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Date: May 15, 2026

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) and San Diego Gas & Electric Company (U902G) for authority to revise their natural gas rates and implement storage proposals effective January 1, 2027 in this Cost Allocation Proceeding.	)	**Application 25-09-014**

Direct Testimony and Schedules of

Brian C. Collins

On behalf of

Indicated Shippers

May 15, 2026

BRUBAKER & ASSOCIATES, INC.

Project 11934

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Direct Testimony of Brian C. Collins

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation, and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic, and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Indicated Shippers.[1] Indicated Shippers' members are Noncore customers who depend on the Southern California Gas Company ("SoCalGas" or "Company") system for their business operations.

Q ARE YOU FAMILIAR WITH 'SOCALGAS'S FILING IN THIS MATTER?

A Yes. I have reviewed the Company's application, testimony, and responses to data requests that have been submitted by Indicated Shippers and by other parties.

Q WHAT SUBJECTS ARE ADDRESSED IN YOUR TESTIMONY?

A In my testimony, I address the following aspects of SoCalGas's Application: (1) SoCalGas's classification of a portion of its Storage costs as Load Balancing costs; (2) SoCalGas's weather design methodology; (3) SoCalGas's Large Electric Generation/Cogeneration ("EG/Cogen") demand forecast; (4) SoCalGas's proposed regulatory account treatment of balances in the Firm Access and Storage Rights Memorandum Account ("FASRMA"), the Noncore Storage Balancing Account ("NSBA"), and the Noncore Fixed Cost Account ("NFCA"); (5) SoCalGas's proposed fully-embedded cost allocation study, including the allocation of Load Balancing Storage costs, Local Transmission ("LT") system costs, and High Pressure Distribution ("HPD") system costs

[1] The Indicated Shippers represent the natural gas non-core customer interests of the following companies in this proceeding: California Resources Corp., Chevron U.S.A. Inc., ConocoPhillips, PBF Holding Company, Phillips 66 Company, and Marathon Petroleum Company LP.

among customer classes and rate schedules; and (6) SoCalGas's Off-System Delivery and Backbone Transmission Service ("BTS") proposals.

II. CONCLUSIONS AND RECOMMENDATIONS

Q PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are summarized as follows:

1. SoCalGas should be required to use maximum design capacities rather than median operating capacity values for the classification and allocation of storage injection and withdrawal costs to the Core, Load Balancing, and Unbundled Storage ("UBS") functions.

2. SoCalGas's enhanced balancing proposal resulting in an increase in the inventory allocation to the Load Balancing function is unsupported and should be rejected.

3. SoCalGas's adjustment to 2014–2018 Heating Degree Day ("HDD") data is unjustified, non-precedential, and should be rejected, as it artificially reduces the standard deviation of HDD and shifts approximately $50 million per year in Core reservation costs to other storage functions.

4. SoCalGas's GHG allowance price forecast of $50–$100/MT for the Cost Allocation Proceeding ("CAP") period is inconsistent with recent, actual market outcomes and should be revised to reflect current Cap-and-Invest settlement prices.

5. The $4 million FASRMA balance should be borne by SoCalGas shareholders, not Noncore ratepayers, and the $27 million NSBA over-collection balance should be applied to offset costs in the Noncore Fixed Cost Account.

6. SoCalGas proposes to allocate system Load Balancing Storage costs among the customer classes using the Average Year Throughput ("AYTP") allocation methodology. This is also known as the Equal Cents Per Therm ("ECPT") method. This proposal incorrectly implies that the costs of Load Balancing Storage are 100% driven by total system throughput on the SoCalGas system. Under the AYTP method, 47.3% of the Load Balancing Storage costs are allocated to

Retail Noncore[2] customers, and 52.7% of the costs are allocated to Core and wholesale customers. This allocation does not align with the principle of cost-causation.

7. Given that the purpose of Load Balancing Storage is to manage customer imbalances, including at times of peak demand, it would be reasonable to allocate Load Balancing Storage costs to classes on a Peak Day[3] demand basis rather than use SoCalGas's proposed system throughput-based allocation. Using a peak demand allocator is further supported by the fact that the vast majority of 'SoCalGas's storage costs are fixed and not varying with throughput.[4]

8. The Peak Day demand allocation method results in reasonable allocations of 28.9% to Retail Noncore customers and 71.1% to Core customers for Load Balancing Storage costs.

9. The LT and HPD systems are also designed and operated to meet peak demand. Thus, the Local Transmission and High Pressure Distribution systems' costs should be allocated using the Peak Day allocator. Given that these systems must meet daily peak requirements rather than monthly peak requirements, I recommend the use of the Peak Day demand allocator to allocate these costs. This would correct the Noncore allocation from 51.8% to 43.9% for

[2] SoCalGas allocates 47.3% of Load Balancing Storage Costs directly to Retail Noncore (defining them as Total Noncore customers without wholesale Noncore customers). See *Chapter 8 Workpapers to the Prepared Direct Testimonies of Frank Seres and Marjorie Schmidt-Pines, Embedded Costs* ("Chapter 8 Workpapers") at 1,Table 26; Sup_Ch 3 Martinez SCG Summary WP_2027 CAP.xls, tab "Scg TCAP Summary", and Ch 8 Seres_Schmidt-Pines_SCG Embedded Cost Model _ 2027 CAP_NL.xls, tab "SoCalGas"). Use of the term Noncore in this testimony includes both retail and wholesale Noncore customers as defined by SoCalGas, and use of the term Retail Noncore excludes wholesale customers as defined by SoCalGas.

[3] Peak Day is defined as the demand for Core HDD-sensitive markets (Res & G10) at 1-in-35 extreme peak-day design temp.; Noncore HDD-sensitive markets (G30-Com) at 1-in-10 cold day design temp.; Noncore industrial and refinery peak day demand is estimated using the ratio of 2024 historical December peak day demand over average December daily demand; UEG/EWG & Large CoGen peak daily load in month of December for Base Hydro water year; all other market segments at average daily load in December month. (Ch 5 Martinez_Scg_MDM_Summary_2027 CAP)

[4] See *Prepared Direct Testimony of Frank Seres and Marjorie Schmidt-Pines, Chapter 8 - Cost Allocation and Embedded Costs* ("SoCalGas Ch.8 (Seres/MSP)"), A.25-09-014, Sep. 30 2025 at Appendix A, Table FS-MSP-24 (2024 SoCalGas Embedded Storage Cost, showing total embedded storage cost of $320.3 million comprised of $213.97 million capital-related cost and $106.29 million O&M and A&G expenses i.e., approximately 67% capital-related (fixed) cost, with the remaining O&M and A&G expenses also largely fixed and not varying with throughput.).

LT costs and the Noncore allocation from 18.0% to 12.2% for HPD costs.

10. Collectively, my recommended allocations for Load Balancing Storage costs, LT system costs, and HPD system costs reduces Noncore customers' allocated embedded cost revenues by approximately $54.8 million, as compared to the Company's proposal.

11. SoCalGas's proposed reallocation of costs from BTS to LT should be based consistently on Peak Day demands; doing so results in approximately $91 million reallocated to Local Transmission, not $116.4 million, as proposed by SoCalGas using its proposed volumetric allocation;

12. SoCalGas has proposed to change its nomination confirmation scheme to confirm BTS nominations in Cycles 1 through 4 up to the Total Net System Capacity ("TNSC"). My alternative proposal makes slight changes to SoCalGas's proposal and also addresses SoCalGas's proposed one-third reduction in BTS capacity to be made available via SoCalGas's triennial Open Season firm rights contracting process.

III. 'SOCALGAS'S CLASSIFICATION OF STORAGE COST FUNCTIONS (CHAPTER 1 – DANDRIDGE)

III.A. Median vs. Maximum Design Capacity

Q PLEASE DESCRIBE SOCALGAS'S PROPOSED METHODOLOGY FOR CLASSIFYING AND ALLOCATING STORAGE COSTS TO THE CORE RESERVATION, LOAD BALANCING, AND UBS FUNCTIONS.

A SoCalGas proposes to allocate storage costs to the Core, Load Balancing, and UBS functions using median operating capacity values for storage injections and withdrawals rather than the maximum design capacities for those functions.[5] The values used by SoCalGas represent median capacity values

[5] *Prepared Direct Testimony of M. Michelle Dandridge*, *Chapter 1 - Storage Overview and Proposals* ("SoCalGas Ch. 1 (Dandridge)"), A.25-09-014, Sep. 30, 2025 at Table MMD-1

over the most recent full winter (November to March) and summer (April to October) season.[6]

Q IS SOCALGAS'S USE OF MEDIAN CAPACITY VALUES APPROPRIATE FOR ALLOCATING NON-FUEL INJECTION AND WITHDRAWAL STORAGE COSTS?

A No. SoCalGas's use of median capacity values is not justified and is inconsistent with cost-causation principles. Virtually all of SoCalGas's storage costs are fixed, both capital-related and Operations and Maintenance ("O&M"), with the exception of compressor fuel.[7] This supports the use of maximum design capacity values, not median values, for the reasons described below.

Q PLEASE EXPLAIN WHY FIXED COSTS NECESSITATE USING MAXIMUM DESIGN CAPACITIES.

A Because storage costs are predominantly fixed, it is the design capacity of the storage system, which is driven by reliability standards,[8] that drives storage cost

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(Proposed Capacities and Allocations for CAP Period 2027-2029), MMD-2 - MMD-4 (proposing summer injection capacity of 458 MMcfd and winter injection capacity of 529 MMcfd based on median Envoy postings, and summer withdrawal capacity of 1,787 MMcfd and winter withdrawal capacity of 1,826 MMcfd based on median Envoy postings for 2024-2025).

[6] *Id.* at MMD-3 - MMD-4.

[7] See SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29, Table FS-MSP-24 (showing 2024 SoCalGas embedded storage cost of $320.3 million comprised of $213.97 million capital-related cost and $106.29 million O&M and A&G expenses); see also Chapter 8 Workpapers at 16 (separately identifying "Storage O&M Excl. Fuel" as a discrete line item, reflecting that compressor fuel is the principal variable component of storage O&M and the balance of capital and non-fuel O&M is fixed); SoCalGas Ch. 1 (Dandridge) at MMD-5 - MMD-7 (storage facilities sized to peak day reliability standards rather than annual throughput, confirming that storage cost incurrence is driven by design capacity, not by usage volume).

[8] See D.22-07-002, *Decision on Track 1A and 1B Issues*, R.20-01-007, Jul. 20, 2022 at 23 (The Commission defines gas reliability as "a measure of the gas system's capacity and ability to deliver uninterrupted service. It consists of adequate physical and operational capacity to transport gas in amounts sufficient to meet customer demand."); see also

incurrence for SoCalGas. Specifically, it is the 1-in-10 cold day reliability design criteria (where both Core and Noncore demands are served) that drive the fixed capital investments and O&M costs associated with SoCalGas's storage facilities.[9] Similar to SoCalGas's transmission and distribution pipeline assets, the injection and withdrawal capacities of SoCalGas's storage system are governed by the design capacities of its compressor and dehydration facilities. Cost-causation principles therefore require that the costs to install and operate those facilities be allocated on the basis of the peak or maximum possible use of those facilities, not on the basis of median, historical utilization.

Q ARE THERE ADDITIONAL REASONS WHY THE USE OF MEDIAN CAPACITY VALUES IS INAPPROPRIATE?

A Yes. First, while it is true that operational injection and withdrawal capacities vary with changing reservoir pressure (injection capacity decreases at higher pressure, while withdrawal capacity decreases at lower pressure, and

D.22-07-002 at Appendix A, A-1 ("Southern California Gas Company (SoCalGas) [is] required to maintain adequate backbone capacity to meet the average day in a 1-in-10 cold and dry year standard established by D.06-09-039"); D.02-11-073, *Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers*, I.00-11-002, Nov. 21, 2002 at 49, Ordering Paragraph 10 (requiring gas utilities to serve core customers under a 1-in-35 cold temperature year and 1-in-35 cold peak day standard); D.04-09-022, *Opinion on Phase I Issues*, R.04-01-025, Sep. 2, 2004 at 31, fn.11 (firm pipeline capacity standard of 100%–120% of average year daily demand); see also SoCalGas Ch. 1 (Dandridge) at MMD-5 (summarizing the Commission's core reliability planning criteria).

[9] See *Prepared Direct Testimony of Eduardo Martinez, Chapter 2 - Weather Design* ("SoCalGas Ch.2 (Martinez)"), A.25-09-014, Sep. 30, 2025 at EM-5:1-7 (defining the 1-in-10-year peak day temperature standard applicable to SoCalGas's noncore markets); SoCalGas Ch. 1 (Dandridge) at MMD-5 (storage capacity is sized to meet core 1-in-35 cold year and peak day standards in combination with the noncore 1-in-10 cold day standard); D.06-09-039, as reaffirmed in D.22-07-002 (1-in-10 cold-and-dry year design standard for noncore service).

vice-versa), this physical phenomenon does not justify using median values. The reason is that it is entirely feasible that 100 percent of the available compressor and dehydration facility design capacities could be simultaneously required, particularly if any portion of those facilities is offline for maintenance. Second, to the extent that the Commission chooses to reduce maximum inventory capacity at Aliso Canyon, which would reduce maximum reservoir operating pressure, it would be internally inconsistent for SoCalGas to use median injection and withdrawal capacities when the inventory allocation itself is premised on maximum inventory capacity. Any such ministerial reduction in maximum inventory will not reduce historical, embedded storage costs.

Furthermore, under SoCalGas's current UBS program structure, the UBS program absorbs the first 10 BCF of any inventory reduction and could reach zero with further inventory cuts;[10] median injection and withdrawal capacities would necessarily change with reduced inventory ceilings, while maximum design capacities would not. Using maximum design capacities thus provides a consistent, administratively efficient framework that avoids the need to recalibrate allocation factors every time inventory constraints change. Further, given that almost all of SoCalGas's non-fuel storage costs are fixed and do not

[10] D.24-07-009, *Decision Adopting All-Party Settlement Agreement and Granting San Diego Gas & Electric Company and Southern California Gas Company Authority to Revise Their Natural Gas Rates and Implement Storage Proposals*, A.22-09-015, Jul. 23, 2024 at 6, Attachment A (adopting the all-party 2024 CAP Settlement, including the storage inventory reduction protocol under which the first 10 Bcf of any Commission-ordered reduction is applied to UBS, with further reductions prorated across classes to specified floors and remaining reductions absorbed by UBS until UBS reaches zero); see also SoCalGas Ch. 1 (Dandridge) at MMD-9:7-14 (Reductions in Storage Inventory Capacities, describing the same reduction protocol).

change with storage injection and withdrawal rates, the use of maximum design capacities is consistent with the principle of cost-causation.

Q WHAT IS SOCALGAS'S SPECIFIC PROPOSAL REGARDING THE ALLOCATION OF INVENTORY COSTS TO THE BALANCING FUNCTION?

A SoCalGas proposes to shift a greater share of storage costs to the Load Balancing function — increasing dedicated balancing inventory from the 8 Bcf floor adopted in D.24-07-009 (the current 2024-2026 CAP Settlement) to 12 Bcf in 2027-2029 — citing what it characterizes as a need to support "enhanced year-round balancing."[11] However, SoCalGas has not quantified or adequately justified this 50% increase in inventory dedicated to the balancing function. When asked to produce all studies, analyses, reports, presentations, and similar documents relating to the need for enhanced year-round balancing functions beyond those currently established for the 2024-2026 CAP period, SoCalGas responded: "Not applicable."[12]

Q HOW MUCH OF THE LOAD BALANCING COSTS DOES SOCALGAS PROPOSE THAT THE RETAIL NONCORE SHARE?

[11] SoCalGas Ch. 1 (Dandridge) at MMD-8:10-13.

[12] SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-02, Question 2-6.b. (when asked to "provide an electronic copy of all studies, analyses, reports, presentations and other similar documents prepared by or for the Applicants relating to the need for enhanced year-round balancing functions beyond those currently established for the 2024-2026 CAP period," SoCalGas responded "Not applicable") (Attached in Appendix B, Page 4-5; see also SoCalGas Ch. 1 (Dandridge) at MMD-8:10-16 (proposing 12 Bcf of storage inventory dedicated to the balancing function for the 2027-2029 CAP period); D.24-07-009 at 6, Attachment A (adopting the all-party 2024 CAP Settlement under which the Balancing inventory floor for the 2024-2026 CAP period is 8 Bcf).

A Approximately 47.3%, calculated on average year throughput.[13] The appropriateness of that allocator, and my recommendation that Load Balancing storage costs instead be allocated on Peak Day demand, is addressed in Section VII below, responding to SoCalGas's Chapter 8 testimony.

Q SHOULD NONCORE CUSTOMERS BE REQUIRED TO BEAR THE INCREMENTAL COSTS OF THIS ASSERTED "ENHANCED" BALANCING NEED?

A No. Core customer gas loads are the main driver of storage balancing because of the highly weather-sensitive, "peaky" nature of those loads. SoCalGas's system is a winter-peaking system.[14] The winter Peak Day requirements of Core customers are more than three times the average daily Core requirements, whereas for Retail Noncore customers, Peak Day requirements are only approximately 1.30 times average daily Retail Noncore requirements, as shown

[13] SoCalGas Ch.8 (Seres/MSP)at FS-MSP-29:13-19 and FS-MSP-31:12-18 (allocating Load Balancing storage costs to customer classes using Average Year Throughput (AYTP) on an Equal Cents Per Therm basis); see also *Id*. at Appendix E (Storage Allocation Percentage Study); *Prepared Direct Testimony of Eduardo Martinez, Chapter 5 - Demand Measures* ("SoCalGas Ch. 5 (Martinez)"), A.25-09-014, Sep. 30, 2025 at EM-8, fn. 3 and EM-9, Table EM-5 (47.3% = 393,484/831,567 for Retail Noncore) (defining the AYTP demand measure used for Load Balancing storage allocation).

