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Witness(es):	Michelle Dandridge
	Paul D. Borkovich
Chapter:	14

JOINT PREPARED REBUTTAL TESTIMONY OF

MICHELLE DANDRIDGE AND PAUL D. BORKOVICH

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

AND SAN DIEGO GAS & ELECTRIC COMPANY

(STORAGE OVERVIEW AND PROPOSALS)

May 2019

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CHAPTER 14

JOINT PREPARED REBUTTAL TESTIMONY OF MICHELLE DANDRIDGE AND PAUL D. BORKOVICH (STORAGE OVERVIEW AND PROPOSALS)

I. INTRODUCTION

Applicants address various arguments, positions, and proposals contained in the direct testimonies of California Public Advocates (Cal PA); The Utility Reform Network (TURN); Southern California Generation Coalition (SCGC); the Indicated Shippers; City of Long Beach, Energy Resources Department (Long Beach); Small Business Utility Advocates (SBUA); and Southern California Edison Company (SCE), which were served on April 12, 2019.[1] These intervenors addressed Applicants' proposals contained in Chapter 1 (Dandridge) related to storage issues.[2]

The Triennial Cost Allocation Proceeding (TCAP) is a proceeding to determine the allocation of costs associated with operating Applicants' gas system (and related costs) among the various customer classes. To do so, Applicants made certain operating assumptions on storage, employed known methodologies to conduct various studies, and presented the results. Intervenors have reviewed and scrutinized Applicants' storage proposals in discovery and have

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[1] Given the volume of the various arguments, positions, and proposals raised by intervenors, Applicants have prioritized which issues to address in rebuttal testimony. Silence on any issue should not be construed as agreement with, or non-opposition to, that issue, as Applicants reserve the right to address additional issues not specifically mentioned in this rebuttal testimony at a later opportunity, such as evidentiary hearings and briefs.

[2] One issue that was not contested in intervenor testimony was Applicants' request that the Commission maintain the current provisions contained in the Noncore Fixed Cost Account tariff preliminary statement, which provides 100% balancing account treatment for noncore throughput.

presented their analyses and recommendations in testimony. While the issues intervenors have addressed in testimony range in technical detail, each intervenor is ultimately advancing the interests of their respective constituents by advocating for a smaller slice of the cost pie. With that motive, each intervenor attempts to establish that Applicants have presented a cost allocation proposal that does not square with certain data, operational realities, or (in their view) superior methodologies.

For example, Cal PA and TURN overall present criticisms of Applicants' proposals, and make corresponding recommendations, which, if adopted, would result in more costs being allocated to noncore customers than what Applicants have proposed. Conversely, SCGC, Indicated Shippers, SBUA, and SCE present criticisms of Applicants' proposals, and make corresponding recommendations, which, if adopted, would result in more costs being allocated to core customers than what Applicants have proposed. This simplified view is not meant to trivialize any intervenor's treatment of the issues in this proceeding. Instead, understanding the ultimate "end-game" is useful when weighing all of the intervenors' arguments, positions, and proposals. The Commission will then render findings on whether Applicants' cost allocation proposals are reasonable and strike a balance of interests, or whether modifications are warranted based on the evidence presented by intervenors.

Chapter 1 presented Applicants' storage proposals, including proposed storage inventory, injection, and withdrawal capacities to be effective in the TCAP period. Those storage proposals have two primary characteristics: (a) operational and (b) cost allocation. These characteristics are interrelated, as the cost allocation being proposed is intended to reflect the manner in which Applicants plan to operate its storage assets. However, because the TCAP is a type of "forecast" application, certain operational assumptions may or may not transpire exactly as Applicants have presented in testimony. Thus, the Commission may not be in a position to make dispositive determinations on the operational side; and, Applicants provide testimony on how it intends on operating its storage assets in the event their assumptions do not materialize. The SoCalGas System Operator will have to manage the gas delivery system as safely and reliably as it can under any and all situations. In contrast to the operational, the cost allocation must be determined by the Commission in this proceeding, irrespective of what operational realities may exist on January 1, 2020, and for the duration of the TCAP period (2020 through 2022). Effective January 1, 2020, Applicants must implement new rates based on the cost allocation adopted in this TCAP.

Where applicable, this rebuttal testimony addresses the issues from an *operational* standpoint and a *cost allocation* standpoint. For instance, several intervenors raise the fact that the Aliso Canyon storage facility is currently restricted operationally by the Commission, but that Applicants' storage proposals assume those restrictions will be lifted in the TCAP period. What impact would those restrictions have on Applicants' inventory, withdrawal, injection proposals, and how do Applicants plan on allocating and using storage assets if their assumptions are not realized? Should Applicants be procuring gas for its Load Balancing or new Reliability functions if there is no actual storage capacity to store that gas? From a cost allocation standpoint, which is the primary purpose of this TCAP, what makes the most sense in terms of how to allocate storage costs among customer classes given some of its storage fields may continue to have limited capacities due to the Commission's Aliso Canyon withdrawal protocol?

II. THE ALISO CANYON ASSUMPTION

Applicants' comprehensive storage proposals are based on the assumption that the current restrictions imposed by the Commission on injection and withdrawal utilization of the

Aliso Canyon storage facility will be lifted, such that 68.6 billion cubic feet (Bcf) of storage capacity will be available for operational use in the TCAP period.[3] That assumption is not unreasonable from an operational standpoint, given the storage facility has been approved by the California Division of Oil, Gas, and Geothermal Resources (DOGGR) to operate at a maximum field pressure of 2,926 pounds per square inch absolute, which corresponds to a total working inventory of approximately 68.6 Bcf. This figure is an important component of the total storage capacity figure of 119.5 Bcf, upon which Applicants base their comprehensive storage proposals.[4]

A. Operational Perspective

While it is true that the SoCalGas System Operator can only manage the natural gas storage and delivery system in accordance with operational realities, the Commission can nonetheless authorize storage allocation capacities for the upcoming TCAP period that are reasonable, even though actual operating capacities may differ from authorized. Consider that Applicants are currently operating under the prior TCAP's authorized storage allocations (*i.e.*, 138.1 Bcf of total storage capacity) even though Applicants do not in actuality have that capacity.

While intervenors like Cal PA and SCGC indicate that Applicants should have provided multiple scenarios based on different Aliso Canyon assumptions,[5] that exercise would have involved speculation about what the Commission might incrementally do with respect to Aliso

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[3] See Chapter 1 (Dandridge), p. 3-4.

[4] See Id. at 3.

[5] See Ex. PubAdv-02.

Canyon, and would have resulted in Applicants having to develop and defend multiple proposals, all of them suffering from the same shortcoming. Applicants note that the Commission authorized inventory at Aliso has changed five times since June 2016, with the increase to 34 Bcf occurring less than four weeks before the submittal of this application.[6] Instead, Applicants developed one comprehensive proposal which represents the operational capability of the four storage facilities, but for the restrictions placed upon it by the Commission. If the Commission lifts its current Withdrawal Protocol at Aliso Canyon, and allows operation to the DOGGR-authorized maximum reservoir pressure, the Commission would have adopted (in this TCAP) authorized storage capacities that would be in line with an operational total storage capacity. If the Commission does not lift the Withdrawal Protocol during the TCAP period, or takes incremental steps to allow for less restrictive use of Aliso Canyon, those authorized storage capacities (as Applicants have proposed) would still be useful and appropriate because they would be adopted based on what the four storage facilities are operationally capable of providing during the TCAP period, whether or not those capabilities are fully realized.

Thus, if the Commission does not adopt our proposal from an operational standpoint, Applicants will operate at reduced storage, injection, and withdrawal capacities as it does today, under its operational tariffs. The load balancing function and core requirements would be allocated in accordance with the available capacities, for the purpose of maintaining system reliability. As such, beginning in 2020, Applicants will not hold capacity for commercial purposes, as it did when the unbundled storage program was viable.

