

Exhibit No: _____
Application: A.25-09-014
Witness: M. M. Dandridge
Chapter: 13

**PREPARED REBUTTAL TESTIMONY OF M. MICHELLE DANDRIDGE
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY
AND SAN DIEGO GAS & ELECTRIC COMPANY
(STORAGE OVERVIEW AND PROPOSALS)**

June 15, 2026

TABLE OF CONTENTS

	<u>Page</u>
I. PURPOSE.....	1
II. APPLICANTS’ USE OF EFFECTIVE (MEDIAN) CAPACITY IS REASONABLE AND CONSISTENT WITH COMMISSION PRECEDENT	1
III. INDICATED SHIPPERS’ PROPOSAL MISCHARACTERIZE COST CAUSATION PRINCIPLES	3
IV. APPLICANTS’ CORE STORAGE ALLOCATION IS REASONABLE AND SUPPORTED BY FORECASTS	4
V. APPLICANTS’ STORAGE ALLOCATION TO LOAD BALANCING REMAINS APPROPRIATE	5

1 **CHAPTER 13**

2 **PREPARED REBUTTAL TESTIMONY OF M. MICHELLE DANDRIDGE**
3 **(STORAGE OVERVIEW AND PROPOSALS)**

4 **I. PURPOSE**

5 The purpose of this rebuttal testimony is to respond to the arguments, positions, and
6 recommendations presented by certain intervenors, including the Southern California Generation
7 Coalition (“SCGC”), Indicated Shippers (“IS”), and the Public Advocates Office (“Cal
8 Advocates”), regarding the storage and cost allocation proposals in this 2027 Cost Allocation
9 Proceeding (“CAP”) of Southern California Gas Company (“SoCalGas”) and San Diego Gas &
10 Electric Company (“SDG&E”, and together with SoCalGas, “Applicants”).

11 **II. APPLICANTS’ USE OF EFFECTIVE (MEDIAN) CAPACITY IS REASONABLE**
12 **AND CONSISTENT WITH COMMISSION PRECEDENT**

13 SCGC and IS oppose Applicants’ use of median or effective operating capacity for
14 injection and withdrawal functions and recommend maximum design capacity.¹ These
15 arguments are not supported.

16 First, Applicants’ storage injection and withdrawal capacities proposed for allocation
17 were based on actual observed capacities posted on Envoy for the most recent full winter and
18 summer seasons.² Hence, Applicants’ proposal reflects effective capacity available for customer
19 use, not theoretical maximum capacity. In this regard, Commission precedent demonstrates that
20 adopted capacities are not design maximums but rather operationally observed levels.³ As
21 further background, Decision (D.) 16-06-039 established storage capacities for the CAP period
22 2016-2019 and set summer injection capacity at 915MMcfd⁴. As Applicants explained in A.14-
23 12-07,⁵ the approved summer injection capacity was estimated by adjusting down the average

¹ Direct Testimony of Catherine E. Yap on behalf of Southern California Generation Coalition (Ex. SCGC-01) at 1-4; Direct Testimony of Brian C. Collins on behalf of Indicated Shippers (Ex. IS-01) at 5-8.

² See, Direct Testimony of M. Michelle Dandridge (SCG-SDGE, Chapter 1) at MMD-4-5.

³ See, e.g., D.20-02-045 at 103 (Ordering Paragraph (OP) 5), Appendix A at 4, 5, 8, 11, 12.

⁴ D.16-06-039 at 16.

⁵ A.14-12-017, *Triennial Cost Allocation Proceeding Phase 1 Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Authority to Revise their Natural Gas Rates Effective January 1, 2016* (December 18, 2014) at 10.

1 injection capacity posted on Envoy for the summer of 2014 and adding the expected injection
2 capacity from the Aliso Canyon Turbine Replacement (ACTR) project which was not available
3 in 2014. D.16-06-039 also adopted a winter withdrawal of 3175 MMcfd although Applicants
4 identified in A.14-12-07 that at the time, the fields could withdraw 3680 MMcfd when storage
5 was full.⁶ Applicants proposed a lower withdrawal number in that proceeding because it better
6 represented the withdrawal capacity that was usually available to customers-in other words, the
7 average effective capacity.