[14] *Southern California Gas Company Summary 2026 Technical Assessment*, April 16, 2026 (available at: SUMMER-2026-TECHNICAL-ASSESSMENT.pdf) ("SoCalGas does not have a summer design standard. This is partly because the SoCalGas system is a winter peaking system and service to core customers is not at risk in the summer season."). See SoCalGas Ch. 3 (Martinez) at EM-9:1-7 and EM-15:1-9 (December consistently the coldest, highest-demand month in SoCalGas's service territory based on more than 20 years of recorded weather data; using December as the planning month for peak month demand); see also 2024 California Gas Report at 157 (available at: 2024-California-Gas-Report-Final.pdf) (showing seasonal demand pattern with winter (Nov-Mar) demand materially exceeding summer demand on the SoCalGas system); SoCalGas Ch. 1 (Dandridge at MMD-3 (proposing winter withdrawal capacity of 1,826 MMcfd versus summer withdrawal capacity of 1,787 MMcfd, reflecting the system's winter-peaking demand profile).

in Schedule BCC-1.[15] To the extent that "enhanced year-round balancing" is required, it is primarily driven by the Core's weather-sensitive demand variability, not by Noncore customers. Moreover, SoCalGas's own tariff Rule 23 establishes curtailment priorities that protect and ensure continuous gas service Core customers, ahead of Noncore customers.[16] It is fundamentally inconsistent with cost-causation principles to increase Noncore customers' share of balancing costs when those same customers are curtailed first under supply shortage conditions that necessitate any purportedly enhanced balancing.

Q IS RELIABILITY A CONCERN REGARDING SOCALGAS'S PROPOSAL TO USE MEDIAN CAPACITY VALUES?

A Yes. Because SoCalGas's storage costs are driven by 1-in-10 cold dry year criteria (where both Core and Noncore demands are served), the maximum design injection, withdrawal, and inventory capacities represent the contingency margin that protects deliveries when storage facilities are partially offline. Allocating on median rather than maximum capacities understates that contingency margin. Doing so unreasonably narrows the storage capability recognized for Noncore service, while at the same time increasing Noncore cost responsibility, under SoCalGas's proposal. Compounding this proposed

[15] Schedule BCC-1, Line 12.

[16] SoCalGas Tariff Rule No. 23 § B (Priority of Service) (establishing curtailment priorities under which Core customers, residential and other Priority 2A customers, receive higher priority of service than Noncore customers during curtailment events, ensuring continuous gas service to Core customers ahead of Noncore loads).

departure from the principle of cost-causation, Noncore customers are already curtailed first under Rule 23 during a system-wide or local supply shortage.[17]

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that the maximum design capacities be used to allocate storage costs to the storage functions.

In the alternative, I recommend that the current capacity allocations agreed to in the all-party settlement and approved by the Commission in D.24-07-009 in SoCalGas's previous Cost Allocation Proceeding (A.22-09-015) be maintained for storage costs classified and allocated to the inventory, injection, and withdrawal storage functions.[18] This will better reflect design capability because the prior allocations were based on actual maximum capacity values experienced on the storage system. It will also keep the Noncore class from bearing a disproportionate and unreasonable share of the enhanced balancing costs in violation of cost causation principles. This change to the Company's proposal would reduce the annual costs classified and

[17] *Ibid.* (establishing the curtailment priority order under which Noncore customers, including Noncore Commercial/Industrial, Electric Generation, and Enhanced Oil Recovery loads (Priorities 3-5), are curtailed before Core customers (Priority 2A) during system-wide or local supply shortages).

[18] D.24-07-009 at 6, Appendix A (adopting the all-party 2024 CAP Settlement and establishing, for the 2024-2026 CAP period, total firm storage capacities of 119.5 Bcf of working inventory, 800 MMcfd of summer injection capacity, 550 MMcfd of winter injection capacity, 1,900 MMcfd of summer withdrawal capacity, and 2,400 MMcfd of winter withdrawal capacity, allocated among the Core, Load Balancing, UBS, and Wholesale classes); see also SoCalGas Ch. 1 (Dandridge) at MMD-2 (describing the capacities and allocations established by D.24-07-009 for the current 2024-2026 CAP period).

allocated to the Load Balancing Function by approximately $800,000 on a total system basis.

Q DO YOUR RECOMMENDATIONS ADDRESS YOUR RELIABILITY CONCERN REGARDING SOCALGAS'S PROPOSAL TO USE MEDIAN CAPACITY VALUES?

A Yes. As stated above, using median capacity values rather than maximum capacities understates the contingency margin for balancing and reduces system flexibility for system balancing to the disproportionate benefit of Core customers. Doing so unreasonably narrows the storage capability recognized for Noncore load balancing service, while at the same time increasing Noncore cost responsibility.

At a minimum, by retaining the storage capacities agreed to in the last CAP proceeding, the current flexibility for load system balancing provided to Noncore customers will be maintained. This will help ensure two critical things for Noncore customers: (1) continued reliability for Noncore customers, and (2) no degradation in reliability currently provided to Noncore customers. Degradation in reliability by reducing storage capacities is a genuine concern for Noncore customers and should be recognized with a proper solution.

IV. WEATHER DESIGN METHODOLOGY (CHAPTER 2 – MARTINEZ)

Q PLEASE DESCRIBE SOCALGAS'S PROPOSED ADJUSTMENT TO HISTORICAL HEATING DEGREE DAY ("HDD") DATA.

A SoCalGas proposes to adjust its HDD data for the 2014–2018 period, thereby increasing HDDs for those years, characterizing those years as a 'warm weather regime' that artificially decreased the HDDs recorded for those years.[19] SoCalGas made a similar HDD adjustment in its 2024 CAP (A.22-09-015) and, purportedly, in its 2020 Triennial Cost Allocation Proceeding, (A.18-07-024). The net impact of SoCalGas's HDD adjustment is to depress the calculated 1-in-35 Cold Year demand, which in turn pushes costs from the Core to the Noncore storage customer class, which is presumed completely curtailed under such an event.

Q HAS THE COMMISSION PREVIOUSLY ADJUDICATED AND APPROVED SOCALGAS'S METHODOLOGY FOR ADJUSTING THE 2014–2018 HDD DATA?

A Not on the merits in a litigated proceeding. SoCalGas asserts that the same warm-weather-regime adjustment was "proposed by SoCalGas in A.22-09-015 and was adopted by the Commission."[20] However, A.22-09-015 was resolved through an all-party settlement, which under Rule 12.5 of the Commission's

[19] SoCalGas Ch. 2 (Martinez) at EM-3:1-7 and fn.5.
[20] *Id*.

Rules of Practice and Procedure does not establish precedent.[21] The methodology has therefore not been independently adjudicated on the merits, and therefore the Commission is not bound by its prior adoption in a settled proceeding when evaluating the same methodology in this instant, litigated proceeding.

Q WHAT IS THE PRACTICAL EFFECT OF SOCALGAS'S HDD ADJUSTMENT ON COST ALLOCATIONS?

A The practical effect is significant and detrimental to Noncore customers. SoCalGas's adjustment to the 2014–2018 HDD data operates in two ways that distort the resulting Cold Year demand forecast. First, the adjustment artificially increases the HDDs for those years, which inflates the calculated 1-in-2 Average Year HDD baseline.[22] Second, and more importantly, the adjustment artificially decreases the Standard Deviation of the HDD data population by compressing the range of observed values. The Standard Deviation is the critical parameter. This is because SoCalGas's 1-in-35 Cold Year design standard is defined as being 2.025 Standard Deviations above the 1-in-2 Average Year HDD.[23] A lower Standard Deviation produces a lower 1-in-35 Cold

[21] The Commission's Rules of Practice and Procedure, Rule 12.5 provides that "[u]nless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding."

[22] SoCalGas Ch.2 (Martinez) at EM-4, fn. 9 ("SoCalGas also refers to the Average Year HDD data (monthly or annual) as a "1-in-2" design because the average or expected value has the characteristic that there is a 50% (*i.e.*, 1-in-2) chance of observing a larger value.").

[23] *Id.* at EM-2:14-EM-3:7 ("Based on this criterion, the Cold Year HDD value is calculated as 2.025 standard deviations more than the Average Year HDD. The resulting SoCalGas Cold Year HDD value is 1,465 HDD.").

Year HDD design value, which in turn reduces the calculated storage requirements assigned to the reliability design that protects Core customers during cold weather events, and thereby shifts costs from Core to Noncore customers. Unlike the 1-in-10 Cold, Dry Year design standard, Noncore customers are presumed 100% curtailed during a 1-in-35 Cold Year event.[24]

Specifically, SoCalGas's adjustment reduces the calculated Standard Deviation of the data population from approximately 205 HDD (the unadjusted 2005–2024 result) to approximately 112 HDD, as proposed in this proceeding. This is a reduction of approximately 93 HDD, or roughly 45 percent. When multiplied by the 2.025 design factor, that HDD compression lowers the 1-in-35 Cold Year HDD value by approximately 188 HDD, to 1,465 HDD, which is approximately 15 percent of the 1,239 HDD Average Year value.[25] Assuming total storage costs of approximately $330 million per year, this 15 percent cold-year-design HDD compression translates to approximately $50 million per year in costs shifted from away from Core reliability to other storage functions, including Load Balancing, which Noncore customers predominantly pay.

[24] D.02-11-073 at 49, Ordering Paragraph 10 (Commission's 1-in-35 Cold Year reliability obligation extends only to core customers); see also SoCalGas Ch. 1 (Dandridge) at MMD-5:12-15 ("The Commission requires the gas utilities to serve core gas customers in a 1-in-35 cold temperature year (Cold Year) and a 1-in-35 cold peak day (Peak Day)."); SoCalGas Ch. 2 (Martinez) at EM-2:14 - EM-3:7 (defining the 1-in-35 Cold Year HDD value used to design the system to serve core load only); SoCalGas Tariff Rule No. 23 § B (Priority of Service) (Noncore loads (Priorities 3-5) curtailed before Core loads in supply-shortage conditions); contrast D.06-09-039, as reaffirmed in D.22-07-002 (1-in-10 cold-and-dry year backbone design standard, which addresses combined core and noncore demand).

[25] See SoCalGas Ch. 2 (Martinez) at EM-4, Table EM-1.

Q IS THIS COST SHIFT AWAY FROM CORE RELIABILITY APPROPRIATE?

A No. The entire premise of the 1-in-35 Cold Year system design is to provide reliability for Core customers during the most extreme cold weather events.[26] Noncore customers are presumed to be 100 percent curtailed under those conditions. It is fundamentally contrary to cost-causation to reduce the HDD Standard Deviation and thereby shift costs of the Core reliability function to other customers, including Noncore customers, who receive no benefit from that storage capacity in the 1-in-35 demand scenario.

Q ARE THERE ADDITIONAL CONCERNS WITH SOCALGAS'S WEATHER DESIGN METHODOLOGY?

A Yes. SoCalGas also relies on the California Energy Commission's 2023 Integrated Energy Policy Report ("IEPR") Additional Achievable Fuel Substitution Scenario 3 Programmatic ("AAFS-3 Programmatic") to project further decreases in Core gas demand.[27] While building decarbonization is a real long-term goal, the pace and penetration of those changes are highly uncertain[28] and may not materialize on the timeline embedded in SoCalGas's

[26] SoCalGas Ch. 1 (Dandridge) at MMD-5:12-15 ("The Commission requires the gas utilities to serve core gas customers in a 1-in-35 cold temperature year (Cold Year) and a 1-in-35 cold peak day (Peak Day)."); SoCalGas Ch. 2 (Martinez) at EM-2:14-EM-3:7 (defining the 1-in-35 Cold Year and Peak Day HDD design values used to size the system to provide reliable service to core customers under extreme cold weather conditions); D.02-11-073 at 49, Ordering Paragraph 10 (establishing the 1-in-35 Cold Year and Peak Day reliability standards applicable to core gas service).

[27] SoCalGas Ch.2 (Martinez) at EM-3:1-EM-4:3 (describing the 2014–2018 warm-weather adjustment and the 2.025 multiplier producing the 1,465 Cold Year HDD value).

[28] See California Energy Commission, 2023 Integrated Energy Policy Report (IEPR), Feb. 2024 (presenting multiple Additional Achievable Fuel Substitution (AAFS) scenarios that span a wide range of building electrification trajectories and explicitly acknowledging significant uncertainty in the pace and ultimate penetration of building decarbonization based on

3-year 2027-2029 forecasting horizon, particularly given current policy uncertainty at both the state and federal level.[29] Additionally, SoCalGas applies a further reduction of 7 HDD per year based on the current temperature trendline.[30] Each of these downward adjustments to the design HDD compounds the effect of the Standard Deviation manipulation described above and further erodes the appropriateness and credibility of SoCalGas's weather design methodology.

technology adoption, equipment turnover, customer choice, and policy implementation) (available at: TN254463_20240214T142545_Adopted 2023 Integrated Energy Policy Report with Errata (1).pdf); SoCalGas Ch.3 (Martinez) at EM-8, fn.8 and EM-10, fn.9 (relying on the CEC's 2023 IEPR AAFS Scenario 3 Programmatic for fuel-substitution assumptions in this CAP); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-02, Question 2-4.a. (quantifying the AAFS sensitivity: if the AAFS-driven Core peak day demand reductions are not achieved, average 1-in-35 Peak Day demand for the 2027-2029 period rises from 2,983 MMcfd to 3,074 MMcfd, with storage withdrawal capacity (Table MMD-2 column F) increasing from 1,935 MMcfd to 2,125 MMcfd, confirming that fuel-substitution forecast uncertainty materially affects storage reliability outcomes) (Attached In Appendix B, Page 2-3).

[29] *Ibid*.; see also Cal. Pub. Util. Code §§ 454.51-454.52 (Integrated Resource Planning); Senate Bill 1477 (2018) (Building Initiative for Low-Emissions Development Program); Senate Bill 1206 (2022) (refrigerant transition); CARB, 2022 Scoping Plan for Achieving Carbon Neutrality, Nov. 16, 2022 (statewide building decarbonization targets, the pace of which depends on future Commission and Legislative implementation actions) (available at: 2022 Scoping Plan Update); compare with current federal regulatory environment (the Inflation Reduction Act's Section 25C and 25D residential energy-efficiency and electrification tax credits, and the Department of Energy appliance efficiency rulemakings, all subject to ongoing administrative and legislative revision), demonstrating substantial federal and state policy uncertainty as to the pace at which building electrification will displace gas demand within the 2027-2029 CAP forecasting horizon.

[30] SoCalGas Ch. 2 (Martinez) at EM-2 - EM-3 ("For the forecast period, projected annual HDDs were reduced each year by 7 HDD's. Projected average year and cold year HDDs both drop by 7 annually: from 1,232 and 1,458 in year 2025, to 1,197 and 1,423 in year 2030. The annual reductions are based on the latest 20-year trend in [HDDs]."); see also *Id.* at EM-3 - EM-4 and Table EM-1 (applying the 7 HDD per year reduction to monthly HDD figures proportionally through the forecast period).

Q WHAT IS YOUR RECOMMENDATION?

A The Commission should reject SoCalGas's weather design methodology and direct SoCalGas to recompute the 1-in-35 Cold Year HDD design value using the unadjusted 2005–2024 HDD data, without the 2014–2018 warm-weather-regime upward adjustment, without the AAFS-3 Programmatic forecast reduction to Core demand, and without the additional 7 HDD per year temperature-trendline adjustment.

Each of those three adjustments made by SoCalGas compresses the Standard Deviation of the HDD data population, reduces the resulting 1-in-35 Cold Year HDD design value, and shifts approximately $50 million per year in storage costs from Core, the customers who actually receive the reliability benefit of the 1-in-35 design, to Noncore customers, who are assumed to be 100 percent curtailed in that design scenario. SoCalGas should be directed to file a workpaper showing the recomputed Average Year HDD, Standard Deviation, and 1-in-35 Cold Year HDD values together with the resulting class-by-class revenue requirement impact relative to its filed methodology.

V. LARGE EG/COGEN DEMAND FORECAST (CHAPTER 4 – FIOLA)

Q WHAT IS YOUR CONCERN WITH SOCALGAS'S ELECTRIC GENERATION ("EG") DEMAND FORECAST?

A SoCalGas uses a GHG allowance price forecast of $50–$100 per metric ton (MT) for the 2027–2029 CAP period, relying on the CEC's 2023 IEPR forecast,

which reaches approximately $93/MT by 2029.[31] This forecast is dramatically inconsistent with current market reality.[32]

Q HOW DOES SOCALGAS'S ASSUMED CARBON PRICE COMPARE TO ACTUAL MARKET CONDITIONS?

A The November 2025 Cap-and-Invest auction settled at $28.32/MT, less than one-third of the $93/MT level embedded in SoCalGas's 2029 forecast and well below the $50/MT lower bound of the range used by SoCalGas.[33] Relying on an allowance price forecast that is currently three times higher than the current market clearing price is not reasonable.

[31] *Prepared Direct Testimony of Robert Fiola, Chapter 4 - Large Electric Generation/Cogen Forecast* ("SoCalGas Ch.4 (Fiola)"), A.25-09-014, Sep. 30, 2025 at RF-4:1-5 (assuming GHG compliance costs of "$50-100 per metric ton of carbon dioxide equivalent").

[32] California Air Resources Board, California Cap-and-Trade Program and Québec Cap-and-Trade System, November 2025 Joint Auction #45 — Summary Results Report at 6 (reporting current vintage settlement price of $28.32 per metric ton of CO2-equivalent and advance auction (vintage 2028) settlement price of $29.61 per metric ton, against the 2025 auction reserve (floor) price of $25.87 per metric ton) (available at: https://ww2.arb.ca.gov/sites/default/files/2025-11/nc-nov_2025_summary_results_report.pdf); see also CARB, California Cap-and-Invest Program, Summary of California-Quebec Joint Auction Settlement Prices and Results, Feb. 2026 (showing settlement prices over the four most recent quarterly auctions ranging from $25.87 to $28.76 per metric ton, all materially below the $50–$100 per metric ton range assumed in SoCalGas Ch.4 (Fiola)) (available at: Summary of Auction Settlement Prices and Results); CARB, California Cap-and-Invest Program and Québec Cap-and-Trade System February 2026 Joint Auction #46 Summary Results Report, Feb. 25, 2026 (current vintage and advance vintage allowances both settling at the floor price of $27.94 per metric ton) (available at: Summary Results Report).