B. Cost Allocation Perspective

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[6] See the Commission's "715 Reports," dated 6/28/2016, 1/17/2017, 7/19/2017, 12/11/2017, and 7/6/2018, which can be accessed at:. http://www.cpuc.ca.gov/General.aspx?id=6442457392

From a cost allocation perspective, the Commission can still adopt Applicants' proposed storage allocations because those allocations are based on what the storage assets are operationally capable of during the TCAP period. In the end, the Commission must adopt an authorized cost allocation in this proceeding such that Applicants can implement updated rates effective January 1, 2020 (or whenever the Commission makes new rates effective). TURN recognizes the big picture here, when it states:

> The SEUs propose to base storage rates on the current physical capacity of their fields, including Aliso Canyon. While it is not entirely clear if or when Aliso Canyon will be allowed to resume full operations, I believe that the SEUs' proposal makes the most sense for purposes of this proceeding. SoCalGas' revenue requirement cannot be changed in this proceeding, as the TCAP takes authorized revenues as a given and considers only cost *allocation*. Thus, if storage costs were spread over smaller capacity values, the unit rates would be higher and customers would pay more, even if the current Aliso restrictions were lifted at some point during the TCAP period. If the restrictions are not lifted, less storage capacity will be available, but there is no mechanism within the scope of this TCAP to adjust the revenue requirement to reflect that. …[7] Rather than charging storage customers

[7] See Prepared Direct Testimony of Michel Peter Florio (April 12, 2019) (TURN/Florio). The sentence that was omitted appears on page 13 and reads: "Any cost disallowances related to the situation at Aliso Canyon will be decided in the Aliso Investigation docket, I.17-02-002." This statement is incorrect, as the scoping memo and ruling from that docket clearly establishes that the cost issue is not in scope in that proceeding.

higher rates now in anticipation of Aliso's not being fully available, I think it makes more sense to set rates assuming full availability . . . .[8]

Cal PA also understands this overarching concept, as Cal PA ultimately does not oppose Applicants' total storage capacity proposal for the 2020 – 2022 TCAP period; its inventory, injection and withdrawal capacity proposals; or elimination of the unbundled storage program,[9] even though Cal PA did question the use of this assumption for Aliso Canyon for the 2020 TCAP base year.[10]

However, in the event the Commission adopts storage inventory capacities that are based on current operational conditions, the corresponding cost allocation would follow the operational treatment described in the section above, *i.e.*, load balancing function and core requirements would be allocated in accordance with the available capacities, for the purpose of maintaining system reliability; unbundled storage program would be eliminated.

III. REBUTTAL TO INTERVENORS ON STORAGE CAPACITY ISSUES

A. SCGC

SCGC proposes an allocation based on Aliso Canyon with an authorized working capacity of 34 Bcf, and with withdrawal limitations per the Aliso Canyon Withdrawal Protocol.[11] SCGC's proposal fails to account for the fact that current restrictions on Aliso Canyon are not

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[8] See Id. at 13. Applicants do not agree with TURN's concluding assertion regarding refunds; notwithstanding, that is not a determination that is within scope of this proceeding and should therefore not be considered.

[9] See Ex. PubAdv-02 (Kjensli), p. 1-2.

[10] See Id. at 7.

[11] See Direct Testimony of Catherine E. Yap (April 12, 2019) (SCGC Direct), p. 45.

just on inventory but also on withdrawal, which is only to be utilized for reliability as a last resort. This leads SCGC to incorrect conclusions.

First, high inventory withdrawal capacity available for the core and load balancing in SCGC's proposal is 2,617 million cubic feet per day (MMcfd), when in fact only 1,317 MMcfd would be available because Aliso Canyon withdrawal is not available for use by customers. As noted previously, Aliso Canyon withdrawal capacity is only available to the SoCalGas System Operator for reliability as an asset of last resort.

Second, the available withdrawal capacities in SCGC's proposal reflect the maximum capacities when storage is full, not taking into account drawdown of storage inventories and correspondingly lower withdrawal capabilities as the winter season progresses.

Third, the available injection capacities in SCGC's proposal is the maximum available during a period where Aliso Canyon was available for injection, which is not always the case given the restrictions placed on the operations of that storage field (*i.e.*, when Aliso Canyon is full, available system injection is reduced). Additionally, SCGC's proposal does not address how allocations would be made as inventory restrictions at Aliso Canyon change.

B. Long Beach

Long Beach recommends approval of Applicants' allocation of storage rights to Long Beach in the amount summarized in Table 1 of Long Beach's testimony, "regardless of any future decisions regarding the use of the Aliso Canyon storage field."[12] This recommendation cannot be accepted because Applicants' proposal, including those capacities allocated to the wholesale core customers (including Long Beach), is made on the assumption of full unrestricted

[12] See Testimony on Behalf of the City of Long Beach, Energy Resources Department (April 12, 2019) (Long Beach Direct), p. 1-1, lines 21-25.

use of Aliso Canyon. If Aliso Canyon is restricted from full use, then regardless of the storage allocations that are authorized by the Commission in this proceeding, the operational allocations will have to be managed to those operational circumstances. Subsequently, allocations to the core wholesale customers will be assigned on a percentage basis similar to what has been proposed in Applicants' testimony.

Long Beach proposes an increase in the allocated winter withdrawal for the core, with a corresponding decrease in winter withdrawal for load balancing.[13] Applicants do not agree with this proposal. In the 2020 TCAP proposal, the core has been allocated sufficient winter withdrawal, which along with balancing withdrawal and additional flowing supplies will help it meet its Peak Day and Cold Year demand. Further, reductions in winter withdrawal for load balancing could result in the declaration of additional low operational flow orders (OFOs), which will impact all shippers on Applicants' transmission system. Long Beach's proposal should not be adopted.

Likewise, Long Beach proposes an increase in allocated summer withdrawal for the core with a corresponding decrease in withdrawal for load balancing unless Applicants can show that this capacity is not needed to meet core demand summer.[14] With core average summer demand at approximately 800 MMcfd, this can easily be achieved with flowing supplies using contracted interstate transportation, Backbone Transportation Service rights, and the proposed core summer withdrawal of 400 MMcfd. Applicants believe withdrawal capacity is better allocated to load balancing for all customers to balance deliveries to usage, and to assist in lowering the number of

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[13] See Id. at p. 1-2, lines 17-20.

[14] See Id. at p. 1-2, lines 21-25.

low OFOs in the summer. No other parties contested the allocation of summer withdrawal capacity.

C. TURN

TURN proposes a decrease in the allocated summer injection for the core, with a corresponding increase in summer injection for load balancing.[15] Applicants' proposed allocation of summer injection for the core is more reasonable and appropriate than what TURN is proposing, because it will provide more flexibility in filling storage capacities in the summer injection months to prepare for the winter. Cal PA appears to agree when it states, "[t] he proposed increase of the core's summer injection to 445 MMcfd is more in line with core's need to prepare for the winter season when core demand is at its highest."[16]

IV. ELIMINATION OF UNBUNDLED STORAGE PROGRAM

Applicants propose to eliminate the Unbundled Storage Program, which is currently suspended. For the upcoming TCAP period, Applicants propose to eliminate this program and use its storage assets for system reliability, not commercial enterprise. Cal PA does not oppose elimination of the Unbundled Storage Program,[17] and most intervenors did not contest this proposal.

SCGC and SCE did oppose eliminating this program. These electric generator parties continue to desire to contract for storage capacity; however, Applicants have stated that there will not be enough storage inventory available for sale to commercial customers. Operationally,

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[15] TURN - Florio, p. 2, lines 21-27.

[16] Ex. PubAdv-02 (Kjensli) at 13.

[17] See Id. at 18-19.

if restrictions on the use of Aliso Canyon inventory and the Aliso Canyon Withdrawal Protocol are not lifted, there would continue to be no storage available for sale, which is the current situation. Moreover, in today's environment, even under Applicants' proposed storage capacity of 119.5 Bcf, there would be insufficient assets to allocate to an Unbundled Storage Program after providing for system reliability needs. Since Applicants' goal is to use storage assets for system reliability, a concern for all customers, Applicants believe that its proposal to eliminate the Unbundled Storage Program is prudent.

However, if the Commission were to order Applicants to provide some level of storage inventory to noncore customers, then any such capacities would have to be taken from the Balancing function, and offered to noncore customers, without an Unbundled Storage Program sharing mechanism. Revenues would be used to reduce Balancing function costs.

