advocates reports 371,925 MMBtu in hedge sales, which is 75 percent of 495,900 MMBtu. Thus, the net volume purchased is 1,700,000 MMBtu – 495,900 MMBtu = 1,204,100: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/sce-natural-gas-gcim-reports/240314-caladvocates-scg-gcim-report-year-29-a2307005.pdf.

60 Ibid*,* Table 2-3i at p. A-12.

61 SoCalGas A.23-07-005, Attachment A at p. 14: https://www.socalgas.com/sites/default/files/2023.07.17_GCIM-Year-29-Application-PDF-A.pdf.

PG&E

PG&E's Core Gas Supply entered into a considerable number of hedges for winter 2022-23, and, on balance, these investments ended up in the money. A financial hedge can be considered in the money if it generates a positive financial settlement, meaning the contract payoff is favorable relative to the market price at the time of execution. Hedging revenue appears to have helped reduce Core Gas Supply's overall procurement cost, significantly reducing core customers' utility bills.[62]

While Core Gas Supply expended ~~put~~ a significant amount of money ~~at risk~~ to pay the premiums, commissions, and fees required to procure financial hedges, the gains from these contracts more than offset these costs. Had Core Gas Supply hedged less or not at all, it would have foregone the gains that ultimately translated to ratepayer savings and reduced bill volatility during a price spike event.

Since financial hedges settle in cash, gains or losses show up directly as dollar amounts, and there was no effect on the volume of gas purchased.

SoCalGas

For winter 2022-23 SoCalGas' Gas Acquisition acquired hedges to purchase 1,700,000 MMBtu of physical gas.[63] Of these, it used 1,204,100 MMBtu for core customer supplies and sold 495,900 MMBtu into the market.[64] Gas Acquisition's hedging portfolio ended winter 2022-23 in the money. A physical gas hedge is in the money when it costs less than the monthly benchmark. Gas Acquisition's net physical hedge costs amounted to $38.6 million,[65] and these hedges resulted in about $10.1 million in ratepayer savings[66] relative to its associated benchmark costs.[67]

Total physical winter hedged volumes made up about 0.61 percent of Gas Acquisition's total volumetric winter gas procured.[68] Total physical winter hedged costs made up about 1.28 percent of the total winter gas costs.[69] The timing of Gas Acquisition's procurement and sale of hedges are considered confidential.

SoCalGas Gas Acquisition has historically hedged a smaller portion of its total core gas demand than PG&E Core Gas Supply. Some of the factors that may contribute to this difference are the higher gas price

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62 The actual savings is considered confidential.

63 Cal Advocates *GCIM Year 29 Monitoring and Evaluation Report,* Table 2-14, p. A-23. For benchmark measuring purposes, Cal Advocates reports 1,275,000 MMBtu in hedged purchases, which is 75 percent of the 1,700,000 MMBtu in total hedged purchases: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/sce-natural-gas-gcim-reports/240314-caladvocates-scg-gcim-report-year-29-a2307005.pdf.

64 Ibid, Table 2-15, p. A-24. Cal Advocates reports 371,925 MMBtu as hedge sales, which is 75 percent of 495,900 MMBtu.

65 Ibid*,* Table 2-3i at p. A-12.

66 SoCalGas A.23-07-005, Attachment A at p. 14: https://www.socalgas.com/sites/default/files/2023.07.17_GCIM-Year-29-Application-PDF-A.pdf.

67 Trading/brokerage fees were negligible relative to total hedging transactions and are not considered for these calculations.

68 Calculated as [*(1.16 Bcf net winter hedge volumes ÷ 190.7 Bcf total net winter gas procured) ×100]*. Total winter gas procured is the sum of Actual Transported Volume for the months of November 2022 through March 2023 found in Cal Advocates *GCIM Year 29 Monitoring and Evaluation Report,* Table 2-10, p. A-19 (one Bcf equals 1,037,000 MMBtu).

69 Calculated as [*($38.6M from hedge costs ÷ $3,017.9M of total winter gas cost) ×100]*. Total actual cost of winter gas procured is the sum of Actual Commodity Costs for the months of November 2022 through March 2023 found in Cal Advocates *GCIM Year 29 Monitoring and Evaluation Report,* Table 2-19, p. A-28.

volatility in the SoCalGas service territory in recent years and a "thinner" trading market with fewer trades at the SoCal Border and Citygate than at the border points for PG&E's pipelines and the PG&E Citygate.[70] High spot price volatility can raise hedging premiums due to increased market risk and the potential for large price swings. A thinner market can also lead to higher premiums because there is less competition when only a few counterparties are willing to take the other side of a hedge. These factors may have led to a more unfavorable hedging market for SoCalGas than PG&E.

[70] *White Paper Part I* pp 47-48 found that the spot market was thinner at the SoCal Citygate than at the PG&E Citygate in winter 2022-23, likely due to the physical constraints associated with El Paso pipeline outages, which had a larger impact on SoCalGas, and to lower overall storage capacity in Southern California: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897251.PDF.

Core Gas Procurement Incentive Mechanisms

In this section of the report, Staff provide: 1) a description of the core gas procurement incentive mechanisms adopted by the CPUC for SoCalGas and PG&E, and 2) a review of the operation of those mechanisms over a 10-year period. Staff describe these mechanisms and their performance in detail to provide parties and decisionmakers with a shared baseline understanding of how they function. Parties and decisionmakers can then use this knowledge when they consider the merits of Staff's recommendations for improvements to these mechanisms.

Structure of the Core Procurement Incentive Mechanisms

Background

The core procurement departments for SoCalGas and PG&E purchase natural gas for the utilities' "bundled" core gas customers, i.e., for those core customers who opt to take procurement service from the utility instead of core transport agents (CTAs). SoCalGas' Gas Acquisition also procures gas for SDG&E bundled core customers. For both SoCalGas and PG&E, the core procurement department is separated by a firewall from the utility's primary function of providing regulated monopoly transportation services. The purpose of this separation is to ensure that the core procurement department does not have access to non-public information about the gas system that could provide an advantage in the gas market over non-affiliated gas shippers.

As part of providing procurement service, the utilities' core procurement departments enter into contracts for interstate pipeline transportation capacity and are allocated some intrastate backbone transmission capacity. These costs are recovered in the SoCalGas,[71] SDG&E,[72] and PG&E[73] core procurement rates, which are updated monthly to account for changes in natural gas commodity prices. In PG&E's case, the costs of core storage, obtained from both PG&E-owned and third-party storage facilities located in PG&E's service territory, are also included as a procurement-related cost.

In the past, the CPUC conducted after-the-fact reasonableness reviews of core procurement costs. In formal proceedings, the CPUC reviewed actual gas costs and determined whether they were reasonably incurred in view of the conditions at the time. If the costs of providing gas to customers were found reasonable, core procurement departments were allowed full recovery of such costs.

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[71] SoCalGas' Core Procurement Gas Price can be found here: https://www.socalgas.com/business/energy-market-services/gas-prices.

[72] SDG&E historical gas procurement rates can be found here: https://tariffsprd.sdge.com/sdge/historical/?utilId=SDGE&bookId=GAS&sectId=GAS-SCHEDS&tarfRateGroup=Core%20Services.

[73] PG&E's Core Procurement Rate (G-CP) can be found here: https://www.pge.com/tariffs/en/rate-information/gas-rates.htmlaccordion-80734fc416-item-372f52fdb8.

Beginning in the mid-1990s, the CPUC adopted various forms of gas cost incentive mechanisms in order to provide California gas utilities with a financial incentive to lower procurement costs relative to market-based benchmark costs. Part of the reason for doing so was the CPUC's general interest in establishing performance-based ratemaking mechanisms at the time. But it was also partly due to the extensive amount of time being spent by the CPUC and involved parties in contentious gas reasonableness review proceedings.

In various decisions, the CPUC expressed its goals for these gas cost incentive mechanisms, which were intended to

- Reduce the regulatory burden and complexity for parties by reducing or eliminating the need for after-the-fact reasonableness reviews;
- Provide the utilities with known, balanced incentives to make efficient purchases, minimize gas costs to ratepayers, and adjust to changing circumstances without micromanagement;
- Encourage the utilities to develop innovative methods for improving performance; and
- Align ratepayer and shareholder interests through the sharing of gains and losses.[74]

In general, the GCIMs compare the utility's actual gas procurement costs to market-based benchmark costs to determine if the utility's costs were reasonable. Costs are determined to be reasonable if actual costs are within a specified range (a "deadband" or "tolerance band") relative to benchmark costs. If actual costs are lower than the range, utility shareholders get a financial reward, but most of the savings beneath the benchmark accrue to ratepayers. If actual costs are higher than the range, shareholders refund a percentage of the overage to customers. The deadband is a certain percentage of commodity benchmark costs. The reward or penalty is a certain percentage of the savings or excess costs below or above the deadband.

Total benchmark costs include both commodity benchmark costs and benchmark costs for interstate and intrastate backbone transportation (and in PG&E's case, storage costs as well). PG&E's incentive mechanism, known as the Core Procurement Incentive Mechanism or CPIM, includes a financial incentive related to these transportation costs. In contrast, the financial incentives for SoCalGas' GCIM are entirely focused on the commodity benchmark costs. (Under the GCIM, the same transportation costs included in the benchmark are also included as actual costs, so they cancel each other out.)

The commodity benchmark costs are largely based on a set of monthly and/or daily gas price indices that are taken from various gas industry journals. Those journals make surveys of deals reached by gas market participants at different pricing locations throughout the U.S. and Canada to develop a price "index" for those locations for a month or a day. The journals post the monthly price indices near the beginning of the calendar month, and certain journals post daily prices indices as well. The indices developed by different journals are typically fairly similar and are often looked to as representative of the "market price of gas" for

[74] For example see D.90-07-065, pp. 58 and 61-63: D9007065_19900718_R9002008.pdf. See also D.93-06-092, pp. 7 and 22-23: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/decisions-rulemakings/d9306092_a9210017.pdf.

a particular day or month. The journals consider these indices to be proprietary and charge significant subscription fees for access to their data, so this information is not publicly available.[75]

The gas price indices chosen for the GCIM/CPIM are applicable to the markets where the utilities procure their supplies. For example, SoCalGas and PG&E procure their supplies from the Southwest basins, the Rockies, Canada, the California border, and the PG&E and SoCalGas Citygates.[76]

The currently effective gas cost incentive mechanisms adopted by the CPUC for the major California gas utilities are:

- The SoCalGas Gas Cost Incentive Mechanism (GCIM), originally adopted in D.94-03-076.[77] As authorized by D.07-12-019,[78] SoCalGas also conducts the gas procurement service for SDG&E core customers. The SoCalGas GCIM now applies to SoCalGas' gas procurement costs for both SoCalGas and SDG&E.
- The PG&E Core Procurement Incentive Mechanism (CPIM), originally adopted as part of the PG&E Gas Accord in D.97-08-055.[79]
- The Southwest Gas GCIM, originally adopted in D.05-05-033.[80] While Staff does not describe the Southwest Gas GCIM in this report, we recommend that Southwest Gas be included in any authorized modifications.

The CPUC has modified SoCalGas' GCIM and PG&E's CPIM over the years, and there are important differences in the designs of each mechanism, including how total benchmark costs are calculated. The GCIM[81] and CPIM[82] are described in the utilities' Preliminary Statements.[83]

Confidential performance reports for the GCIM and CPIM are provided by the utilities to the CPUC's Energy Division and Cal Advocates on a monthly and quarterly basis. Cal Advocates evaluates the GCIM/CPIM reports submitted by the utilities for each GCIM/CPIM Year to confirm the results and

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[75] The federal Energy Information Administration makes some less granular gas market information publicly available. For example, it publishes daily spot prices by region (Today in Energy Daily Prices - U.S. Energy Information Administration (EIA)), aggregated monthly prices for California (California Natural Gas Prices), and often includes some SoCalGas and PG&E Citygate data in its Natural Gas Weekly Update (Natural Gas Weekly Update).

[76] For SoCalGas, border purchases are made at points where the interstate pipeline system and PG&E's backbone system interconnect with SoCalGas' pipeline system. Citygate purchases are made at the point where SoCalGas' backbone system interconnects with its local transmission system. Similarly, for PG&E border purchases are typically made at the point where interstate pipelines interconnect with PG&E's backbone system, and citygate purchases are made at the point where PG&E's backbone system interconnects with its local transmission system.

[77] D.94-03-076: https://files.cpuc.ca.gov/LegacyCPUCDecisionsAndResolutions/Decisions/Decisions%20D9403076/D9403076_A9310034.pdf

[78] D.07-12-019: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/76171.PDF

[79] D.97-08-055: D9708055_19970801_A9212043.pdf

[80] D.05-05-033: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/46641.PDF.

[81] SoCalGas' Preliminary Statement for its GCIM can be found here in Part VIII: https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

[82] The Preliminary Statement for PG&E's CPIM is on Sheets 12-13 of its Gas Preliminary Statement Part C.9: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

[83] However, as discussed later, Staff believes that PG&E's Preliminary Statement description does not adequately spell out details of the CPIM structure, and there are some missing details in SoCalGas' Preliminary Statement as well.

issues *Monitoring and Evaluation Reports*. CPUC approval for the shareholder award is provided either through a proceeding (SoCalGas) or advice letter (PG&E) process.

SoCalGas GCIM Structure

The SoCalGas GCIM Structure section of this report provides a detailed description of how benchmark and actual costs are determined under the GCIM. The GCIM includes costs for the gas commodity, transportation, and hedging. The mechanism compares the benchmark costs for these items, which are based on indices, to actual costs. SoCalGas' total GCIM benchmark and actual costs include two main components: 1) commodity benchmark and actual costs, which include some of the costs of hedging; and 2) transportation benchmark and actual costs. The total annual benchmark costs are compared to annual actual costs to determine GCIM performance results.

SoCalGas Gas Acquisition makes the bulk of its gas commodity purchases from producers in the U.S. Southwest, the Rocky Mountain region, and Canada. Gas Acquisition also procures some supplies at the SoCal Border and SoCal Citygate.

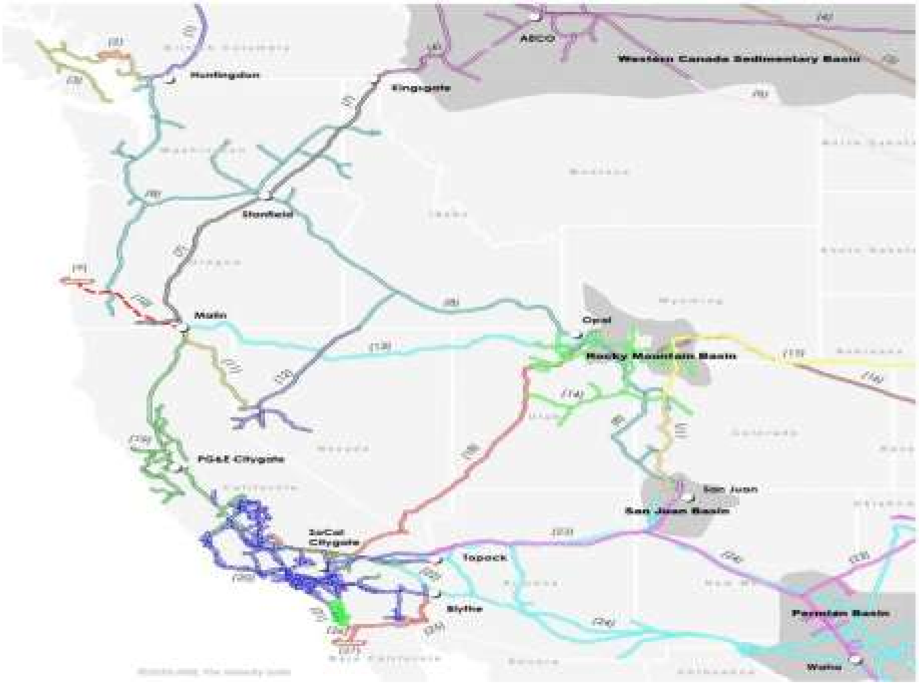
To transport the gas commodity from the production basins to the SoCalGas pipeline system, Gas Acquisition enters into contracts for firm interstate pipeline and PG&E backbone transmission capacity.[84] Recently, Gas Acquisition has held firm capacity primarily on interstate pipelines owned by the El Paso Natural Gas Company, Transwestern Pipeline Company, and Kern River Gas Transmission Company as well as on the "Canadian path" (TransCanada Pipeline/Gas Transmission Northwest (GTN)/PG&E backbone).[85,86] In addition, SoCalGas allocates some utility backbone transmission capacity to core customers to transport the supplies to the local transmission system.

[84] Firm capacity contracts on an interstate pipeline provide the customer with the ability to transport up to a certain volume of gas, as specified in the contract, on a daily basis for every day that the contract is in effect. These contracts require the payment of a fixed monthly reservation amount regardless of the volume of gas that the customer actually transports. A relatively small volumetric rate is also applied to the volumes that are actually transported.

[85] See Cal Advocates *Monitoring and Evaluation Report for GCIM Year 30*: Microsoft Word - A2406005 Public Advocates Office Monitoring and Evaluation Report on SoCalGas Applicaiton - CA-01 crk 011725.

[86] NOVA Gas Transmission Pipeline (NGPL) and Foothills Pipeline provide transportation in Canada to the U.S./Canadian border. Gas Transmission Northwest then provides transportation from the Canadian border to the California/Oregon border. The PG&E backbone transmission system then provides gas transportation from the Oregon border to the SoCalGas system interconnection with PG&E.