[33] California Air Resources Board, California Cap-and-Trade Program and Québec Cap-and-Trade System, November 2025 Joint Auction #45 — Summary Results Report at 6, Nov. 26, 2025 (current vintage allowances settled at $28.32 per metric ton of CO2-equivalent and advance auction (vintage 2028) allowances settled at $29.61 per metric ton, against the 2025 auction reserve (floor) price of $25.87 per metric ton) (available at https://ww2.arb.ca.gov/sites/default/files/2025-11/ncnov_2025_summary_results_report.pdf).

Q WHAT IS THE IMPACT OF AN OVERSTATED CARBON PRICE ON SOCALGAS'S EG DEMAND FORECAST?

A SoCalGas uses the PLEXOS dispatch model to estimate electric generation dispatch and therefore gas consumption by EG customers.[34] Overstating the carbon price in PLEXOS artificially increases the simulated operating cost of gas-fired generation relative to alternative resources, which causes the model to artificially suppress gas-fired dispatch, which in turn artificially depresses SoCalGas's gas demand forecast for the EG customer class.

Q WHAT IS YOUR RECOMMENDATION?

A The Commission should require SoCalGas to use a carbon price forecast grounded in current market data and consistent with actual Cap-and-Invest auction outcomes.

VI. REGULATORY ACCOUNTS (CHAPTER 6 – GADANI)

Q WHAT IS SOCALGAS'S PROPOSAL REGARDING THE NONCORE STORAGE BALANCING ACCOUNT?

A SoCalGas proposes to use the approximately $27 million over-collection currently residing in the NSBA to eliminate the approximately $4 million accrued balance in the FASRMA.[35] SoCalGas witness Gadani presents this as a

[34] SoCalGas Ch.4 (Fiola) at RF-1:16-22 and RF-2:4-13 (PLEXOS production-cost model; selecting CEC's mid demand forecast with AAEE Scenario 3 and AAFS Scenario 3 Programmatic).

[35] *Prepared Direct Testimony of Paul D. Borkovich, Chapter 10 - Off-System Delivery and Backbone Transportation Service Proposals* ("SoCalGas Ch. 10 (Borkovich)"), A.25-09-014, Sep. 30, 2025 at PDB-9:13-PDB-10:11 (proposing to credit positive Noncore

straightforward offset of one regulatory account balance against another.[36] It is nothing of the sort.

Q IS SOCALGAS'S PROPOSED TRANSFER FROM THE NSBA TO ELIMINATE THE FASRMA BALANCE REASONABLE?

A No. The proposed transfer fails the fundamental cost-causation test because the costs recorded in the FASRMA have no direct nexus to gas storage customer costs, thus there is no cost-causation. Of the $4 million FASRMA balance, approximately $3.1 million represents unrecovered capital costs that arose because SoCalGas speculated that SoCalGas Citygate pricing would be lower than pricing available from interstate pipelines,[37] a bet that proved to be incorrect.[38] Approximately $0.8 million consists of accrued interest on those

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Storage Balancing Account (NSBA) over-collections to the Firm Access Storage Rights Memorandum Account (FASRMA) as part of the Annual Regulatory Account Balance update until the FASRMA under-collection (an approximately $4 million balance) is fully offset by the approximately $27 million NSBA over-collection).

[36] *Prepared Direct Testimony of Payal Gadani, Chapter 6 - Regulatory Accounts* ("SoCalGas Ch.6 (Gadani)"), A.25-09-014, Sep. 30, 2025 at PG-4:5-PG-5:15 (proposing transfer of NSBA over-collection to FASRMA).

[37] *Id.* at PG-4:5-PG-5:9 ("The FASRMA is $4.0 million under-collected as of September 1, 2025. The under-collected balance is primarily due to unrecovered capital revenue requirement of $3.1 million related to the system modifications required to comply with D.11-03-029 to provide interruptible and firm OSD services."); see also SoCalGas Ch. 10 (Borkovich) at PDB-7:7-PDB-8:14 (acknowledging that, although SoCalGas had projected that expansion of OSD service to additional receipt points would increase backbone utilization, gas-on-gas competition, and storage utilization, "SoCalGas does not foresee any changes in gas demand, sources or market conditions that would make on-system supply competitive in off-system markets," and that interruptible OSD has not been offered since December 2017); D.11-03-029, *Decision Regarding the Expansion of Off-System Delivery*, A.08-06-006, Mar. 10, 2011 (authorizing expansion of OSD service that gave rise to the system-modification capital costs now recorded in FASRMA).

[38] SoCalGas Ch. 10 (Borkovich) at PDB-7:7-PDB-8:14 (acknowledging that, contrary to the projections that supported D.11-03-029, "SoCalGas does not foresee any changes in gas demand, sources or market conditions that would make on-system supply competitive in off-system markets," that available backbone and storage capacity "is not as robust as it was back in 2011 at the time of the issuance of D.11-03-029," and that interruptible OSD service

unrecovered capital costs, and approximately $0.1 million is made up of $0.2 million of O&M Costs offset by $30,000 of Off-System Delivery ("OSD") revenues.[39] The OSD program that generated the FASRMA deficit was a speculative SoCalGas initiative,[40] not a service that benefited Noncore storage customers, as is evident from the meager $30,000 in total OSD revenues collected.[41]

Q WHAT IS YOUR RECOMMENDATION?

A The costs recorded in the FASRMA are all OSD capital expenditures, O&M costs and interest, not costs driven by Noncore storage customers' use of the system. The $4 million FASRMA balance should be borne by SoCalGas shareholders, not ratepayers.

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has not been offered since December 2017, with insufficient OSD activity to recover the FASRMA balance at current rates).

[39] See SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-05, Question 5-1.b. (Attached in Appendix B, Page 6).

[40] D.11-03-029 at 15 ("it is difficult to predict what the future gas demand, source of gas and market conditions will be like"); SoCalGas Ch. 10 (Borkovich) at PDB-7:7-PDB-8:14 (acknowledging that SoCalGas's pre-D.11-03-029 expectations (that OSD expansion would increase backbone utilization, gas-on-gas competition, and unbundled storage revenues) did not materialize, that on-system supply is not competitive in off-system markets, and that interruptible OSD service has not been offered since December 2017, leaving the FASRMA capital revenue requirement unrecovered).

[41] SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-05, Question 5-1.b. (acknowledging that the $0.1 million difference between the $4.0 million FASRMA under-collected balance and the $3.9 million in capital and interest costs is composed of $0.2 million of O&M costs offset by only $30,000 in total OSD revenues recorded since program inception) (Attached in Appendix B, Page 6); see also SoCalGas Ch.6 (Gadani) at PG-4:5-PG-5:9; SoCalGas Ch. 10 (Borkovich) at PDB-7:7-PDB-8:14 (interruptible OSD has not been offered since December 2017).

Q IF THE FASRMA BALANCE IS NOT APPROPRIATELY ASSIGNED TO NONCORE STORAGE CUSTOMERS, WHERE SHOULD THE $27 MILLION NSBA OVER-COLLECTION BE APPLIED?

A SoCalGas itself acknowledges that the $27 million NSBA over-collection resulted from the success of the UBS program, which is 100 percent Noncore in nature.[42] Because the over-collection is attributable to Noncore UBS customers, the $27 million should be returned to Noncore customers by applying it as an offset against costs in the NFCA, rather than being used to eliminate an unrelated speculative FASRMA loss that should be borne by shareholders.

VII. COST ALLOCATION AND EMBEDDED COSTS (CHAPTER 8 – SERES & MARJORIE SCHMIDT-PINES)

VII.A. Migration from LRMC to Fully-Embedded Cost Allocation

Q IS SOCALGAS'S PROPOSED MIGRATION FROM LONG-RUN MARGINAL COST TO FULLY-EMBEDDED COST ALLOCATION REASONABLE?

A As a general matter, yes, SoCalGas's proposed migration from Long-Run Marginal Cost ("LRMC") to fully-embedded cost allocation is a reasonable methodological change.[43] Because of the potential impact on Core residential

[42] SoCalGas Ch.6 (Gadani) at PG-5:5-15 ("The NSBA balances authorized costs for unbundled storage service with revenues collected from customers who contract for storage service under the unbundled storage program. In addition, the NSBA records net revenues from hub services collected under SoCalGas' G-PAL (Operational Hub Services) tariff." This confirms that the approximately $27 million NSBA over-collection consists of net revenues from the wholly-Noncore Unbundled Storage (UBS) program and from G-PAL hub services); see also SoCalGas Ch. 10 (Borkovich) at PDB-9:13-PDB-10:11 (proposing to transfer this UBS-derived NSBA over-collection to FASRMA).

[43] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-1:5 - FS-MSP-2:20.

customers, SoCalGas proposes mitigation for this class in the form of a ringfenced transition adjustment. The $150 million per year Transition Adjustment proposed by SoCalGas, which shifts a portion of the resulting cost increase away from residential Core customers to Core Commercial and Industrial customers, appears to be reasonable in this instance.[44]

VII.B. Asset Retirement Obligations

Q HAS SOCALGAS JUSTIFIED ITS INCLUSION OF ASSET RETIREMENT OBLIGATIONS IN ITS EMBEDDED COST CALCULATION?

A No. SoCalGas has not justified its proposed inclusion of Asset Retirement Obligations ("ARO") in the embedded cost basis used for cost allocation in this proceeding.[45] SoCalGas confirmed in discovery that "AROs are included in capital costs" used in its functional allocations.[46] Inclusion of those amounts is inconsistent with cost-causation and basic ratemaking principles for at least four reasons, each described below.

[44] *Id.* at FS-MSP-32:12-17 and FS-MSP-34, Table FS-MSP-27 (proposed Transition Adjustment of $150 million reallocated from Residential to Core C/I).

[45] *Id*. at FS-MSP-12, Table FS-MSP-8 and accompanying functional allocation discussion (including Asset Retirement Obligation (ARO) amounts within the capital cost components used to derive functional embedded cost allocations); see also Chapter 8 Workpapers at 6; SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-06, Question 6-5.a. ("AROs are included in capital costs.") (confirming inclusion of AROs in the embedded cost basis used for functional and class-level cost allocation in this proceeding) (Attached in Appendix B, Page 7).

[46] SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-06, Question 6-5.a. (Attached in Appendix B, Page 7); see also SoCalGas Ch.8 (Seres/MSP) at Appendix A, Table FS-MSP-1 (showing total Underground Storage net book value of approximately $1.99 billion inclusive of ARO).

Q WHAT IS YOUR FIRST CONCERN WITH INCLUDING AROS IN THE EMBEDDED COST BASE?

A ARO amounts represent the fair estimate of obligations to dismantle and remediate plant at the end of its useful life: they are future-period costs, not the cost of plant currently providing service to ratepayers. Embedding hundreds of millions of dollars of estimated future decommissioning obligations into the present cost-allocation basis is incompatible with the foundational regulatory principle that ratepayers pay only for plant that is used and useful in providing current service.[47] The proper regulatory mechanism for recovering eventual retirement costs is through depreciation accruals and net-salvage assumptions tested in the depreciation study, not through inflation of the embedded cost base used for class allocation in a Cost Allocation Proceeding.

Q WHAT IS YOUR SECOND CONCERN?

A ARO estimates do not meet the known-and-measurable standard that ordinarily governs forward-looking inclusions in ratemaking calculations.[48] Each ARO is a present-value calculation that depends on assumptions about asset retirement method, the regulatory regime in effect at the time of retirement, cost escalation, and the discount rate applied. While SoCalGas improperly includes AROs for several asset classes, looking at SoCalGas's underground storage facilities

[47] See D. 84-09-089, 1984 Cal. PUC LEXIS 1013 at 72 (The Commission "has closely adhered to the 'used and useful' principle, which requires that utility property be actually in use and providing service in order to be included in the utility's ratebase.")

[48] The "known and measurable" standard is a longstanding ratemaking principle limiting forward-looking adjustments to test-year revenue requirement to those that are reasonably certain in both occurrence and amount. See, e.g., D.16-06-054, *Decision Addressing the General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company and The Proposed Settlements*, A.14-11-003/A.14-11-004, Jul.1, 2016 at 193.

acutely illustrates this concern: the future of Aliso Canyon storage operations, SoCalGas's largest storage facility, remains the subject of ongoing Commission review, with authorized maximum inventory levels subject to change, including the possibility of reduced capacity and eventual closure.[49] The decommissioning cost ultimately incurred for the Aliso Canyon, Playa del Rey, Honor Rancho, and La Goleta storage fields will depend on regulatory decisions that have not yet been made. Embedding a current point estimate of those obligations in the cost-allocation base, and then allocating that estimate to customer classes who may or may not be on the system when retirement occurs, is inappropriate and unjust.

Q WHAT IS YOUR THIRD CONCERN?

A Inclusion of the ARO regulatory asset in the embedded cost base creates a meaningful risk of double-recovery unless offset by the accumulated depreciation of the corresponding Asset Retirement Cost ("ARC"). Under FAS 143 / ASC 410-20 and the analogous FERC USOA treatment, recognition of an

[49] D.24-12-076, *Decision Adopting Biennial Assessment Process*, I.17-02-002, Dec. 19, 2024 (establishing a biennial assessment process for evaluating the ongoing need for Aliso Canyon storage, authorizing the Commission to recommend increases, decreases, or maintenance of Aliso Canyon's maximum storage inventory in 10 Bcf increments based on the biennial reliability assessment, and adopting a peak day demand threshold of 4,121 MMcfd at which, if forecast for two consecutive years and consistent with reliability and just and reasonable rates, the Commission will open a proceeding to consider permanent closure and decommissioning of the facility); see also CPUC Energy Division, 2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076, Oct. 1, 2025 (first biennial assessment report issued pursuant to D.24-12-076 (available at: 2025_aliso_canyon_biennial_assessment.pdf); D.21-11-008, *Decision Setting the Interim Range of Aliso Canyon Storage Capacity at Zero to 41.16 Billion Cubic Feet*, I.17-02-002, Nov. 4, 2021 (setting interim Aliso Canyon maximum storage capacity at up to 41.16 Bcf); D.23-08-050, *Decision Granting in Part and Denying n Part the Joint Petition for Modification of Decision 21-11-008*, I.17-02-002, Aug. 31, 2023 (increasing Aliso Canyon maximum storage inventory to 68.6 Bcf).

ARO produces both a long-term liability (the ARO) and a capitalized ARC added to the related plant account, which is then depreciated over the asset's life.[50] ARO expense flows through operating expenses; ARC depreciation flows through depreciation expense; and the net plant figure used for rate-base purposes would reflect the ARC net of its accumulated depreciation.[51]

Q WHAT IS YOUR FOURTH CONCERN?

[50] Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ¶¶ 3, 6-11 (Fin. Accounting Standards Bd. June 2001) (recognition of an ARO requires the entity to record a liability for the fair value of the obligation and capitalize a corresponding asset retirement cost (ARC) by increasing the carrying amount of the related long-lived asset, with subsequent depreciation of the ARC over the asset's service life and accretion of the liability to its expected settlement amount), now codified at FASB Accounting Standards Codification (ASC) Topic 410-20 (Asset Retirement Obligations); see also 18 C.F.R. pt. 201 (FERC Uniform System of Accounts for Natural Gas Companies), Gas Plant Instruction No. 24 and Account 108 (Accumulated Provision for Depreciation of Gas Plant) and Account 230 (Asset Retirement Obligations) (analogous regulatory accounting treatment under which the ARC is added to the related plant account, depreciated over the asset's service life, and the offsetting ARO liability is accreted to its expected settlement amount); FERC Order No. 631, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations, 68 Fed. Reg. 19,610 (Apr. 21, 2003) (adopting parallel ARO accounting requirements for jurisdictional natural gas pipelines and electric utilities to conform regulatory accounting with SFAS 143).

[51] Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ¶¶ 13-15 (Fin. Accounting Standards Bd. June 2001) (now codified at FASB Accounting Standards Codification (ASC) Topic 410-20) (accretion of the ARO liability is recognized as an operating expense over the asset's life, the capitalized asset retirement cost (ARC) is depreciated as part of depreciation expense over the same service life, and the carrying amount of the related long-lived asset — ARC plus original cost, less accumulated depreciation — is the figure included in net plant); see also 18 C.F.R. pt. 201 (FERC Uniform System of Accounts for Natural Gas Companies), Account 108 (Accumulated Provision for Depreciation of Gas Plant) (recording accumulated depreciation, including depreciation of ARCs, against the related plant accounts for net-plant determination) and Account 411.10 / Account 403 (recording accretion expense and ARC depreciation expense as operating expenses); FERC Order No. 631, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations, 68 Fed. Reg. 19,610, 19,612-15 (Apr. 21, 2003) (adopting parallel income-statement and rate-base accounting treatment for AROs of jurisdictional natural gas pipelines and electric utilities, under which net plant for ratemaking purposes reflects the ARC net of its accumulated depreciation).

A The ARO inclusion is concentrated in functions whose costs are then allocated to Noncore customers using throughput-based allocators that are themselves disputable.[52] The embedded cost in the Company's study shows a total Underground Storage net book value of approximately $1.99 billion, with ARO broken out as a discrete component within that figure.[53] Underground Storage Load Balancing costs are then allocated between Core and Noncore using AYTP,[54] the same allocator I address extensively in Section VII. of my testimony as inconsistent with cost causation. Compounding an unjustified inclusion (ARO) with a flawed allocator (AYTP) imposes a doubly-removed-from-cost-causation share of legacy storage decommissioning estimates onto Noncore

[52] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29:4-12 and Appendix E (Storage Allocation Percentage Study, allocating embedded storage costs (including ARO components capitalized into the storage plant accounts — first to injection, withdrawal, and inventory functions and then to Core Reservation, Load Balancing, and UBS); *Id.* at FS-MSP-31:12-18 (allocating Load Balancing storage costs to Core/Noncore on Average Year Throughput (AYTP), and allocating Local Transmission and High Pressure Distribution costs on Cold Year Peak Month (CYPM) and related throughput-based demand measures); see also *Id.* at FS-MSP-12, Table and Chapter 8 Workpapers at 6 (showing functional cost components, including ARO-bearing accounts, that flow into the throughput-based class allocations); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-06, Question 6-5.a. ("AROs are included in capital costs" within the functional allocation tables) (Attached in Appendix B, Page 7).