V. LOAD BALANCING

A. TURN

TURN proposes that the core should not pay for load balancing inventory or withdrawal, rather only for load balancing injection.[18] Practically speaking, this proposal would mean that the core would never be allowed to incur a daily or monthly negative imbalance (i.e., core would be under a permanent daily balancing condition for underdeliveries with a 0% tolerance). Core suppliers would need to balance its deliveries to usage with only positive imbalances every single day of the year only when the storage inventory allocated to the core is not full. Once the storage inventory allocated to the core is full, core would not be able to use load balancing

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[18] See Prepared testimony of William Pera Marcus (April 12, 2019) (TURN/Marcus), p. 23-24.

injection capacity either (*i.e.*, core would be subject to daily balancing with a 0% tolerance.)

TURN's proposal is unrealistic today, even as the core balances its deliveries to a forecast usage. In a separate ongoing proceeding,[19] the scope is considering whether or not the Commission should require the core to balance to actual usage rather a forecast usage. Under this scenario, achieving a positive imbalance on a daily basis would be extremely difficult, when you take into account uncontrollable factors such as cuts in flowing supplies, and would place core customers at a disadvantage to noncore customers. Applicants believe all customers, including the core, benefit from the full range of load balancing services, as evidenced by the active participation of customers in the daily and monthly imbalance trading market.

Not only will TURN's proposal be difficult for the core to operate under, but there will also need to be significant changes to Applicants' systems to accommodate this proposal, with its many restrictions imposed on the core for balancing and the potential penalties incurred by the core when not adhering to these restrictions. For these reasons, TURN's proposals should not be adopted.

B. Indicated Shippers

Indicated Shippers presents an analysis alleging that over the years 2013-2017, the core used 79% of withdrawal balancing assets and the noncore used only 21% of withdrawal balancing assets.[20] Therefore, Indicated Shippers proposes that costs of ALL balancing assets

[19] See A.17-10-002, Application of SoCalGas and SDG&E to Incorporate Advanced Meter Infrastructure Data into the Core Balancing Process.

[20] Indicated Shippers Testimony of Mr. Collins Schedule BCC-2 page 1 of 1 and Workpapers.

(inventory, injection, and withdrawal) should be allocated based on this result, *i.e.*, 79% to the core and 21% to the noncore.[21] This proposal is flawed for several reasons.

First, the Indicated Shippers' analysis uses data only on those days where the noncore had a net negative imbalance, which represents approximately only 20% of the data supplied to Indicated Shippers. Table 1 below reflects this, using Indicated Shippers' data, entitled "Storage Withdrawal for Noncore Customer Balancing".[22]

Table 1

Storage Withdrawal for Noncore Customer Balancing (Imbalance)				
Year	**Obs**	**Minimum**	**Percentile inflection point negative noncore imbl to positive noncore imbl.**	**Maximum**
2013	365	(608)	15%	1,122
2014	365	(294)	12%	1,029
2015	365	(908)	20%	873
2016	366	(312)	20%	632
2017	365	(228)	24%	606
			Avg. 18%	

As one can see looking at the "Percentile[23] inflection point, negative noncore imbl. to positive noncore imbl." column, the noncore imbalance is negative on about 18% of the days observed, and the noncore imbalance is positive on 82% (*i.e.*, 100% - 18% negative noncore imbalances) of the days observed, with more significant upper limit strain (see Maximum column) on the system than on the lower limit side (see Minimum column). The analysis ignores

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[21] Source: Indicated Shippers Testimony of Mr. Collins, Workpapers p. 13, Table 1.

[22] See Id. at Workbook "Schedule BCC-2 and Workpapers", Daily Data tab.

[23] A percentile is a measure used in statistics indicating the value below or above which a given percentage of observations in a group of observations falls. For example, the 10th percentile is the value below which 10% of the observations may be found, and 90% of the observations are greater than this value.

the remaining +80% of the data which include positive and negative imbalance days, and customers' use of balancing assets for those days. Further, Indicated Shippers fails to recognize that the balancing function is provided to all customers on a year-round basis to manage positive customer imbalances, not just negative imbalances as implied by its analysis.

Using the data provided to Indicated Shippers (as reflected in their workpapers), the Applicants performed an analysis similar to the one by Indicated Shippers, but instead also used data on the positive customer imbalances, which Indicated Shippers ignored. The results of the analysis in Table 2 below, show that core customers accounted for only 32% of the total system balancing storage injections for the period 2013-2017, resulting in the noncore customers accounting for the remaining 68%.

Table 2

Annual System Storage Injections Required for Customer Over-Delivery Imbalances		
	Noncore	**Core**
2013-2017	68.1%	31.9%

The analysis above shows that simple changes in assumptions regarding the data aggregation can lead to vastly different conclusions regarding use of storage balancing assets. Regardless of the assumption used, balancing assets of storage inventory, injection and withdrawal are available to all customers every day.

Analytical corrections notwithstanding, Indicated Shippers' proposal inappropriately recommends allocating costs only on historical withdrawal activity instead of also on injection activity, and only on those days when there was a net negative customer imbalance (withdrawal), concluding that "The PCTI allocator is the most appropriate method to distribute costs among customer classes as it accounts for a customer's actual use of the system which may contribute to those under- or over-deliveries necessitating or foregoing access to load balancing assets."[24] As shown above, despite this statement, the analysis performed only uses data on days with under-deliveries, and ignores any use of injection for balancing, not only on net positive customer imbalance days but also on net negative customer imbalance days.

Applicants advocate staying with the Average Year Throughput cost allocation and rate design models for the load balancing function. Chapter 9 (Schmidt-Pines) provides that "(i)n determining cost allocation, the following principles are followed by SoCalGas: allocate costs to customer classes based on cost causality, and maintain consistency with the existing practices whenever possible."[25] The component of the storage embedded cost that is allocated across customer classes on the basis of Average Year Throughput in the 2020 TCAP SoCalGas rate model is the balancing function (commonly referred to as "Load Balancing").

Load Balancing refers to the service provided by the SoCalGas System Operator to accommodate imbalances between a customer's actual usage and the gas it schedules for delivery to the system. The Load Balancing service is a year-round service. Customers' relative usage of the Load Balancing service is most likely to depend on their respective level of gas usage. In the 2016 TCAP Phase 1 decision (D.16-06-039), the Commission, through its adoption of a settlement agreement, authorized results based on the use of Average Year Throughput for allocating Load Balancing costs, which continued the longstanding practice of allocating these

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[24] See Id. at p. ES-2, lines 16-19.

[25] Chapter 9 (Schmidt-Pines), p. 2.

costs in this manner. While prior settlements do not set precedent, maintaining Average Year Throughput would promote consistency.

Therefore, in accordance with the cost allocation principles of cost causation and maintaining consistency with existing practices, Applicants find it reasonable that the cost associated with Load Balancing continue to be allocated based on Average Year Throughput in the same manner as they are today.

C. Cal PA

Cal PA does not oppose the 16 Bcf storage inventory allocated to the Balancing function but has requested the Applicants provide additional data and information to illustrate how it will reduce OFOs.[26] Applicants stated that the new proposed allocations will help reduce the number of OFOs declared and was referring specifically to the proposal of 840 MMcfd of withdrawal capacity allocated to the Balancing function.[27] Applicants provided an analysis in discovery to SCGC which shows that if 840 MMcfd withdrawal had been available for balancing in the years 2015-2017, there would have been a minimal number of low OFOs declared.[28], and Applicants believe this will be the case in the future.

D. SCGC

SCGC contests Applicants' proposal of 16 Bcf for the Balancing function. SCGC alleges that "Applicants rely upon an over-simplified analysis to justify their proposal."[29] While

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[26] See Ex. PubAdv-02 (Kjensli) at 15.

[27] See Chapter 1 (Dandridge) at 13.

[28] Applicants' Response to SCGC Data Request Set 4, Question 4.5.2, including relevant portions of the referenced attachment, which is attached as Appendix A.

[29] SCGC Direct at 12.