8 SCGC incorrectly states that in A.18-07-024 (the “2020 TCAP”), and Decision (D.)
9 D.20-02-045 “the Commission established injection and withdrawal capacities based on the
10 maximum levels of injection and withdrawal capacity rather than values based on the average of
11 the utilized capacities during some historic period.”⁷ The injection and withdrawal capacities
12 established in D.20-02-045⁸, were in fact from Applicants’ storage proposal in A.18-07-024⁹,
13 and were based on available injection and withdrawal capacities posted on Envoy, not maximum
14 levels. In the 2020 TCAP, Applicants proposed a reduced summer injection capacity from the
15 915 MMcfd derived from an average posted injection to 790 MMcfd. Applicants proposed the
16 reduction to "match reduced injection capability as a result of well safety enhancements" -in
17 other words, in A.18-07-024, Applicants proposed to further adjust an average posted injection
18 capacity once again to better reflect effective capacity. This proposed capacity was adopted by
19 the Commission in D.20-02-045. Similarly, as Applicants explained in A.18-07-024, the
20 approved winter injection capacity of 500 MMcfd represented the sum of the average posted
21 injection capacity posted during the 2015 Winter and the additional capacity provided by the
22 ACTR Project, which was not available in 2015.

23 Second, SCGC’s and IS’ recommendation to rely on maximum design capacity¹⁰ ignores
24 the distinction between engineering capacity and deliverable service. In so doing, SCGC and IS
25 argue that a storage fields’ maximum design capacity should be used for allocation purposes

⁶ *Id.*

⁷ Ex. SCGC-01 (Yap) at 3.

⁸ See, e.g., D.20-02-045 at 103 (OP 5), Appendix A at 4, 5, 8, 11, 12.

⁹ A.18-07-024, Direct Testimony of Michelle Dandridge (SCG-SDGE, Chapter 1) at 4-5.

¹⁰ Ex. SCGC-01 (Yap) at 1-4; Ex. IS-01 (Collins) at 5-8.

1 instead of the fields' actual daily capacity made available for customer use.¹¹ As the
2 Commission has previously recognized, however, the relevant metric for ratemaking is the
3 capacity that customers can reasonably rely upon, not the highest achievable output under ideal
4 conditions.¹²

5 Finally, Applicants' use of recent observed operating conditions ensures that proposed
6 capacities reflect current system realities, including operational limitations. By contrast,
7 intervenors' proposals rely on assumptions based on one day occurrences. One day maximum
8 withdrawal and injection capacities posted on Envoy from a past period do not provide a better
9 indicator of what capacities may be operationally available for the next CAP period of 2027 -
10 2029.

11 Accordingly, Applicants' capacity methodology remains the most reasonable and
12 consistent with precedent.

13 **III. INDICATED SHIPPERS' PROPOSAL MISCHARACTERIZE COST** 14 **CAUSATION PRINCIPLES**

15 IS asserts that storage costs should be allocated based on maximum design capacity
16 because costs are predominantly fixed.¹³ This argument oversimplifies cost causation principles.

17 Cost causation means that customers (or customer classes) should pay rates that reflect
18 the costs they cause the utility to incur. While Applicants acknowledge that storage is sized for
19 peak performance, that performance is not permanent and reduces throughout the injection and
20 withdrawal seasons. Although storage withdrawal capacity is at its greatest at the start of the
21 winter operating season when inventory is typically at its most full, that withdrawal capacity
22 diminishes throughout the winter as inventory is withdrawn and reservoir pressure is
23 reduced. The inverse is the case during the summer operating season, where injection capacity is
24 at its greatest at the beginning of the season when inventory is typically at its low-point, and that
25 injection capacity diminishes throughout the summer as inventory is filled up and reservoir
26 pressure is increased. While IS is correct that storage costs are fixed, it is not correct that

¹¹ *Id.*

¹² See, e.g., D.20-02-045 at 103 (OP 5), Appendix A at 4, 5, 8, 11, 12; D.16-06-039 at 16.

¹³ Ex. IS-01 (Collins) at 6-8.

1 Applicants plan their system under the assumption that maximum injection and withdrawal
2 capacity will always be available.