[53] Chapter 8 Workpapers at 1, Table 26 (showing Total Underground Storage net plant of approximately $1,986,018 thousand, i.e., approximately $1.99 billion, comprising gross plant of $2,383,425 thousand less accumulated depreciation of $397,407 thousand, with Asset Retirement Obligation amounts shown as a discrete line item within the Underground Storage functional category); see also SoCalGas Ch.8 (Seres/MSP) at FS-MSP-12, Table FS-MSP-8 (functional allocation of embedded costs reflecting the same Underground Storage net plant total, including the ARO component); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-06, Question 6-5.a. ("AROs are included in capital costs" within the functional allocation tables) (Attached in Appendix B, Page 7).

[54] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (proposing to allocate Underground Storage Load Balancing costs between Core and Noncore customer classes using the Average Year Throughput (AYTP) demand measure on an Equal Cents Per Therm basis); see also *Id*. at FS-MSP-29:13-19 and Appendix E (Storage Allocation Percentage Study); SoCalGas Ch.5 (Martinez) at EM-8, fn. 3 and EM-9, Table EM-5, (defining the AYTP demand measure used for Load Balancing storage allocation).

customers. SoCalGas proposes this unfair imposition of costs even though the underlying storage build-out was driven primarily by Core supply reliability requirements, and the cash decommissioning outflows lie decades in the future. If the Commission is nonetheless persuaded that AROs should be included in embedded costs, those amounts should, at minimum, be allocated using the methodology I recommend for the function in which they reside (Peak Day for Load Balancing Storage), not AYTP.

Q WHAT IS YOUR RECOMMENDATION ON ARO TREATMENT?

A The Commission should direct SoCalGas to remove ARO amounts from the embedded cost base used for class allocation in this proceeding. SoCalGas should be directed to file a compliance workpaper that (i) identifies the ARO component included in each functional cost category, (ii) reruns the class allocations with AROs set to zero, and (iii) quantifies the class-by-class revenue requirement impact of the exclusion. Recovery of eventual decommissioning costs is properly addressed through depreciation and net-salvage assumptions in a future depreciation proceeding that considers the future regulatory actions and determinations that will actually drive those end-of-life asset retirement costs and timing.

VII.C. BTS-to-Local Transmission Reallocation

Q PLEASE DESCRIBE SOCALGAS'S PROPOSED REALLOCATION OF TRANSMISSION COSTS FROM BACKBONE TO LOCAL TRANSMISSION.

A SoCalGas proposes to reallocate approximately $116.4 million per year in transmission costs from its BTS function to the Local Transmission function.[55] This reallocation is based on SoCalGas's premise that the Backbone Transmission system provides both Backbone and Local Transmission services to Backbone-connected Electric Generation ("EG") customers.[56] SoCalGas creates a new dual-use artifice to justify shifting recorded Backbone-related costs to Local Transmission-connected customers, despite the fact that all SoCalGas customer classes pay Backbone costs, either directly or indirectly, via rates (e.g., Core customers).

Q IS SOCALGAS'S COMPUTATION OF THE $116 MILLION REALLOCATION AMOUNT METHODOLOGICALLY SOUND?

A No. SoCalGas's computational methodology is flawed. SoCalGas uses peak summer day Backbone-connected EG demand to back into Local-connected EG demand, and then multiplies that Backbone-connected fraction of total peak summer day EG demand by the annual average EG gas demand to derive the $116.4 million reallocation figure.[57] This hybrid methodology, combining peak

[55] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-26:2-6 and Tables FS-MSP-22A/22B (reallocating $116.4 million, or 20% of the $569.3 million combined backbone base, from Backbone to Local Transmission).

[56] *Id.* at FS-MSP-24:12-14 ("For a segment of customers, primarily Electric Generation (EG) facilities directly served by BBT assets, the backbone infrastructure performs both its primary backbone role and an additional local transmission role.").

[57] *Id.* at FS-MSP-24:12-FS-MSP-26:6 and Tables FS-MSP-22A/22B (describing the Backbone-to-Local reallocation methodology, under which SoCalGas (1) measures recorded peak summer day Backbone-connected Electric Generation (EG) demand for years 2022-2024, (2) computes the Backbone-connected EG share of total peak summer day EG demand on the system, and (3) applies that peak summer day share to annual average EG gas demand to derive a Local-connected fraction and the resulting $116.4 million reallocation from Backbone Transmission to Local Transmission, i.e., 20% of the $569.3 million combined

day fractions with annual average volumes, is internally inconsistent and methodologically unsupportable. Backbone costs are primarily capital-related and driven by peak day reliability requirements.[58] Using annual average EG demand to scale capital costs that are incurred to meet peak day requirements violates the fundamental principle of cost-causation. If any reallocation between Backbone Transmission and Local Transmission is to occur, the calculation must use peak day demands for both Backbone-connected and Local-connected EG customers, consistently.

Q IF THE CALCULATION WERE CORRECTED TO USE PEAK DAY DEMANDS CONSISTENTLY, WHAT WOULD THE RESULT BE?

A If peak day demands are used consistently for both Backbone-connected and Local-connected EG customers, the resulting reallocation would be approximately $91 million per year, as compared to SoCalGas's proposed $116.4 million. The $25.4 million per year difference is material and represents an excessive and unjustified allocation of costs from Backbone to Local Transmission customers that must be corrected.

backbone base); see also Chapter 8 Workpapers, tab "BBT LT Margin" and tab "LT & BBT," column z (workpaper computations supporting the reallocation).

[58] *Id*. at FS-MSP-21:1-14 and Table FS-MSP-21 ("SoCalGas's backbone capital-related costs are derived from the transmission net book value and transmission depreciation expense of SoCalGas's backbone facilities," with the backbone share representing 71.9% of total SoCalGas transmission capital-related cost, confirming that backbone costs are predominantly capital-related); SoCalGas Ch.10 (Borkovich) at PDB-3:9-14 (backbone capacity is sized to the minimum backbone system design standard); D.06-09-039, as reaffirmed in D.22-07-002 (establishing the 1-in-10 cold-and-dry year peak day backbone system design standard, which drives peak-day-based backbone capacity sizing); see also D.04-09-022 at 31, fn.11 (firm pipeline capacity standard of 100%–120% of average year daily demand, applied to peak-day reliability planning).

Q WHAT IS YOUR RECOMMENDATION?

A If the Commission determines that some reallocation is appropriate, the reallocation amount should be no greater than approximately $91 million per year, computed using peak day demands consistently for both Backbone-connected and Local-connected EG customers. The $25.4 million per year difference between SoCalGas's proposed $116.4 million figure and the corrected $91 million figure is the direct result of SoCalGas's internally inconsistent hybrid methodology, combining peak day Backbone-connected fractions with annual average EG volumes, and must be corrected regardless of the Commission's ultimate disposition of the threshold (i.e., factual) reallocation question of whether the Backbone Transmission system truly does provide a Local Transmission function in addition to the Backbone function.

VII.D. Cost Allocation Measures

Q BEFORE BEGINNING YOUR DISCUSSION OF THE ALLOCATIONS OF THE STORAGE, TRANSMISSION, AND DISTRIBUTION COSTS OF THE SOCALGAS SYSTEM TO THE VARIOUS CUSTOMER CLASSES, PLEASE DESCRIBE SOME OF THE METHODS THAT SOCALGAS APPLIES IN ITS COST ALLOCATIONS AND EXPLAIN THEIR MEANINGS.[59]

[59] The AYTP, CYTP, and CYPM allocators referenced throughout this section are demand-measure allocators (Average Year Throughput, Cold Year Throughput, and Cold Year Peak Month, respectively) derived from the consolidated demand forecasts presented in SoCalGas Ch.5 (Martinez) at EM-8:1 - EM-12:15, and applied to embedded costs in SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 and the accompanying Embedded Cost Workpapers.

A Please refer to Schedule BCC-1. This schedule summarizes the key physical quantities that SoCalGas uses in its allocations of these costs and the resulting allocation percentages. The physical measures here are in thousands (M) of therms.[60]

Looking at Schedule BCC-1, AYTP is the volume of therms delivered to customers during what is characterized as an average year in terms of temperature and other parameters. It is a purely volumetric measurement and does not make any distinction as to when the therms were used by customers, such as to meet critical times of peak demand on the system.

Cold-Year Throughput ("CYTP") is the annual volume of therms delivered to customers through the SoCalGas system during what SoCalGas classifies as a "cold" year.

Cold-Yeak Peak Month ("CYPM") represents the volume of therms consumed by all customers during the (peak) month of highest use during a year classified as a cold year.

SoCalGas uses the Peak Day demand allocator, previously described above, to allocate the costs of Medium Pressure Distribution to customers. This allocator would be appropriate for both LT and HPD costs as well.

The class allocation factors that result from these different measures are shown on lines 4-6 in BCC-1. Note that the CYPM allocator allocates considerably more costs to Core customers than the AYTP and CYTP

[60] One therm is equivalent to 100,000 British Thermal Units (Btu), or, 0.1 Million Btu (MMBtu).

allocators. This is meaningful because CYPM is a closer approximation of the actual underlying cost driver, peak demand, than either of AYTP or CYTP.

BCC-1, lines 7-9, convert the AYTP, CYTP and CYPM usages into an average daily volume, which makes it easier to see the variations in load characteristics between Core and Noncore customers. Note that for Core customers, the average daily throughput on the peak day is over 1.8 times the average daily throughput during the peak month of a cold year as seen on Line 14 of BCC-1.

Q WHAT IS SHOWN NEXT ON SCHEDULE BCC-1?

A Peak day requirements are shown on lines 10 and 11 of Schedule BCC-1. Peak day requirements are somewhat akin to peak demand (which is usually measured in kilowatts delivered during a given hour) on an electric system. In other words, it represents the maximum “draw” that the system has to be capable of serving. Note that the peak day requirement for Core customers shown on line 10 is more than three times the average daily usage during an average year, which is shown on line 7.

These statistics are converted into a ratio basis on lines 12 through 15, derived by dividing the peak demand on line 10 by the various average values shown on lines 7 through 9. As noted previously and illustrated in my Figures BCC-1 and BCC-2, below, for Core customers, the peak day requirements are more than 3.0 times the average daily requirements, whereas for Noncore customers, the peak day requirements are only 1.5 times the average daily

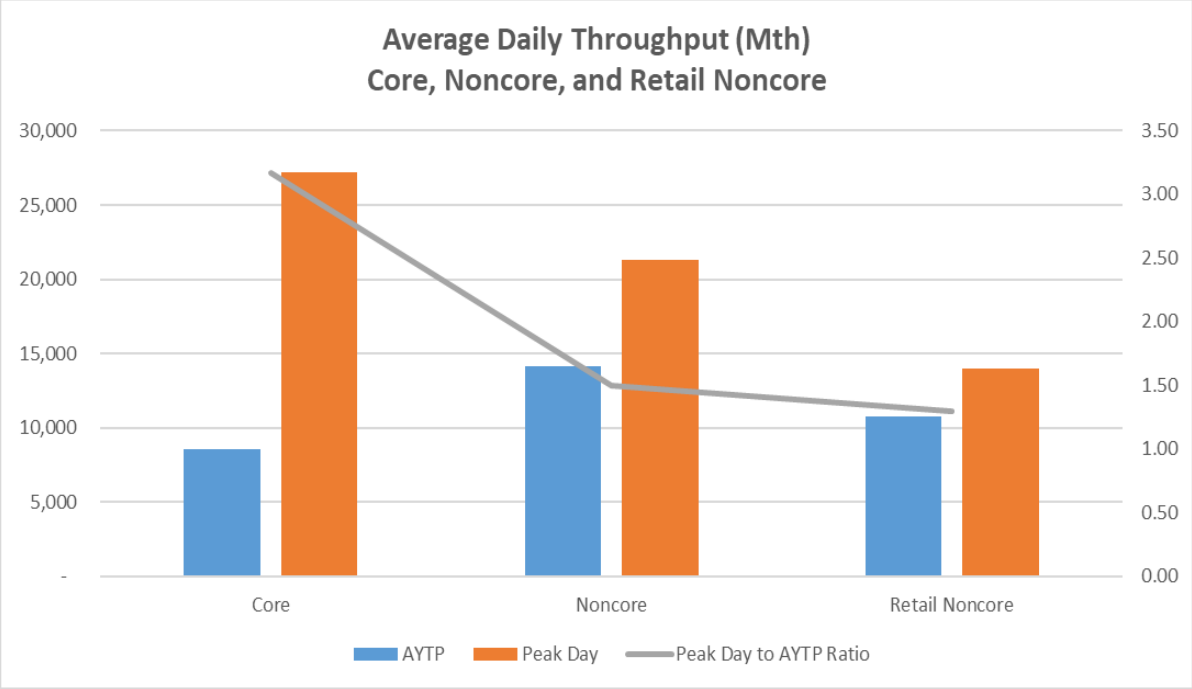
requirements. For Retail Noncore (no wholesale), the average is even lower at approximately 1.3 times the average daily requirements. This is a vivid illustration of the highly fluctuating nature of Core customers' demand over the course of a year.

Figure BCC-1: Peak Day to Average Day Ratio — Core vs. Noncore (SoCalGas System)

Customer Class	Peak Day / Avg Year Ratio
Core	Over 3.0×
Noncore	Approximately 1.5×

Source: Schedule BCC-1 (Core peak day demand more than three times average daily usage during an average year; Noncore peak day demand approximately 1.5 times average daily usage). Underlying data derived from the SoCalGas embedded cost workpapers.

Figure BCC-2



Q PLEASE ELABORATE ON THE SIGNIFICANCE OF THESE DIFFERENCES.

A Pipelines and other components of a gas system have to be designed to deliver the maximum requirements of customers when the customers place those

maximum requirements on the system.[61] A system designed to meet average throughput would not be capable of serving customer requirements on peak days or even on many other days when demand is between the average and the maximum peak.

Allocating the fixed costs associated with gas system components on an annual average or even a peak month average throughput basis is the gas system analogue of allocating electric generation capacity on annual or monthly average kilowatt-hours instead of on peak demands. This makes no sense for electric systems or for gas systems.

In order for the Company's gas system to serve the daily aggregated demands of customers on each and every day of the year, the system must be designed, built, and operated based on the need to meet the day of expected greatest customer demand on the system, the Peak Day.

VII.E. Local Transmission Cost Allocation

Q HOW DOES SOCALGAS ALLOCATE THE COSTS OF THE LOCAL TRANSMISSION SYSTEM TO CUSTOMERS?

[61] D.06-09-039, as reaffirmed in D.22-07-002 (establishing the 1-in-10 cold-and-dry year peak day backbone system design standard, which requires gas pipeline and storage facilities to be sized to deliver core and noncore peak day demand under extreme cold conditions); D.02-11-073 at 49, Ordering Paragraph 10 (1-in-35 Cold Year and Peak Day reliability standards for core gas service); D.04-09-022 at 31, fn.11 (firm pipeline capacity standard of 100%–120% of average year daily demand, applied to peak-day reliability planning); see also SoCalGas Ch.1 (Dandridge) at MMD-5 (storage system designed to meet combined core 1-in-35 Cold Year and noncore 1-in-10 cold day peak day requirements); SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (recognizing that Local Transmission and High Pressure Distribution systems are sized to and allocated on Cold Year Peak Month demand, reflecting the design-for-peak principle); James C. Bonbright, Albert L. Danielsen & David R. Kamerschen, Principles of Public Utility Rates 491-93 (2d ed. 1988) (peak-responsibility principle: capacity-related utility costs are caused by, and should be allocated based on, customer demands during the system peak period the facilities are designed to serve.).

A SoCalGas allocates the costs of Local Transmission using CYPM volumes.

Q IN YOUR OPINION, IS THE USE OF CYPM APPROPRIATE FOR THE ALLOCATION OF LOCAL TRANSMISSION COSTS?

A No. Again, gas systems have to be designed to meet the peak requirements imposed on them. Systems or system components designed to meet average annual volumes or even average monthly volumes (such as CYPM) would not be capable of supplying customers' requirements on peak days.

Q WHAT IS THE ALLOCATION OF LOCAL TRANSMISSION COSTS BETWEEN CORE AND NONCORE CUSTOMERS BASED ON 'SOCALGAS'S CYPM?

A SoCalGas allocates 51.8% of Local Transmission costs to Noncore customers and 48.2% to Core customers.[62]

Q WHAT WOULD BE THE ALLOCATION BETWEEN CORE CUSTOMERS AND NONCORE CUSTOMERS OF LOCAL TRANSMISSION IF THE MORE COST-BASED PEAK DAY ALLOCATION WERE USED?

A The allocation of local transmission costs using the Peak Day Allocation, which I believe is correct, allocates 56.1% to Core customers and 43.9% to Noncore customers.

[62] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (allocating Local Transmission costs on CYPM); see also SoCalGas Ch. 5 (Martinez) at EM-8:1-EM-12:15 (consolidated demand forecasts underlying the CYPM allocator).

VII.F. High Pressure Distribution Cost Allocation

Q HOW DOES SOCALGAS ALLOCATE THE COSTS OF THE HIGH PRESSURE DISTRIBUTION SYSTEM TO CUSTOMERS?

A As with Local Transmission, SoCalGas uses CYPM volumes.

Q IN YOUR OPINION, IS THE USE OF CYPM ALSO INAPPROPRIATE FOR THE ALLOCATION OF HIGH PRESSURE DISTRIBUTION SYSTEM COSTS?

A Yes. For the same reasons discussed above with respect to Local Transmission, CYPM does not capture peak-day requirements and therefore is not an appropriate allocator for the High Pressure Distribution System.

Q WHAT IS THE ALLOCATION OF HIGH PRESSURE DISTRIBUTION SYSTEM COSTS BASED ON SOCALGAS'S CYPM?