Applicants' analysis may be simple, it provides the support for the proposal, proving that Applicants' monthly balancing rules would allow customers to accrue cumulative positive imbalances up to 8 Bcf and cumulative negative imbalances up to 8 Bcf. Subsequently, SCGC uses Applicants' analysis (which SCGC considers as over-simplified), and recommends allocating 10 Bcf inventory to the positive Balancing function, along with a complicated procedure on how to manage negative customer cumulative imbalances.

SCGC proposes to decrease the load balancing inventory to 10 Bcf, with the 6 Bcf difference being allocated to an Unbundled Storage Program.[30] SCGC states that 8 Bcf storage inventory and its gas supply is not needed to cover negative customer imbalances and provides a proposal that the System Operator instead procures gas to cover these negative imbalances. SCGC also proposes that the System Operator sell customers' gas once a certain level of positive customer imbalance has been reached.[31] This seems like an overly complicated, half-baked proposal to manage customer imbalances, not only in the associated procurement and selling activities, but also in the tracking of these activities and allocation of the costs incurred. Complications aside, however, the System Operator does not have the authority to sell positive customer imbalance gas as it does not hold title to that gas unless it exceeds the 8% monthly balancing requirement.. Therefore, SCGC's proposal cannot be implemented without significant changes to balancing services offered by the Applicants.

Without 8 Bcf of load balancing inventory available to cover all potential negative cumulative customer imbalances, the management of gas supply and inventory to cover negative

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[30] See Id. at p. 25, lines 10-12.

[31] Id. at p. 2 lines 11-13.

transportation imbalances will continue to depend on gas supplies previously stored by other customers. SCGC's recommendation that the SoCalGas System Operator buy and sell gas to manage negative transportation customer imbalances rather than have the System Operator reserve storage inventory and procure gas to provide the service would require a lower negative monthly imbalance if the total negative balance is limited to a lower total inventory quantity. Under SoCalGas tariff rate Schedule No. G-IMB the System Operator provides a no-charge balancing service to transportation customers whose cumulative imbalance at the end of the monthly imbalance trading period is within 8 percent of the customer's usage. The gas provided to transportation customers with negative imbalances comes from the storage accounts of core customers and the transportation accounts of customers with positive imbalances. Applicants proposed to create a separate reservation of storage inventory and corresponding gas supply to create a reserve to address the requirements for negative transportation imbalances (within monthly tolerances) that would not affect the storage inventory held by others.[32] Applicants determined that 8 Bcf of storage inventory is required to provide this service at the current negative eight percent monthly imbalance level.

VI. NEW RELIABILITY FUNCTION

Various intervenors expressed concerns with the new Reliability function, and specifically that the 21 Bcf of Reliability function gas that Applicants propose to procure is in actuality cushion gas and should therefore be classified and treated as cushion gas.[33] Applicants address some of these concerns here.

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[32] See Chapter 1 (Dandridge) at 12

[33] SCGC Direct at p.1 lines 22-25; PubAdv-02 (Kjensli) at 18, lines 13-16; Long Beach page 1-2, lines 26-32;

A. SCGC

SCGC states that, [t]he 21 Bcf of "reliability" inventory should be recategorized as cushion or base gas, and the field inventories should be correspondingly reduced from 119.5 Bcf to 98.5 Bcf, the actual level of inventory capacity for working gas in the field . . . ."[34] This issue here is twofold. First, SCGC essentially disputes the creation of the new Reliability function, since the 21 Bcf assigned to it will not actually represent any working capacity. Second, SCGC disputes the proposed ratemaking treatment of the Reliability function gas itself. As SCGC points out, cushion gas has a specific rate recovery treatment,[35] which is not the treatment Applicants are proposing.[36]

With respect to the new Reliability function, SoCalGas disagrees with SCGC's view that the 21 Bcf of storage capacity allocated to that function will essentially serve no working purpose, such that it should be carved out of the total storage capacity allocated among customer classes. The 21 Bcf of storage capacity will provide the inventory needed to provide a higher withdrawal deliverability for all customers on the system, on a year-round basis.

With respect to the ratemaking treatment of the Reliability function gas itself, Applicants do not think that Reliability function gas matches all of the attributes of cushion gas. Applicants define cushion gas as the volume of gas intended to serve as the permanent inventory within a storage reservoir that is required to maintain adequate pressure for deliverability rate throughout the withdrawal season. This definition is generally consistent with DOGGR's definition of cushion gas, as well as the Federal Energy Resources Commission (FERC) definition of cushion

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[34] SCGC Direct at 10-11.

[35] See Id. at 11-12.

[36] See Chapter 6 (Ahmed), p. 4-5.

gas. Although the purpose of the proposed Reliability function inventory is to provide a minimum withdrawal rate, the 21 Bcf of gas that Applicants propose to procure is not exactly identical to cushion gas, even if it would perform a similar function for the TCAP period.

Cushion gas is specific to each storage field and cannot be moved between fields. The Reliability function gas, in contrast, is intended to be mobile such that the System Operator can transfer Reliability function gas to optimize the location of inventory among its storage fields to maximize withdrawal. This function is essential at minimum for the duration of this upcoming TCAP period, so that the System Operator can exercise flexibility while collecting information to better understand storage field performance changes attributed to safety enhancements made to storage wells.

Safety enhancements made to all storage field wells have impacted withdrawal capability, thus necessitating higher minimum inventory levels to meet withdrawal deliverability for system reliability and operational flexibility.[37] The full impact of recent and ongoing well safety enhancements are not yet realized, as the work being performed is ongoing and potentially subject to change if the underlying requirements change (*e.g.*, U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's underground natural gas storage regulations are in a state of interim final rule status and requirements may still be subject to additional change, and similarly with DOGGR's regulations and requirements). For all of these reasons, the Reliability function gas should be afforded the ratemaking treatment proposed by Applicants, and not be treated as cushion gas.

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[37] See Chapter 1 (Dandridge) at 3.

If Applicants' total storage capacity does not reach 119.5 Bcf and Aliso Canyon remains under the current Withdrawal Protocol (or any other limiting protocol), Applicants realize that from an operational standpoint, the new Reliability function could not be implemented immediately or until those limitations are lifted. Under that circumstance, Applicants would not procure Reliability function gas until it was operationally feasible to do so. However, it would still be reasonable for the Commission to authorize the new Reliability function (and corresponding memorandum account) in this TCAP because in the event storage limitations are lifted, Applicants will have the requisite authority and mechanisms in place to implement its Reliability function.

B. Cal PA

Cal PA opposes the proposal for 21 Bcf of gas inventory for withdrawal deliverability and $8.3 million in associated costs, claiming that Applicants have not provided adequate evidence and information to warrant the establishment of 21 Bcf of gas inventory.[38] However, Cal PA supports maintaining sufficient capacity to meet the 1-in-35 Cold Peak day and 1-in-35 Cold Year planning standards.[39]

The new Reliability function is an integral part of Applicants' goal of maintaining sufficient capacity to meet those reliability standards. The 21 Bcf of Reliability inventory is required to provide the proposed firm withdrawal rate allocated to the Core and to Balancing.[40] Without the 21 Bcf of Reliability inventory, Applicants would be unable to provide the proposed

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[38] See Ex. PubAdv-02 at 16-18.

[39] See Id. at 17.

[40] Chapter 1 (Dandridge) p. 14, lines 15-20.

2,000 MMcfd of firm withdrawal to Core and Wholesale, and the 400 MMcfd of firm withdrawal for Balancing. Also, Applicants have produced in discovery support for the need of the 21 Bcf of gas inventory for withdrawal deliverability. [41]

C. Long Beach

Long Beach states that "if it is necessary to increase the Aliso Canyon storage field pressure as SoCalGas has claimed."[42] Applicants have not made its Reliability function specific to any storage field(s). As stated earlier, the 21 Bcf is needed to provide a minimum withdrawal rate from the storage fields in aggregate.

Furthermore, Long Beach recommends that the new storage related account proposed in Chapter 6 (Ahmed), the Reliability Function Cost Memorandum Account (RFCMA), should be allocated like cushion gas.[43] As explained above, the 21 Bcf of reliability gas should not be classified as cushion gas. Therefore, Long Beach's proposal to record the 21 Bcf in FERC account 117.1 and allocate as cushion gas should not be adopted.