Figure 1: Western North American Natural Gas Pipelines Map (not to scale)



1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

Source: 2022 California Gas Report, p. 16.

With the exception of contracts whose terms are considered pre-approved,[87] the interstate pipeline contracts are approved via special, expedited advice letters by Staff, after the utility has sought and generally received pre-approval by Cal Advocates, and sometimes TURN, both ratepayer advocacy organizations.[88] The costs of this firm interstate and backbone capacity are recovered in the core procurement rate and are included in the transportation component of both the GCIM benchmark and actual costs.

Core storage costs are not included in the GCIM. SoCalGas recovers core firm storage costs in core transportation rates, not core procurement rates. However, gas storage has an impact on core customers' gas commodity costs. SoCalGas allocates a significant portion of its storage capacity to core customers, which helps ensure that core customers have a high degree of reliability. Gas Acquisition also uses storage to

[87] See D.04-09-022 for the guidelines describing contract terms that are pre-approved.

[88] The pre-approval process reflects the time-sensitive nature of the competitive market for bidding for pipeline capacity rights, but the CPUC itself makes the final decision on approval of the transportation contracts.

balance core customers' daily gas deliveries with demand and largely avoid Operational Flow Order penalties.[89] Storage also helps keep core customers' gas commodity prices down by reducing Gas Acquisition's need to purchase gas in the spot market when prices are high. In addition, Gas Acquisition can reduce core customers' net costs by selling stored gas on days when prices are high and the gas is not needed for reliability. SoCalGas recovers core firm storage costs in core transportation rates, not core procurement rates.

GCIM Benchmark Commodity Costs

Below is a description of how the monthly commodity benchmark costs for the SoCalGas GCIM are calculated. GCIM benchmark commodity costs are the sum of 1) benchmark costs for mainline, border, and citygate purchases, and 2) 25 percent of the benchmark costs for physical hedges.

Benchmark Costs for Mainline Purchases

Mainline benchmark costs are based on gas commodity prices in each of the gas production basins where SoCalGas Gas Acquisition purchases gas. Gas supplies are delivered from these gas production basins to the California border directly on large interstate "mainline pipelines" as described above.[90] The price of the gas commodity varies by basin due to local market conditions.[91] The benchmark indices for each purchasing location are weighted by Gas Acquisition's actual net purchase volumes for the month. SoCalGas first determines the actual net purchase volumes (i.e., gross purchase volumes less sales volumes) from each basin location by pipeline, such as from El Paso/San Juan, the Rockies, or Canada. Then, it calculates a weighted percentage of total net purchases for each location.

SoCalGas' GCIM Reports identify the monthly price indices for each of those locations and the sources used for the indices. For most locations, SoCalGas uses two journals to develop a basin price index, so a simple average of those two indices is calculated for those basins.[92]

Then, the index for a particular basin is multiplied by the volume weighted percentage for that location to develop a volume-weighted index for each location. SoCalGas then adds the different volume-weighted indices to calculate a volume-weighted Mainline Gas Commodity Reference price index. SoCalGas multiplies total monthly mainline purchase volumes (less sales) by the Mainline Gas Commodity Reference Price.

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[89] An Operational Flow Order (OFO) is a mechanism that requires gas customers to balance their deliveries with their demand within a specified tolerance band. Gas customers are subject to financial penalties if the difference between their deliveries and demand falls outside of the specified tolerance band. Operational Flow Orders are described in SoCalGas' tariff in its Rule 41 at: SCG_GAS_G-RULES_41.

[90] "Mainline" purchase costs could also be referred to as "basin" purchase costs, but the SoCalGas Preliminary Statement, the SoCalGas GCIM Monthly Reports, and the Cal Advocates *Monitoring and Evaluation Reports* all refer to these purchase costs as "mainline" purchase costs, so Staff will use that term.

[91] For example, gas commodity prices in the Permian Basin tend to be low due to the combination of limitations on pipeline capacity and the fact that gas is produced as a byproduct of oil drilling and there are financial penalties for flaring unused gas. When there is not enough space in the pipelines to take all the gas that is produced, prices go negative. Natural Gas Intelligence, "Waha Natural Gas Prices Vulnerable as Limited Egress, Maintenance Threaten Supply Gluts — The Outlook," April 22, 2025.

[92] SoCalGas uses the following journals to develop its commodity benchmark indices: Inside FERC Gas Market Report for the Southwest basins, Rockies, SoCal Border, and SoCal Citygate prices; Natural Gas Intelligence for Southwest, Rockies, SoCal Border, and SoCal Citygate prices; Canadian Gas Price Reporter for AECO prices (AECO is the pricing point for the production basin in Alberta, Canada where Gas Acquisition makes Canadian gas purchases).

Benchmark Costs for Border and Citygate Purchases

SoCalGas follows a similar process to calculate the benchmark for gas commodity purchases made at the SoCal Border and SoCal Citygate. First, SoCalGas determines the volumes purchased (less sales) at each location. Second, SoCalGas determines the index price for each location. As with the Mainline Benchmark, SoCalGas' GCIM Reports identify the monthly price indices for each location and the sources used for the indices. Where more than one journal is used to develop an individual price index, a simple average is calculated. Third, SoCalGas multiples the purchase volumes by the average index for each location.

SoCalGas then totals the Mainline, Border, and Citygate benchmark commodity costs.

Benchmark Costs for Physical Hedges

The GCIM benchmark also includes 25 percent of the benchmark costs associated with winter physical hedge transactions. Staff's understanding is that physical hedges are fixed-price contracts entered into outside of bidweek for future actual gas deliveries that SoCalGas Gas Acquisition designates as a hedge at the time of execution. (In contrast, financial hedges do not include delivery of actual gas molecules.) In its reports, SoCalGas calculates the benchmark costs for such physical hedges in the same way it calculates the benchmark for other purchases. That is, the purchase and sales volumes are multiplied by the appropriate index for the hedge. However, as discussed later in this report, Staff are unaware of this treatment being adopted in a CPUC decision, and it is not specified in the SoCalGas Preliminary Statement, so there is no clear regulatory authority specifying how to incorporate physical winter hedges in the GCIM benchmark and actual costs. As explained further below, there is no benchmark cost for financial hedges.

GCIM Actual Commodity Costs

Actual commodity costs include how much SoCalGas Gas Acquisition spent to procure gas supplies as well as certain other costs. They consist of:

1. the actual gas commodity purchase costs and a cost reduction to reflect sales of procured volumes,
2. a credit adjustment to reflect net revenue after expenses from Secondary Market Services (SMS) transactions,
3. an adjustment for the net costs or gains from off-system parks and loans, and
4. an adjustment to reflect authorized percentages of certain hedging transaction gains or losses.

More information about these inputs into the actual commodity cost is provided below.

Actual Commodity Purchase Costs and Sales Credits

Actual commodity purchase costs are the costs of Gas Acquisition's Mainline, SoCal Border, and SoCal Citygate purchases for core customers.

SoCalGas Gas Acquisition may sell some of its procured supplies to other wholesale market participants in order to reduce its net commodity costs. When Gas Acquisition makes such a sale, the actual commodity costs under the GCIM are reduced. The volumes used to determine the benchmark costs are also reduced to reflect the sales volumes. Sales typically result in fairly significant reductions in GCIM actual gas costs.

Secondary Market Services Transactions

Net revenues from Secondary Market Services transactions are included in the GCIM as a reduction to actual commodity costs. Gas Acquisition sells Secondary Market Services to noncore customers and marketers by using core assets (such as core storage) when not fully needed for core reliability. These services may include "parks," where SoCalGas Gas Acquisition allows a noncore customer or marketer to store its gas supplies using core storage capacity. Secondary Market Services also includes "loans," which involve Gas Acquisition loaning gas supplies to noncore customers and marketers for later repayment of those supplies at the same location for a term specified in the transaction contract. Staff reviewed some of these transactions in a recent GCIM period. Many of them appear to be short-term transactions, ranging from a day or two to over a month. The revenues SoCalGas Gas Acquisition earns from Secondary Market Services are a significant component of overall GCIM savings, as discussed later in this report.

Off-System Parks and Loans

While SoCalGas Gas Acquisition sells parks and loans to other SoCalGas customers through its Secondary Market Services program, it also contracts for parks and loans from other entities outside the SoCalGas system, such as interstate pipeline or storage companies. Gas Acquisition enters into these transactions to help manage the variability of core supply, price volatility, and demand fluctuation. Off-system parks and loans are typically executed to address gas supply issues, such as on Operational Flow Order days or pipeline maintenance events. Such transactions might include storing gas off-system or borrowing gas. Usually, Gas Acquisition is charged a fee for such services, but there are cases when the entity pays a fee to Gas Acquisition, possibly to balance the entity's own delivery obligations. For example, in Year 30, which ended in March 2024, SoCalGas received $900,000 in off-system parks and loans net revenues. These costs and revenues are quite small relative to overall commodity costs.

Hedging Gains and Losses

Gas Acquisition undertakes hedging transactions primarily to protect core customers from gas price volatility, with most hedging focused on the winter months. Hedges are like insurance: they can protect customers when gas prices are very high, but when gas prices are low, they often lose money.[93] In D.10-01-023, the CPUC expressed its goal of creating "a reasonable balance between the goals of holding the utility financially responsible for its hedging activities while limiting potential investor risks to avoid creating a disincentive to hedge at levels appropriate to protect ratepayers."[94] In that decision, the CPUC also determined that 25 percent of all hedging gains and losses would be included in the GCIM while the remaining 75 percent would be excluded from the GCIM and directly allocated to core customers.[95]

According to the SoCalGas Preliminary Statement, hedges may be physical or financial. In practice, these types of hedges are treated differently in the GCIM calculations.[96] While the Preliminary Statement indicates that 25 percent of the gains and losses of winter hedges "from physical and financial transactions" are included in GCIM actual costs, it does not specify how physical hedging benchmark costs should be treated

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[93] D.10-01-023, FOF 1: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.
[94] Ibid, COL 4.
[95] Ibid, COL 9.
[96] SoCalGas' Preliminary Statement for its GCIM (Part VIII) can be found here: https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

or whether there is a benchmark cost for physical hedges. Despite this lack of clarity in the Preliminary Statement, in practice, SoCalGas includes a benchmark cost for physical hedges that is the same as the benchmark cost for regular gas supply purchases.

For the winter hedge, 25 percent of gains or losses are included in GCIM actual costs. Gains reduce actual costs; losses increase actual costs. Financial hedges are not included in the benchmark costs.

In contrast, physical winter hedges are included in the benchmark costs. While 25 percent of the costs of the physical hedges are included in the GCIM actual costs, these costs are offset by a benchmark cost set at the monthly index price for the month that the hedge is used. If physical hedge costs are lower than benchmark costs, they are counted as savings. If they are higher than benchmark costs, they are considered to be "excess costs."

SoCalGas Gas Acquisition may also enter into non-winter hedges. The Preliminary Statement indicates that 100 percent of the net gains and losses from non-winter hedges are to be included in GCIM actual costs.

GCIM Transportation Costs

Transportation costs are essentially "pass-through" costs under the GCIM because the same amount is recorded in both the benchmark and actual costs. For this reason, transportation costs do not affect the calculation of the savings or excess costs.

Benchmark transportation costs consist of 1) the reservation costs to transport natural gas on interstate pipelines and the intrastate backbone transmission pipelines[97] less any credits for the release of interstate pipeline capacity, and 2) the actual volumetric costs of transportation.

Calculation of the GCIM Tolerance Band and Rewards or Penalties

On an annual basis, the monthly totals of the benchmark commodity and transportation costs are compared to the monthly totals of the actual commodity and transportation costs to determine if a reward or penalty is warranted. If actual total costs are within a certain range, or "tolerance band," around the total benchmark costs, then all procurement costs are considered to be reasonable.

The SoCalGas tolerance band range is calculated as a percentage of the annual benchmark commodity cost. The gas commodity tolerance band ranges from 1 percent below the benchmark to 2 percent above the benchmark. The SoCalGas GCIM tolerance bands and savings sharing bands are described in its Preliminary Statement Part VIII, Sections C.8 and C.9.[98]

[97] "Reservation costs" for pipeline capacity are monthly fixed costs paid to the pipeline for the right to use pipeline capacity, whether the initial purchaser actually uses such rights or not. Gas must be nominated onto the system in advance of the transportation, and if a transporter does not nominate gas up to the full amount reserved, the remaining transportation rights are released back into the market to be sold to the highest bidder. The amount of these fixed costs depends on the amount of capacity volume reserved and the type of rate. The "volumetric" transportation costs are the costs associated with actually flowing gas. Volumetric costs are mostly based on the energy costs associated with running compressors that physically move gas within the pipeline. Reservation costs are much higher than volumetric costs because they pay down the cost of building and maintaining mainline interstate and intrastate pipelines.

[98] The link to SoCalGas' Preliminary Statement Part VIII can be found here: https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM

If actual costs are outside this range, then the utility receives a financial reward or penalty. If costs are below the tolerance band, the utility's shareholders receive a financial reward, while ratepayers receive a much larger share of the amounts below the tolerance band. If actual costs are above the tolerance band, shareholders and ratepayers equally split the excess costs above the tolerance band, thus shielding ratepayers from the full losses due to poor performance. The amount of the reward or penalty is calculated as a percentage of the savings or excess costs. The table below describes the percentages.

Table 2: SoCalGas GCIM Reward or Penalty Percentages

Sharing Band	Ratepayer Share	Shareholder Share
Actual costs higher than tolerance range (2% over benchmark)	50% of excess over tolerance	50% of excess over tolerance
Actual costs within tolerance range	No sharing	No sharing
Actual costs greater than 1% lower than benchmark, less than 5%	75% of savings amounts greater than 1% below benchmark	25%
Actual costs greater than 5% lower than benchmark	90% of savings amounts greater than 5% below benchmark	10%

In addition to these parameters, the GCIM caps the maximum shareholder reward at 1.5 percent of actual annual gas commodity costs.

GCIM Performance Reporting and Preliminary Statement Description

SoCalGas' GCIM reporting includes monthly GCIM performance updates, its annual report workpapers, and an annual report that is submitted via a formal application. SoCalGas provides confidential monthly GCIM performance results and the annual report workpapers to Staff and Cal Advocates. The utility then files an annual application to the CPUC on June 15 for the previous GCIM year (April through March). Cal Advocates prepares its *Monitoring and Evaluation Report*, verifies SoCalGas' information, and may make an alternative recommendation to the utility's request. The CPUC then issues a decision on the SoCalGas application.

GCIM monthly report reward and penalty amounts are recorded to the SoCalGas Gas Cost Rewards and Penalties Account (GCRPA) and recovered/credited in the Core Procurement Rates for SoCalGas and SDG&E core procurement customers. If the CPUC ultimately adopts a reward or penalty different from the amounts recorded in GCIM monthly reports, an adjustment is made and balanced in the GCRPA.[99]

PG&E CPIM Structure

The PG&E CPIM Structure section of this report provides a detailed description of how benchmark and actual costs are determined under the CPIM. The CPIM includes costs for the gas commodity, transportation, storage, and hedging, and compares the benchmark costs for these items to actual costs.

[99] See SoCalGas Preliminary Statement Part V, Balancing Accounts, Gas Costs and Rewards Account: https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

PG&E Core Gas Supply procures the gas commodity from Canada, the Rockies, and the Southwest, as well as at the PG&E Border and Citygate.[100]

Several different pipelines are used to transport the gas commodity to the PG&E gas system. Core gas supplies from Canada are transported via the TransCanada and GTN Pipelines. Rockies supplies are primarily delivered over the Ruby Pipeline. Southwest supplies are delivered over the El Paso and Transwestern Pipelines.

PG&E Core Gas Supply enters into contracts for firm interstate pipeline capacity, which are typically approved by Staff. Recently, Core Gas Supply has held contracts for firm capacity on the TransCanada/GTN path, Ruby, and El Paso.[101] Most of this capacity is for bundled PG&E core customers.[102] These costs, along with costs for backbone capacity on the PG&E system, are recovered in the core procurement rate and included in the CPIM.

PG&E core storage costs are recovered in the core procurement rate and, unlike those of SoCalGas, are included in the CPIM benchmark and actual costs. However, storage is a pass-through cost under the CPIM because the same costs are recorded in both the benchmark and actual costs. Prior to 2019, PG&E Core Gas Supply primarily used PG&E-owned storage to meet core storage requirements. Under PG&E's Natural Gas Storage Strategy adopted in D.19-09-025, Core Gas supply is allocated some PG&E-owned storage capacity and is also required to obtain storage capacity for bundled core customers from independent storage providers.[103] *White Paper II* discussed in detail aspects of the transactions between ISPs and PG&E Core Gas Supply.

CPIM Benchmark Commodity Costs

The method by which PG&E's CPIM benchmark commodity costs are calculated is somewhat different from and more complicated than the SoCalGas method. In a nutshell, PG&E calculates daily benchmark costs using a prescribed "daily sequencing" of purchases. Based on a methodology most recently approved in a Memorandum of Understanding between PG&E and Cal Advocates,[104] PG&E determines the "benchmark purchase sequence" for every day during the month. The benchmark volumes that result from the sequencing are multiplied by the indices for the particular location (basin, border, or citygate) and type of purchase (monthly or daily). The daily benchmark commodity costs are then totaled for the month and year.