A SoCalGas allocates 82.0% of High Pressure Distribution System costs to Core customers and 18.0% to Noncore customers.[63]

Q WHAT WOULD BE THE ALLOCATION BETWEEN CORE CUSTOMERS AND NONCORE CUSTOMERS OF HIGH PRESSURE DISTRIBUTION SYSTEM COSTS IF THE MORE COST-BASED PEAK DAY ALLOCATION WERE USED?

[63] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (allocating High Pressure Distribution costs on CYPM); see also SoCalGas Ch.5 (Martinez) at EM-8:1-EM-12:15 (consolidated demand forecasts).

A The allocation of High Pressure Distribution System costs using the Peak Day Allocation, which I believe is correct, allocates 87.8% to Core customers and 12.2% to Noncore customers.

VII.G. Storage Cost Separation – Core Seasonal vs. Load Balancing

Q DOES SOCALGAS SEPARATE ITS TOTAL STORAGE COSTS INTO COSTS FOR CORE ONLY AND COSTS ALLOCATED TO BOTH CORE AND NONCORE?

A Yes. SoCalGas directly assigns 55.7% of its total storage costs to Core classes as "Seasonal Storage" capacity.[64] This storage is used to provide a reliable year-round supply of natural gas to Core customers. The remaining costs are assigned to the Load Balancing Storage and UBS functions, with the Load Balancing costs then allocated to both Core (with wholesale) and Retail Noncore classes.

Q IS SOCALGAS'S STORAGE COST ASSIGNMENT SCHEME REASONABLE?

A As described above, I have concerns with the calculation of the Core HDD demand used to directly assign costs to the Core customers for 1-in-35 year Core reliability.

[64] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29:4-12 and Appendix E (Storage Allocation Percentage Study); see also SoCalGas Ch.1 (Dandridge) (functional separation of seasonal storage capacities); A portion of seasonal storage cost (12.4%) is allocated to San Diego Gas & Electric Company ("SDG&E"), a Noncore wholesale customer.

VII.H. Load Balancing Storage – AYTP Critique

Q HOW DOES SOCALGAS PROPOSE TO ALLOCATE LOAD BALANCING STORAGE COSTS?

A SoCalGas proposes to use the AYTP allocator.[65]

Q IS SOCALGAS'S USE OF THE AYTP ALLOCATOR REASONABLE?

A No. AYTP bears little relationship to the use of storage for load balancing and does not appropriately attribute load balancing cost responsibility between Core and Retail Noncore customers.

Q ARE AYTP VOLUMES A REASONABLE BASIS FOR ALLOCATING THE COST OF THE BALANCING FUNCTION AMONG CUSTOMER CLASSES?

A Absolutely not. Use of AYTP implicitly assumes that the daily and seasonal characteristics of all customer classes are the same, since AYTP does not make any distinction as to when customers are taking service. This is unrealistic because Core customers have a predominant winter peak demand that sets the annual peak demand on the system.[66] As shown earlier in this testimony, Core

[65] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (proposing to allocate Load Balancing storage costs between Core and Noncore customer classes using the Average Year Throughput (AYTP) demand measure on an Equal Cents Per Therm basis); see also *Id*. at FS-MSP-29:13-19 and Appendix E (Storage Allocation Percentage Study); SoCalGas Ch.5 (Martinez) at EM-8, fn. 3 and EM-9, Table EM-5 (defining the AYTP demand measure used for Load Balancing storage allocation).

[66] SoCalGas Ch.3 (Martinez) at EM-9:1-7 (December consistently the coldest, highest-demand month in SoCalGas's service territory based on more than 20 years of recorded weather data) and EM-15:1-9 (using December as the planning month for peak month demand for HDD-sensitive Core markets); SoCalGas Ch.1 (Dandridge) at MMD-5 to MMD-6 and Table MMD-2 (Core Peak Day demand on a 1-in-35 cold peak day drives the system's peak day reliability requirement); 2024 California Gas Report at 157 (showing Core demand on the SoCalGas system peaking in the winter heating season and setting the annual peak) (available at: 2024-California-Gas-Report-Final.pdf); SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18

customers' peak-to-average demand ratio is far higher than that of Noncore customers (i.e., >3.0 for Core versus 1.5 for Noncore).[67] AYTP does not recognize this fact.

AYTP also does not make any distinction as to customer need for use of the storage system because of imbalances between when gas is delivered to the SoCalGas system on behalf of customers and when it is used (burned) by those customers.

Q WHAT PERCENTAGES OF LOAD BALANCING STORAGE COSTS ARE ALLOCATED TO CORE CUSTOMERS AND TO RETAIL NONCORE CUSTOMERS UNDER THE AYTP ALLOCATION METHOD APPLIED BY SOCALGAS?

A Under the AYTP allocation method, Core (and wholesale) customers are allocated 52.7% of Load Balancing Storage costs and Retail Noncore customers are allocated 47.3% of such costs.[68]

Q HOW DOES SOCALGAS INCUR, CLASSIFY, AND ALLOCATE LOAD BALANCING STORAGE COSTS?

(Local Transmission and High Pressure Distribution allocated on Cold Year Peak Month, reflecting Core-driven winter peaking).

[67] See Schedule BCC-1, Line 12.

[68] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-31:12-18 (proposing AYTP as the Core/Noncore allocator for Load Balancing Storage); see also SoCalGas Ch.5 (Martinez) at EM-8:1-EM-12:9 (Average Year Throughput forecast underlying AYTP); See also Schedule BCC-2.

A SoCalGas incurs these costs for storage assets used to address customer imbalances and to meet Peak Day demands. It classifies the costs as injection, inventory, or withdrawal related,[69] but allocates all three components between Core and Noncore customer groups (and to Noncore sub-classes) using the same AYTP allocator, each group's or class's AYTP as a percentage of total system AYTP.[70]

'SoCalGas's total throughput is served predominantly by pipeline delivered gas, not by storage assets.[71] The primary purpose of Load Balancing Storage assets is to address the difference between the scheduled pipeline gas receipts and the demand for gas supply (i.e., gas sendout). Load Balancing

[69] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29:4-12 (allocating embedded storage costs into injection, inventory, and withdrawal functions, with seasonalized capacities for each); see also *Id*. Appendix E (Storage Allocation Percentage Study) (29.8% injection, 32.9% withdrawal, 37.3% inventory); SoCalGas Ch. 1 (Dandridge) at MMD-2 to MMD-3 and Table MMD-1 (presenting proposed storage capacities by injection, withdrawal, and inventory function, with separate summer and winter injection and withdrawal capacities).

[70] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29:4-12 and Appendix E (Storage Allocation Percentage Study) (allocating embedded storage costs first across the injection, inventory, and withdrawal functions); *Id*. at FS-MSP-31:12-18 (proposing to allocate Load Balancing storage costs — across all three of the injection, inventory, and withdrawal components — between Core and Noncore customer groups, and among Noncore sub-classes, using the Average Year Throughput (AYTP) demand measure on an Equal Cents Per Therm basis, such that each group's or class's share equals its AYTP as a percentage of total system AYTP); see also SoCalGas Ch.5 (Martinez) at EM-8, fn. 3 and EM-9, Table EM-5 (defining AYTP as the demand measure used by SoCalGas for Load Balancing storage allocation).

[71] See SoCalGas Ch. 1 (Dandridge) at MMD-5 - MMD-6 and Table MMD-2 (showing that Core 1-in-35 Cold Year winter demand of 1,381 MMcfd is served by 949–1,139 MMcfd of interstate pipeline (winter flowing) supply combined with only 503 MMcfd of storage withdrawals, i.e., interstate pipeline supply provides the substantial majority of total throughput, with storage providing the balancing increment); 2024 California Gas Report at 157 (showing that on the SoCalGas system annual throughput is served predominantly by interstate pipeline-delivered gas, with storage withdrawals representing only the seasonal- and balancing-related portion of total annual throughput) (available at: 2024-California-Gas-Report-Final.pdf); see also SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29 - FS-MSP-31 (functional separation of pipeline (Backbone, Local Transmission, High Pressure Distribution) costs from Underground Storage costs, reflecting that pipeline assets, not storage, deliver the majority of system throughput).

Storage serves only a portion of 'SoCalGas's total throughput. In other words, Load Balancing Storage assets are needed to address *imbalances,* not to serve total throughput, and it is therefore unreasonable to allocate the costs thereof to customer classes based on total throughput. Doing so does not follow the principle of cost-causation, particularly for Noncore customers who have a more stable and less peaky use of the system.

VII.I. Customer Imbalances and Class Load Factors

Q PLEASE DISCUSS THE SIGNIFICANCE OF CUSTOMER IMBALANCES.

A A customer imbalance is the difference between the amount of natural gas delivered via pipelines to SoCalGas's system on behalf of customers and the actual use of natural gas by those customers. This difference can result in either an under-delivery (actual burn is greater than delivered gas) or an over-delivery (actual burn is less than delivered gas). The net aggregate customer imbalances constitute the total system net imbalance.[72] The system net imbalance can produce either a net storage injection (over-delivery of gas to the system) or a net storage withdrawal (under-delivery of gas to the system).

On the SoCalGas system, net storage injections and withdrawals have two components: (1) Core storage, which serves Core customer requirements

[72] SoCalGas Ch. 1 (Dandridge) at MMD-6:22 - MMD-7:5 ("The balancing function refers to the service provided by the System Operator to accommodate imbalances between a customer's actual usage and the gas it schedules for delivery to the system. These aggregate imbalances result in either under deliveries or over deliveries of gas to the system. SoCalGas utilizes its storage functions of inventory, injection and withdrawal and operational flow orders (OFO) procedures to manage these imbalances to maintain a reliable system."); see also SoCalGas Tariff Rule No. 30 (defining customer imbalances and the system balancing services SoCalGas provides between scheduled deliveries and actual customer burns).

and can be scheduled for injections and withdrawals; and (2) Load Balancing Storage, which serves both Core and Noncore customers, addresses customer imbalances, and is the mechanism by which SoCalGas prevents its system from becoming over- or under-pressured.

Q DO CUSTOMERS PERFECTLY MATCH THEIR NATURAL GAS DELIVERIES INTO THE SOCALGAS SYSTEM WITH THEIR ACTUAL NATURAL GAS BURNS OFF OF THE SOCALGAS SYSTEM?

A No. It is virtually impossible for a customer to be 100% balanced, where natural gas delivered always equals natural gas burned. Various factors can contribute to customer imbalances. However, some customer classes are more prone to imbalances than others. For example, residential Core customers are generally more prone to imbalances during winter peaking periods because of the predominantly weather-sensitive nature of their loads as compared to Noncore customer class loads.[73] Nevertheless, EG customers are a subset of Noncore and can exhibit much greater load swings than many commercial and industrial Noncore customers, who generally exhibit more consistent gas consumption patterns.[74]

[73] See SoCalGas Ch. 2 (Martinez) at EM 5: 5-7. .

[74] See SoCalGas Ch.4 (Fiola) at RF-1:16-22 and RF-2:4-13 (using a PLEXOS production-cost simulation model to forecast Electric Generation gas demand because EG dispatch, and therefore EG gas burn, varies significantly day-to-day with hydro conditions, renewable output, electric load, and unit availability); *Id.* at RF-3:14-RF-4:5 and Table RF-2 (developing a Winter Coincidental Peak Day forecast specifically for EG because of EG's pronounced day-to-day load swings); see also *Chapter 4 Workpapers to the Prepared Direct Testimony of Robert Fiola, Large Electric Generation/Cogen Forecast* ("Chapter 4 Workpapers") (showing day-to-day variability in modeled EG gas demand); compare SoCalGas Ch.2 (Martinez) at EM-3:8 - EM-4:5 (most Noncore retail commercial and industrial

Q WHAT FACTORS CONTRIBUTE TO CUSTOMERS' NATURAL GAS IMBALANCES?

A For residential Core customers, winter weather can be greatly responsible for customer imbalances. For example, colder than expected weather can cause a significant mismatch between scheduled gas receipts for residential Core customers as compared to actual Core gas burn during the winter peaking period.[75]

With regard to Noncore customers, production changes and equipment outages can cause an imbalance between scheduled natural gas receipts and actual natural gas burn. Depending on the specific circumstances, a production change at an industrial customer's facility could cause either an under-delivery or over-delivery of natural gas.

Equipment outages at an industrial customer's facility or a forced generating unit outage for an EG customer would likely cause an over-delivery of gas.

Weather can also be responsible for imbalances for certain Noncore customers such as EG customers. EG customer imbalances typically occur

customers "not HDD-sensitive," reflecting the more consistent gas consumption patterns of typical Noncore C&I load relative to EG).

[75] SoCalGas Ch.1 (Dandridge) at MMD-6:22-MMD-7:9 (storage balancing function exists to absorb the difference between scheduled deliveries to the system and actual customer burn, with SoCalGas using injection, withdrawal, and Operational Flow Order (OFO) procedures to manage these imbalances); SoCalGas Ch.2 (Martinez) at EM 5: 5-7; see also SoCalGas Tariff Rule No. 30 (defining customer imbalances and the schedule-versus-burn mismatch the storage balancing function is designed to absorb); SoCalGas Tariff Rule No. 41 / Operational Flow Order procedures (issued when forecast cold weather is expected to drive Core burn above scheduled receipts).

during the summer season, resulting from warmer than expected weather patterns, when the demand for electricity and dispatch of gas-fired generation may be greater than forecasted, resulting in an under-delivery of gas.

Q DO CLASS LOAD FACTORS HELP ILLUSTRATE THE WEATHER-SENSITIVE NATURE OF CORE CUSTOMER DEMANDS?

A Yes. Load factor is defined as the ratio of average demand to peak day demand. For Core customers, that ratio is 33.6%; for Noncore customers, that ratio is 67.0%.[76] When no variability in load occurs over the course of a year, the customer class load factor would be an ideal 1.0 or 100%.[77] The higher the load factor, the more efficiently the customer uses the Company's system capacity. Thus, Noncore customers have a load factor much closer to 1.0 or 100% than Core customers, resulting in Noncore customers' more efficient use of system capacity than Core customers. A ratio of 33.6% indicates that the variability in Core demand is much greater than that of Noncore demand and is not as stable as that of Noncore customers. In other words, Core customer loads are "peakier" than those of Noncore customers on average, largely because of weather and related heating demand.

Q WHAT IS THE IMPACT ON RETAIL NONCORE CUSTOMERS OF USING AYTP FOR ALLOCATING LOAD BALANCING STORAGE COSTS?

[76] See Schedule BCC-1, Line 16

[77] Load factor has been calculated using the Company's cold year data, where the CYTP allocator annual volume is first divided by 365 to derive Average Demand. Average Demand is then divided by the Peak Day demand to calculate load factor.

A While Retail Noncore customers represent 47.3% of AYTP, they account for a much smaller share of system imbalance, as the preceding load-factor and weather-sensitivity discussion shows. Allocating 47.3% of Load Balancing Storage costs to Noncore customers is therefore inconsistent with cost causation.

VII.J. Peak Day Alternative for Load Balancing Storage

Q GIVEN THAT THE AYTP METHOD PROPOSED TO BE APPLIED TO LOAD BALANCING STORAGE BY SOCALGAS IS NOT COST-BASED, WHAT ALTERNATIVE SHOULD BE CONSIDERED?

A An allocation that recognizes the maximum annual Peak Day demand placed on the storage facilities by customers; a peak demand allocator. SoCalGas itself maintains that its storage costs are fixed,[78] which makes a capacity-based (peak demand) allocator the more appropriate match to cost causation.

Q HOW DOES A PEAK DAY ALLOCATION RECOGNIZE LOAD BALANCING STORAGE USAGE CHARACTERISTICS OF CUSTOMER CLASSES?

A The Peak Day allocation is a measure of the maximum demand requirements of customer classes for the service, in this case, storage. A Peak Day demand

[78] SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29 and Table FS-MSP-24 (showing 2024 SoCalGas embedded storage cost of $320.3 million comprised of $213.97 million capital-related cost and $106.29 million O&M and A&G expenses, i.e., approximately 67% capital-related (fixed) cost, with the remaining O&M and A&G expenses also largely fixed and not varying with throughput); see also SoCalGas Ch.1 (Dandridge) at MMD-5 - MMD-7 (storage facilities sized to peak day reliability standards, confirming that storage cost incurrence is driven by design capacity rather than by annual throughput).

allocation recognizes that facilities must be sized to meet the simultaneous maximum demands placed on them, in the aggregate, by all SoCalGas customers.

Q HAVE YOU DEVELOPED AN ALTERNATIVE TO THE AYTP ALLOCATOR FOR BALANCING STORAGE COSTS USING PEAK DAY?

A Yes. Under my proposed alternative allocation, Load Balancing Storage costs are considered demand related.

Q WHAT IS YOUR RECOMMENDATION?

A Using a Peak Day allocation, the allocation of load balancing storage costs to Retail Noncore customers is 28.9%, versus the 47.3% proposed by SoCalGas using the AYTP.

Q WHAT IS THE IMPACT OF YOUR RECOMMENDED COST ALLOCATIONS?

A Collectively, my recommended allocations for Load Balancing Storage costs, LT system costs, and HPD system costs reduces Noncore customers' allocated embedded cost revenues by approximately $54.8 million as compared to the Company's proposal. This is shown on Schedule BCC-2.

VIII. OFF-SYSTEM DELIVERY AND BACKBONE TRANSMISSION SERVICE (CHAPTER 10 – BORKOVICH)

VIII.A. Noncore Storage Balancing Account and Firm Access and Storage Rights Memorandum Account

Q DOES SOCALGAS WITNESS BORKOVICH TAKE THE SAME POSITION AS WITNESS GADANI REGARDING THE NSBA AND FASRMA?

A Yes. Consistent with the position taken by SoCalGas witness Gadani in Chapter 6, SoCalGas witness Borkovich argues that the $27 million NSBA over-collection should be used to neutralize the $4 million FASRMA balance.[79] As I discussed in Section VI above, I oppose this proposal for the reasons articulated there. The OSD program was not a Noncore storage service. SoCalGas speculated that OSD service would generate net positive revenues.[80] That speculation proved incorrect.[81] SoCalGas tries to characterize the FASRMA balance as a Noncore issue, but in reality, SoCalGas's Gas Acquisition Department could have been marketing gas to OSD customers using not only flowing supplies on its BTS capacity, but also storage assets allocated to the Core.[82] There is no principled basis for requiring Noncore

[79] SoCalGas Ch.10 (Borkovich) at PDB-9:13-PDB-11:6 (proposing to apply NSBA over-collections to FASRMA balance until the FASRMA under-collection is offset).