VII. MISCELLANEOUS ISSUES

A. Long Beach

Long Beach recommends Applicants revise Rule No. 30 to explicitly state that wholesale core firm rights holders will only have their rights pro-rated when other core customers have their rights pro-rated.[44] Long Beach states that Applicants' firm storage rights are over-subscribed, and this has affected Long Beach's ability to fully utilize its approved rights. Long

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[41] See Applicants' Response to Cal PA Data Requests DR-013-03; Cal Adv. DR-049-01; Cal Adv. DR-049a.

[42] Long Beach Chapter 1 at p. 1-2, lines 13-16

[43] Long Beach Chapter 3 Transmission Level Service Rates at p. 3-20 to 3-21.

[44] Long Beach Chapter 2 at p. 2-6, lines 6-8.

Beach fails to recognize that all firm storage subscribers have had their rights affected due to the restrictions placed on Aliso Canyon by the Commission. These restrictions have reduced the storage inventory, injection and withdrawal capacities that are available to all firm storage subscribers, not just Long Beach. If available firm inventory capacity is reduced from what is proposed by Applicants, all core firm capacity holders will continue to have their rights prorated, with the capacities available on a first come, first served basis.

B. SCE

SCE incurred a $815 million 2018 Energy Resource Recovery Account (ERRA) undercollection.[45] To address it, SCE has sought every opportunity to divert the focus off of itself, in spite of its status as one of the largest noncore balancing agents on the SoCalGas system, and to avoid taking any accountability for an $815 million undercollection. In furtherance of its campaign, SCE has propagated the narrative that high natural gas prices, resulting from SoCalGas' Stage 4 OFO Noncompliance charges given system capacity constraints, was the reason behind its massive undercollection. SCE has advanced this narrative in a number of regulatory proceedings and forums, including its own ERRA trigger proceeding (A.18-11-009[46]), and in a recently litigated petition for modification action (A.14-06-021/A.14-

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[45] See Prepared Intervenor Testimony of Southern California Edison Company (April 12, 2019) (SCE Direct), p. 6.

[46] In A.18-11-009, Clean Power Alliance tested SCE's claims that natural gas price spikes caused the undercollection

> With little detail, SCE explained in its August advice letter, repeated summarily in the Update and the Trigger Application, that the "primary driver behind the triggering of the ERRA Balancing Account (ERRA BA) in July 2018, with no self correction expected by year-end, is the dramatic increase in gas and electric wholesale market prices that were experienced in late July 2018 and early August 2018." It repeats a similar explanation in its Supplemental Testimony, focusing primarily on natural gas spikes and the resulting higher power prices. This explanation to the Commission is at odds with the facts. First, the natural gas spikes underlying

12-017, consolidated[47]). Applicants' TCAP is a gas cost allocation proceeding and should not be used as yet another platform for SCE to further propagate its narrative and to plant seeds to advance its electric rates issues.[48]

Using its narrative as a foundation, SCE makes two recommendations in its testimony. First, SCE recommends the Commission modify SoCalGas' Gas Cost Incentive Mechanism calculation.[49] Second, SCE recommends that the Commission open a new rulemaking proceeding to develop a full requirements cost-based supply tariff for dispatchable electric generation customers.[50]

Regarding SCE's first recommendation, SCE suggests that there should be an elimination of incentives in the Gas Cost Incentive Mechanism under certain system conditions. SCE goes

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> SCE's explanation occurred during the July and August 2018 heatwaves, as SCE acknowledges. Yet the biggest increases in the undercollection occurred in September ($193 million) and November ($181 million); July and August increases combined were less than the increases for either September or November. SCE still has not explained to the Commission why the biggest increases occurred in September and November.

Clean Power Alliance concluded that SCE's undercollection was not a foregone conclusion under the Southern California natural gas and market power conditions; and, a well-hedged market participant who managed its portfolio appropriately should not find itself in SCE's position. See A.18-11-009, Opening Brief of Clean Power Alliance of California (December 21, 2018), pp. 12-13. However, the Commission opted to allow this critical inquiry to go unaddressed by simply concluding that it does not review the reasonableness of SCE's procurement activities or compliance with the its bundled procurement plan in this trigger application. See D.19-01-045, *mimeo*, p. 11.

[47] In A.14-06-021/A.14-12-017, SCE appears to have preliminarily succeeded in convincing some at the Commission of its narrative, despite contrary evidence and serious questions raised by parties over the soundness and completeness of SCE's claims. A proposed decision was issued on April 29, 2019, with comments due by May 20, 2019.

[48] In discovery, Applicants sought information from SCE to support its testimony claims. In response to Applicants' data requests, SCE refused to produce documentation in its possession that could have given Applicants (and the Commission) insight into the root causes of the $815 million undercollection, claiming attorney client privilege, attorney work product, confidentiality, and burden. SCE's full responses are attached in Appendix B.

[49] See SCE Direct at 9-10.

[50] See Id. at 8-9.

so far as to speculate that SoCalGas' System Operator and gas procurement department (which are separated and bound by Commission rules and requirements[51]) may be knowingly (or unknowingly) manipulating the gas market. SCE states, "[o]ne way to create an opportunity to procure gas below the benchmark is to have the gas system operator declare an OFO and then have GAD offer balancing service at attractive rates that contribute to shareholder awards. Thus, there is an inherent conflict of interest and potentially a subconscious incentive to use these rights to earn extra shareholder awards."[52] The Commission should disregard these baseless and disparaging remarks. Moreover, the Commission should reject SCE's recommendation to eliminate incentives in the Gas Cost Incentive Mechanism under certain system conditions because it is clearly out of scope in a cost allocation proceeding. As SCE is well aware, SoCalGas' Gas Cost Incentive Mechanism awards are thoroughly reviewed annually through a formal application process.

SCE's second recommendation is for the Commission to open a rulemaking proceeding to implement a full requirements cost-based gas supply tariff for dispatchable electric generation customers. Such a requirement would create significant obstacles. As with its first recommendation, SCE's second recommendation is out of scope and thus seeks relief that the Commission cannot grant in this TCAP proceeding. This portion of SCE's testimony is subject

[51] The "Remedial Measures" were adopted in the Merger Proceeding (see D.98-03-073) and then subsequently revised in the Omnibus Proceeding (see D.07-12-019), placing restrictions on the communications and relationship between the SoCalGas System Operator and the Gas Acquisition Department.

[52] SCE Direct at 8 (FN 14).

to a pending motion to strike jointly filed by Shell Energy and the Indicated Shippers, a motion that Applicants find reasonable and will support.[53]

In short, Applicants' TCAP should not be used as SCE's platform to advance its own agenda to address past and ongoing electric rate issues. Raising out-of-scope issues through testimony is inappropriate, wasteful of parties' and the Commission's resources, and prejudicial to the treatment of issues that should be addressed in other proceedings.

C. Indicated Shippers

The Indicated Shippers propose that SoCalGas be required to provide credits for Backbone Transmission Service reservation charges when pipeline capacity is not available due to repair or replacement activity.[54] However, Indicated Shippers provide insufficient detail for Applicants to consider this proposal, for the 2020 TCAP period, or prior to the October 1, 2020 – 2023, Backbone Transmission Service term.

The proposal further ignores the options already available to Backbone Transmission Service shippers to nominate their capacity on an alternate firm basis when primary capacity is not available. Finally, SoCalGas' tariff Schedule G-BTS already includes a refunding mechanism for Open Season Backbone Transmission Service subscribers to address pipeline outages in progress when a new three-year Backbone Transmission Service term begins. Given the options already available, this proposal should not be adopted.

This concludes the prepared rebuttal testimony.

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[53] See Joint Motion of Shell Energy North America (US), L.P. and the Indicated Shippers to Strike a Portion of the Prepared Testimony of Southern California Edison Company (April 25, 2019).

[54] See Direct Testimony and Schedules of Maurice Brubaker (April 12, 2019) (Indicated Shippers/Brubaker), p. 6.