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[100] For PG&E, border purchases are typically at the point of interconnection between interstate pipelines and the PG&E backbone system, such as Malin or Topock. But PG&E might also make purchases at locations such as Kingsgate near the Canadian/U.S. border at the interconnect between Foothills and GTN. PG&E Citygate purchases are at the point of interconnection between the PG&E backbone system and the PG&E local transmission system.

[101] Cal Advocates, *Monitoring and Evaluation Report (CPIM Year 28),* August 23, 2024: 240823-cal-advocates-cpim-year-28-report.pdf.

[102] Under D.15-10-050, PG&E was authorized to contract for interstate pipeline capacity on behalf of core transportation agents (CTAs). PG&E allocates a portion of its firm interstate pipeline capacity to CTAs according to their total market share of core volumes. CTAs are then responsible to pay for that allocated capacity. D.15-10-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M155/K504/155504363.PDF.

[103] D.19-09-025, OP 12: D1909025 Authorizing PG&E_s 2019-2022 Revenue Requirement for Gas Transmission and Storage Service.pdf.

[104] Approved via Advice Letter 4271-G submitted July 3, 2020: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4271-G.pdf.

The process for calculating CPIM daily benchmark commodity costs is described in more detail below.

First, PG&E's Core Gas Supply determines the "benchmark daily load" or benchmark volume of purchases to be delivered to the citygate for each calendar day during the month. To do this, PG&E's Gas System Planning Department provides PG&E Core Gas Supply with daily estimated bundled core burner tip requirements.[105] The CPIM methodology proscribes various adjustments to these daily estimates,[106] and then a daily benchmark core procurement requirement at the citygate is calculated.

Second, the "benchmark daily load sequence" of benchmark purchases is determined per the requirements outlined in the CPIM. (Note that these benchmark purchases are specified only for the purpose of setting benchmark costs and are not based on PG&E's actual purchases. Further, PG&E is not required to follow the pattern of benchmark purchases.) The first part of the benchmark sequence is partly based on PG&E Core Gas Supply's interstate pipeline portfolio[107] and partly on its backbone capacity. It is composed of four "fixed" blocks of monthly purchases:

- 75 thousand dekatherms per day (MDth/d) from the Rockies via the Ruby Pipeline,
- 75 MDth/d from AECO,[108]
- 75 MDth/d from San Juan (during months when Southwest interstate capacity is available), and
- 75 MDth/d at Malin (the interconnect point at the California/Oregon border).

Then, up to six "moving" blocks of benchmark purchases are included from the Rockies, AECO, or San Juan. The sequence of these purchases is based on a least-cost set of indices from the two previous months. Benchmark purchases are specified up to the interstate capacity amounts held by Core Gas Supply for the month. Then, if additional supplies are needed, benchmark purchases are sequenced for two more moving blocks at border points (Topock and Malin), the sequence of which is determined by least-cost monthly indices from the previous calendar month. Border purchases are sequenced up to the backbone capacity held by Core Gas Supply. Finally, if more purchases are needed, PG&E Citygate purchases are included in the benchmark.

Third, the sequenced volumes are multiplied by an index price (monthly or daily depending on the type) for the current month or day to arrive at daily benchmark dollars. (The index price used here includes not only the index determined at the relevant point of purchase but also interstate and backbone shrinkage[109] and

105 These core procurement requirements do not include volumes purchased by Core Transport Agents.

106 These adjustments include: the addition of distribution shrinkage volumes; a relatively minor monthly "imbalance" amount is allotted to core procurement requirements, which is prorated evenly over the month; and Core Gas Supply's anticipated monthly storage profile of injections or withdrawals is prorated over the days of the month.

107 The Cal Advocates *Monitoring and Evaluation Report for CPIM Year 28* shows that during that year PG&E had an interstate pipeline portfolio consisting of firm capacity on the Canadian path (NGTL, Foothills and GTN) up to 360 MDth/d), the Ruby Pipeline (250 MDth/d, and El Paso Natural Gas (162 MDth/d for November through March).

108 AECO stands for Alberta Energy Company. Per the Canada Energy Regulator's Energy Information Glossary, "The AECO Hub is the Canadian benchmark price for natural gas on the Nova Gas Transmission Ltd. (NGTL) system, and is located at the Niska, Alberta gas storage facilities": CER – Energy Information Program – Glossary.

109 A pipeline company typically requires a transporting customer to provide the pipeline company with a small percentage of the volumes of gas being transported, partly as fuel for running the pipeline's compression stations and partly to reflect volume losses that occur during transportation. That small percentage is referred to as shrinkage.

volumetric transportation rates to the citygate.) Fixed and moving block volumes are multiplied by the current monthly indices. Additional border and citygate volumes are multiplied by daily indices.[110]

Finally, the benchmark dollars for each day during the month are totaled to arrive at the monthly commodity benchmark dollars.

CPIM Benchmark Costs for Hedges

The CPIM benchmark includes 80 percent of the gains or losses from hedging under the PG&E winter hedge program in the benchmark commodity costs.

CPIM Benchmark Costs for Merchandise Processing Fee

The CPIM benchmark also includes the U.S. Customs and Border Protection Merchandise Processing Fees (MPF) assessed on purchases of Canadian gas supplies.

CPIM Actual Commodity Costs

CPIM actual commodity costs include:

1. actual commodity purchase costs and sales credits;
2. actual volumetric interstate and backbone transmission transportation costs;
3. a credit for Cochrane extraction revenue;
4. a charge for MPFs;
5. 100 percent of the gains or losses from the hedging program; and
6. an adjustment for miscellaneous costs and revenues

Actual Commodity Purchase Costs, Sales Credits and Volumetric Transportation Costs

Since the benchmark commodity costs of purchases under the CPIM are calculated to the citygate, all actual commodity net purchase costs include not only the purchase costs at the point of purchase, less sales credits, but also all volumetric transportation costs to the citygate. Sales credits are deducted from actual purchase costs under the CPIM.

Cochrane Extraction Revenues

Cochrane Extraction Revenues are credits that PG&E obtains pursuant to its contract to supply feed gas for natural gas liquids extraction associated with deliveries on the TransCanada/NGTL system. These amounts are credits to CPIM actual costs with no adjustment to benchmark dollars.

Merchandise Processing Fees

The same MPF costs that are included in the benchmark costs are included in the actual costs. Thus, these costs are a pass-through cost and do not affect the calculation of CPIM savings or excess costs.

[110] The following indices are used in PG&E's CPIM: Inside FERC Gas Market Report for San Juan and Rockies monthly indices, Canadian Price Reporter for the monthly AECO-C index, Natural Gas Intelligence for the monthly Malin index and the daily PG&E Topock and PG&E Citygate indices, and Platts Gas Daily for the Mailin daily index.

Hedging Costs/Gains

Per D.10-01-023, the treatment of hedging costs under the CPIM is different from the SoCalGas GCIM.[111] In the CPIM, 80 percent of all hedging costs/gains under the winter hedge program are included in the commodity benchmark costs, and 100 percent of the costs/gains are included in actual costs. Under the hedging settlement approved in that decision, PG&E must have "a combination of storage, physical fixed-price contracts and financial instruments to cover the targeted core portfolio customer average forecast demand." The percentages of core demand to be covered and the months of the coverage under the settlement are confidential.

For hedges conducted outside the winter hedge program, all costs/gains are included in the CPIM as adjustments to actual costs, with no adjustment to benchmark costs. Staff have not been able to find the authorization for such treatment in a CPUC decision or in the PG&E Preliminary Statement. However, this treatment does not appear to have raised concerns for Cal Advocates in its annual *Monitoring and Evaluation Reports*. Also, in contrast to SoCalGas, there is no specific mention in PG&E's Preliminary Statement of any distinction between "financial" and "physical" hedges.

Miscellaneous Costs and Revenues

Miscellaneous Costs and Revenues are not usually described in Cal Advocates' reports, and they are not included in PG&E's Preliminary Statement. A Cal Advocates *Monitoring and Evaluation Report for CPIM Year 20* indicates that these costs might include minor costs such as broker fees, peaking contract demand fees, operational flow order charges, interest, and parking and lending charges.

CPIM Transportation and Storage Costs

The volumetric costs for interstate and intrastate pipelines and storage are included as part of the CPIM daily commodity benchmark sequencing as well as the actual commodity costs. (Volumetric transport rates are used to develop benchmark indices at the citygate. Actual monthly volumetric transport costs are included in CPIM actual costs.)

Full interstate, intrastate, and storage reservation costs are also included in the CPIM as benchmark costs. If PG&E is able to obtain a discount or to release some interstate capacity, that serves to reduce actual costs. Thus, PG&E has an incentive to reduce interstate pipeline transportation reservation costs.

Calculation of CPIM Tolerance Band Range and Rewards or Penalties

Like the SoCalGas GCIM, the annual totals of the CPIM benchmark commodity and transportation costs are compared to the annual totals of the actual commodity and transportation costs to determine whether a reward or penalty is warranted. But under the CPIM, the benchmark totals are the sum of the daily benchmark costs. If actual total costs are within a certain range, or "tolerance band," around the total benchmark costs, then all procurement costs are considered to be reasonable.[112]

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[111] D.10-01-023: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/112833.PDF.
[112] PG&E Gas Preliminary Statement Part C, Section 9: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

The PG&E CPIM tolerance band range is calculated as a percentage of the annual benchmark commodity cost. The gas commodity tolerance band ranges from 1 percent below the benchmark to 2 percent above the benchmark.

If actual costs are outside this range, then utility shareholders: 1) receive a financial reward if actual costs are below the tolerance band range, or 2) split the excess costs equally with ratepayers if actual costs are above the tolerance band range. The amount of the reward or penalty is calculated as a percentage of the savings or excess costs.

The PG&E CPIM has a slightly simpler sharing mechanism than the SoCalGas GCIM. For the amounts of savings lower than the tolerance range, ratepayers receive 80 percent of the savings and shareholders receive 20 percent. For costs higher than the tolerance range, excess costs are shared equally between shareholders and ratepayers.

Table 3: PG&E CPIM Reward or Penalty Percentages

Sharing Band	Ratepayer Share	Shareholder Share
Actual costs higher than tolerance range (2% over benchmark)	50% of excess over tolerance	50% of excess over tolerance
Actual costs within tolerance range	No sharing	No sharing
Actual costs greater than 1% lower than benchmark	80% of savings	20% of savings

There is also a cap of 1.5 percent of annual gas commodity costs on shareholder awards.

CPIM Performance Reporting and Preliminary Statement Description

As explained in the Sources and Methodologies section above, PG&E provides confidential monthly and quarterly CPIM reports to Staff and Cal Advocates. PG&E also provides a summary report for each CPIM year to Staff and Cal Advocates. Once Cal Advocates has submitted its *Monitoring and Evaluation Report* on the CPIM, PG&E requests approval of the results in a Tier 2 advice letter filing. Those advice letters are then reviewed by Energy Division staff. After the annual reward or penalty is approved, the amount is recorded in the Core Sales Subaccount of the PG&E Purchased Gas Account (PGA). The PGA is regularly amortized as part of the core procurement rate.[113] The CPUC has not set a deadline for PG&E to submit its annual report, and, in the last three cycles, PG&E has taken between 16 and 20 months after the end of the CPIM period to submit its report.

The PG&E Gas Tariff Preliminary Statement Part C, Section C.9,[114] does not provide adequate detail about the structure of the CPIM. Missing details include the nature of the benchmark daily sequencing methodology and costs and the types of costs that are included as actual cost adjustments. Some of these items are more clearly explained in the annual Cal Advocates *Monitoring and Evaluation Reports*, but they also do not explain the daily sequencing methodology.

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113 See PG&E Gas Preliminary Statement, Part D, Purchased Gas Account, Section 6.a.4 under Core Sales Subaccount: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_D.pdf.

114 PG&E Gas Preliminary Statement Part C, Section 9: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

Differences Between the GCIM and CPIM

There are several differences between the structures and processing of the SoCalGas GCIM and PG&E CPIM. Staff summarize the major differences between the two incentive mechanisms in Table 4 and provide more detail below.

Table 4: Major Differences between the GCIM and CPIM

	GCIM	CPIM
CPUC process	Application	Tier 2 Advice Letter
Deadline for Utility Annual Report/Application	Annual report and Application by June 15	No set deadline
Deadline for Cal Advocates Report	10/15	None
Reporting Year	April-March	November-October
Preliminary Statement Description	Describes calculations for benchmark costs (except for physical hedges), actual costs, and determination of reward	Does not describe calculation of benchmark or actual costs
Includes Storage?	No	Yes, as a pass-through cost
Transportation	Pass-through cost	Includes an incentive to reduce transportation reservation costs; impacts rewards/penalties
Commodity Benchmark: Volume	Based on actual Gas Acquisition purchases	Benchmark volume and sequence are based on the CPIM methodology
Commodity Benchmarks Prices	Benchmark prices are based on first-of-month indices at relevant Mainline trading points and the SoCal Border and Citygate	Monthly or daily index prices for sequenced locations calculated to citygate delivery point
Winter Financial Hedge Benchmark Costs	Gains/losses not included	80% of gains/losses included
Winter Financial Hedge Actual Costs	25% of gains/losses included	100% of gains/losses included
Winter Physical Hedge Benchmark Costs	25% of applicable commodity benchmark price included	n/a
Winter Physical Hedge Actual Costs	25% of actual net hedging cost included	n/a
Ratepayer/Shareholder Sharing Below Benchmark	Between 1% and 5% below benchmark: 75% ratepayers/25% shareholders More than 5% below benchmark: 90% ratepayers/10% shareholders	80% ratepayers/20% shareholders
Ratepayer/Shareholder Sharing Above Benchmark	50% ratepayers/ 50% shareholders	50% ratepayers/ 50% shareholders

1. Core storage costs are included in PG&E's CPIM as both actual costs and benchmark costs, i.e., as a pass-through cost that does not impact the reward or penalty calculations. SoCalGas' GCIM does not include core storage costs.
2. The method by which PG&E's CPIM gas commodity benchmark costs are determined is quite different than under SoCalGas' GCIM. For example, under the GCIM, benchmark costs are calculated using actual monthly purchase and sales volumes. Under the CPIM, benchmark costs are calculated using an assumed sequence of purchases to meet daily core requirements, taking into account an assumed storage injection and withdrawal profile.
3. PG&E's CPIM does not include a credit adjustment to actual gas commodity costs for Secondary Market Services.
4. There are also some relatively minor differences: off-system parks and loans are included in SoCalGas' GCIM actual costs but not the CPIM~~; Cochrane Extraction Revenue is included under the CPIM as a credit to actual costs but not the GCIM; the CPIM includes MPFs as a benchmark cost and an actual cost, while these amounts are not included in the GCIM~~.
5. There are differences in the savings sharing bands and the ratepayer/shareholder sharing percentages.
6. The treatment of hedging gains or costs is different.
7. The CPIM provides an incentive to reduce transportation costs.
8. There are differences in the calendar months used for annual GCIM and CPIM performance.
9. SoCalGas must file a formal CPUC application to receive its GCIM shareholder award while PG&E need only file a Tier 2 advice letter.
10. SoCalGas must file its GCIM report and application by June 15 of each year for the previous April–March period[115] while PG&E has no set deadline by which it must file its CPIM advice letter.[116]

Comparison of the Performance of the GCIM and CPIM

Introduction

Staff reviewed the performance of different components of the SoCalGas GCIM and the PG&E CPIM over 10-year periods. Through its review, Staff considered (1) the Sierra Club's comments; (2) whether the CPUC should authorize changes to the GCIM and/or CPIM to mitigate ratepayer harm should gas price spikes recur; and (3) whether these mechanisms met the objectives set forth by the CPUC over time and whether improvements might be made. Staff also considered the structure of the GCIM and CPIM, the reporting and CPUC review process, and how clearly the GCIM and CPIM are described in the utilities' tariffs.

Staff mainly used the *Monitoring and Evaluation Reports* issued by Cal Advocates in our review. These public reports are available on Cal Advocates' website, so the information in them can be disclosed without raising

[115] SoCalGas Preliminary Statement Part VIII, Gas Cost Incentive Mechanism (GCIM) (D) and (E): https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

[116] PG&E Gas Preliminary Statement Part C, Sections 9 and 14: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

any confidentiality concerns.[117] Staff also reviewed several of the confidential monthly and quarterly GCIM and CPIM reports, but we do not discuss confidential data in this report. Staff also met with SoCalGas and PG&E core procurement staff to discuss their overall procurement strategy and process.

The 10-year review periods cover different calendar years for each utility because PG&E submits its CPIM reports to the CPUC much later than SoCalGas.[118] The months are different because the GCIM and CPIM years include different months (April–March vs. November–October). The 10-year period for the GCIM review includes GCIM Years 21-30, which cover the period from April 1, 2014 through March 31, 2024.[119] The 10-year period for the CPIM review includes CPIM Years 20-29, which cover the period from November 1, 2012 through October 31, 2022. PG&E did not submit its CPIM report for Year 30, which includes winter 2022-23 until July 29, 2025. Neither Cal Advocates nor the CPUC have officially reviewed PG&E's CPIM Year 30 report, so Staff did not include that year in all our analyses.

Staff did not conduct a detailed review of individual purchases, sales, hedges, or market conditions for this section of the report during the review period, but Staff did review GCIM/CPIM performance in a few select months.