[80] *Id.* at PDB-7:7-PDB-8:14 (acknowledging that, at the time of D.11-03-029, SoCalGas/SDG&E expected the expansion of OSD service to other receipt points would (1) increase utilization of the backbone system and BTS revenue and lower transportation rates for on-system customers, (2) increase gas-on-gas competition, and (3) increase storage utilization and unbundled storage revenues, expectations that did not materialize, with interruptible OSD not offered since December 2017 and on-system supply not competitive in off-system markets); see also D.11-03-029 at 15 ("it is difficult to predict what the future gas demand, source of gas and market conditions will be like"); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-05, Question 5-1.b. (only $30,000 in total OSD revenues collected against the $4.0 million FASRMA balance, confirming the projected net positive revenues did not materialize) (Attached in Appendix B, Page 6).

[81] SoCalGas Ch.10 (Borkovich) at PDB-7:7-PDB-8:14 (acknowledging that SoCalGas's pre-D.11-03-029 expectations, that OSD expansion would (1) increase backbone utilization and BTS revenue, (2) increase gas-on-gas competition, and (3) increase storage utilization and unbundled storage revenues, thereby generating net positive revenues to recover the FASRMA capital revenue requirement, did not materialize, with on-system supply not competitive in off-system markets and interruptible OSD not offered since December 2017); see also D.11-03-029 at 15 ("it is difficult to predict what the future gas demand, source of gas and market conditions will be like"); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-05, Question 5-1.b. (only $30,000 in total OSD revenues collected against the $4.0 million FASRMA balance, confirming that the projected net positive OSD revenues did not materialize) (Attached in Appendix B, Page 6).

[82] SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-07, Question 7-1.a ("Yes," confirming that SoCalGas's Gas Acquisition Department would have been eligible

Storage customers to bear the consequences of SoCalGas's failed commercial speculation.

VIII.B. Rule 30 – Existing BTS Nomination Framework

Q DOES MR. BORKOVICH PROPOSE CHANGES TO RULE 30?

A Yes. Mr. Borkovich's proposal would amend SoCalGas Tariff Rule No. 30 to confirm Backbone Transportation Service ("BTS") nominations up to the TNSC ("Total Net System Capacity") during the Evening, Intraday 1, Intraday 2, and Intraday 3 nomination cycles, regardless of whether an Operational Flow Order ("OFO") has been declared.[83] While the existing Rule 30 confirmation protocol may create uncertainty for shippers as to how much of their nominated gas volumes will actually be confirmed and scheduled, I do not support adoption of his proposal as filed. Instead, I propose a more limited and phased modification to Rule 30 to address the underlying issue while preserving system reliability and operational flexibility.

to market gas supply to OSD expansion customers, including by using flowing supplies on the backbone transportation system and storage assets allocated to the Core, demonstrating that the FASRMA shortfall is not solely attributable to Noncore service) (Attached in Appendix B, Page 8); see also SoCalGas Ch.10 (Borkovich) at PDB-7:7-PDB-8:14 (acknowledging that the original D.11-03-029 expectations, including increased BTS utilization and storage utilization, contemplated revenue contributions from system-wide assets, not solely from Noncore-allocated capacity); SoCalGas Response to Indicated Shippers Data Request Set IS-SCG-05, Question 5-1.b. (only $30,000 in total OSD revenues collected against the $4.0 million FASRMA balance) (Attached in Appendix B, Page 6).

[83] SoCalGas Ch.10 (Borkovich) at PDB-12:16-PDB-13:12 (proposing to confirm BTS nominations up to Total Net System Capacity in the Evening, Intraday 1, Intraday 2, and Intraday 3 cycles regardless of OFO status).

Q PLEASE SUMMARIZE THE EXISTING BTS NOMINATION, CONFIRMATION AND SCHEDULING FRAMEWORK UNDER RULE 30.

A Rule 30, Section D.7 establishes five nomination cycles for the SoCalGas Gas Day, which begins at 7:00 a.m. Pacific Standard Time. The nomination deadlines and effective times are as follows:

Table BCC-1 – Rule 30 Nomination Cycle Deadlines and Effective Times

Cycle	Cycle No.	Nomination Deadline	Effective Time
Timely	C1	11:00 a.m. Day-Ahead	7:00 a.m. Gas Day
Evening	C2	4:00 p.m. Day-Ahead	7:00 a.m. Gas Day
Intraday 1	C3	8:00 a.m. Gas Day	12:00 p.m. Gas Day
Intraday 2	C4	12:30 p.m. Gas Day	4:00 p.m. Gas Day
Intraday 3	C5	5:00 p.m. Gas Day	8:00 p.m. Gas Day

Source: Rule 30, Sheets 8–9 (Section D.7).[84]

Q HOW DOES RULE 30 ESTABLISH THE PRIORITY AMONG DIFFERENT CATEGORIES OF BTS NOMINATIONS?

A Rule 30, Section D.3 establishes a four-tier confirmation order for BTS nominations: (1) Firm Primary; (2) Firm Alternate Within-the-Zone; (3) Firm Alternate Outside-the-Zone; and (4) Interruptible.[85] Within each tier,

[84] SoCalGas Tariff Rule No. 30, Sheets 8–9 § D.7 (nomination cycles and effective times).

[85] SoCalGas Tariff Rule No. 30 § D.3 (Confirmation of Nominations) (establishing the four-tier confirmation order for Backbone Transportation Service nominations, (1) Firm

nominations are pro-rated when the receipt point or transmission zone is over-nominated. Section D.3 also establishes bumping rules, under which Firm Primary may bump Firm Alternate scheduled quantities through the Evening Cycle, Firm Alternate Within-the-Zone may bump Firm Alternate Outside-the-Zone through the Evening Cycle, and any Firm category may bump Interruptible through the Intraday 2 Cycle. Bumping is not allowed in the Intraday 3 Cycle.[86] Mr. Borkovich is not proposing any changes to the confirmation order or to the bumping rules.[87]

Q HOW IS THE SYSTEM-WIDE CAPACITY LIMIT CURRENTLY APPLIED DURING THE NOMINATION CYCLES?

A This is the central operational issue Mr. Borkovich addresses. Rule 30, Section D.3 currently provides that SoCalGas will confirm nominations up to the system capacity limitation defined in Section F (i) during the Intraday 1, Intraday 2, and Intraday 3 cycles when an OFO has been declared, and (ii) during the Intraday 3 cycle on a non-OFO Gas Day when nominations exceed system capacity. The TNSC confirmation cap is therefore not currently applied in the Evening Cycle on any day, and is not applied in the Intraday 1 or Intraday 2 cycles on non-OFO days.

Primary, (2) Firm Alternate Within-the-Zone, (3) Firm Alternate Outside-the-Zone, and (4) Interruptible, with pro rata allocation within each tier when a receipt point or transmission zone is over-nominated, and specifying the associated bumping rules among tiers).

[86] SoCalGas Tariff Rule No. 30 § D.3 (confirmation order and bumping rules).

[87] See SoCalGas Response to Data Request IS-SCG-08, Question 8.1.a. (Attached in Appendix B, Page 9).

Q PLEASE EXPLAIN THE ELAPSED PRO-RATA RULE REFERENCED IN RULE 30.

A Rule 30, Section D.3 incorporates the North American Energy Standards Board ("NAESB") Elapsed Pro-rata Rule. Under this rule, the Elapsed Prorated Scheduled Quantity ("EPSQ") is defined as the portion of a scheduled quantity that would have theoretically flowed up to the effective time of an intraday nomination, calculated based on a uniform hourly flow rate equal to one twenty-fourth of the daily scheduled quantity.[88] EPSQ functions as a floor on how far a properly nominated and scheduled quantity may be reduced in any subsequent intraday cycle. The rule reflects the operational reality that gas already flowed cannot be un-flowed.[89]

Q PLEASE CALCULATE THE EPSQ FLOORS THAT APPLY AT EACH SOCALGAS INTRADAY CYCLE.

A Because the SoCalGas Gas Day begins at 7:00 a.m. and the intraday cycle effective times are 12:00 p.m. (Intraday 1), 4:00 p.m. (Intraday 2), and 8:00 p.m. (Intraday 3), the elapsed flow time at each effective time is 5, 9, and 13 hours,

[88] North American Energy Standards Board (NAESB), Wholesale Gas Quadrant (WGQ) Standard 1.3.18 (defining "Elapsed Prorated Scheduled Quantity" (EPSQ) as the portion of a scheduled quantity that would have theoretically flowed up to the effective time of an intraday nomination, calculated based on a uniform hourly flow rate equal to one twenty-fourth of the daily scheduled quantity); see also SoCalGas Tariff Rule No. 30 § D (incorporating EPSQ methodology for intraday nomination scheduling on the SoCalGas backbone transportation system).

[89] See North American Energy Standards Board (NAESB) WGQ Standard 1.3.18 (Elapsed Prorated Scheduled Quantity); SoCalGas Tariff Rule No. 30 § D.3 (incorporating NAESB EPSQ rule).

respectively. The EPSQ floors are therefore as represented in Table BCC-2, below:

Table BCC-2 — EPSQ Floors at Each SoCalGas Intraday Cycle

Cycle	Effective Time	Hours Elapsed	EPSQ Floor
Intraday 1	12:00 p.m.	5	5/24 = 20.83%
Intraday 2	4:00 p.m.	9	9/24 = 37.50%
Intraday 3	8:00 p.m.	13	13/24 = 54.17%

VIII.C. EPSQ Leakage and Mr. Borkovich's Proposal

Q HOW DOES THE ELAPSED PRO-RATA RULE INTERACT WITH THE BTS CONFIRMATION ORDER DURING A GAS DAY ON WHICH NOMINATIONS EXCEED SYSTEM CAPACITY?

A This interaction between the EPSQ floors and confirmation timing is the operational concern Mr. Borkovich raises. On a non-OFO Gas Day, lower-priority Firm Alternate and Interruptible nominations may schedule freely in the Timely and Evening cycles because Rule 30 does not apply the TNSC confirmation cap in those cycles. As the Gas Day progresses, those scheduled quantities accrue EPSQ protection at the rates shown in Table BCC-2. By the time the Intraday 3 confirmation cap is applied at 5:00 p.m. on the Gas Day, more than half (54.17 percent) of any lower-priority nominations scheduled from earlier cycles is locked in by EPSQ and protected from scheduling cuts. The Section D.3 confirmation order, which is supposed to give Firm Primary

transportation first call on system capacity, is effectively reversed for the locked-in EPSQ portion of lower-priority schedules, effectively treating the EPSQ volumes as Firm Primary. An actual Firm Primary nomination submitted in the Intraday 1, Intraday 2 and Intraday 3 cycles has to compete against EPSQ-protected Firm Alternate and Interruptible volumes that were scheduled the prior day in the Evening Cycle.

Q HAVE YOU QUANTIFIED THE MAGNITUDE OF THIS EPSQ LEAKAGE?

A Yes. Using the standard NAESB calculation, and as shown in Table BCC-2 above, the EPSQ floor at the SoCalGas Intraday 1 effective time of 12:00 p.m. equals 5/24, or approximately 20.83 percent, of any scheduled quantity that survived from the prior cycle. By Intraday 2, that floor rises to 37.50 percent. By Intraday 3, it rises to 54.17 percent. On any Gas Day where total nominations exceed TNSC and the cap is not applied until Intraday 3, more than half of whatever lower-priority volume scheduled in the day-ahead cycles is locked in under the Elapsed Pro-rata Rule regardless of priority. In essence, lower priority EPSQ volumes have the potential to “bump” an equivalent Primary Firm volume due to the Elapsed Pro-rata Rule.

Q PLEASE SUMMARIZE MR. BORKOVICH’S PROPOSAL AT PAGES 12 AND 13 OF HIS TESTIMONY.

A Mr. Borkovich proposes to amend Rule 30, Section D.3 to require SoCalGas to confirm BTS nominations to the TNSC in the Evening, Intraday 1, Intraday 2,

and Intraday 3 cycles, regardless of OFO status. This would expand the existing TNSC confirmation cap from one cycle on non-OFO days (Intraday 3) to four cycles on every Gas Day. Mr. Borkovich frames the change as conforming SoCalGas's confirmation practices to align with "accepted industry practices" and as preventing lower-priority nominations from displacing higher-priority nominations through EPSQ accumulation.[90]

Q DO YOU HAVE ANY RESPONSE TO MR. BORKOVICH'S STATEMENT THAT HIS PROPOSED CHANGE CONFORMS TO "ACCEPTED INDUSTRY PRACTICES"?

A It is my understanding that most pipelines typically operate based on fixed capacity amounts. During periods of significant maintenance, this fixed amount is disrupted. However, pipelines strive to commit to a fixed capacity value for the Gas Day. Because SoCalGas operates based on a variable demand profile, there is an inherent uncertainty in what capacity is available to customers, even firm capacity at times. Therefore, SoCal's uniqueness requires a unique solution. It should strive to apply "accepted industry practices" as best as possible but its inherent operational nature prevents it from adopting those practices absolutely.

[90] SoCalGas Ch. 10 (Borkovich) at PDB-12:6-PDB-13:1 ("Approval of this proposal would allow SoCalGas firm BTS customers a better opportunity to schedule gas under their higher confirmation order contracts, not just in earlier scheduling cycles, but in later scheduling cycles too and for SoCalGas BTS to better conform with accepted industry practices."); see also *Id*. at PDB-12:1-9 (explaining that under the current confirmation methodology, allowing nominations of a lower confirmation order to be scheduled in earlier scheduling cycles "displac[es] nominations of a higher confirmation order in later cycles, due to the elapsed pro-rata rules," i.e., EPSQ accumulation).

Q DOES IT APPEAR THAT THE CURRENT SOCALGAS CONFIRMATION SCHEME LIKELY CREATES AN OPERATIONAL PROBLEM WORTH ADDRESSING?

A Yes. The EPSQ leakage Mr. Borkovich identifies is real, mechanical, and a legitimate concern for shippers holding higher-priority Firm Primary BTS rights. However, I disagree with Mr. Borkovich on the scope of the proposed remedy. His proposal goes further than necessary to address the problem and creates new operational and reliability risks that he does not adequately address in his direct testimony.

VIII.D. Concerns with Mr. Borkovich's Proposal

Q PLEASE IDENTIFY YOUR SPECIFIC CONCERNS WITH MR. BORKOVICH'S PROPOSAL.

A I have four concerns with the proposal as filed.

Q WHAT IS YOUR FIRST CONCERN?

A My first concern is that applying the TNSC confirmation cap in the Evening Cycle, which has a nomination deadline of 4:00 p.m. one day prior to the flow day, requires SoCalGas to forecast TNSC approximately fifteen hours before the 7:00am PST start of the SoCalGas Gas Day. TNSC is a daily operational figure that depends on the physical operating capacities of receipt points and transmission zones "adjusted for operational constraints (i.e. maintenance, localized restrictions, and upstream delivery pressures) as determined each

day," per Rule 30, Section D.3. Forecasting that figure with sufficient accuracy at 4:00 p.m. the day before flow is meaningfully harder than forecasting it at 12:30 p.m. on the Gas Day, when morning operational data, actual upstream delivery pressures, and confirmed maintenance statuses on both the SoCalGas and upstream pipeline systems are available.

Q WHY DOES THE TIMING OF THE TNSC DETERMINATION MATTER?

A Because TNSC will be the binding constraint that drives nomination cuts under the proposal, beginning with each Evening Cycle, before the Gas Day commences. If SoCalGas's day-ahead TNSC forecast is conservative, that is, lower than as-flowed system capacity turns out to be, nominations will be cut more deeply than necessary, capacity will be left unused from 7:00am through 12:00pm, and shippers will need to scramble to acquire replacement gas to flow in subsequent cycles to backfill for the cuts. If SoCalGas's day-ahead TNSC forecast is too aggressive, that is, higher than as-flowed capacity, the cap fails to prevent the over-nomination problem the proposal is designed to address. The Evening Cycle is a cycle where forecast accuracy is weakest,[91] and Mr.

[91] It is a well-established principle of operational gas and power forecasting that day-ahead forecasts (those prepared for the Evening (Timely) nomination cycle, which closes the calendar day before the gas flow day) carry the longest forecast horizon of any nomination cycle and therefore exhibit the largest mean absolute error and the lowest skill, with forecast accuracy progressively improving in the same-day Intraday cycles as actual weather, electric load, hydro conditions, renewable output, and unit availability become known. See North American Energy Standards Board (NAESB), Wholesale Gas Quadrant (WGQ) Standards 1.3.x (Nominations Related Standards) (defining the Timely (Evening), Evening, and Intraday nomination cycles, with the Timely cycle prepared the day before flow on the longest forecast horizon, and successive Intraday cycles allowing nominators to refine quantities as same-day information becomes available); see also SoCalGas Tariff Rule No. 30 § D.7 (Nomination Cycles and Effective Times) (same cycle structure on the SoCalGas system); cf. SoCalGas Ch. 4 (Fiola) at RF-1:16-22 and RF-2:4-13 (using day-ahead PLEXOS modeling that itself

Borkovich provides no evidence in his direct testimony regarding the historical accuracy of Evening Cycle TNSC forecasts.

Q WHAT IS YOUR SECOND CONCERN?

A My second concern is that nomination cuts made in the Evening Cycle are operationally difficult to remedy. Once a Firm Alternate or Interruptible nomination is cut at 4:00 p.m. Evening Cycle, the affected shipper has limited ability to bring incremental supply onto the SoCalGas system in subsequent cycles. Upstream interstate pipelines have their own NAESB-coordinated cycle deadlines,[92] and a shipper's ability to redirect gas, secure new upstream capacity, or arrange alternate delivery within the remaining timeframe will likely be constrained. As a general operational matter, it is comparatively easy to reduce on-system receipts late in the Gas Day, but considerably harder to increase on-system receipts. Cutting nominations in the Evening Cycle

reflects the materially greater day-ahead uncertainty in EG dispatch driven by hydro, renewable output, electric load, and unit availability, the same variables that drive Total Net System Capacity uncertainty in the Evening Cycle).