VIII. WITNESS QUALIFICATIONS[55]

My name is Paul D. Borkovich. My business address is 555 West Fifth Street, Los Angeles, CA 90013. I am employed by SoCalGas as the Energy Markets Segment Manager in the Capacity Products Support Department. My responsibilities are to manage transportation services provided by suppliers and marketers who provide gas to SDG&E and SoCalGas customers. I also manage the Backbone Transportation Service program, the California Energy Hub back office, policies and procedures for scheduling and nominations on the SDG&E and SoCalGas systems, daily operation and enhancements to SoCalGas' Electronic Bulletin Board, and all aspects of SoCalGas' and SDG&E's interconnect and operational balancing agreements with pipelines delivering natural gas into their integrated transmission system.

I have been employed by SoCalGas in numerous positions relating to gas operations and gas markets, and have been responsible for various aspects of utility operations, sales and marketing, regulatory matters, and customer relations.

I graduated in 1981 from the University of California at Santa Barbara, with a Bachelor of Science degree in Mechanical Engineering, and in 1985 from the University of Southern California with a Master of Science degree in Petroleum Engineering.

I have previously testified before the Commission. Most recently, I was a presenter at the TCAP Workshop held on March 21, 2019, where I presented on Applicants' storage proposals and operational flow orders.

[55] Please see Chapter 1 (Dandridge) for witness Michelle Dandridge's witness qualifications.

APPENDIX A

DATA RECEIVED: 2-9-19
DATE RESPONDED: 2-26-18

QUESTION 4.5:

4.5. With respect to Dandridge's testimony at 11 that states: "Applicants are proposing that allocations to withdrawal for the summer be increased from 525 MMcfd to 840 MMcfd. Allocating 840 MMcfd withdrawal to the balancing function will provide transportation customers more flexibility in managing their deliveries to actual usage without an unbundled storage program."

4.5.1. Please explain why it is operationally appropriate to increase the summer withdrawal capacity allocated to the balancing function from 525 MMcfd to 840 MMcfd.

4.5.2. Please provide a copy of all studies, memos, and reports that discuss whether 840 MMcfd is an appropriate level of withdrawal capacity to be allocated to the balancing function during the summer months.

RESPONSE 4.5:

4.5.1. The projected summer withdrawal capacity is 1,240 MMcfd. The summer average demand for Core including wholesale is approximately 30% of the total system summer average demand. 30% of 1,240 MMcfd is approximately 400 MMcfd, which, along with flowing supplies, will be sufficient for the Core and wholesale in the summer. The remainder of the summer withdrawal capacity (i.e., 840 MMcfd) would be allocated to balancing. Additionally 840 MMcfd summer withdrawal will provide transportation customers more flexibility in managing their deliveries to actual usual without an unbundled storage program as described in Response 4.1.7.

4.5.2._See attached file: SCGC-04-4.4.2 & 4.5.2. Applicants do not have additional studies, memos, and reports that discuss whether 400 MMcfd is a sufficient level of withdrawal capacity to be allocated to the balancing function during the winter months.

Count of Summer Low OFO Balancing Days >840 MMcfd WD

Count of Summer Low OFO Balancing Days >840 MMcfd WD	Year		
Month	2016	2017	Grand Total
Apr		0	0
May		0	0
Jun	0	0	0
Jul	0	0	0
Aug	0	1	1
Sep	0	0	0
Oct	0	0	0
Grand Total	0	1	1

Count	Low OFO Called	Balancing WD required to AVOID Low OFO Trigger (MMcf)	Count Balancing Days >840 MMcfd WD
1	12/6/15	478	0
2	12/28/15	512	0
3	12/29/15	337	0
4	2/3/16	356	0
5	2/5/16	498	0
6	2/14/16	353	0
7	3/6/16	596	0
8	3/7/16	480	0
9	6/1/16	306	0
10	6/3/16	250	0
11	6/8/16	176	0
12	6/13/16	336	0
13	6/16/16	239	0
14	6/17/16	281	0
15	6/19/16	595	0
16	6/20/16	447	0
17	6/27/16	411	0
18	6/29/16	443	0
19	6/30/16	183	0
20	7/5/16	495	0
21	7/7/16	298	0
22	7/12/16	379	0
23	7/14/16	356	0
24	7/18/16	528	0
25	7/19/16	370	0
26	7/20/16	390	0
27	7/22/16	244	0
28	7/23/16	198	0
29	7/26/16	195	0
30	7/27/16	239	0
31	7/28/16	346	0
32	7/29/16	454	0
33	7/30/16	185	0
34	8/8/16	292	0
35	8/14/16	274	0
36	8/15/16	357	0
37	8/16/16	412	0
38	8/17/16	182	0
39	8/19/16	169	0
40	8/22/16	218	0

41	8/29/16	603	0
42	8/30/16	319	0
43	9/6/16	388	0
44	9/19/16	543	0
45	9/20/16	271	0
46	9/26/16	412	0
47	9/27/16	303	0
48	9/28/16	474	0
49	9/29/16	227	0
50	9/30/16	285	0
51	10/1/16	434	0
52	10/3/16	311	0
53	10/5/16	245	0
54	10/17/16	298	0
55	10/19/16	259	0
56	10/21/16	73	0
57	10/24/16	110	0
58	10/25/16	151	0
59	10/26/16	163	0
60	10/31/16	405	0
61	11/21/16	551	0
62	11/27/16	276	0
63	11/28/16	889	1
64	11/29/16	506	0
65	12/1/16	360	0
66	12/3/16	298	0
67	12/4/16	451	0
68	12/5/16	273	0
69	12/8/16	336	0
70	12/12/16	422	0
71	12/19/16	666	0
72	12/20/16	556	0
73	12/21/16	393	0
74	12/23/16	322	0
75	12/24/16	303	0
76	12/27/16	338	0
77	12/28/16	381	0
78	12/30/16	344	0
79	12/31/16	594	0
80	1/1/17	307	0
81	1/2/17	391	0
82	1/7/17	342	0
83	1/9/17	413	0
84	1/12/17	310	0

85	1/17/17	258	0
86	1/22/17	364	0
87	1/23/17	743	0
88	1/24/17	277	0
89	1/25/17	351	0
90	1/26/17	208	0
91	1/27/17	334	0
92	1/28/17	622	0
93	1/29/17	227	0
94	1/30/17	210	0
95	2/2/17	272	0
96	2/7/17	275	0
97	2/13/17	266	0
98	2/17/17	264	0
99	2/18/17	303	0
100	2/27/17	584	0
101	2/28/17	428	0
102	3/1/17	339	0
103	3/2/17	368	0
104	3/3/17	286	0
105	3/4/17	251	0
106	3/5/17	513	0
107	3/7/17	393	0
108	3/8/17	202	0
109	3/9/17	217	0
110	3/13/17	292	0
111	3/20/17	231	0
112	3/27/17	212	0
113	3/29/17	245	0
114	3/30/17	284	0
115	4/2/17	227	0
116	4/3/17	270	0
117	4/5/17	199	0
118	4/10/17	236	0
119	4/17/17	185	0
120	4/19/17	224	0
121	4/20/17	138	0
122	5/1/17	236	0
123	5/22/17	375	0
124	6/5/17	379	0
125	6/19/17	628	0
126	6/20/17	245	0
127	6/21/17	515	0
128	6/26/17	499	0

129	6/27/17	297	0
130	7/7/17	377	0
131	8/21/17	330	0
132	8/23/17	326	0
133	8/27/17	372	0
134	8/28/17	929	1
135	8/29/17	355	0
136	9/1/17	379	0
137	9/11/17	517	0
138	9/18/17	385	0
139	9/25/17	405	0
140	9/28/17	384	0
141	10/11/17	307	0
142	10/16/17	427	0
143	10/23/17	456	0
144	10/26/17	311	0
145	11/6/17	140	0
146	11/14/17	242	0
147	12/4/17	368	0
148	12/5/17	206	0
149	12/7/17	310	0
150	12/8/17	215	0
151	12/11/17	232	0
152	12/12/17	276	0
153	12/13/17	264	0
154	12/14/17	292	0
155	12/15/17	202	0
156	12/18/17	427	0
157	12/19/17	687	0
158	12/20/17	770	0
159	12/21/17	618	0
160	12/22/17	886	1
161	12/23/17	539	0
162	12/24/17	334	0
163	12/25/17	281	0

APPENDIX B

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET S o C a l G a s - S C E - 0 0 1

To: SoCalGas
Prepared by: Robert Grimm
Job Title: Senior Advisor
Received Date: 4/22/2019

Response Date: 5/6/2019

Question 01: On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

"Indeed, SCE's 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices."