Review of the SoCalGas GCIM

Staff reviewed the following key components of the SoCalGas GCIM:

1. whether actual gas purchases are made at overall costs that are lower than benchmark-based costs,
2. how SoCalGas incorporates sales of gas into its overall procurement strategy and practice and the extent to which sales help SoCalGas lower overall procurement costs,
3. the location of the gas purchases that SoCalGas makes, i.e., the proportion of purchases and sales that are made in the basin, at the border, or at the citygate,
4. how hedging costs or gains have impacted GCIM performance results and overall core costs,
5. how Secondary Market Services revenues have impacted GCIM performance results,
6. the impact of off-system parks and loans on GCIM performance,
7. the GCIM structure, including how benchmark costs are determined, the cost/savings sharing structure, and the reward cap.

Staff did not review interstate transportation costs or core backbone transmission costs under the GCIM because these costs are "pass-through" components. That is, although these components are included in the GCIM, the actual costs and the benchmark costs for these components are the same. All cost-saving incentives are related to the commodity portion of the GCIM.

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[117] In a few cases, Cal Advocates did not attach the appendix, which includes a great deal of data, to its *Monitoring and Evaluation Report*. Staff obtained these appendices directly from Cal Advocates staff. This occurred, for example, with the Cal Advocates report for the CPIM Year 26 ending in October 2019. Also, the Cal Advocates *Monitoring and Evaluation Report* for CPIM Year 29 was issued to the service list on July 21, 2025, but as of the date of this report had not yet been posted on the Cal Advocates web site.

[118] Staff has received confidential monthly CPIM reports from PG&E through January 2024. PG&E submitted its CPIM Annual Report for Year 30, which includes winter 2022-23, on July 29, 2025. Staff expects that the Cal Advocates *Monitoring and Evaluation Report for CPIM Year 30* will be issued some months from now.

[119] SoCalGas must submit its annual GCIM application by June 15 for the prior GCIM year ending in March. Cal Advocates then typically submits its audit report in the fall. So, the Cal Advocates report for GCIM Year 31 ending in March 2025 is not yet available.

Sales Are Critical to Beating the GCIM Benchmark

Staff found that SoCalGas Gas Acquisition's net actual purchase costs are consistently below benchmark costs. A number of factors contribute to the net cost of actual purchases being lower than the benchmark cost as explained in the examples below. However, Staff found that sales are a very significant component of Gas Acquisition's GCIM procurement activity and performance.

One way to beat the benchmark is to purchase gas supplies at prices below monthly benchmark prices. For example, SoCalGas Gas Acquisition might make purchases in the San Juan basin at an average monthly price of $2.00 per dekatherm (Dth), while the benchmark price for that month is $2.02/Dth. In this example, no sales are needed to beat the benchmark price.

A second way to beat the benchmark, even when the average price of purchased gas supplies is above the benchmark price, is to sell some core gas supplies for a particular location at prices that are higher than the purchase price. For example, assume that the GCIM citygate monthly benchmark is $2.75/Dth. Gas Acquisition purchases 2,000 Dth of gas at the citygate for a monthly average of $2.76/Dth, but it sells 1,000 Dth of supplies at the citygate for $2.85/Dth. The benchmark cost for those supplies is $2,750, while the net actual cost is $2,670. In this case, Gas Acquisition's sales would lower actual net citygate costs below the benchmark cost.

Volumes purchased in one month might also be injected into storage and, if not needed to meet core reliability, later sold at the citygate at a higher price in a subsequent month.

Table 5 below illustrates how sales contributed to Gas Acquisition's beating benchmark costs. The table shows annual gross purchases, sales, and benchmark commodity costs over a 10-year period. In every year: 1) gross purchase costs were above benchmark costs, and 2) sales credits reduced net purchase costs to below benchmark costs. In almost every year, sales credits amounted to a significant fraction (more than 10 percent) of gross purchase costs, and in some years more than 20 percent.

Table 5: SoCalGas GCIM Actual Gross Purchases, Sales, and Benchmark Commodity Costs ($000s)

GCIM Year	Ending in March	Gross Purchase Costs	Sales	Net Purchase Costs	Benchmark Commodity Costs
21	2015	$1,673,931	$298,180	$1,375,751	$1,410,860
22	2016	$1,033,648	$250,191	$783,457	$ 800,337
23	2017	$1,245,217	$242,171	$1,003,046	$1,021,436
24	2018	$1,171,476	$178,502	$992,974	$1,036,166
25	2019	$1,452,866	$263,310	$1,189,556	$1,250,565
26	2020	$979,751	$81,477	$898,274	$935,735
27	2021	$1,038,718	$277,903	$760,815	$927,660
28	2022	$2,233,544	$303,868	$1,929,676	$2,018,336
29	2023	$4,796,566	$557,034	$4,239,532	$4,603,238
30	2024	$1,499,171	$274,261	$1,224,910	$1,287,677

The table shows a wide variation in the gross purchase costs, sales amounts, and net purchase costs over the years. This is mainly due to variations in the unregulated price of gas and in core gas requirements.

Note that the "net purchase costs" shown above are not the total actual commodity costs that are compared to the above benchmark costs for the purpose of calculating GCIM savings. Other adjustments such as Secondary Market Service credits and hedging costs/gains must be made to determine total actual GCIM costs.

Sales allow SoCalGas Gas Acquisition to balance reliability with cost savings. SoCalGas Gas Acquisition's primary mandate is to provide core customers with reliable gas supplies. A significant portion of Gas Acquisition's purchases are thus made under long-term contracts, meaning contracts with terms longer than one month. For example, in its *Monitoring and Evaluation Report for GCIM Year 30*, Cal Advocates indicates that Gas Acquisition maintained a gas supply portfolio consisting of about 85 percent long-term supply arrangements, 12 percent month-to-month baseload agreements, and 3 percent daily purchase transactions and sales. These types of contracts are intended to help ensure a high degree of supply reliability for core customers.

While meeting core load requirements and balancing core demand are Gas Acquisition's primary obligations, it can also look for opportunities to buy or sell gas that will lower overall costs. Daily purchase and sales opportunities arise due to the volatility of prices in the market, particularly during extreme weather events elsewhere in the continental United States or when transportation infrastructure fails leading to temporary gas scarcity. Gas Acquisition's ability to take advantage of these opportunities is enhanced by having significant amounts of core storage capacity. So long as Gas Acquisition continues to meet its storage objectives, it can make storage withdrawals and sell those supplies when opportunities arise. Alternatively, if prices fall, Gas Acquisition can purchase additional supplies and inject that gas into storage for later use. While Gas Acquisition should always be on the lookout for low-cost gas supply arrangements, it also needs to conduct its procurement activity to ensure that there are adequate volumes of gas to meet core reliability requirements throughout the winter. The SoCalGas Preliminary Statement, Part VIII specifies the target core storage inventory volumes for the winter months as well for July 31.[120]

Purchases and Sales During Winter 2022-23

Staff looked at GCIM performance during the high-priced period from December 2022 through February 2023.

During December 2022, Gas Acquisition achieved $111 million in actual commodity savings relative to benchmark costs under the GCIM. At the citygate, Gas Acquisition achieved savings by selling gas at an average sales price that was well above the citygate benchmark price, even though its gross purchases were made at an average price that was slightly above the benchmark. Gas Acquisition was likely able to do this because the monthly benchmark citygate price was set at the beginning of December and spot prices increased dramatically later in the month after a new outage on the El Paso pipeline. Similarly, Gas Acquisition's gross border purchases were slightly above the December benchmark price, but sales were made at prices well above the benchmark price. Significant savings were thus also achieved through border sales.

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[120] See SoCalGas Preliminary Statement Part VIII Section (C)(7): https://tariffsprd.socalgas.com/scg/tariffs/content/?utilId=SCG&bookId=GAS&sectId=G-PRELIM.

In January 2023, Gas Acquisition achieved a GCIM savings of $220 million primarily due to net mainline and citygate purchases priced below the high benchmark prices.

In February 2023, a $24 million savings was achieved primarily due to mainline net purchase costs being about $21 million lower than the mainline benchmark costs.

In *High Natural Gas Prices in Winter 2022-23, Part I (White Paper Part I),* Staff made a number of observations about Gas Acquisition's purchases during the winter of 2022-23. First, Staff stated that, "Monthly indexed prices for most months in winter 2022-2023 were likely also higher due to SoCalGas Gas Acquisition's fixed price monthly purchases." In addition, Staff found that "SoCalGas Gas Acquisition's trades constituted a substantial portion of the trades used to calculate monthly indexed prices at several delivery points including the SoCal Citygate."[121] Finally, Staff found that the bidweek market for the SoCal Citygate was less liquid than the comparable market for PG&E.

Staff did not investigate such issues outside the winter 2022-23 time period and the months leading up to the winter in *White Paper Part I*. But these findings raise a possible concern that the CPUC may wish to consider in a future proceeding, namely that the magnitude of Gas Acquisition's purchases and sales may influence the monthly indices used in calculating GCIM benchmark costs.

Location of Purchases, Sales, and Savings

To determine where the majority of GCIM savings occurred, Staff reviewed the location of the purchases and sales made, i.e., whether the purchases/sales were made in the basin (mainline purchases/sales), at the SoCal Border, or the SoCal Citygate. Staff found that, while most net purchase costs were incurred via mainline purchases/sales, the bulk of the savings came through citygate net purchases relative to benchmark costs.[122]

Most gross purchases are mainline purchases, rather than border or citygate purchases. This outcome is not surprising since Gas Acquisition has a significant amount of firm interstate pipeline and backbone transmission capacity at its disposal, partly to ensure core reliability and partly to allow a diversity of supply opportunities. Cal Advocates' *Monitoring and Evaluation Reports* show that Gas Acquisition's average interstate pipeline capacity utilization has been in the range of 69 percent to 95 percent during the review period.

Sales, on the other hand, are weighted toward the border and citygate, rather than the mainline.

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121 Energy Division Staff, *High Natural Gas Prices in Winter 2022-23, Part I, I.23-03-008*, Updated February 10, 2025. pp 47-48: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897251.PDF.

122 It is not readily possible to compare the average prices of net purchases in specific basins with the benchmark indices for the basins using the publicly available Cal Advocates data. The *Monitoring and Evaluation Reports* do not provide the indices, the basin-by-basin benchmark costs, or the basin-by-basin benchmark volumes.

Table 6: SoCalGas GCIM Purchase and Sales by Location ($000s)

GCIM Year	Ending in March	Mainline Purchases	Border Purchases	Citygate Purchases	Mainline Sales	Border Sales	Citygate Sales
21	2015	$1,418,873	$124,906	$130,152	($94,942)	($63,625)	($139,613)
22	2016	$857,110	$32,791	$143,747	($50,552)	($49,916)	($149,723)
23	2017	$932,022	$110,540	$202,655	($128,888)	($50,811)	($62,472)
24	2018	$840,796	$160,547	$170,133	($78,925)	($14,306)	($85,271)
25	2019	$658,142	$237,094	$557,629	($75,624)	($42,822)	($144,864)
26	2020	$571,613	$131,667	$276,471	($43,581)	($24,431)	($13,465)
27	2021	$734,162	$46,938	$257,618	($129,433)	($108,691)	($39,779)
28	2022	$1,416,106	$196,273	$621,166	($68,821)	($172,574)	($62,473)
29	2023	$3,087,437		$1,709,129*	($144,355)		($412,679)*
30	2024	$920,529		$578,641*	($142,006)		($132,255)*

*Note: The Cal Advocates *Monitoring and Evaluation Report for GCIM Year 29* does not show the adjustment for physical hedges for border and citygate purchases and sales separately. The above amount shows the total purchases and sales amount for border and citygate purchases and sales after the adjustment was made. The *Monitoring and Evaluation Report for GCIM Year 30* does not provide border and citygate purchases and sales separately. The GCIM Year 30 figures in the table show total combined border/citygate purchases and sales.

Table 6 above shows that: 1) while mainline gross purchase costs were higher than border or citygate purchases costs, sales credits were more heavily weighted toward the border and citygate, 2) in some years, border and citygate sales credits were larger than the gross purchase costs at those locations, and 3) border/citygate purchases appear to have become a more prominent portion of overall purchase costs in recent years, i.e., since 2019.

Border and citygate are common purchase and sale locations and comprise a significant portion of SoCalGas Gas Acquisition's overall purchases and sales. In addition, these purchases/sales seem to be a significant source of GCIM savings. Some of these purchases and sales could be related to managing core supply reliability and balancing requirements and avoiding penalties.[123]

Border and citygate prices are almost always higher than mainline prices because at least some portion of the full upstream interstate transportation rates are typically incorporated in those prices. Some interstate pipeline transportation costs are likely to be included in border prices, and some backbone transportation costs are added to citygate prices. And, if there is congestion on interstate pipelines or on the SoCalGas

[123] On low OFO days, Gas Acquisition may purchase gas at the citygate to avoid penalties for underdelivering gas relative to core demand. On high OFO days, it may sell gas to avoid penalties for delivering too much gas relative to core demand.

backbone system, or other adverse market conditions occur, border or citygate prices may rise well above mainline prices. During the course of a month or year, one would expect some volatility in the daily prices at the border due to changing weather and market conditions. Commodity price volatility can open up possibilities for making daily purchases and/or sales relative to the monthly GCIM benchmark for those locations, especially given the large storage capacity available to SoCalGas.

As shown in Table 7 below, net actual mainline costs typically end up being fairly close to benchmark mainline costs. Larger savings typically occur through citygate net purchases, relative to the benchmark costs for those purchases. It could be that these savings partly arise due to a larger degree of price volatility at the citygate, which provides more opportunities to make daily purchases during the month at a lower price than the monthly benchmark or to sell at a higher price than the benchmark price. Given the large storage capacity allocated to core customers, combined with noncore customers' lack of access to the Unbundled Storage Program for most of this period,[124] one might expect economically beneficial opportunities to arise.

[124] The Unbundled Storage Program enables noncore customers to purchase gas storage capacity from SoCalGas. The program was discontinued after the leak at the Aliso Canyon natural gas storage field due to insufficient gas storage capacity. SoCalGas reinstated the program in fall 2023 after the CPUC increased the Aliso Canyon maximum allowable operating pressure to 68.6 Bcf in D.23-08-050: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.PDF. See also Advice Letter 6185-G: Advice Letters | SoCalGas and the Settlement Agreement for D.24-07-009: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K556/536556034.PDF.

Table 7: GCIM Savings Due to Net Purchases at the Mainline, Border, and Citygate ($000)[125]

GCIM Year	Ending in March	Mainline Savings	Border Savings	Citygate Savings	Combined Border and Citygate Savings
21	2015	$6,670	($53,491)	$81,930	$28,439
22	2016	$4,028	$1,994	$10,858	$12,852
23	2017	$2,594	$7,989	$7,807	$15,796
24	2018	$6,806	$1,163	$35,223	$36,386
25	2019	$10,271	$5,697	$45,042	$50,739
26	2020	($4,397)	$8,171	$33,687	$41,858
27	2021	$85,523	$54,170	$27,152	$81,322
28	2022	$2,094	($1,977)	$88,542	$86,565
29	2023	$98,296			*$265,410
30	2024	($29,878)			*$92,646

* Note: Table shows savings due to border and citygate activity on a combined basis for years 29 and 30 because (1) Cal Advocates' *Monitoring and Evaluation Report for GCIM Year 29* does not show the adjustment for physical hedges for border and citygate purchases and sales separately and for *Year 30* does not distinguish between border and citygate actual costs are purchases/sales. Further, because 25 percent of physical hedge benchmark and actual costs are included in the GCIM, some of the savings or excess costs in Years 29 and 30 are related to physical hedges.

Table 7 above shows only the types of savings that occurred due to net purchases of gas relative to benchmark costs for the different types of purchases. It does not include GCIM savings due to Secondary Market Services revenues, for example.

Table 7 above shows that: 1) For each of the different locations, Gas Acquisition's net purchase costs were priced below benchmark costs in most years. This means that, on average (not necessarily every month and not necessarily for every pricing point), Gas Acquisition is purchasing net supplies that are priced below monthly benchmark gas indices. 2) Even when one pricing point had net excess costs relative to benchmark costs, savings at other pricing points more than offset those excess costs. 3) The bulk of the net purchase savings are achieved through citygate net purchases relative to the monthly citygate benchmark indices. The largest overall savings occurred in GCIM Year 29, which ended in March 2023, related to the significant price swings that occurred during winter 2022-23.

Total savings ballooned during GCIM Year 29 to amounts not experienced during any previous GCIM year, even prior to the review period. The Cal Advocates *Monitoring and Evaluation Report* shows that that the bulk

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[125] Negative numbers are excess costs relative to benchmark costs.

of the GCIM savings that occurred that year were during winter 2022-23. Of the $417.6 million in annual savings, $354.6 million occurred during the December 2022 through February 2023 period. As shown above, the annual savings occurred due both to mainline savings and border/citygate-related savings, but primarily the latter.

Hedging Costs and Gains

Hedging costs and gains are incorporated in the GCIM in specified ways, depending on the nature of the hedging instrument and the purpose.

- Financial winter hedge costs/gains do not affect the benchmark costs, but 25 percent of those costs/gains are included in actual costs.
- Twenty-five percent of winter physical hedge costs are included as actual GCIM costs. In addition, 25 percent of the associated benchmark costs for such purchases are included in the GCIM benchmark costs.[126]
- Non-winter hedge costs do not affect the benchmark costs, and 100 percent of those costs/gains are included as actual costs.