[92] North American Energy Standards Board (NAESB), Wholesale Gas Quadrant (WGQ) Standards 1.3.x (Nominations Related Standards) (establishing standardized nomination cycle deadlines, Timely (Evening), Evening, and Intraday 1, 2, and 3, applicable to all NAESB-compliant interstate natural gas pipelines, with each cycle having a fixed nomination deadline and a fixed effective time for gas flow); see also FERC Order No. 587, Standards For Business Practices of Interstate Natural Gas Pipelines, 61 Fed. Reg. 39,053 (July 26, 1996), and successor orders (incorporating NAESB WGQ Standards into 18 C.F.R. Part 284 and requiring jurisdictional interstate pipelines to adopt the NAESB-standardized nomination cycle structure); 18 C.F.R. § 284.12 (NAESB business practices for interstate pipelines); see, e.g., El Paso Natural Gas Co., FERC Gas Tariff, General Terms and Conditions, § 14 (Nominations and Scheduling), and Transwestern Pipeline Co., FERC Gas Tariff, General Terms and Conditions, § 16 (Nominations and Scheduling) (each implementing the NAESB-standardized cycle deadlines on the principal interstate pipelines that deliver gas to the SoCalGas system).

therefore puts disproportionate stress on shippers and their upstream supply arrangements, as well as on the system's residual flexibility.

Q WHAT IS YOUR THIRD CONCERN?

A My third concern is that earlier and more aggressive nomination cuts will push affected shippers toward greater reliance on storage withdrawals to cover their gas day requirements. Shippers having access to storage rights could feasibly use storage for backfilling cuts, but such short-term tactics could undermine the shipper's long-term strategic justification for subscribing to storage. Further, as the Commission is aware, SoCalGas's storage capacity is presently constrained by ongoing Storage Integrity Management Program ("SIMP") work,[93] by the regulatory uncertainty surrounding Aliso Canyon inventory limits,[94] and by the unbundled storage program allocations described in Mr. Borkovich's

[93] SoCalGas Ch. 10 (Borkovich) at PDB-9:13-PDB-10:3 ("Reductions in storage capacity attributable to the Storage Integrity Management Program (SIMP) are expected to continue in the foreseeable future."); see also SoCalGas Ch.1 (Dandridge) at MMD-2 to MMD-3 (proposed 2027-2029 storage capacities of 118.8 Bcf working inventory, 458 MMcfd summer / 529 MMcfd winter injection, and 1,787 MMcfd summer / 1,826 MMcfd winter withdrawal, reduced from the 2024-2026 D.24-07-009 levels of 119.5 Bcf, 800/550 MMcfd injection, and 1,900/2,400 MMcfd withdrawal, reflecting in part ongoing SIMP-related capacity constraints).

[94] D.24-12-076 at 62 (establishing a biennial assessment process under which the Commission may, every two years, recommend increases, decreases, or maintenance of Aliso Canyon's maximum storage inventory in 10 Bcf increments based on the biennial reliability assessment, and adopting a peak day demand threshold of 4,121 MMcfd at which the Commission will open a proceeding to consider permanent closure and decommissioning, a regulatory framework that, by design, leaves the future inventory level of Aliso Canyon subject to recurring biennial reassessment); see also CPUC Energy Division, 2025 Aliso Canyon Biennial Assessment Report Pursuant to D.24-12-076, Oct. 1, 2025, (first biennial assessment report issued pursuant to D.24-12-076) (available at: 2025 aliso canyon biennial assessment.pdf); D.21-11-008 at 1 (interim Aliso Canyon maximum storage capacity of up to 41.16 Bcf); D.23-08-050 (increasing Aliso Canyon maximum storage inventory to the current 68.6 Bcf level, illustrating the recurring inventory-level changes that drive ongoing regulatory uncertainty regarding Aliso Canyon storage capacity).

accompanying testimony at page 10.[95] Mr. Borkovich himself acknowledges that "available backbone and storage capacity is not as robust as it was back in 2011."[96] His confirmation cap proposal would predictably increase storage withdrawal demand at precisely the time when storage availability is contracting. He does not address this interaction in his direct testimony.

Q WHAT IS YOUR FOURTH CONCERN?

A My fourth concern is that Mr. Borkovich's proposal would make TNSC the binding scheduling constraint in four cycles per non-OFO Gas Day, but his proposal contains no provisions for transparency around how TNSC is calculated, what inputs SoCalGas uses, what value is binding for any given confirmation, or how shippers may verify the calculation after the fact. Under existing Rule 30, OFO calculations are subject to the methodology described in Rule 41 and the operational data posted on Envoy. The TNSC value that would drive non-OFO confirmation cuts under the proposal as early as the Evening Cycle lacks comparable methodological transparency.

VIII.E. Proposed Alternative

Q PLEASE DESCRIBE YOUR PROPOSED ALTERNATIVE.

[95] SoCalGas Ch. 10 (Borkovich) at PDB-10:1-15 (describing the Unbundled Storage (UBS) program allocations and the NSBA over-collection of net UBS-derived revenues that SoCalGas proposes to apply to the FASRMA balance); see also SoCalGas Ch. 1 Dandridge at MMD-7 - MMD-8 (describing the UBS program structure and proposed allocation of 28 Bcf of working inventory capacity, 15 MMcfd of summer injection, 15 MMcfd of winter injection, 15 MMcfd of winter withdrawal, and 15 MMcfd of summer withdrawal to the UBS program); SoCalGas Ch.8 (Seres/MSP) at FS-MSP-29 - FS-MSP-31 and Table FS-MSP-25 (showing the $32 million UBS cost allocation derived from the UBS capacity rights described above).

[96] SoCalGas Ch. 10 (Borkovich) at PDB-7:13-15 ("available backbone and storage capacity is not as robust as it was back in 2011 at the time of the issuance of D.11-03-029.").

A My proposed alternative consists of five elements:

1. Phase 1 – Apply the TNSC confirmation cap on non-OFO Gas Days to the Intraday 2 cycle nomination deadline (12:30pm day of flow) only;

2. Decline to extend the TNSC cap to the Evening Cycle at this time;

3. Require SoCalGas to file a compliance report twelve months after Phase 1 implementation, with extension to the Intraday 1 cycle conditional on a satisfactory operational record of the Intraday 2 cycle being obtained in the Phase 1 TNSC application;

4. Add TNSC calculation and posting transparency requirements to Rule 30; and

5. Provide transitional protection for shippers whose existing nomination patterns rely on Alternate or Interruptible BTS to match upstream firm capacity holdings, through the remaining term of existing firm BTS capacity rights contracts.

Q WHY HAVE YOU SELECTED THE INTRADAY 2 CYCLE FOR PHASE 1 IMPLEMENTATION?

A I have selected Intraday 2 for three reasons. First, the Intraday 2 nomination deadline of 12:30 p.m. on the Gas Day is well past the start of operational data flow at 7:00 a.m., which means SoCalGas can forecast TNSC with materially higher accuracy than at any earlier point in the cycle, especially the Evening Cycle. Second, the Intraday 2 effective time of 4:00 p.m. provides three and one-half hours of lead time during which shippers and pipelines can adjust their on-system and off-system delivery arrangements. That is meaningful operational flexibility. Third, the Intraday 2 cycle is the cycle in which any possible gaming behavior on non-OFO days would bite hardest: shippers anticipating an Intraday 3 windowing cut have an incentive to inflate their Intraday 2 nominations specifically to maximize the EPSQ floor that will protect

them in Intraday 3. Applying the cap at Intraday 2 directly addresses that possible gaming dynamic earlier in time; 4.5 hours earlier as shown above in Table BCC-1.

Q HOW MUCH OF THE EPSQ LEAKAGE PROBLEM WOULD THE INTRADAY 2 CAP ADDRESS?

A A substantial portion. To illustrate by means of comparison, consider a hypothetical non-OFO Gas Day, on which total nominations exceed TNSC by 1,000 MMcfd, comprising 200 MMcfd of Interruptible, 300 MMcfd of Firm Alternate Outside-the-Zone, and 500 MMcfd of Firm Alternate Within-the-Zone scheduled in the Evening Cycle, in addition to Firm Primary nominations assumed to be exactly equal to TNSC.

Under the existing Rule 30, the TNSC cap is not applied until Intraday 3, when EPSQ floors equal 54.17 percent of each tier's Intraday 2 scheduled quantity. The protected lower-priority volume that survives the Intraday 3 cut equals approximately 542 MMcfd (108 + 163 + 271), which requires an equal and offsetting 542 MMcfd cut to Firm Primary nominations. Under my Phase 1 alternative, the cap is applied at Intraday 2, using Intraday 1 scheduled quantities as the reference base because my Phase 1 proposal declines to extend the cap to the Evening Cycle, when EPSQ floors equal 37.50 percent of each tier's Intraday 1 scheduled quantity. The protected lower-priority volume that survives Intraday 2 equals approximately 376 MMcfd (75 + 113 + 188). The Phase 1 cap therefore reduces EPSQ-protected lower-priority scheduled

volume by approximately 166 MMcfd , or roughly 31 percent of the existing leakage. That capacity is reallocated within the system to the Firm Primary tier, consistent with the Section D.3 confirmation order. In other words, cuts to Firm Primary capacity will be 166 MMcfd less with the Intraday 2 cycle TNSC cap than with the current Intraday 3 cycle TNSC cap.

Q WHY DOES YOUR ALTERNATIVE DECLINE TO EXTEND THE CAP TO THE EVENING CYCLE?

A For the reasons set out in my first and second concerns above. Day-ahead TNSC forecasting is meaningfully less accurate than intraday TNSC determination, and Evening Cycle cuts are operationally difficult to remedy because shippers have limited ability to redirect gas before Gas Day flow begins at 7:00 a.m. Extending the cap to the Evening Cycle creates the largest reliability and system efficiency risk identified in my four concerns above, while addressing only a marginal increment of the EPSQ leakage problem. The cost-benefit balance appears to not favor that extension. Mr. Borkovich's direct testimony provides no analysis demonstrating that Evening Cycle application is necessary to achieve the proposal's stated objectives.

Q WHY DOES SUBSTANTIAL EPSQ-PROTECTED VOLUME REMAIN UNDER PHASE 1 OF YOUR PROPOSED ALTERNATIVE?

A Because Phase 1 is intentionally conservative: it advances the cap one cycle earlier than existing Rule 30 (from Intraday 3 to Intraday 2) and declines to

extend application to the Evening Cycle at this time. That gradualism is deliberate. Allowing two cycles of operational experience under the Intraday 2 TNSC cap before considering further extension to Intraday 1 gives the Commission, SoCalGas, and shippers an experience baseline on which to evaluate whether extending the TNSC cap to earlier cycles is warranted. The remaining EPSQ-protected volume is the cost of that gradualism, and my proposed Phase 2, an Intraday 1 cap contingent on demonstrated need and reliability data developed during Phase 1, is the mechanism for capturing additional EPSQ leakage if experience supports it. A single-step move from Intraday 3 to Evening Cycle application, as proposed by Mr. Borkovich, by contrast, would foreclose that stepwise opportunity for evaluation and course correction.

Q IS THE EXISTING EVENING CYCLE BUMPING FRAMEWORK ADEQUATE TO PROTECT FIRM PRIMARY RIGHTS AT THE DAY-AHEAD STAGE?

A Yes, in significant part. Under existing Rule 30, Section D.3, Firm Primary nominations may bump scheduled Firm Alternate quantities through the Evening Cycle, and Firm Alternate Within-the-Zone may bump Firm Alternate Outside-the-Zone through the Evening Cycle. These bumping rules already provide a mechanism for higher-priority Evening nominations to displace lower-priority Evening nominations within the existing framework. The remaining gap, Firm Primary nominations submitted intraday, is exactly what the Phase 1 Intraday 2 cap I propose is designed to protect.

Q PLEASE DESCRIBE THE PHASE 2 ELEMENT OF YOUR ALTERNATIVE.

A I propose the following: Twelve months after Phase 1 implementation, SoCalGas would be required to file a compliance report with the Commission, served on all parties to this proceeding, addressing at minimum: (i) the number of Gas Days on which the Intraday 2 TNSC cap was binding; (ii) the magnitude of nomination cuts effected by the cap, broken out by confirmation tier; (iii) the frequency of OFO declarations before and after Phase 1 implementation; (iv) any reliability incidents associated with the Phase 1 implementation; (v) observed shipper behavior changes, including any reduction in Intraday 2 nomination inflation; and (vi) the historical accuracy of TNSC forecasts at the Intraday 2 confirmation deadline. Conditional on a satisfactory operational record, SoCalGas could file a Tier 2 advice letter to extend the TNSC cap to the Intraday 1 cycle. Parties would have an opportunity to respond to and protest such an advice letter on the basis of the compliance record.

Q WHY HAVE YOU PROPOSED A PHASED RATHER THAN IMMEDIATE ONE-STEP IMPLEMENTATION?

A Because Mr. Borkovich's proposal is, by his own description, a meaningful change to scheduling protocol that affects every BTS shipper.[97] The compliance

[97] SoCalGas Ch. 10 (Borkovich) at PDB-12:1-PDB-13:1 (describing the proposed change to SoCalGas's BTS nomination confirmation methodology, under which SoCalGas would confirm BTS nominations up to Total Net System Capacity, as a change designed to affect the scheduling outcomes of every BTS shipper by altering how nominations of differing confirmation orders are confirmed across cycles, and stating that "Approval of this proposal would allow SoCalGas firm BTS customers a better opportunity to schedule gas under their

record and baseline information from a Phase 1 extension of the TNSC cap from Intraday 3 to Intraday 2 will allow the Commission and parties to evaluate, on the basis of actual operational data rather than projections, whether further extension of the cap is warranted. This would be consistent with a phased implementation for tariff changes that affect operational reliability and that have not been subject to extensive operational testing.

Q WHAT TRANSPARENCY REQUIREMENTS DO YOU PROPOSE?

A I propose that Rule 30, Section D.3 be amended to require SoCalGas to: (i) post on its Envoy electronic bulletin board, in advance of implementation, the methodology and key inputs used to calculate TNSC for confirmation purposes, including identification of the data sources and any operational adjustments applied; (ii) post the binding TNSC value used at each cycle deadline on the SoCalGas Envoy system; (iii) include in its compliance report any Gas Day on which the as-flowed system capacity materially differed (long or short) from the TNSC value used to confirm nominations during that Gas Day, with materiality defined as a difference of greater than five percent; and (iv) maintain a reasonable historical archive of TNSC values and any corrections thereto, and supporting calculations, available for review by Commission staff and parties on reasonable notice.

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higher confirmation order contracts, not just in earlier scheduling cycles, but in later scheduling cycles too and for SoCalGas BTS to better conform with accepted industry practices"); see also *Id*. at PDB-11:7-PDB-12:5 (proposed reduction in firm BTS contractual capacity from 3,775 MMcfd to 110% of the forecast minimum backbone system design standard, applicable to all BTS shippers).

Q WHY ARE THESE TRANSPARENCY REQUIREMENTS IMPORTANT?

A Because the TNSC value drives the confirmation cuts. Under the existing Rule 30 protocol, the cap is applied only once per Gas Day, in Intraday 3, on a non-OFO day; the operational consequences of an inaccurate TNSC determination are correspondingly limited under the current scheme.[98] Under my alternative, the TNSC determination becomes a binding scheduling constraint at Intraday 2 every Gas Day on which nominations exceed TNSC. Shippers whose nominations are cut have a legitimate interest in being able to verify that the TNSC value used was reasonable. SoCalGas is the only party with operational visibility into the inputs to that calculation, so the burden of demonstrating reasonableness should rest with SoCalGas.

Q PLEASE EXPLAIN THE TRANSITIONAL PROTECTION ELEMENT OF YOUR ALTERNATIVE

A Some shippers hold firm capacity on upstream interstate pipelines (such as El Paso, Transwestern, or Kern River) and rely on Firm Alternate or Interruptible BTS on the SoCalGas system at their corresponding receipt points. These Firm Alternate and Interruptible arrangements may exist because Firm Primary BTS at that receipt point was not available in the most recent BTS open season,

[98] SoCalGas Tariff Rule No. 30 § D (Nominations and Confirmations) (under the existing tariff, the Total Net System Capacity (TNSC) cap on confirmations is applied only once per Gas Day, in the Intraday 3 cycle on a non-OFO day, such that the operational consequences of an inaccurate TNSC determination are limited to that single late-day cycle on non-OFO days under the current scheme).

because the shipper's flow patterns vary across receipt points, or for other commercial reasons. These shippers made commercial decisions under the existing Rule 30 framework, and the next BTS open season will not occur until contracts become effective October 1, 2026. Affected shippers cannot quickly convert from Firm Alternate to Firm Primary BTS in response to a tariff change. I propose that the Phase 1 implementation include a one-cycle transitional period running through the conclusion of the 2029 BTS open season, during which Firm Alternate Within-the-Zone nominations approximately matching an existing upstream firm capacity contract for the same Gas Day may be designated as protected at confirmation. SoCalGas would publish a streamlined registration process for eligible transitional shippers in Envoy. After the transitional period, the standard Rule 30 Section D.3 confirmation order would apply without exception.

Q PLEASE DESCRIBE WHY THE TRANSITIONAL PROTECTION IN YOUR ALTERNATIVE PROPOSAL IS REASONABLE.

A Mr. Borkovich's proposal could harm shippers who hold upstream firm capacity but rely on Firm Alternate or Interruptible BTS for ultimate delivery. Shippers can't be presumed to be able to immediately acquire Firm Primary BTS rights at their preferred receipt point(s). BTS open seasons occur only every three years.[99] The transitional protection allows affected shippers a single 3-year

[99] SoCalGas Ch. 10 (Borkovich) at PDB-3, fn.3 ("The BTS open season is currently a triennial process."); see also *Id*. at PDB-7 (confirming that "[t]he BTS open seasons will remain as three-year terms," with the next open season covering capacity contracts effective October 1, 2026 through November 1, 2029); D.24-07-009 at Attachment A (adopting the all-party 2024

open-season cycle to either acquire Firm Primary BTS at their preferred receipt point or restructure their upstream capacity holdings, before the new Phase 1 confirmation protocol fully applies. This is consistent with sound regulatory practice for transitions that affect commercial arrangements made in reliance on existing tariff terms.