On lines 10-12, page 8 of the same testimony, SCE states:

"SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E's system."

1. Does SCE have any workpapers, notes, emails, memos, excel files, or documents in its possession that relate to SCE's analysis of its 2018 ERRA undercollection? Please provide an unqualified "yes" or "no."

Response to Question 01:

Yes.

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET S o C a l G a s - S C E - 0 0 1

To: SoCalGas
Prepared by: Magesh Srinivasan
Job Title: Senior Advisor
Received Date: 4/22/2019

Response Date: 5/6/2019

Question 02: On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

"Indeed, SCE's 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices."

On lines 10-12, page 8 of the same testimony, SCE states:

"SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E's system."

2. Please provide all workpapers, notes, emails, memos, excel files, or documents in the possession of SCE (specifically in possession of, or retrievable by, Robert Thomas, Robert Grimm, and/or Anthony Frontino) that relate to SCE's analysis of its 2018 ERRA undercollection.

Response to Question 02:

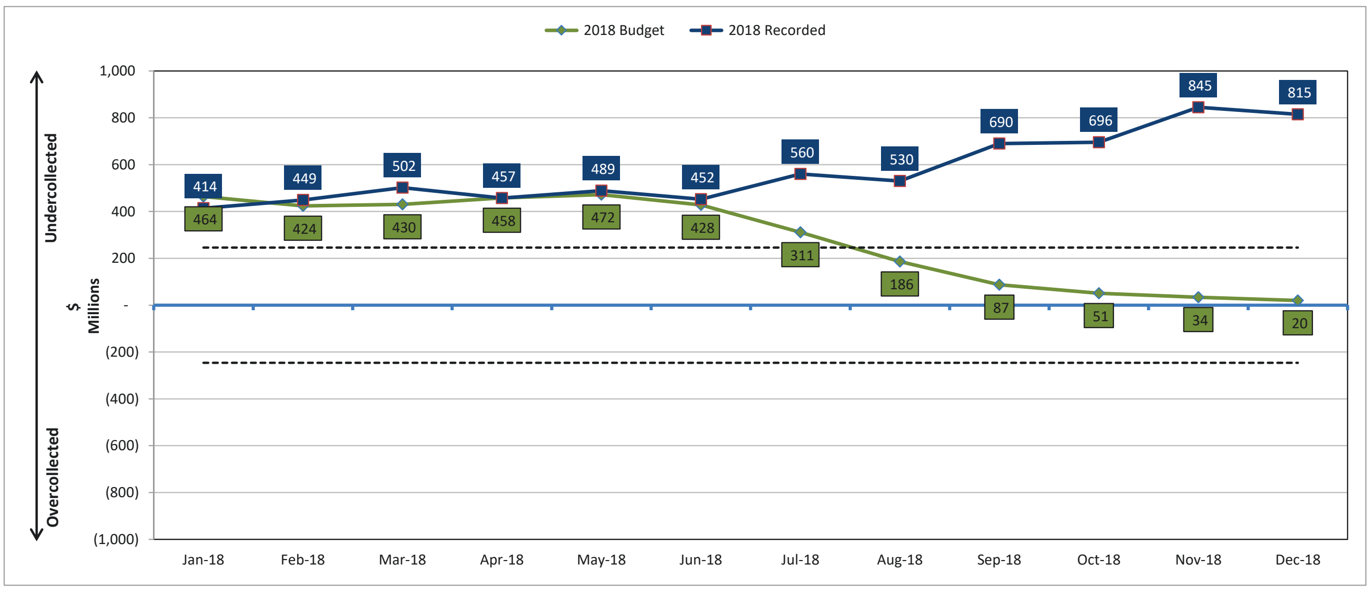
SCE objects to this request to the extent that it calls for information that is protected by the attorney-client privilege and/or work product doctrine. SCE further objects to this request to the extent that it calls for the disclosure of any proprietary business information and/or confidential market sensitive commercial information. SCE also objects that this request is overbroad and unduly burdensome in that it is not reasonably limited to documents relevant to the scope of this proceeding and information that is not equally available to SoCalGas. Notwithstanding those objections, SCE responds with the attached document(s).

Please refer to the CPUC website regarding A. 18-05-003 to obtain filed documents and CPUC decisions about the 2018 ERRA under-collection.

SCE has also provided the attachment *2018 ERRA Under collection and Prices.xlsx*

Attached spreadsheet shows SCE's monthly ERRA recorded under collection. Post June-2018 the under collection increased due to higher gas prices compared to the forecast that went into the rate forecast.

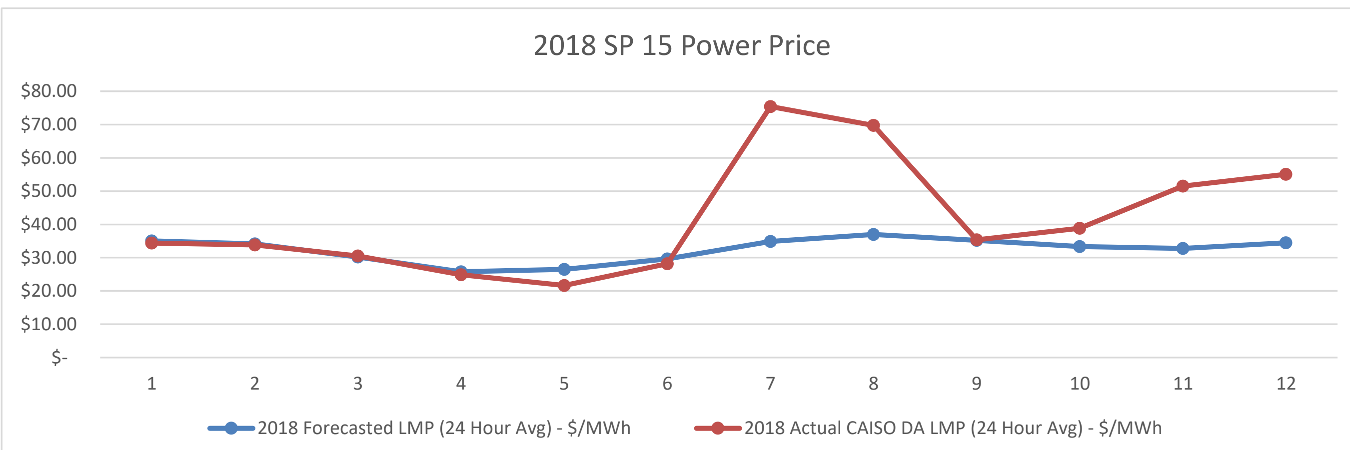
	2018 Budget	2018 Recorded		
Jan-18	464	414	246	(246)
Feb-18	424	449	246	(246)
Mar-18	430	502	246	(246)
Apr-18	458	457	246	(246)
May-18	472	489	246	(246)
Jun-18	428	452	246	(246)
Jul-18	311	560	246	(246)
Aug-18	186	530	246	(246)
Sep-18	87	690	246	(246)
Oct-18	51	696	246	(246)
Nov-18	34	845	246	(246)
Dec-18	20	815	246	(246)