3 While storage costs include significant fixed components, the allocation of those costs
4 must reflect how the system is planned and operated, including the level of capacity that is
5 actually made available for customers' use. Using maximum design capacity would artificially
6 dilute cost responsibility by spreading costs across capacity that is not operationally available.

7 Moreover, IS' proposal¹⁴ fails to recognize that system planning incorporates operating
8 margins, maintenance outages, and inventory-dependent performance, all of which affect usable
9 capacity. Allocating costs based on unachievable maximum conditions would therefore
10 misrepresent the actual drivers of cost incurrence.

11 **IV. APPLICANTS' CORE STORAGE ALLOCATION IS REASONABLE AND**
12 **SUPPORTED BY FORECASTS**

13 Cal Advocates recommends a significant reduction in Core inventory (to approximately
14 60-65 Bcf) and withdrawal capacity based on recent historical demand data, rather than demand
15 forecasts from the 2024 California Gas Report (2024 CGR).¹⁵ This proposal should be rejected.

16 As an initial matter, there are errors in Cal Advocates' testimony. Specifically, in Table
17 B-1.¹⁶ In Table B-1, current Core inventory per Decision (D.) 24-07-009 is not 76 Bcf, but 80.3
18 Bcf¹⁷, which results in a -4.3 Bcf change from current to proposed, not no change as indicated in
19 Table B-1. Also, current UBS inventory per D.24-07-009 is not 29 Bcf, but 25 Bcf¹⁸, which
20 results in a +3 Bcf change from current to proposed, not a -1 Bcf change as indicated in Table B-
21 1.

22 Applicants' core allocation proposal is based on reliability planning standards using the
23 2024 CGR's forward-looking demand forecasts, including extreme weather conditions that have
24 not necessarily occurred in recent years. Reliance on a limited historical window, as proposed by

¹⁴ Ex. IS-01 (Collins) at 5-9.

¹⁵ Direct Testimony of Maricela Sierra on behalf of Public Advocates Office (Ex. CA-02) at 1-2, 12-13.

¹⁶ Ex. CA-02 (Sierra) at 18.

¹⁷ D.24-07-009, Appendix A at 6.

¹⁸ *Id.*

1 Cal Advocates, fails to account for low-probability but high-impact events, which the system
2 must be designed to withstand.

3 Furthermore, Cal Advocates' methodology assumes that recent lower demand levels will
4 persist indefinitely, despite acknowledged uncertainty in future conditions, including weather
5 variability and market dynamics. A planning approach that systematically underestimates
6 potential peak demand would expose the system to reliability risks.

7 In sum, Applicants' approach appropriately balances observed data with established
8 reliability standards, ensuring that core customers, who have priority service obligation, continue
9 to receive reliable service under extreme conditions.

10 **V. APPLICANTS' STORAGE ALLOCATION TO LOAD BALANCING REMAINS**
11 **APPROPRIATE**

12 IS oppose Applicants' recommendation that "SoCalGas's enhanced balancing proposal
13 resulting in an increase in the inventory allocation to the Load Balancing function is unsupported
14 and should be rejected." ¹⁹ IS' argument is without merit.

15 As a threshold matter, IS incorrectly states that "SoCalGas proposes to shift a greater
16 share of storage costs to the Balancing function — increasing dedicated balancing inventory
17 from the 8 Bcf floor adopted in D.24-07-009 (the current 2024-2026 CAP Settlement) to 12 Bcf
18 in 2027-2029."²⁰ Applicants would like to clarify that 12 Bcf, not 8 Bcf, of inventory is currently
19 allocated to the Balancing function per D.24-07-009.²¹ Applicants' proposal is to maintain the
20 current 12 Bcf, not propose a change from 8 Bcf to 12 Bcf. Applicants' load balancing
21 framework reflects the fact that balancing services provide system-wide benefits, including
22 maintaining operational stability and enabling all customers to manage imbalances today.

23 This concludes my rebuttal testimony.

¹⁹ Ex. IS-01 (Collins) at 3.

²⁰ Ex. IS-01 (Collins) at 9.

²¹ D.24-07-009, Appendix A at 6.