For most of the years studied, hedging resulted in fairly minor costs or gains. However, physical hedges resulted in large excess costs in Year 30. Staff found that the gain or losses from financial hedges in GCIM Years 21-28 were modest. In GCIM Year 29, which ended in March 2023, Gas Acquisition incurred large physical hedging costs, but those physical hedges resulted in net savings of $10.1 million relative to benchmark costs. GCIM Year 30 also saw large costs for physical hedges, but they resulted in large excess costs of roughly $210 million compared to the benchmark. Under the GCIM, only 25 percent of those excess costs, or $52.5 million, were included in the Year 30 GCIM. Thus, SoCalGas shareholders still received an award. If 100 percent of the excess costs had been included, shareholders would have incurred a $27 million penalty.

The table below shows the hedging gains or losses that SoCalGas has included and excluded from the GCIM actual costs. Excluded costs/(gains) are recovered from/credited to core ratepayers. SoCalGas includes some benchmark costs for physical hedges in the GCIM, so the physical hedge costs shown below are not necessarily "excess costs" relative to the benchmark costs associated with those hedges. Indeed, in 2023, the physical hedges resulted in net savings relative to the benchmark costs for those purchases.

126 As noted above, the SoCalGas Preliminary Statement does not clearly describe how physical hedges should be treated in the GCIM. Here Staff describe how SoCalGas reports that it allocates physical hedges in GCIM actual and benchmark costs.

Table 8: Hedging (Gains)/Losses Included in GCIM Actual Costs ($000s)

GCIM Year	Ending in March	Winter hedge financial derivative (gains)/losses in GCIM actual costs	Winter hedge financial (gains)/losses excluded	Winter hedge costs due to physical hedging in GCIM actual costs	Physical hedge costs excluded	Non-winter hedge (gains)/losses included in GCIM actual costs
21	2015	$508	$1,523			($54)
22	2016	$173	520			$87
23	2017	$665	$1,995			($57)
24	2018	$211	$634			($23)
25	2019	($1,628)	($4,884)			($435)
26	2020	($1,075)	($3,226)			$219
27	2021	$428	$1,284			($34)
28	2022	($3)	($8)			($2,717)
29	2023			$9,644	$28,933	$3
30	2024	$3,074	$9,222	*$111,549	*$334,648	$3

*The Cal Advocates *Monitoring and Evaluation Report for GCIM Year 30* does not clearly identify physical hedge costs. The figures shown in the above table are taken from the SoCalGas application for Year 30.[127]

As explained below, the physical hedge costs shown in the table above do not necessarily represent "excess costs" under the GCIM. The costs need to be compared to the associated benchmark costs for those types of physical transactions.

SoCalGas' Preliminary Statement does not provide a clear description of how winter physical hedges should be treated in the GCIM, but in practice, SoCalGas calculates benchmark costs for physical hedge supplies in the same manner as other "normal" physical supplies. That is, the volume of the physical hedges for a month at a particular location (e.g., the SoCalGas citygate) is multiplied by the monthly index price for that location. Some savings are generated if benchmark costs for physical hedges exceed actual costs in a month. Similarly, excess costs occur if the benchmark costs are lower than the actual costs for the physical hedges. Staff did not examine the details for how the benchmark costs were determined for physical hedges because that information is not provided in the Cal Advocates *Monitoring and Evaluation Reports*.

[127] SoCalGas Application (A.) 24-06-005: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K840/533840507.PDF.

As shown in Table 8 above, financial hedging costs or gains were fairly modest amounts that did not affect the GCIM costs or savings to a great degree. In addition, occasional gains largely offset losses. Non-winter financial hedges also did not have a significant impact on the GCIM.

Physical hedges were a different story, with significant costs since 2022-23 and large excess costs in 2023-24 and 2024-25. In GCIM Year 29 ending in March 2023, physical hedge costs amounted to roughly $38.6 million but resulted in about $10.1 million in savings relative to their associated benchmark costs. In GCIM Year 30 ending in March 2024, physical hedge costs amounted to $446.2 million and resulted in about $210 million in excess, above-benchmark costs.[128] GCIM Year 31 ending in March 2025 has not yet been reviewed by Cal Advocates or the CPUC. However, SoCalGas' GCIM application shows roughly $89.8 million in physical hedging costs, of which $30.6 million were excess, above-benchmark costs.[129] In all cases, only 25 percent of the gains or excess costs from physical hedging were incorporated into the GCIM.

The GCIM is supposed to account for Gas Acquisition's procurement practices. Physical hedges are not only part of SoCalGas' hedging practice but also part of its supply procurement practice. The combination of the large excess costs of physical hedges in the last two years and the overlap between physical hedges and procurement cause Staff to question whether excluding 75 percent of physical hedging costs continues to be in the best interest of ratepayers.

To mitigate ratepayer harm by increasing transparency, the CPUC should consider requiring SoCalGas, in this proceeding, to clearly define physical hedges and explain how they are treated under the GCIM in its Preliminary Statement. This update could potentially be done in a Tier 1 advice letter. Staff also recommend that Cal Advocates clearly identify gains and excess costs from physical gas hedges in its *Monitoring and Evaluation Reports*. The only indication of large excess costs in Cal Advocates' *GCIM Year 30 Monitoring and Evaluation Report* is a brief note in the section on the Examination of the Purchased Gas Account that $335 million in costs related to winter hedges were excluded from the GCIM actual costs.[130] Staff might not have noticed these large costs if SoCalGas had not noted them in their application.[131]

In addition, to improve oversight and protect ratepayers from large physical hedging losses that are only partially included in the GCIM, the CPUC may want to review how physical hedges are treated under the GCIM and consider a cap on hedging costs in a future proceeding.

Secondary Market Services Revenues

Secondary Market Services Transactions (SMS) revenues are an important source of GCIM savings. Gas Acquisition does not earn Secondary Market Services revenues through procurement activity per se, but rather by using core assets that might be otherwise used for core procurement. For example, there could be some interplay between whether Gas Acquisition considers using storage for sales or whether it uses storage to obtain Secondary Market Services revenues.

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[128] SoCalGas A.24-06-005, p. A-12: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K840/533840507.PDF.
[129] SoCalGas A.25-06-012, pp. A-11–A-12: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M569/K283/569283808.PDF.
[130] Cal Advocates *Monitoring and Evaluation Report SoCalGas GCIM Year 30:* pp. 2-10–2-11: Microsoft Word - A2406005 Public Advocates Office Monitoring and Evaluation Report on SoCalGas Applicaiton - CA-01 crk 011725.
[131] See SoCalGas A.24-06-005, Table 2, pg. A-7: GCIM Year 30 https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M533/K840/533840507.PDF.

There is no benchmark for Secondary Market Services revenues. Any net revenues obtained from Secondary Market Services are a direct savings in actual costs relative to the GCIM commodity benchmark. The table below shows that annual Secondary Market Services net revenues have had an important impact on GCIM performance results over the review period and are an important source of GCIM savings.

In fact, in many years, Secondary Market Services revenues are quite comparable to the level of savings achieved though the different types of net purchases detailed in Table 7 above.

Table 9: Secondary Market Services (Revenues) and Costs Included in the SoCalGas GCIM ($000s)

GCIM Year	Ending in March	SMS Revenues	SMS Costs	Net SMS Revenues	Net SMS Revenues as % of Total GCIM Savings
21	2015	($ 9,686)	$1,233	($ 8,453)	19.6%
22	2016	($12,998)	$1,106	($11,892)	42.2%
23	2017	($10,556)	$1,119	($ 9,437)	34.8%
24	2018	($20,104)	$1,118	($18,986)	30.8%
25	2019	($43,876)	$1,087	($42,789)	40.6%
26	2020	($44,887)	$1,197	($43,690)	53.3%
27	2021	($19,606)	$1,159	($18,447)	10.0%
28	2022	($32,227)	$1,193	($31,034)	25.4%
29	2023	($55,359)	$1,263	($54,096)	13.0%
30	2024	($14,971)	$1,294	($13,677)	18.4%

Net Secondary Market Services revenues began to increase significantly around Year 24, ending in March 2018. To provide more information on this trend, Staff reviewed the Cal Advocates *Monitoring and Evaluation Reports* for GCIM Years 18, 19, and 20, which had net Secondary Market Services revenues of $10.1 million, $9.5 million, and $9.5 million respectively. This is similar to GCIM Years 21-23. The jump to $19.0 million in GCIM Year 24 corresponds with the period after the Aliso Canyon Gas Storage leak and the October 1, 2017, rupture of Line 235-2. It could be that Secondary Market Services transactions became more appealing and valuable given the combined impact of these two events, especially since access to SoCalGas' Unbundled Storage Program was unavailable for noncore customers and marketers during this period. The Unbundled Storage Program was suspended after the Aliso Canyon leak and restarted in fall 2023 after the CPUC raised Aliso Canyon maximum inventory to 68.6 Bcf.[132]

[132] See SoCalGas Advice Letter 6185-G, which went into effect on September 1, 2023: Advice Letters | SoCalGas.

Off-System Parks and Loans

The costs and revenues from off-system parks and loans are very small and do not significantly impact the GCIM results. However, they may be a useful tool for Gas Acquisition in conducting its procurement activity or daily balancing to avoid Operational Flow Order penalties.

Off-system park and loan amounts first began to appear as actual costs in GCIM Year 22 ending in March 2016. For the most part, off-system parks and loans are net costs, but in Year 30 they resulted in a net credit.

Table 10: Off-System Parks and Loans Amounts Included as GCIM Actual Costs ($000s)

GCIM Year	Ending in March	Costs or (Revenues)
21	2015	NA
22	2016	$349
23	2017	$65
24	2018	$267
25	2019	$403
26	2020	$36
27	2021	$153
28	2022	$196
29	2023	$159
30	2024	($900)

Summary of GCIM Performance

The following tables summarize much of the key GCIM data showing how savings were achieved.

Table 11: Overall View of GCIM Performance ($000s)

GCIM Year	Ending in March	Total Benchmark Commodity Costs	Gross Purchase Costs	Sales	Net Financial Hedge Costs/ (Gains)*	Off-System Parks and Loans	Net SMS Revenues	Total Actual Commodity Costs	GCIM Savings
		A	B	C	D	E	F	G=B+C+D+E +F	H=A-G
21	2015	$1,410,860	$1,673,931	($298,180)	$454	NA	($8,453)	$1,367,752	$43,108
22	2016	$ 800,337	$1,033,648	($250,191)	$259	$349	($11,892)	$772,173	$28,164
23	2017	$1,021,436	$1,245,217	($242,171)	$608	$65	($9,437)	$994,282	$27,154
24	2018	$1,036,166	$1,171,476	($178,502)	$188	$267	($18,986)	$974,443	$61723
25	2019	$1,250,565	$1,452,866	($263,310)	($2,063)	$403	($42,789)	$1,145,107	$105,458
26	2020	$ 935,735	$ 979,751	($81,477)	($856)	$36	($43,690)	$853,764	$81,971
27	2021	$ 927,660	$1,038,718	($277,903)	$394	$153	($18,447)	$742,915	$184,745
28	2022	$2,018,336	$2,233,544	($303,868)	($2,720)	$196	($31,034)	$1,896,118	$122,218
29	2023	$4,603,238	$4,796,566	($557,034)	$3	$159	($54,096)	$4,185,598	$417,640
30	2024	$1,287,677	$1,499,471	($274,261)	$3,077	($900)	($13,677)	$1,213,410	$74,267

*Note: The net hedge costs/(gains) amounts in the table above are the net amounts for financial hedges included as GCIM actual costs, i.e. 25 percent of hedge costs/gains for winter hedges and 100 percent of hedge/costs/gains for non-winter hedges. This column does not include physical hedges. The Total Commodity Benchmark Costs for Years 29 and 30 include 25 percent of the benchmark costs for physical hedges. Similarly, the Gross Purchase Costs and Sales for those years also include the costs/credits related to physical hedges.

Table 12 below shows that it was generally the case that during the review period citygate net purchases and Secondary Market Services revenues were the main components that resulted in GCIM savings.

Table 12: Percent Savings by Key Components ($000)[133]

GCIM Year	Ending in March	Total Actual Savings	% Due to Mainline	% Due to Border	% Due to Citygate	% Due to SMS
21	2015	$43,108	15.50%	(124.10%)	190.10%	19.60%
22	2016	$28,164	14.30%	7.10%	38.60%	42.20%
23	2017	$27,154	9.60%	29.40%	28.80%	34.80%
24	2018	$61,723	11.00%	1.90%	57.10%	30.80%
25	2019	$105,458	9.70%	5.40%	42.70%	40.60%

133 Negative percentages mean that a certain component reduced GCIM savings rather than contributed to savings.

GCIM Year	Ending in March	Total Actual Savings	% Due to Mainline	% Due to Border	% Due to Citygate	% Due to SMS
26	2020	$81,971	(5.40%)	10.00%	41.10%	53.30%
27	2021	$184,745	46.30%	29.30%	14.70%	10.00%
28	2022	$122,218	1.70%	(1.60%)	72.40%	25.40%
29	2023	$417,640	23.50%		63.6%*	13.00%
30	2024	$74,267	(40.20%)		124.7%*	18.40%

*Cal Advocates did not differentiate border and citygate purchases and sales for the GCIM Year ending March 2024. The figure shown in the above table is the percentage of total savings made by border/citygate net purchases. The "Total Actual Savings" are the total actual net savings resulting from all components of the GCIM, i.e., including hedging and off-system parks and loans. Thus, the percentage savings shown above do not add up to 100 percent.

The following table shows savings and shareholder rewards as a percentage of actual commodity costs. It also shows the shareholder reward as a percentage of savings.

Table 13: GCIM Savings and Rewards ($000)

GCIM Year	Ending in March	Total Savings	Final Ratepayer Share	Final Shareholder Reward	Savings as % of Total Actual Commodity Costs	Shareholder Reward as % of Total Actual Commodity Costs	Reward as % of Savings	GCIM Reward Cap Met?
21	2015	$43,108	$35,858	$7,250	3.2%	0.5%	16.8%	
22	2016	$28,164	$23,123	$5,040	3.7%	0.7%	17.9%	
23	2017	$27,154	$22,919	$4,235	2.7%	0.4%	15.6%	
24	2018	$61,723	$50,369	$11,353	6.3%	1.2%	18.4%	
25	2019	$105,458	$88,660	$16,799	9.2%	1.5%	15.9%	
26	2020	$81,971	$69,166	$12,806	9.6%	1.5%	15.6%	Yes
27	2021	$184,745	$173,601	$11,144	24.9%	1.5%	6.0%	Yes
28	2022	$122,218	$99,903	$22,313	6.5%	1.2%	18.3%	
29	2023	$417,641	$394,961	$22,681[134]	10.0%	0.5%	5.4%	Yes
30	2024	$74,267	$60,402	$13,865	6.1%	1.1%	18.7%	

Total savings and the shareholder award varied significantly over the 10-year period. As can be seen in the table above, the savings ranged from 2.7 percent to 24.9 percent of total actual commodity costs. The final shareholder rewards were in the range of 5.4 to 18.7 percent of the total savings and were between 0.4 and 1.5 percent of total actual commodity costs. However, in several of the years, i.e., 2020, 2021 and 2023, the

[134] Note that the CPUC reduced the shareholder award for GCIM Year 29 below the 1.5 percent shareholder reward cap in recognition of the high prices experienced that year.

shareholder reward "cap" of 1.5 percent of actual commodity costs determined the final shareholder reward.[135] Absent the cap, the shareholder reward would have been higher. (In Year 25, the cap was not quite met. The reward as a percentage of actual commodity costs was 1.47 percent.)

Had all excess physical hedging costs (i.e., costs in excess of benchmark costs) for GCIM Year 30 ending in March 2024 been included in the GCIM, there would have been a substantial overall net loss of $83.3 million relative to benchmark costs rather than a net savings. Such excess costs would have been above the upper tolerance zone of 2 percent of benchmark commodity costs. Had 100 percent of physical hedging costs been included in the GCIM, SoCalGas would have faced a penalty of $27.0 million rather than receiving a shareholder reward.

Similarly, for GCIM Year 31 ending in March 2025, SoCalGas reports net savings of $42.1 million and a shareholder reward of $8.4 million in its application.[136] However, these results are partly due to the exclusion of 75 percent of the excess physical hedging costs from the GCIM.

The general pattern of consistent savings and shareholder rewards has existed for many years, even prior to the 10-year period under review in this report. In fact, SoCalGas' Year 31 application shows that savings and rewards were achieved every year under the GCIM, except the initial year of operation in 1995. Since 2018, it appears that the amounts of the savings and final shareholder rewards have become consistently higher than in previous years (except for the unusual years during the California energy crisis in the early 2000s), even after the rewards were reduced due to the application of the 1.5 percent cap and the reduction to the 2023 reward.

The savings as a percentage of actual commodity costs during the review period (Years 21-30) are more than three times as much as the previous 10 years, and the shareholder rewards as a percentage of actual costs are more than twice what they were during the previous 10 years as can be seen in Table 14 below. This change may be due in part to the combination of commodity price volatility caused by pipeline and storage constraints in the SoCalGas service territory and the fact that noncore customers had no access to new Unbundled Storage contracts between 2016 and 2023. Having no storage capacity themselves, noncore customers were likely more dependent on core gas sales when gas was scarce, which may have driven up the prices core customers received for their excess supplies.

Given this pattern of savings and rewards, the CPUC may wish to consider some adjustments to the GCIM in another proceeding that preserve the benefits of the incentive mechanism while increasing the allocation of savings to core customers.

[135] The shareholder reward cap was established in 2002. See D.02-06-023: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/16315.PDF.
[136] SoCalGas Application Regarding Year 31 of its GCIM, D.25-06-012: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M569/K283/569283808.PDF.