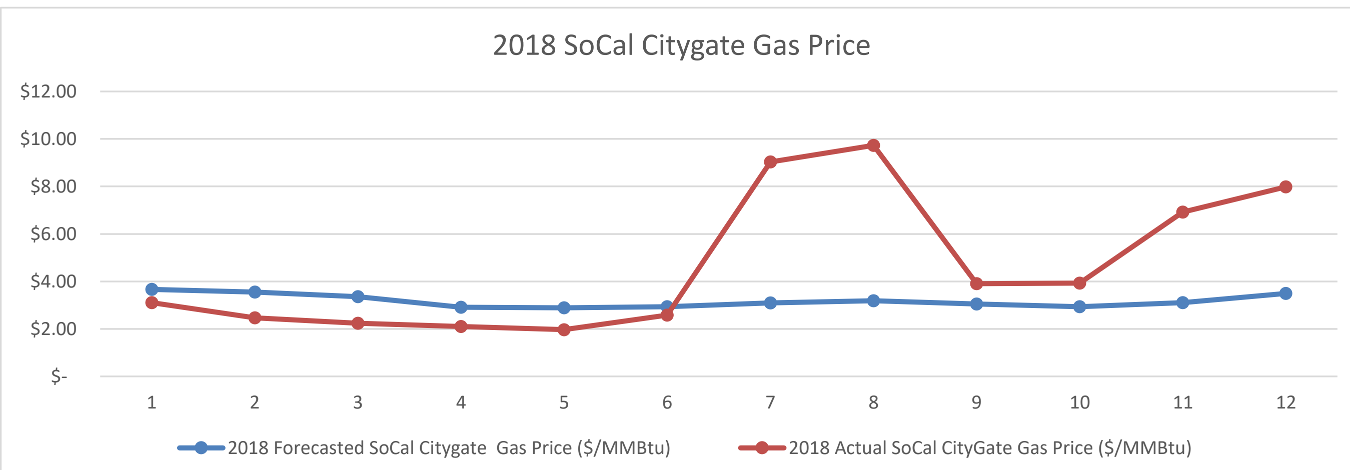


2018 Budget
2018 Recorded
Undercollected
Overcollected
$ Millions
1,000
800
600
400
200
-
(200)
(400)
(600)
(800)
(1,000)
414
449
502
457
489
452
560
530
690
696
845
815
464
424
430
458
472
428
311
186
87
51
34
20
Jan-18
Feb-18
Mar-18
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18

	2018 Forecasted LMP (24 Hour Avg) - $/MWh	2018 Actual CAISO DA LMP (24 Hour Avg) - $/MWh
January	$ 35.05	$ 34.37
February	$ 34.11	$ 33.83
March	$ 30.22	$ 30.52
April	$ 25.77	$ 24.88
May	$ 26.51	$ 21.65
June	$ 29.64	$ 28.17
July	$ 34.90	$ 75.42
August	$ 36.98	$ 69.73
Septembe	$ 35.19	$ 35.33
October	$ 33.31	$ 38.84
November	$ 32.80	$ 51.49
December	$ 34.50	$ 55.04
	$ 32.42	**$ 41.60**

	2018 Forecasted SoCal Citygate Gas Price ($/MMBtu)	2018 Actual SoCal CityGate Gas Price ($/MMBtu)
January	$ 3.66	$ 3.11
February	$ 3.56	$ 2.46
March	$ 3.36	$ 2.23
April	$ 2.92	$ 2.10
May	$ 2.89	$ 1.97
June	$ 2.94	$ 2.58
July	$ 3.10	$ 9.03
August	$ 3.19	$ 9.73
Septembe	$ 3.04	$ 3.90
October	$ 2.93	$ 3.93
November	$ 3.11	$ 6.92
December	$ 3.50	$ 7.98
	$ 3.18	**$ 4.66**


2018 SP 15 Power Price
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1
2
3
4
5
6
7
8
9
10
11
12
2018 Forecasted LMP (24 Hour Avg) - $/MWh
2018 Actual CAISO DA LMP (24 Hour Avg) - $/MWh


2018 SoCal Citygate Gas Price
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
1
2
3
4
5
6
7
8
9
10
11
12
2018 Forecasted SoCal Citygate Gas Price ($/MMBtu)
2018 Actual SoCal CityGate Gas Price ($/MMBtu)

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET SoCalGas-SCE-001

To: SoCalGas
Prepared by: Robert Grimm
Job Title: Senior Advisor
Received Date: 4/22/2019

Response Date: 5/6/2019

Question 03: On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

"Indeed, SCE's 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices."

On lines 10-12, page 8 of the same testimony, SCE states:

"SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E's system."

3. Does SCE have any workpapers, notes, emails, memos, excel files, or documents in its possession that SCE relied upon to prepare its intervenor testimony? Please provide an unqualified "yes" or "no."

Response to Question 03:

Yes.

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET S o C a l G a s - S C E - 0 0 1

To: SoCalGas
Prepared by: Magesh Srinivasan
Job Title: Senior Advisor
Received Date: 4/22/2019

Response Date: 5/6/2019

Question 04:
On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

"Indeed, SCE's 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices."

On lines 10-12, page 8 of the same testimony, SCE states:

"SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E's system."

4. Please provide all workpapers, notes, emails, memos, excel files, or documents that SCE (specifically, Robert Thomas, Robert Grimm, and Anthony Frontino) relied on when preparing the aforementioned testimony, specifically as to the statements quoted above

Response to Question 04:

SCE objects to this request to the extent that it calls for information that is protected by the attorney-client privilege and/or work product doctrine. SCE further objects to this request to the extent that it calls for the disclosure of any proprietary business information and/or confidential market sensitive commercial information. SCE also objects that this request is overbroad and unduly burdensome in that it is not reasonably limited to documents relevant to the scope of this proceeding and information that is not equally available to SoCalGas. Notwithstanding those objections, SCE responds as follows.

Please refer to the responses for **(SoCalGas-SCE-001, 02)**

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET S o C a l G a s - S C E - 0 0 1

To: SoCalGas
Prepared by: Robert Grimm
Job Title: Senior Advisor
Received Date: 4/22/2019

Dated: 5/6/2019

Question 05:
On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

“Indeed, SCE’s 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices.”

On lines 10-12, page 8 of the same testimony, SCE states:

“SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E’s system.”

5. Does SCE believe that the OFO penalty pricing was the sole cause of SCE’s 2018 $815 million ERRA undercollection (i.e., 100% responsible for the undercollection)? Please provide an unqualified “yes” or “no.”

Response to Question 05:

No.

Southern California Edison
A.18-07-024 – 2020 TCAP

DATA REQUEST SET S o C a l G a s - S C E - 0 0 1

To: SoCalGas
Prepared by: Robert Grimm
Job Title: Senior Advisor
Received Date: 4/22/2019

Response Date: 5/6/2019

Question 06: On lines 20-22, page 6 of the Prepared Intervenor Testimony of Southern California Edison Company (SCE), SCE states:

"Indeed, SCE's 2018 ERRA balancing account was approximately $815 million undercollected as a result of much higher power prices than originally forecast because of the adverse impact that OFO penalty pricing had on CAISO power prices."

On lines 10-12, page 8 of the same testimony, SCE states:

"SCE, however, must advocate for the interests of its five million customers who have already suffered nearly $1 billion more than the average historical cost of power due to the constraints on SCG/SDG&E's system."

6. If the answer to Question 5 is anything but an unqualified "yes," please explain what other factors contributed to the 2018 ERRA undercollection.

a. Were there other factors that contributed to the 2018 undercollection that SCE did not mention in its Prepared Intervenor Testimony?
b. Were there factors that contributed to the 2018 undercollection that were not related to natural gas prices? If so, please describe those other factors.
c. Can SCE quantify or approximate how much, in terms of percentage, did those other factors contribute to the 2018 ERRA undercollection of $815 million, relative to the OFO penalty pricing?
d. Please provide, to the best of SCE's ability (and with whatever caveats or qualifiers are necessary), a percentage breakdown of the factors that contributed to the undercollection.

Response to Question 06:

a. SCE's 2018 ERRA Undercollection is the mathematical result of the revenues derived from customer retail ERRA rates (which are set the year before on a forecast basis) and market revenues collectively being lower than ERRA-related costs (largely payments to PPA counterparties and to the CAISO for SCE's Residual Net Short position). The principal reason for the ERRA Undercollection is that 2018 costs were significantly higher than the forecast SCE used to set customer rates the year before. The principal reason that 2018 ERRA costs were higher is that the price of natural gas sets the marginal cost of electricity in Southern California. The OFO penalty pricing structure materially contributed to the unnaturally high price of natural gas during relevant periods of 2018. Other factors, including weather-related customer demand, also influence the marginal price of electricity in the CAISO markets.

b. See response immediately above.
c. SCE has not performed that analysis, and it would be difficult to quantify for several reasons, including because SCE does not have insight into the CAISO bidding behavior of gas-fired generators who sold into the CAISO markets in 2018.
d. See response immediately above.