VIII.F. BTS Open-Season Capacity – 110% of Minimum Design Standard

Q WHAT IS SOCALGAS'S PROPOSAL REGARDING THE AMOUNT OF BTS CAPACITY AVAILABLE FOR CONTRACTING IN THE BTS OPEN SEASON?

A SoCalGas proposes to reduce the BTS capacity available for contracting in open seasons by approximately one-third through its "110% of Minimum Design Standard" proposal. Under this approach, the capacity offered in the open season would be set at 110% of minimum design standards, rather than peak design capacity.[100]

Q WHAT IS SOCALGAS'S STATED RATIONALE FOR ITS PROPOSAL?

A SoCalGas's stated rationale is reliability headroom.

Q WHAT IS YOUR CONCERN WITH THE COMPANY'S PROPOSAL?

CAP Settlement, which confirms three-year BTS open season terms aligned with the CAP cycle); SoCalGas Tariff Schedule G-BTS (Backbone Transportation Service) (BTS firm capacity rights are awarded through periodic open seasons rather than continuously available, such that a shipper holding only Firm Alternate or Interruptible BTS cannot be presumed to be able to acquire Firm Primary BTS rights at a preferred receipt point on demand).

[100] SoCalGas Ch. 10 (Borkovich) PDB-11:7-15 and PDB-11, Table PDB-4) (proposing to reduce firm BTS contractual limit from 3,775 MMcfd to 110% of forecast minimum backbone design standard).

A While recognizing BTS shippers' delivery reliability and flow assurance concerns, SoCalGas has not provided adequate justification for its proposed one-third reduction in available BTS contracting capacity. Reducing the capacity offered in the open season does not incentivize SoCalGas to efficiently and expeditiously perform its maintenance on the Backbone Transmission system. Customers should receive service for 100% of the BTS capacity that they pay for in rates.[101] Offering less capacity in the open season while continuing to collect full Backbone Transmission cost-of-service revenues leaves customers paying for capacity they cannot contract for with no corresponding consequence to the Company.

Q DOES YOUR RULE 30 PHASE 1 ALTERNATIVE HELP ADDRESS DELIVERY RELIABILITY CONCERNS RAISED BY SOCALGAS?

A Yes. If my alternative Rule 30 proposal is implemented, delivery reliability and flow assurance concerns related to EPSQ leakages on over-nominations days identified by the Company can be addressed at the scheduling layer with an Intraday 2 TNSC cap and transparency, rather than by shrinking contracted capacity offered to the market. The TNSC scheduling cap would help obviate 'SoCalGas's proposal to permanently reduce one-third of BTS capacity.

[101] D.20-02-045, *Decision Addressing San Diego Gas & Electric Company and Southern California Gas Company Triennial Cost Allocation Proceeding Application, A.18-07-024*, Feb. 27, 2020 at 105, Ordering Paragraph 14 (directing SoCalGas and SDG&E to submit a credit mechanism that "compensates Backbone Transmission Service customers for services they pay for but do not receive").

IX. CONCLUSION

Q WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes.

Q INSOFAR AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU BELIEVE IT TO BE CORRECT?

A Yes, I do.

Q INSOFAR AS THIS MATERIAL IS IN THE NATURE OF PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?

A Yes, it does.

Q DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THIS PROCEEDING?

A Yes.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

APPENDIX A

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in

support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Guam Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kansas Corporation Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Maryland Public Service Commission, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Carolina Utilities Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of

Utah, the Virginia State Corporation Commission, the Washington Utilities and Transportation Commission, the Public Service Commission of Wisconsin, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 1,000 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

APPENDIX B

Question 2-4.

Please reference page MMD-6 of Chapter 1, the Prepared Direct Testimony of M. Michelle Dandridge, Storage Overview & Proposals, footnote 7, providing citations to the SoCalGas 2024 California Gas Report prepared by the California Gas and Electric Utilities ("CGR"). Please also reference Table 33 "Core 1-in-35 Year Extreme Peak Day Demand, MMcf/d" on page 157 of the CGR.

TABLE 33 – CORE 1--IN--35 YEAR EXTREME PEAK DAY DEMAND, MMcf/d

Year	SoCalGas Core Demand	SDG&E Core Demand	Other Core Demand	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand*
2024	2,625	302	155	3,082	*-19*
2025	2,600	300	157	3,056	*-39*
2026	2,571	295	158	3,025	*-54*
2027	2,550	293	160	3,003	*-74*
2028	2,528	291	162	2,981	*-95*
2029	2,513	290	163	2,966	*-105*
2030	2,499	289	165	2,952	*-112*

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation. Forecast embodies the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 3 programmatic.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach, City of Vernon, and Ecogas.
(4) The criteria for extreme peak day design are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.6 degrees Fahrenheit for SoCalGas' service area and 43.5 degrees Fahrenheit for SDG&E's service area.
(5) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

The far-right column of Table 33 shows the estimated impacts on core peak day demand of Applicant's fuel substitution assumptions ("AAFS").

a. Please describe any changes Applicant's would make to the proposed allocations of storage inventory, injection and withdrawal rights if the core peak day demand AAFS reductions included in Table 33 are not achieved.

Response a.

If the core peak day demand AAFS reductions are not achieved, the average Peak Day 1-35 demand for 2027-2029 period would be 3074 MMcfd (adding the average of the Estimated AAFS Impact on Core Peak Day Demand for years 2027 –2029 of 91 MMcfd to the 2983 MMcfd). This would result in changes to Table MMD-2 column D to 3074 and column F to 1935 to 2125

b. Please confirm whether the SoCalGas Core Demand column values incorporate all Heating Degree Day (HDD) adjustments proposed by Mr. Eduardo Martinez in his testimony Chapters 2, 3 and 5. See Note (1) in Table 33 above.

Response b.
Not applicable. The SoCalGas Core Demand used for Chapter 1 was from the 2024 California Gas Report (CGR).

Response c.
See Response a. SoCalGas and SDGE confirm that the Btu conversion factors listed on pages 134 and 141 of the Chapter 5 Workpapers are the factors used to prepare MDth/day to MMcfd and vice versa conversions.

Question 2-6.

Please reference page MMD-8 of the Prepared Direct Testimony of M. Michelle Dandridge, Storage Overview & Proposals, Lines 10-16, where Ms. Dandridge states:

> *In order to support enhanced year-round balancing functions, Applicants are proposing to allocate 12 Bcf of storage inventory, 184 MMcfd of summer injection capacity, 374 MMcfd of winter injection capacity, 1212 MMcfd of summer withdrawal capacity and 256 MMcfd of winter withdrawal capacity to the balancing function. The 12 Bcf of storage inventory allocation will be used to provide 10% monthly balancing when customers create positive imbalances by delivering more gas into the system than what they use, up to 12 Bcf on a combined basis.*

a. Please provide a detailed narrative of the "enhanced" year-round balancing functions being proposed by SoCalGas in addition to the positive 10% monthly balancing tolerance, which is already currently provided to all customers under SoCalGas's Schedule G-IMB (at p.1).

Response a.

Applicants propose to continue with the enhanced year-round balancing functions that are currently provided to all customers. The 12 Bcf of storage inventory will continue to provide 10% monthly balancing and the injection and withdrawal capacities will continue to provide daily balancing when customers bring in more or less supplies against their demand.

b. Please provide an electronic copy of all studies, analyses, reports, presentations and other similar documents prepared by or for the Applicants relating to the need for enhanced year-round balancing functions beyond those currently established for the 2024-2026 CAP period.

Response b.

Not applicable.

Question 2-7.

Please reference page MMD-3 of the Prepared Direct Testimony of M. Michelle Dandridge, Storage Overview & Proposals, specifically Table MMD-1 shown below:

Table MMD-1: Proposed Capacities and Allocations for CAP Period 2027-2029

	Inventory Bcf	Injection Summer MMcfd	Injection Winter MMcfd	Withdrawal Summer MMcfd	Withdrawal Winter MMcfd
Core	76	250	135	540	1500
Balancing	12	184	374	1212	256
UBS	28	15	15	15	15
Wholesale	2.8	9	5	20	55
Total	**118.8**	**458**	**529**	**1787**	**1826**
	Inventory	Injection Summer	Injection Winter	Withdrawal Summer	Withdrawal Winter
Core	64.0%	54.6%	25.5%	30.2%	82.1%
Balancing	10.1%	40.2%	70.7%	67.8%	14.0%
UBS	23.6%	3.3%	2.8%	0.8%	0.8%
Wholesale	2.4%	2.0%	0.9%	1.1%	3.0%
	100%	**100%**	**100%**	**100%**	**100%**

a. For each storage field on the PG&E system, please provide that field's respective contribution in Bcf to the Total Inventory capacity of 118.8 Bcf above.

Response a.

SoCalGas objects on the ground the term "PG&E system" misstates testimony and is vague and ambiguous in this context. Given the context of the question, SoCalGas assumes that the question refers to the SoCalGas system and will answer the question accordingly. Subject to and without waiving the foregoing, SoCalGas provides the following response: See Chapter 1, page MMD 3, lines 2-12.

Question 5-1.

Please reference pages PG-4, PG-5 and Attachment A, in Chapter 5, the Prepared Direct Testimony of Payal Gadani, Regulatory Accounts – SoCalGas.

a. Please explain why the Firm Access and Storage Rights Memorandum Account (FASRMA) is not listed on Attachment A.

Response a.

Attachment A is a list of regulatory accounts which are authorized for amortization in rates as of July 2025, per AL 6384-G-A, AL 6430-G-A and AL 6493-G. Firm Access and Storage Rights Memorandum Account (FASRMA) is not on the list since there is no authorization of recovery of its under collected balance.

b. Please provide a detailed accounting for the difference in $4.0 FASRMA undercollected account balance and the $3.9 million ($3.1 million capital revenue requirement plus $0.8 million interest) as stated on page PG-5, Lines 1-4.

Response b.

Pursuant to D.11-03-029, FASRMA records system modification costs (O&M & Capital revenue requirement) providing interruptible and firm Off-System Delivery (OSD) services and any related OSD Revenues to recover these costs. The $0.1 million difference between the $4.0 million FARSMA under collected account balance and the $3.9 Million ($3.1 million capital requirement plus $0.8 million interest) as stated on page PG-5, Lines 1-4, is made up of $0.2 million of O&M Costs offset by ($30) thousand of OSD Revenues.

Question 6-4.

Please reference page FS-MSP Appendix A-1 of Chapter 8, Prepared Direct Testimony of Frank Seres and Marjorie Schmidt-Pines, Cost Allocation and Embedded Costs.

a. Please provide a breakdown of each Transmission function line items (FERC Accounts 365-372) between Backbone Transmission and Local Transmission subcategories. If breakdown is not feasible for some FERC Accounts, please provide a detailed explanation describing the infeasibility.

Response a.

Please see excel SCG Embedded Cost Model_Public_Draft, tab "LT & BBT" columns R through AD. The file was provided in response to IS-01. See file, Ch 8 Seres_Schmidt-Pines_SCG Embedded Cost Model_2027 CAP_NL.

Question 6-5.

Please reference Table FS-MSP-8 on page FS-MSP-12 of Chapter 8, Prepared Direct Testimony of Frank Seres and Marjorie Schmidt-Pines, Cost Allocation and Embedded Costs. Please also reference Table 26 in Chapter 8 Workpapers to the Prepared Direct Testimony of Frank Seres and Marjorie Schmidt-Pines, Embedded Costs.

a. Please confirm that the functional allocations of embedded costs in these tables include Asset Retirement Obligation (ARO).

Response a.
AROs are included in capital costs.

Question 7-1.

Please reference page PDB-10 of Chapter 10, Prepared Direct Testimony of Paul D. Borkovich, Off-System Delivery and Backbone Transportation Service Proposals, at Lines 10-14 where Mr. Borkovich states:

> *At the time of issuance of D.11-03-2 029, SoCalGas/SDG&E expected that the expansion of OSD service to other SoCalGas and SDG&E receipt points would 1) increase utilization of the backbone system, increase BTS revenue, and lower transportation rates for on-system customers; 2) increase gas-on-gas competition; and 3) increase storage utilization and unbundled storage revenues.*

a. Please confirm whether SoCalGas's Gas Acquisition Department would have been eligible to market gas supply to OSD expansion customers (if any).

Response a.

Yes.

Question 8-1.

Please reference pages PDB-12 & PDB-13 of Chapter 10, Prepared Direct Testimony of Paul D. Borkovich, Off-System Delivery and Backbone Transportation Service Proposals, where Mr. Borkovich states:

> *SoCalGas proposes confirming BTS nominations up to the Total Net System Capacity during the Evening, Intraday 1, Intraday 2, and Intraday 3 cycles regardless of a Gas Day's OFO status when total nominations exceed the Total Net System Capacity. SoCalGas and SDG&E currently confirm BTS nominations up to the Total Net System Capacity during the Intraday 1, Intraday 2, and Intraday 3 cycles for Gas Days in which an OFO was declared, and only during the Intraday 3 cycle on Gas Days in which an OFO was not declared.*
>
> *Delaying the confirmation of BTS nominations up to the Total Net System Capacity in later scheduling cycles allows nominations of a lower confirmation order to be scheduled in earlier scheduling cycles, thereby displacing nominations of a higher confirmation order in later cycles, due to the elapsed pro-rata rules. Approval of this proposal would allow SoCalGas firm BTS customers a better opportunity to schedule gas under their higher confirmation order contracts, not just in earlier scheduling cycles, but in later scheduling cycles too and for SoCalGas BTS to better conform with accepted industry practices.*

a. Please confirm whether SoCalGas is proposing any changes to the confirmation order and bumping rules set forth in Section D.3 of SoCalGas's Rule 30.

Response a.

No. SoCalGas is not proposing any changes to the confirmation order or the bumping rules set forth in Section D.3 of SoCalGas's Rule 30.

Schedule BCC-1

SoCalGas
Throughput and Peak Measures

Mth Throughput

Line		Core (1)	Noncore (2)	Total (3)	Retail Noncore (4)
1	Average Year Throughput (AYTP)	3,139,169	5,176,497	8,315,665	3,934,845
2	Cold Year Throughput (CYTP)	3,341,781	5,205,696	8,547,477	3,937,973
3	Cold Year Peak Month (CYPM)	450,909	484,314	935,223	338,020

Percent

		Core (1)	Noncore (2)	Total (3)	Retail Noncore (4)
4	Average Year Throughput (AYTP)	37.8%	62.2%	100.0%	47.3%
5	Cold Year Throughput (CYTP)	39.1%	60.9%	100.0%	46.1%
6	Cold Year Peak Month (CYPM)	48.2%	51.8%	100.0%	36.1%

Average Daily Throughput
Mth/Day

		Core (1)	Noncore (2)	Total (3)	Retail Noncore (4)
7	Average Year Throughput (AYTP)	8,600	14,182	22,783	10,780
8	Cold Year Throughput (CYTP)	9,156	14,262	23,418	10,789
9	Cold Year Peak Month (CYPM)	15,030	16,144	31,174	11,267

Peak Day Requirements

		Core (1)	Noncore (2)	Total (3)	Retail Noncore (4)
10	Mth	27,221	21,291	48,512	14,028
11	Percent	56.1%	43.9%	100.0%	28.9%

Ratio of Peak Day to Average Day

		Core (1)	Noncore (2)	Total (3)	Retail Noncore (4)
12	Average Year Throughput (AYTP)	3.17	1.50	2.13	1.30
13	Cold Year Throughput (CYTP)	2.97	1.49	2.07	1.30
14	Cold Year Peak Month (CYPM)	1.81	1.32	1.56	1.24
15	Peak Day	1.00	1.00	1.00	1.00
16	Load Factor	33.6%	67.0%	48.3%	76.9%

Source:
Sup_Ch 3 Martinez SCG Summary WP_2027 CAP

SoCalGas
Summary of Noncore Cost Allocation ($'000)

SoCalGas Proposed

Line		Core (1)	Noncore [1] (2)	Total (3)	Allocator (4)
1	**High Pressure Distribution**	140,076	30,830	170,906	Cold Year Peak Month
2	**% of Total**	82.0%	18.0%	100.0%	
3	**Local Transmission**	149,457	160,530	309,987	Cold Year Peak Month
4	**% of Total**	48.2%	51.8%	100.0%	
5	**Storage Load Balancing**	58,198	52,273	110,471	AYTP
6	**% of Total**	52.7%	47.3%	100.0%	
7	**Total Cost**	347,731	243,633	591,364	

Indicated Shippers Proposed

Line		Core (1)	Noncore [1] (2)	Total (3)	Allocator (4)
7	**High Pressure Distribution**	150,020	20,886	170,906	Peak Day
8	**% of Total**	87.8%	12.2%	100.0%	
9	**Local Transmission**	173,941	136,046	309,987	Peak Day
10	**% of Total**	56.1%	43.9%	100.0%	
11	**Storage Load Balancing**	78,528	31,943	110,471	Peak Day
12	**% of Total**	71.1%	28.9%	100.0%	
13	**Total Cost**	402,489	188,875	591,364	

Difference (Indicated Shippers - Company)

Line		Core (1)	Noncore [1] (2)	Total (3)
7	**High Pressure Distribution**	9,944	(9,944)	-
9	**Local Transmission**	24,484	(24,484)	-
11	**Storage Load Balancing**	20,330	(20,330)	-
13	**Total Cost**	54,758	(54,758)	-

[1] Allocation is calculated for Retail Noncore

Sources:
Sup_Ch 3 Martinez SCG Summary WP_2027 CAP
Table 26, Chapter 8: Embedded Costs - Cost Allocation Workpaper
Ch 8 Seres_Schmidt-Pines_SCG Embedded Cost Model _ 2027 CAP_NL