Table 14: GCIM Savings and Rewards for Years 11–20 ($ millions)

GCIM Year	Ending in March	Commodity Cost	Total Savings	Reward	Savings as % of Commodity	Reward as % of Commodity	Reward as % of Savings
11	2005	$2,103	$31.4	$2.5	1.5%	0.1%	8.0%
12	2006	$2,923	$69.1	$9.8	2.4%	0.3%	14.2%
13	2007	$2,135	$57.7	$8.9	2.7%	0.4%	15.4%
14	2008	$2,349	$50.1	$6.5	2.1%	0.3%	13.0%
15	2009	$2,661	$75.6	$12.0	2.8%	0.5%	15.9%
16	2010	$1,548	$39.9	$6.0	2.6%	0.4%	15.0%
17	2011	$1,559	$40.9	$6.2	2.6%	0.4%	15.2%
18	2012	$1,547	$37.5	$5.4	2.4%	0.3%	14.4%
19	2013	$1,107	$34.7	$5.8	3.1%	0.5%	16.7%
20	2014	$1,485	$70.4	$13.7	4.7%	0.9%	19.5%
Total		$19,417	$507.3	$76.8	2.6%	0.4%	15.1%

Overall Structure and Process

Staff reviewed the structure of the GCIM, the process by which reports are submitted to the CPUC and by which CPUC review is conducted, and the description of the GCIM in SoCalGas' Preliminary Statement.

Staff found that:

1. the GCIM structure is readily understandable and logical;
2. with a couple of exceptions, the GCIM is generally well-explained in SoCalGas' tariff Preliminary Statement, Part VIII;[137]
3. GCIM confidential monthly reports are submitted to the CPUC in a timely fashion and provide a great deal of information that is useful and understandable, although confidential;
4. the GCIM performance and shareholder reward approval process is simple and straightforward, and has undoubtedly reduced the regulatory burden on parties relative to a reasonableness review of procurement costs;
5. SoCalGas meets its annual deadline for filing the GCIM application for the previous year's costs;
6. Cal Advocates' *Monitoring and Evaluation Reports* are generally issued in a timely manner and provide a great deal of useful, public information. The reports for the most recent 10-year period are now publicly available on the Cal Advocates' web site.

Staff recommend that the CPUC authorize changes to increase transparency and thereby mitigate harm to ratepayers should gas price spikes recur in this proceeding. Specifically, Staff recommend that the CPUC:

1. Require that SoCalGas' Preliminary Statement: 1) define the type of transactions that are considered to be physical hedges; 2) explain how physical gas hedges are incorporated in the GCIM benchmark

costs, 3) state how off-system parks and loans are incorporated in the GCIM, and 4) provide a listing of the specific publications used to develop indices used in the GCIM.

2. Request that Cal Advocates' *Monitoring and Evaluation Reports* fully report and explain the gains and excess costs of physical hedges conducted by SoCalGas Gas Acquisition and how they are incorporated in GCIM benchmark and actual costs.
3. Request that Cal Advocates' *Monitoring and Evaluation Repots* present border and citygate purchase and sale information separately rather than combined.
4. Request that Cal Advocates' *Monitoring and Evaluation Reports* tables to show the benchmark costs and volumes by basin and the monthly indices used in the GCIM..

Summary Comments on the GCIM

Staff found that:

1. The GCIM has provided SoCalGas' Gas Acquisition with clear benchmarks for its procurement activities, and this has resulted in significant savings for core ratepayers relative to those benchmarks.
2. Gas Acquisition has been able to procure supplies at net costs that are lower than the market index-based benchmark costs.
3. Sales are a significant procurement-related activity and are one of the reasons net purchase costs are below commodity benchmark costs.
4. GCIM net purchase savings can result from mainline, border, or citygate purchase and sales activity but are mainly through citygate purchases and sales. This may indicate that Gas Acquisition is able to make daily purchases at the citygate at prices that are below the monthly benchmark and/or make daily sales at the citygate when prices are above the monthly benchmark to achieve much of GCIM savings.
5. Gas Acquisition has access to substantial amounts of storage capacity that allow it to not only meet core reliability requirements but to take advantage of purchase and sales opportunities.
6. Secondary Market Services revenues add an important source of GCIM savings, often amounting to levels that are comparable to savings achieved through other components of procurement activity. It appears that Secondary Market Services revenues increased following the Aliso Canyon accident, and particularly after the subsequent rupture of Line 235-2 during years when Unbundled Storage capacity was not available.
7. Financial derivative hedging activity has generally resulted in small losses with occasional gains.
8. To the extent physical hedging activities are clearly illustrated in Cal Advocates reports and SoCalGas GCIM applications, they resulted in savings in Year 29 (2022-23) but very large "excess" costs (i.e. costs greater than benchmark costs) in Year 30 (2023-24). Most of those savings or excess costs were not included as actual costs under the GCIM but were still credited to, or paid by, core ratepayers. Despite the fact that Year 30 physical hedging activity resulted in very large excess costs, the GCIM structure still resulted in large net savings relative the GCIM benchmark and a reward for SoCalGas shareholders. If all physical hedge benchmark costs and actual costs had been included in GCIM Year 30, a net loss would have occurred.
9. Off-system parks and loans result in very small gains or losses relative to other components of GCIM actual costs. These transactions are a tool that can be used to address gas supply delivery issues such as High Operational Flow Order days or pipeline maintenance events. To increase

transparency and, thereby, reduce ratepayer harm, the SoCalGas Preliminary Statement should clearly indicate that off-system park and loan costs/revenues are included in GCIM actual costs.

10. While SoCalGas has an incentive to lower procurement costs relative to benchmark costs, its primary responsibility is to reliably provide sufficient gas supplies core customers and supplies and to meet balancing requirements.
11. SoCalGas achieved savings under the GCIM every year of the review period, and those savings resulted in shareholder rewards every year.
12. The GCIM reward cap ensures that shareholder rewards will not exceed 1.5 percent of commodity costs. The cap was employed three times, and the reward was reduced beyond the cap in 2023.
13. In Year 29, the shareholder reward resulting from GCIM performance resulted in a very large reward even at the 1.5 percent cap, but SoCalGas and Cal Advocates recommended, and the CPUC approved, a further reduction in the reward amount.
14. The savings and shareholder rewards as a percentage of actual commodity costs are higher in recent years compared to the previous 10 years.
15. The GCIM structure is understandable and generally well-explained in SoCalGas' Preliminary Statement.
16. To increase transparency, and, thereby, mitigate ratepayer harm, Staff would like to see a clear explanation for how physical hedges are defined and treated under the GCIM in the Preliminary Statement and would like to see a clear explanation for how off-system parks and loans are treated.
17. Cal Advocates' *Monitoring and Evaluation Reports* usually provide excellent summaries of GCIM performance and much detailed, public information. The reports are publicly available on the Cal Advocates web site going back about 10 years. Most of the time Cal Advocates agrees with the results in SoCalGas' GCIM performance report but occasionally makes alternative recommendations.
18. There is little mention in the Cal Advocates report for Year 30 that SoCalGas physical hedges resulted in $210 million in excess costs despite the information being included in the SoCalGas application. Fuller discussion of such important activity would help the CPUC and the public evaluate SoCalGas' GCIM reward requests and the functioning of the GCIM itself.
19. SoCalGas is at risk for 25 percent of the costs or gains related to its winter hedging activity.
20. Physical hedging costs (only 25 percent of which were included in the GCIM) were incurred partly for physical supply procurement and partly for hedging purposes.
21. The GCIM tolerance band, sharing tiers, and reward cap all help to ensure that the bulk of the GCIM savings goes to ratepayers. But given that SoCalGas has been able to achieve GCIM savings and rewards in virtually every year since the GCIM was established, the savings and rewards appear to be fairly routine, with minimal risk to the utility. In recent years, the level of savings relative to benchmark costs and relative to actual commodity costs has become quite high relative to previous years. The shareholder reward as a percentage of actual commodity costs has also increased relative to previous years, even after application of the reward cap.
22. This is not to say that SoCalGas' GCIM savings have been easy to achieve. SoCalGas needs to not only look for savings opportunities but also needs to ensure that core customers have adequate supplies of gas, core storage is adequately filled, and that core deliveries are balanced.
23. The GCIM reporting, review, and approval process generally allows the CPUC and staff insight into SoCalGas' procurement data and has undoubtedly reduced CPUC and parties' regulatory

burden. The GCIM process benefits greatly from the detailed participation of Cal Advocates, who directly represent ratepayers.

24. The following are some questions the CPUC may want to consider in a future proceeding:
    a. Should a portion of citygate and border benchmark prices be daily rather than monthly?
    b. Should the shareholder cap be reduced to 1 percent from its current level of 1.5 percent?
    c. Should a larger portion of physical hedging costs be included in the GCIM benchmark and actual costs?
    d. Would a cap on hedging costs benefit ratepayers?
    e. Should the share of ratepayer savings be increased?
    f. Should all, or a portion, of Secondary Market Services revenues be included in actual costs?
    g. Should the upper tolerance band be lowered to 1 percent to match the lower tolerance band of 1 percent?
    h. Should the portion of savings going to shareholders be limited?

Review of the PG&E CPIM

Staff examined the following components of the PG&E CPIM:

1. whether actual gas purchases are made at overall costs that are lower than benchmark-based costs;
2. how PG&E incorporates sales of gas into its overall procurement strategy and practice, and the extent to which sales help PG&E ~~SoCalGas~~ lower overall procurement costs;
3. the location of gas purchases that PG&E makes, i.e., the proportion of purchases and sales that are made in the basin, at the border, or at the citygate;
4. how hedging costs or gains have impacted CPIM performance results and overall core costs;
5. how Cochrane extraction revenues impact CPIM results;
6. the CPIM structure, including how benchmark costs are determined, the cost/savings sharing structure, and the reward cap; and
7. transportation costs.

Sales Are Critical to Beating the CPIM Benchmark

As with SoCalGas, sales were critical to PG&E Core Gas Supply's ability to beat benchmark costs. Gross purchase costs were above benchmark commodity costs for every year during the review period, but sales brought net purchase costs below benchmark costs.

The table below shows Core Gas Supply's gross purchase costs, including the actual volumetric transportation costs, less sales credits, compared to the benchmark commodity costs. (Recall that CPIM benchmark costs include volumetric costs to move the supplies to the citygate.)

Table 15: CPIM Gross Purchase Gas Costs, Volumetric Costs, Sales, and Benchmark Costs ($000s)

CPIM Year	Ending in October	Gross Purchase Costs	Volumetric Transport Costs	Sales Credits	Net Purchase Costs	Benchmark Commodity Costs*
20	2013	$1,013,146	$26,496	($238,265)	$801,377	$810,502
21	2014	$1,114,488	$22,748	($236,139)	$901,097	$922,316
22	2015	$ 825,057	$28,300	($353,314)	$500,043	$521,363
23	2016	$ 584,553	$28,318	($213,453)	$399,418	$420,874
24	2017	$ 773,217	$24,542	($211,011)	$586,748	$600,907
25	2018	$ 573,625	$25,770	($165,078)	$434,317	$454,062
26	2019	$ 633,725	$27,154	($117,427)	$542,542	$594,686
27	2020	$ 503,382	$39,472	($121,359)	$421,495	$440,621
28	2021	$ 981,625	$50,251	($373,206)	$658,670	$775,321
29	2022	$1,572,203	$53,852	($389,060)	$1,236,995	$1,249,807

*Not including benchmark costs for hedging or merchandise processing fees.

The table above shows significant variation over the years in the gross purchase costs, sales credits, and net purchase costs. This variation is primarily due to fluctuations in gas prices and core demand.

PG&E Core Gas Supply's net purchase costs are far lower than those of SoCalGas Gas Acquisition because: 1) PG&E has far fewer core customers than the combined total of SoCalGas and SDG&E;[138] 2) a larger proportion of core customers in the PG&E service territory have their gas procured by CTAs than in the SoCalGas service territory, and the utilities' core procurement departments do not procure gas supplies for CTA customers;[139] 3) PG&E Core Gas Supply has more access than SoCalGas to Canadian gas, which tends to be cheaper than gas from most other basins;[140] and 4) in recent years, gas commodity prices in the PG&E service territory have been less volatile than in the SoCalGas service territory, where lower supply availability due to pipeline outages on both upstream interstate pipelines and the SoCalGas intrastate system, and reductions in gas storage availability after the Aliso Canyon incident, have caused repeated gas price spikes.[141]

As is the case with SoCalGas, sales are a significant component of PG&E Core Gas Supply's procurement activity. In fact, Core Gas Supply's sales appear to be an even larger fraction of gross purchase costs. Core

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[138] According to the American Gas Association, in 2023, SoCalGas and SDG&E had a combined 6.6 million residential gas customers and PG&E had 4.0 million. In their most recent GRC decisions, SoCalGas and SDG&E indicated they had 5.9 million and 900,000 customer meters respectively, for a combined total of 6.8 million total customers. See D.24-12-074, p. 70: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf. PG&E provides service to 4.3 million, residential, industrial, and commercial customers. See D.23-11-069, p. 50: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M520/K896/520896345.pdf .

[139] Verified in confidential data request responses collected by Staff in early 2025.

[140] Business News Today, "AECO vs. Henry Hub: is Canadian gas about to become the world's cheapest LNG feedstock?" July 4, 2025: AECO vs. Henry Hub: is Canadian gas about to become the world's cheapest.

[141] Energy Division Staff, *Winter 2018-19 SoCalGas Conditions and Operations Report,* January 6, 2020: Microsoft Word - Winter2018-19LookbackReport-Final-January2020.

Gas Supply's sales ranged from about 18 percent to over 40 percent of gross purchase costs during the study period.

Location of Purchases, Sales, and Savings

To determine where the majority of CPIM savings occurred, Staff reviewed the location of the purchases and sales made, i.e., whether the purchases/sales were made in the basin/mainline, at the PG&E Border, or the PG&E Citygate. Staff found that: 1) most of PG&E Core Gas Supply's purchase costs were basin purchase costs (although in more recent years, border and citygate purchases have become a larger portion of the portfolio), and 2) sales credits are more heavily weighted to border/citygate sales, especially given the lower level of border/citygate purchases. In fact, citygate sales credits were greater than citygate purchase costs in almost every year and comprised a very significant portion of overall sales.

Table 16: PG&E CPIM Purchases and (Sales) by Location ($000s)

CPIM Year	Ending in October	Basin Purchases	Border & Other Purchases*	Citygate Purchases	Basin Sales	Border & Other Sales*	Citygate Sales
20	2013	$948,498	$47,744	$16,904	($7,830)	($12,433)	($218,003)
21	2014	$998,685	$46,453	$69,349	($63,230)	($3,164)	($169,745)
22	2015	$692,015	$124,743	$8,299	($21,517)	($4,185)	($327,611)
23	2016	$449,418	$122,270	$12,435	($14,734)	($6,253)	($192,466)
24	2017	$523,889	$145,849	$103,478	($57,218)	($15,422)	($138,370)
25	2018	$371,312	$130,248	$72,065	($43,731)	($6,507)	($114,839)
26	2019	$389,984	$123,962	$119,778	($11,997	($16,118)	($89,311)
27	2020	$380,593	$71,403	$51,385	($29,804	($2,384)	($89,171)
28	2021	$562,628	$289,123	$129,875	($162,344)	($70,058)	($140,804)
29	2022	$1,064,489	$324,839	$182,875	($115,787)	($47,189)	($226,083)

*In the above table, "Border & Other Purchases" and "Border & Other Sales" includes purchases and sales identified in Cal Advocates *Monitoring and Evaluation Reports* as "CGT," "GTN," and "Topock."

It is difficult to compare CPIM benchmark and actual costs using only data from the Cal Advocates *Monitoring and Evaluation Reports* because the benchmark costs include calculated volumetric transportation charges while the actual net purchase costs do not. CPIM benchmark costs are calculated to the citygate, i.e., based on benchmark indices which include calculated volumetric transportation costs to move supplies from the basin or border to the citygate, with adjustments for fuel. In order to directly compare basin and border net costs to benchmark costs, one would need to determine the appropriate amount of volumetric transportation costs to add to each of the basin and border actual net costs. In order to create the table below, Staff assumed that actual volumetric transportation costs were only attributable to basin and border net purchases so that basin/border savings could be compared to citygate savings.

Table 17: CPIM Savings by Location ($000s)

CPIM Year	Ending in Oct.	Basin Net Purchase Costs	Border Net Purchase Costs	Volumetric Transport Costs	Total Net Costs of Basin and Border Purchases	Total Benchmark for Basin and Border Purchases	Citygate Net Purchase Costs	Citygate Benchmark Costs
20	2013	$940,668	$35,311	$26,497	$1,002,475	$803,879	($201,099)	$6,623
21	2014	$935,455	$43,289	$22,747	$1,001,492	$901,940	($100,396)	$20,376
22	2015	$670,498	$120,558	$28,299	$819,356	$519,577	($319,312)	$1,785
23	2016	$435,114	$116,017	$28,318	$579,449	$405,864	($180,031)	$15,010
24	2017	$466,671	$130,427	$24,542	$621,640	$527,204	($34,892)	$73,703
25	2018	$327,581	$123,741	$25,770	$477,092	$394,490	($42,774)	$59,572
26	2019	$377,987	$107,844	$27,154	$512,985	$458,257	$30,467	$136,429
27	2020	$350,789	$69,019	$39,472	$459,280	$391,159	($37,786)	$49,462
28	2021	$400,284	$219,065	$50,251	$669,600	$702,963	($10,929)	$72,358
29	2022	$948,702	$277,650	$53,852	$1,280,204	$1,149,873	($43,208)	$99,934
Total					$7,423,573	$6,255,206	($939,960)	$535,252

As can be seen in Table 17 above, citygate net purchases relative to citygate benchmark costs have been the main driver of CPIM savings during the review period. Citygate sales credits far exceeded citygate purchase costs in every year during the review period. However, this trend seems to have become less significant in the latter years of the review period. On a combined basis, the net costs of basin and border purchases were above the combined benchmark costs for those purchases for every year except 2021.

However, as discussed further below, a large part of the apparent excess costs due to basin/border net purchases and savings due to citygate net purchases can likely be explained by the differences in benchmark load <u>volumes</u> for these locations compared to the amount of actual net volumes for these locations. This feature of the CPIM is described in more detail below.

Purchases and Sales During Winter 2022-23

Staff examined CPIM performance and procurement activity for the high-prices months of December 2022 through February 2023 as well as a few randomly selected months (November 2013, July 2014, February 2018, and March 2022). Staff found a variety of patterns. Net purchase prices for a particular basin might be below, near, or above the index. However, for the period from December 2022 through February 2023, the primary impact on CPIM performance, by far, was related to PG&E Core Gas Supply's winter and non-winter hedge activity. Core Gas Supply's winter hedge appears to have had the biggest impact in saving its gas ratepayers money during that volatile period in the Western gas market.

Benchmark Sequence Volumes vs. Actual Net Purchase Volumes

There are several differences in the way benchmark volumes and costs are calculated under the CPIM compared to the GCIM. For the CPIM, benchmark volumes are not directly based on actual monthly net purchase volumes as they are under the GCIM. Instead, the benchmark volumes are based on daily forecasted procurement volumes needed to meet daily core requirements while accounting for the presumed storage injection or withdrawal profile, and a presumed sequencing of purchases.

Benchmark costs are also calculated differently. First, the CPIM benchmark commodity cost is based on an assumed sequence of purchases at various locations rather than on actual purchase volumes for various locations as under the GCIM. Second, as noted above, CPIM benchmark prices are calculated to the citygate. Third, the CPIM incorporates daily, rather than monthly, benchmark pricing for some supplies.

The daily load sequence under the CPIM provides a forecast of daily core procurement supply requirements to the citygate, given a presumed storage injection and withdrawal profile. Then, the CPIM sets up a sequence of assumed benchmark core gas purchases that would allow PG&E to meet those supply requirements. However, PG&E Core Gas Supply is not required to purchase the daily benchmark load volumes, follow that sequence of purchases, or match the presumed storage profile.

Core Gas Supply can thus register gains or losses under the CPIM compared to the benchmark simply because its actual gas volumes purchased do not match the benchmark purchasing sequence. For example, in one of the months that Staff examined, the CPIM load sequencing resulted in a benchmark load (and therefore also costs) for citygate purchases of zero. While Core Gas Supply purchased very small volumes at the citygate that month, it made significant sales. The net actual cost for citygate purchases was a significant negative amount, relative to the benchmark cost of zero, resulting in a large savings amount for net citygate purchases that month. Other purchases/sales had net excess costs relative to their benchmark costs, but the large citygate savings resulted in overall savings for that month.

In another monthly example, March 2022, Core Gas Supply's total net purchase volumes were moderately more than the daily benchmark load. In that month, Core Gas Supply's actual commodity costs thus exceeded the benchmark costs by $16 million. On the other hand, in September 2022, Core Gas Supply's net purchase volumes were much less than the benchmark load volumes, resulting in $17 million in savings. The difference between benchmark volumes and (actual) net purchase volumes is the only reason for excess costs or savings in those months. This illustrates that differences between benchmark and actual volumes can have an important impact on the CPIM results.

The CPIM thus not only incentivizes Core Gas Supply to procure supplies at a low price relative to the benchmark indices but also provides "benchmark budget" costs that Core Gas Supply can choose how to meet or exceed. Core Gas Supply has options on the purchase and sales locations, the volumes of its purchases/sales to make at those locations, and, to an extent, options on the total monthly volumes to purchase or sell. At the same time, Core Gas Supply needs to make sure that it maintains pipeline supplies and storage levels that assure core reliability.

Table 18 below shows how the actual net volumes of gas purchased by Core Gas Supply can differ from the benchmark. It should also be noted that net purchase volumes indicate the volumes purchased/sold at the point of purchase/sale, while the daily load volumes are amounts delivered to the citygate. Some volumetric "shrinkage" occurs as gas supplies are delivered over interstate pipelines and the backbone transmission system. In order to deliver a certain volume at the citygate, a slightly greater volume must be purchased in the basin or at the border.

Table 18: PG&E Actual Net Purchase Volumes vs. Benchmark Load Volumes

CPIM Year	Ending in October	Actual Net Purchase Volumes (MMBtu)	Benchmark Load Volumes (MMBtu)
20	2013	241,969	233,940
21	2014	217,738	210,954
22	2015	193,129	208,569
23	2016	186,600	213,345
24	2017	231,572	224,463
25	2018	232,122	224,588
26	2019	240,530	234,243
27	2020	214,056	206,316
28	2021	240,736	233,266
29	2022	230,697	223,945
	Total	2,229,149	2,213,629

Over the 10-year review period, volume differences are fairly large in some years, such as 2016. But, on average, the amount of the difference is only 0.7 percent. In addition, basin and border net purchase volumes were consistently higher than benchmark volumes, while citygate net purchases were consistently well below benchmark volumes.

Hedging Costs and Gains

As with SoCalGas, financial derivative hedges were a fairly modest component of CPIM actual and benchmark costs during most of the review period years. See Table below. In most years hedging resulted in costs, rather than gains, and the net actual costs were slightly more than the benchmark costs. Hedging results for winter CPIM Year 30, which includes winter 2022-23, have not yet been publicly reported. However, Core Gas Supply's financial hedges in that year appear to have resulted in significant gains.

Table 19: PG&E Financial Hedging Losses and (Gains) ($000s)

CPIM Year	Ending in October	Actual Winter Hedge Costs (100%)	Winter Hedge Costs in Benchmark (80%)	Actual Non-Winter Hedge Costs
20	2013	$23,132	$18,506	($345)
21	2014	$10,237	$8,190	($34)
22	2015	$7,925	$6,340	($2,108)
23	2016	$7,593	$6,074	$5,034
24	2017	$8,036	$6,429	($948)
25	2018	$8,622	$6,898	$515
26	2019	($2,621)	($2,097)	$1,144
27	2020	$6,658	$5,327	$1,475
28	2021	$12,488	$9,990	$12,679
29	2022	$3,458	$2,766	$12,856

Cal Advocates *Monitoring and Evaluation Reports* do not indicate that Core Gas Supply procured any physical hedges during the study period.

Cochrane Extraction Revenues and Miscellaneous Costs

Cochrane Extraction Revenues contributed small amounts to CPIM savings as shown in the table below, while miscellaneous costs were fairly small. As explained above, Cochrane Extraction Revenues are credits that PG&E obtains pursuant to its contract to supply feed gas for natural gas liquids extraction associated with deliveries on the Transcanada system. These amounts are credits to CPIM actual costs with no adjustment to benchmark dollars.

Table 20: Cochrane Extraction (Revenue) and Miscellaneous Costs ($000s)

CPIM Year	Ending in October	Cochrane Extraction Revenues	Misc. Costs
20	2013	($7,703)	$325
21	2014	($7,624)	$537
22	2015	($2,449)	$274
23	2016	($2,561)	$607
24	2017	($3,445)	$280
25	2018	($5,099)	$231
26	2019	($2,670)	$251
27	2020	($1,827)	$407
28	2021	($3,892)	$509
29	2022	($5,260)	$469

Interstate Transportation Cost Savings and Storage Costs

Under the CPIM, Core Gas Supply has an incentive to reduce interstate transportation reservation costs by attempting to achieve discounts or allowing some of its core interstate capacity to be used by other parties. These efforts have typically resulted in small cost savings as shown in the following table.

Bundled core storage reservation costs are included in both CPIM benchmark and actual costs. The storage benchmark costs are exactly the same as the storage actual costs, so there are no savings or excess costs associated with storage under the CPIM.

Volumetric interstate and backbone transmission costs are a component of CPIM actual commodity costs.

Table 21: CPIM Interstate and Backbone Transportation Reservation Costs, Savings, and Storage Costs

CPIM Year	Ending in October	Full Interstate and Backbone Transport Reservation Costs	Transportation Savings	Storage Costs
20	2013	$212,450	($3,058)	$48,341
21	2014	$189,288	($12,938)	$45,943
22	2015	$188,502	($9,655)	$44,928
23	2016	$181,518	($2,771)	$49,288
24	2017	$180,257	($376)	$63,628
25	2018	$182,841	($306)	$64,931
26	2019	$183,337	($204)	$69,226
27	2020	$203,091	($111)	$79,446
28	2021	$228,061	($198)	$53,717
29	2022	$239,062	($158)	$53,721

Summary of CPIM Performance

The table below summarizes CPIM commodity cost performance during the review period. Table 22 does not include costs or savings related to interstate transportation, backbone transmission, or storage. The benchmark costs consist of the following: 1) benchmark commodity costs, 2) 80 percent of winter hedge costs/(gains), and 3) merchandise processing fees.

Table 22: Overall View of CPIM Commodity Performance Compared to Benchmark ($000)

CPIM Year	Ending in Oct.	Total Commodity Benchmark Costs	Gross Purchase Costs	Sales Credits	Vol. Trans. Costs	Other Costs*	Winter Hedge Costs	Total Actual Commodity Costs	CPIM Commodity Savings
		A	B	C	D	E	F	G=B+C+D+E+F	H=G-A
20	2013	$829,008	$1,013,146	($238,265)	$26,496	($7,723)	$23,132	$816,786	$12,222
21	2014	$930,506	$1,114,488	($236,139)	$22,748	($7,121)	$10,237	$904,213	$26,293
22	2015	$527,703	$825,057	($353,314)	$28,300	($4,283)	$7,925	$503,685	$24,018
23	2016	$426,948	$584,553	($213,453)	$28,318	$3,080	$7,593	$410,091	$16,857
24	2017	$607,482	$773,217	($211,011)	$24,542	($3,967)	$8,036	$590,817	$16,665
25	2018	$461,106	$573,625	($165,078)	$25,770	($4,207)	$8,622	$438,732	$22,374
26	2019	$592,735	$633,725	($117,427)	$27,154	($1,129)	($2,621)	$539,702	$53,033
27	2020	$446,094	$503,382	($121,359)	$39,472	$201	$6,658	$428,354	$17,740
28	2021	$785,457	$981,625	($373,206)	$50,251	$9,442	$12,488	$680,600	$104,857
29	2022	$1,252,719	$1,572,203	($389,060)	$53,852	$8,211	$3,458	$1,248,664	$4,055

* Other Costs are Cochrane Extraction Revenue, Non-Winter Hedge Costs, Miscellaneous Costs and Revenues, and merchandise processing fees.

The winter hedge costs that are included as actual costs in Table 22 above appear higher than those of SoCalGas Gas Acquisition for the years shown, but the difference is not as large as it seems. Under the GCIM, only 25 percent of winter hedge costs/(gains) are included as actual costs with no adjustment to the benchmark. But under the CPIM, 100 percent of actual hedge costs/(gains) are included as actual costs, and 80 percent of such costs/(gains) are included in the CPIM benchmark. So, in column A above, 80 percent of the winter hedge amounts shown in column F are included in the benchmark costs.

It appears that the main way that PG&E is able to achieve savings under the CPIM relative to benchmark costs is through sales at the citygate. These sales results in net citygate costs that are well below the CPIM benchmark cost at the citygate.

In 2021, total savings increased significantly due to sales in February 2021 during Winter Storm Uri. In that month, heavy sales mainly occurred in basins or at the border. Of the $105 million in commodity savings achieved in 2021, PG&E achieved CPIM commodity savings of $112.8 million in the month of February 2021 alone. In fact, total sales credits were so large that month that they exceeded gross purchase costs.

Table 23: Total View of CPIM Performance ($000s)

CPIM Year	Ending in October	Commodity Benchmark	Transport & Storage Benchmark	Total Benchmark	Commodity Actual Costs	Transport & Storage Actual Costs	Total Actual Costs	CPIM Savings
		A	B	C=A+B	D	E	F=D+E	G=C-F
20	2013	$829,008	$260,791	$1,089,799	$816,786	$257,733	$1,074,519	$15,280
21	2014	$930,506	$235,231	$1,165,737	$904,213	$222,293	$1,126,506	$39,231
22	2015	$527,703	$233,431	$761,134	$503,685	$223,776	$727,461	$33,673
23	2016	$426,948	$230,806	$657,754	$410,091	$228,035	$638,126	$19,628
24	2017	$607,482	$243,885	$851,367	$590,817	$243,509	$834,326	$17,041
25	2018	$461,106	$247,772	$708,878	$438,732	$247,446	$686,198	$22,680
26	2019	$592,735	$252,563	$845,298	$539,702	$252,359	$792,061	$53,237
27	2020	$446,094	$282,537	$728,631	$428,354	$282,246	$710,780	$17,851
28	2021	$785,457	$281,778	$1,067,235	$680,600	$281,580	$962,180	$105,055
29	2022	$1,252,719	$292,783	$1,545,502	$1,248,664	$292,625	$1,541,289	$4,213

The table below summarizes CPIM savings and shareholder rewards during the review period.

Table 24: CPIM Savings and Rewards ($000s)

CPIM Year	Ending in October	Total Savings	Final Ratepayer Share	Final Shareholder Reward	Savings as % of Actual Costs	Reward as % of Savings	CPIM Cap Met?
20	2013	$15,280	$13,882	$1,398	1.4%	9.1%	
21	2014	$39,231	$33,245	$5,985	3.5%	15.3%	
22	2015	$33,673	$27,994	$5,679	4.6%	16.9%	
23	2016	$19,628	$16,556	$3,072	3.1%	15.7%	
24	2017	$18,894 *	$16,331	$2,563	2.3%	13.6%	
25	2018	$22,680	$19,066	$3,518	3.3%	15.5%	
26	2019	$53,237	$45,413	$8,096	6.7%	15.2%	Yes
27	2020	$17,851	$15,173	$2,678	2.5%	15.0%	
28	2021	$105,055	$94,846	$10,210	10.9%	9.7%	Yes
29	2022	$4,213	$4,213	$0.0	0.3%	0%	
30	2023	$196,846	$170,217	$26,629	9.4%	13.5%	Yes

*For CPIM Year 24, the Cal Advocates *Monitoring and Evaluation Report* shows some adjustments to actual and benchmark costs related to previous CPIM years. This resulted in a slightly higher level of savings than the amount actually achieved in Year 24, as shown in Table 22. For Year 25, Cal Advocates slightly lowered the shareholder reward achieved that year for "GTN Kingsgate adjustments" from Years 23 and 24 to the amount shown in the above table.

In Table 24 above, Staff include the public version of the CPIM Year 30 Report that PG&E submitted to the CPUC on July 29, 2025. Cal Advocates has not yet issued its *Monitoring and Evaluation Report* for CPIM Year 30.[142] Also, the Final Ratepayer Share and the Final Shareholder Reward reflect the adjusted ratepayer and shareholder shares of the CPIM savings after the shareholder reward cap of 1.5 percent of commodity costs is applied. In 2019, 2021, and 2023 the shareholder reward cap was reached. In Table 24, 1) the total savings include the savings due to transportation discounts and 2) actual costs also include transportation costs. So, one should not directly compare Table 22 to Table 13 for SoCalGas.

As can be seen in Table 24: 1) the CPIM savings were a fairly steady amount as a percentage of actual costs through 2020, but increased in 2021 due to the extreme market volatility related to Winter Storm Uri, fell in 2022, and increased again in 2023; 2) the CPIM rewards were a fairly steady percentage of the savings, except for 2022 and 3) the CPIM shareholder reward amounts were noticeably lower than the SoCalGas rewards for comparable years.

Table 25 provides a more direct comparison between the performance results of the SoCalGas GCIM and PG&E CPIM by looking at just commodity cost performance. Staff included public data for CPIM Year 30 in this table but note that these costs have not yet been reviewed by Cal Advocates or the CPUC.

Table 25: Commodity Cost Performance under the PG&E CPIM and SoCalGas GCIM ($000s)

CPIM Year	Ending in October	CPIM Commodity Cost Savings	CPIM Commodity Savings as % of Actual Commodity Costs	GCIM Year	Ending in March	GCIM Commodity Cost Savings	GCIM Savings as % of Actual Commodity Costs
20	2013	$ 12,222	1.5%	19	2013	$34,700	3.1%
21	2014	$26,293	2.9%	20	2014	$70,399	4.7%
22	2015	$24,018	4.8%	21	2015	$43,108	3.2%
23	2016	$16,857	4.1%	22	2016	$28,164	3.7%
24	2017	$16,665	2.8%	23	2017	$27,154	2.7%
25	2018	$22,374	5.1%	24	2018	$61,723	6.3%
26	2019	$53,033	9.8%	25	2019	$105,458	9.2%
27	2020	$17,740	4.1%	26	2020	$81,971	9.6%
28	2021	$104,857	15.4%	27	2021	$184,745	24.9%
29	2022	$4,055	0.3%	28	2022	$122,218	6.5%
30	2023	$196,066	11.0%[143]	29	2023	$417,640	10.0%
				30	2024	$74,267	6.1%

The GCIM savings amounts for 2012 and 2013 are taken from SoCalGas A.24-06-005.

[142] PG&E Year 30 CPIM Report (November 2022 – October 2023): pge-annual-cpim-202211-thru-202310-year-30.pdf.

[143] pge-annual-cpim-202211-thru-202310-year-30.pdf

There is a timing difference between the CPIM and GCIM Years, so one should not necessarily make a direct comparison for a particular year. The CPIM Year is November through October, while the GCIM Year is April through March. The table shows that, over the years, the level of commodity savings as a percentage of commodity costs was comparable under the two mechanisms. However, the table also shows that SoCalGas consistently achieves a higher overall level of savings compared to the benchmark.

There was a sizeable jump in the level of savings as a percentage of gas commodity costs under both the GCIM and CPIM for the period that included February 2021. This increase was related to the extreme market volatility during Winter Storm Uri, when gas spot prices spiked well over $100/MMBtu in many parts of the country and surged to $1,192/MMBtu in Oklahoma.[144] But that percentage of savings dropped in the following year. (PG&E CPIM commodity savings in February 2021 are noted above. Savings under the GCIM amounted to $122.8 million in February 2021, largely due to significant basin and border sales. As was the case with PG&E, sales credits exceeded gross purchase costs that month under the GCIM.)

Similarly, the final shareholder rewards as a percentage of actual commodity costs under the CPIM and GCIM are comparable, but the GCIM actual rewards are higher. This would likely come about because SoCalGas GCIM actual commodity costs are higher than those of PG&E, in part due to the larger number of bundled core customers served by SoCalGas.

Table 26: Final Shareholder Reward as Percentage of Actual Commodity Costs ($000)

PG&E CPIM Year	Ending in October	Final CPIM Shareholder Reward	CPIM Reward as % of Actual Commodity Costs	SoCalGas GCIM Year	Ending in March	Final GCIM Shareholder Reward	GCIM Reward as % of Actual Commodity Costs
19	2012	$5,063	0.7%	18	2012	$5,400	0.3%
20	2013	$1,398	0.2%	19	2013	$5,800	0.5%
21	2014	$5,985	0.7%	20	2014	$13,710	0.9%
22	2015	$5,679	1.1%	21	2015	$7,250	0.5%
23	2016	$3,072	0.7%	22	2016	$5,040	0.7%
24	2017	$2,563	0.4%	23	2017	$4,235	0.4%
25	2018	$3,518	0.8%	24	2018	$11,353	1.2%
26	2019	$8,096	1.5%	25	2019	$16,799	1.5%
27	2020	$2,678	0.6%	26	2020	$12,806	1.5%
28	2021	$10,210	1.5%	27	2021	$11,144	1.5%

144 EIA, Natural Gas Weekly Update, for the week ending February 17, 2021: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/02_18/.

PG&E CPIM Year	Ending in October	Final CPIM Shareholder Reward	CPIM Reward as % of Actual Commodity Costs	SoCalGas GCIM Year	Ending in March	Final GCIM Shareholder Reward	GCIM Reward as % of Actual Commodity Costs
29	2022	0	0	28	2022	$22,313	1.2%
30	2023	$26,629	1.5%	29	2023	$22,681[145]	0.5%
				30	2024	$13,865	1.1%

The GCIM shareholder reward figures for 2012 and 2013 are taken from SoCalGas A.24-06-005. The CPIM figures for 2023 are what PG&E has requested and have not yet been reviewed or approved by Cal Advocates or the CPUC.

Staff have included public data for CPIM Year 30 in Table 26. PG&E's request indicates that the CPIM Shareholder Reward cap was again met in Year 30. Without the cap, PG&E could have requested a reward of $35.4 million. Cal Advocates has not yet issued its *Monitoring and Evaluation Report* for Year 30, and the CPUC has not yet approved Year 30 results. [146]

As for SoCalGas, the savings and shareholder rewards under the CPIM also seem to have become routine during the review period, and the shareholder cap was met three times in recent years.

On average, the CPIM savings and shareholder reward as a percentage of total actual costs was higher during the review period than during the previous six years, but this appears to be largely the result of a single year: 2021. And, only a small savings amount and no shareholder reward is indicated for the year ending October 2022. For CPIM Years 14 through 19, savings as a percentage of total costs (including transportation costs) averaged 2.9 percent, while for CPIM Years 20-29, savings as a percentage of total costs averaged 3.6 percent. For CPIM Years 14 through 19, rewards as a percentage of total costs averaged 0.4 percent but rose to 0.5 percent for the review period.[147] However, if PG&E's CPIM Year 30 request is included in the average of Years 20 through 30, rewards as a percentage of total costs rise to 0.6 percent.

Approval Process, CPIM Structure, and Reporting

Reporting and Approval Process

The CPIM reporting and approval process is described in the Sources and Methodologies section above. PG&E submits its monthly and annual CPIM reports to the CPUC on a delayed basis. SoCalGas regularly submits its annual GCIM application to the CPUC by the June 15 deadline and is similarly able to submit its quarterly GCIM reports within a few months. Staff recommend that the CPUC consider requiring PG&E to file its monthly CPIM reports on a regular schedule and the annual report by a set deadline.

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[145] Note that the SoCalGas GCIM reward for Year 29 was reduced below the 1.5 percent shareholder reward cap by the CPUC in recognition of the high gas prices experienced that year.

[146] PG&E Year 30 GCIM Report (Public): pge-annual-cpim-202211-thru-202310-year-30.pdf

[147] Staff used total actual costs for this comparison because we do not have ready access to all data for CPIM Years prior to the review period.

CPIM Structure

The CPIM is generally described in the PG&E tariff Preliminary Statement, Part C, Section 9.[148] However, the description does not clearly explain: a) the daily benchmark load sequence, b) how daily benchmark indices are determined, c) how daily benchmark costs are determined, d) the inclusion of Cochrane Extraction Revenues, or e) the magnitude of the tolerance range. These components should be explained in the Preliminary Statement.

It is not clear why the daily sequence of purchases beyond the initial blocks of sequenced purchases needs to be as complicated as it is. Specifically, Staff questions why least-cost secondary blocks of purchases should be based on indices for previous months. The process is not straightforward. There are up to eight "moving blocks" of sequenced purchases. The process of determining the sequence of benchmark purchases for a calendar month involves setting the sequence of a number of benchmark purchases in a calendar month based on least cost monthly gas price indices for one or even two prior months. More importantly, setting the benchmark sequence of purchases based on least-cost indices for a prior month or two does not seem to necessarily mean that those indices will be the least-cost indices for the calendar month in question. The CPIM should provide an incentive for least-cost purchases in the current calendar month. A better alternative might be to simply set the sequence for the first and second set of moving block benchmark purchases based on the least-cost monthly indices for the current calendar month in question. Staff recommend that the CPUC consider this, and other potential changes to improve the performance of the incentive mechanisms, in another proceeding.

Staff suggest that the CPUC consider broader changes to the incentive mechanisms in another proceeding by asking the following questions: Does the greater complexity of the CPIM deliver better results for core customers compared to the simpler GCIM? If so, do the benefits of the CPIM outweigh its burden of added complexity, and is there a way to streamline the CPIM while maintaining those benefits?

Summary Comments on the CPIM

1. Sales credits are a significant means by which PG&E Core Gas Supply is able to lower its gas procurement costs relative to benchmark costs.
2. Most of the CPIM savings come are from citygate net purchases and sales costs relative to CPIM benchmark costs for citygate purchases.
3. Cochrane Extraction Revenues contribute relatively modest amounts toward reducing actual CPIM costs.
4. Through the CPIM Year ending in October 2022, Core Gas Supply's hedges had a relatively modest cost impact on CPIM actual costs.
5. The CPIM provides PG&E Core Gas Supply with known benchmarks, generally based on market-based gas price indices, by which to conduct its procurement activity.
6. The PG&E CPIM benchmark structure is more complicated than SoCalGas' GCIM. Part of the reason may be an intent to provide: 1) an incentive to purchase from the least-cost basin, and 2) an intent to provide a "benchmark budget" which allows PG&E's options on how to meet or better the benchmark budget costs, and 3) daily benchmark pricing for border and citygate purchases.
7. The CPIM benchmark sequencing of "secondary, or moving, blocks" is not straightforward and does not necessarily encourage lowest cost purchases.

[148] PG&E Preliminary Statement Part C, Section 9: https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_C.pdf.

8. Core Gas Supply was able to regularly achieve significant commodity savings under the CPIM relative to benchmark costs during the review period.
9. Core Gas Supply was able to regularly achieve shareholder rewards under the CPIM during the review period. The CPIM shareholder cap came into play three times in recent years. No shareholder reward resulted from performance during the 2021-22 CPIM year.
10. PG&E submits its CPIM reports to the CPUC on a very delayed basis. The monthly and annual CPIM reports should be submitted on a set schedule to increase transparency and streamline stakeholder participation. These reports provide the best insight into Core Gas Supply's actual core procurement, interstate transportation, and backbone transmission costs. Since better transparency and stakeholder participation may mitigate harm to ratepayers should a gas price spike recur, Staff recommend that the annual report be submitted by a set deadline, so that a more timely review of PG&E's CPIM is possible.
11. The CPIM has clearly resulted in a reduction in the regulatory burden on the CPUC and staff related to the review of PG&E gas procurement costs.
12. The PG&E Preliminary Statement does not adequately describe the CPIM. To increase transparency, which may mitigate ratepayer harm, the Preliminary Statement should clearly describe:
    a. the daily benchmark load sequence,
    b. how daily benchmark indices to the citygate are determined,
    c. how daily benchmark costs are determined,
    d. the inclusion of Cochrane Extraction Revenues,
    e. the magnitude of the tolerance range, and
    f. the nature of "miscellaneous costs."
13. Some questions the CPUC may wish to consider in a future proceeding are:
    a. Should the shareholder cap percentage be reduced?
    b. Should the secondary block process be changed to something that is more straightforward and logical?
    c. Should the upper tolerance band be lowered to 1 percent?
    d. Should the percentage share of savings going to shareholders be limited?

Staff Recommendations

Staff provide three recommendations below for consideration by the CPUC in this proceeding, as well as recommendations that could potentially be considered in a future proceeding that looks at changes to the CPIM and GCIM more broadly. These recommendations focus mainly on the GCIM and CPIM with some discussion of the overlapping issue of hedging. Staff remain supportive of the CPUC's original goals for the core gas procurement incentive mechanisms, which were intended to:

- Reduce the regulatory burden and complexity for parties by reducing or eliminating the need for after-the-fact reasonableness reviews,
- Provide the utilities with known, balanced incentives to make efficient purchases, minimize gas costs to ratepayers, and adjust to changing circumstances without micromanagement,
- Encourage the utilities to develop innovative methods for improving performance, and
- Align ratepayer and shareholder interests through the sharing of gains and losses.

In this evaluation, Staff looked for ways to preserve the benefits of the incentive mechanisms while making them more transparent, simple, aligned, and effective for core customers. Staff recommend that the CPUC consider authorizing three simple changes in this proceeding that could lay the groundwork for more substantive changes in a future proceeding: 1) requiring the utilities to update their Preliminary Statements to better describe their incentive mechanisms; 2) requiring all utilities to follow the same CPUC process (application or advice letter) when requesting their shareholder reward; and 3) requiring PG&E to submit its reports by a set deadline. Updating the Preliminary Statements would increase transparency and stakeholders' ability to effectively review incentive mechanism results should a future price spike occur. Having all utilities follow the same CPUC process would increase consistency across utilities. Requiring PG&E to submit its reports timely would ensure that, should the CPUC mandate any changes to the shareholder reward, the reallocation of funds to ratepayers would be done without a long delay.

Staff also recommend more substantive changes to increase the simplicity, alignment, and effectiveness of the incentive mechanisms that the CPUC may wish to consider in a future proceeding. These changes could result in better oversight and more savings being allocated to ratepayers, rather than shareholders. They could also, more broadly, improve the incentive mechanisms while maintaining the benefits of performance-based ratemaking. Staff provide an overview of all our proposed changes in the sections below.

Staff benefitted from the work of Cal Advocates in reviewing the annual GCIM and CPIM reports. Two changes could improve the *Monitoring and Evaluation Reports* and increase transparency and stakeholder understanding: 1) not combining border and citygate purchases and sales into a single category; and 2) considering ways to more clearly describe the benchmark and actual costs of physical hedges. These changes would increase the ability of stakeholders to evaluate the effectiveness of the incentive mechanisms.

Transparency

One of the first steps Staff took in preparing this report was to review the utilities' Preliminary Statements for the GCIM and CPIM. Improving the description of these programs in the Preliminary Statements would increase transparency and may increase stakeholders' ability to effectively participate in CPUC processes and mitigate ratepayer harm should gas price spikes recur. In addition, having a clear description of the current incentive mechanisms in the utilities' Preliminary Statements would make it easier to consider broader changes in a future proceeding, should the CPUC decide to open one.

To increase transparency and improve stakeholder participation and, thereby, potentially mitigate harm to ratepayers should gas price spikes recur, Staff recommend that the CPUC in this proceeding:

1. Require the utilities to submit Tier 1 advice letters updating their Preliminary Statements to thoroughly describe all aspects of their core procurement incentive mechanisms as set out below.
    a. Indicate which gas industry journals are used to calculate benchmark costs.
    b. SoCalGas GCIM:
        i. Define what types of transactions count as physical hedges and describe how benchmark costs for physical hedges are addressed under the GCIM.
        ii. Clearly indicate that off-systems park and loan costs and revenues are a component of GCIM actual costs.
    c. PG&E CPIM:
        i. For benchmark costs, describe the following:
            1. how the daily benchmark load amounts are determined,
            2. how benchmark daily indices to the citygate are developed,
            3. how benchmark costs are developed, and
            4. the CPIM purchase sequence.
        ii. For actual costs, describe the following:
            1. the types of costs that are included in actual CPIM commodity costs, especially net purchases costs, volumetric transportation costs, Cochrane extraction revenues, merchandise processing fees, 100 percent of winter hedge losses/(gains), and miscellaneous costs; and
            2. the types of costs that are included in the actual transportation cost component of the CPIM.

Simplicity

There are trade-offs between simple and complex policies. Simpler programs are easier for staff, parties, and the public to understand. Also, it is easier to maintain a shared understanding of a simpler program as time passes and the people who shaped the policy move on.

That said, there are circumstances in which greater complexity leads to such significant gains in effectiveness that the trade-off between simplicity and complexity is worthwhile. Staff suggest that the CPUC consider broader changes to the incentive mechanisms by asking the following questions in a future proceeding: Does the greater complexity of the CPIM deliver better results for core customers compared to the simpler GCIM? If so, is there a way to streamline the CPIM while maintaining those benefits? If not, should the GCIM structure, or a hybrid structure, be adopted for both utilities?

Alignment

There are differences between the SoCalGas and PG&E pipeline systems, the markets they access, and how they operate, which may justify some differences in how they are regulated. However, Staff recommend that similar programs be aligned across the utilities whenever possible to allow straightforward comparison of utility performance and to reduce the burden on staff and stakeholders who must spend time mastering the nuances of differing utility programs to oversee them effectively.

Therefore, Staff recommend that the CPUC consider bringing the utilities' core procurement and hedging programs into closer alignment where possible.

In this proceeding Staff suggest that the CPUC act to streamline stakeholder participation and, thereby, potentially mitigate the harm to ratepayers should gas price spikes recur, by authorizing the following changes:

2. Require all utilities to follow the same process for receiving CPUC approval of the shareholder award, either via an application or a Tier 2 or 3 advice letter.
3. Require PG&E's Annual CPIM Report and advice letter/application to be submitted by a set annual deadline.

To potentially make broader changes to the incentive mechanisms, Staff further recommend that the CPUC consider the following questions in a future proceeding:

- Should all utilities follow similar procedures for calculating benchmark and actual costs?
- Should all the incentive mechanisms include an incentive for reducing transportation costs similar to that of PG&E?
- Should the utilities follow the same procedures, with the same percentages, for incorporating hedging into actual and benchmark costs?

Effectiveness

While Staff support the idea of providing an incentive to gas utilities to procure reliable gas supplies for core customers at the lowest possible cost, we also want to appropriately balance risks and rewards for both ratepayers and shareholders. Shareholders have consistently received rewards under the GCIM and CPIM for decades, under many different market conditions. Shareholders' consistent wins and almost non-existent losses raise the question: could the rules of these incentive mechanisms be modified to preserve the benefits of performance-based ratemaking while allocating more of the savings to ratepayers?

The following are some suggestions for broader changes to the GCIM/CPIM that the CPUC may wish to consider in future proceeding:

- Reduce the shareholder reward cap for both the GCIM and CPIM from its current level of 1.5 percent of commodity costs to 1 percent.
- Limit the shareholder reward to no more than 15 percent of the overall savings for both the CPIM and GCIM.
- Reduce the upper tolerance band for both the GCIM and the CPIM from the current level of 2 percent of benchmark commodity costs to no more 1 percent.
- Include a higher percentage of the actual and benchmark costs for physical hedges into the GCIM and use the same percentage for the CPIM.

- Include only a portion of Secondary Market Services revenues in actual costs. While entering into Secondary Market Contracts requires some investment of utility staff time that should be incentivized, these transactions create minimal risk for utilities.
- Consider a cap on hedging costs.