Application No: A.14-12-017
Exhibit No.:
Witness: Steve Watson

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

PREPARED REBUTTAL TESTIMONY

OF STEVE WATSON

SOUTHERN CALIFORNIA GAS COMPANY AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

July 17, 2015

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PURPOSE

The purpose of my rebuttal testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) is to: (1) note parties' agreement on the total embedded costs of storage; (2) note parties' agreement on the total seasonal storage capacities; (3) present the merits of Pacific Gas and Electric Company's (PG&E) cost allocation method; (4) note most parties' agreement on the balancing capacity allocations under SoCalGas and SDG&E's balancing proposal; (5) discuss Office of Ratepayer Advocates' (ORA) and Southern California Edison Company's (Edison) disagreements on off-season core/noncore firm storage capacity allocations; (6) rebut Indicated Shippers' (IS) and Southern California Generation Coalition's (SCGC) concerns on the new high Operational Flow Order (OFO) proposal; (7) rebut parties' objections to 5% monthly balancing; (8) discuss the proper shareholder incentive sharing mechanism; (9) rebut IS' objections to the proposed G-TBS tariff change; (10) discuss California producer meter aggregation; (11) reiterate the lack of need for SoCalGas' unique G-TBS storage transaction postings; (12) concede that the core should bear an allocation of load balancing inventory costs; and (13) rebut the flawed proposal of Shell Energy North America (US), L.P. (Shell) concerning firm storage rights.

I. PROPOSED EMBEDDED COSTS OF STORAGE SHOULD BE ADOPTED

No party disputes the embedded costs of $96.19 million in 2016 and $110.58 million for the 2017-2019 period provided in the Direct Testimony of Sim-Cheng Fung. Those costs should be adopted.

II. PROPOSED TOTAL FIRM SEASONAL CAPACITIES SHOULD BE ADOPTED

No party disputes the proposed total firm winter/summer capacities described in Table 3 of my Direct Testimony. That table was developed with recent Envoy capacity postings in mind and recognizes that summer withdrawal capacities are significantly lower than winter capacities and that winter injection capacities are significantly lower than summer capacities due to necessary off-season maintenance. Firm injection and withdrawal capacities can be seriously prorated during the off-season periods unless this revision is made. The pro-rationing of firm capacity, especially injection capacity, is an issue about which Shell legitimately complains.[1]

Parties also do not dispute the allocations of winter withdrawal or summer injection capacities. As will be discussed later, ORA and Edison dispute the core/noncore split of off-season injection and withdrawal capacities, and City of Long Beach (Long Beach) opposes any increase in asset allocation to the balancing function. Table 3 of my Direct Testimony is reproduced as Table 1 below, with notations for undisputed and disputed capacity allocations.

Table 1 Storage Capacity Allocations (MMcfd)
(**Bold**: ORA/Edison Dispute; <u>Underlined</u>: Long Beach Disputes)

	Bcf	**Withdrawal** Winter	**Withdrawal** Summer	**Injection** 2016 Summer	**Injection** 2017-2019 Summer	**Injection** 2016 Winter	**Injection** 2017-2019 Winter
Total	138.1	3175	1812	770	915	390	535
Balancing	5.1	<u>525</u>	<u>525</u>	200	<u>345</u>	200	<u>345</u>
Core	83	2,225	**1,081**	388	388	**190**	**190**
Unbundled	50	425	**206**	182	182	**0**	**0**

III. "STATUS QUO" COST ALLOCATION IS INCOMPATIBLE WITH SEASONAL CAPACITIES AND IS INFERIOR TO PG&E'S COST ALLOCATION METHOD

Despite the fact that no party disputes the total firm seasonal capacities described in Table 1 above, several parties propose the "status quo" cost allocation presented in Table 3 of

[1] Direct Testimony of Mr. Dyer at 8.

my Supplemental Testimony, which had been ordered by assigned Administrative Law Judge Sean Wilson.[2] As emphasized in that Supplemental Testimony, the "status quo" methodology "does not make a distinction between on-cycle and off-cycle firm capacities."[3] Therefore, it is completely incompatible with the off-season injection and withdrawal capacities in Table 1. The fundamental flaw of the "status quo" approach is that it inappropriately assumes that on-season firm capacities can be maintained throughout the off-season periods.

Parties supporting "status quo" cost allocation complain that SoCalGas and SDG&E do not provide sufficient justification for adopting the cost allocation methodology utilized by PG&E.[4] The prime reason for adopting the PG&E method is that, unlike SoCalGas and SDG&E's "status quo," it recognizes the differences in winter/summer injection and withdrawal capacities.

A second reason for proposing the PG&E cost allocation methodology is that it is more objective. Embedded costs (which are not under dispute) are divided by this total decatherms (dths) of firm service capacity (which are also not under dispute) to provide a single $/dth cost. These costs are then multiplied by the total firm service capacity dths for the three storage services. This results in about 67% of the costs being allocated to withdrawal, 22% to injection, and 11% to inventory. This is very similar to the allocation among functions that we observe in the PG&E Gas Accord workpapers.[5] The "status quo" SoCalGas/SDG&E method, on the other hand, starts with an extremely subjective assumption. Lacking an objective way to attribute cost causation to the three sub-functions, it assumes that one-third of the total costs are caused by

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2 Direct Testimony of Mr. Emmrich (TURN) at 1-3; Direct Testimony of Mr. Stannik (ORA) at 5-11; Direct Testimony of Mr. Fulmer (Long Beach) at 1-2; Direct Testimony of Ms. Yap (SCGC) at 24.

3 Supplemental Testimony of Mr. Watson at 3.

4 Direct Testimony of Mr. Emmrich at Section 2; Direct Testimony of Mr. Fulmer at Sections I.5 and III; Direct Testimony of Ms. Yap at 24.

5 D.11-04-031, Gas Accord V Settlement Agreement, Appendix A, Table A-6.

injection; one-third of the total costs are caused by withdrawal; and one-third of the costs are caused by inventory.[6] The Utility Reform Network (TURN) implies this one-third cost causation method was based on a study,[7] which is incorrect. Rather, as correctly recognized by SCGC's witness Ms. Yap, the one-third allocation among functions is an assumption: "when one attributes the various elements of storage revenue requirement to the three storage subfunctions, *i.e.*, injection, inventory, and withdrawal, there is no basis for distinguishing among the sub-functions on a cost causation basis."[8] What Ms. Yap may not recognize, however, is that PG&E's equal storage unit cost method overcomes this difficulty by dividing total costs by total storage units to get the same $/dth for each storage unit.

Parties advocating the "status quo" object to the PG&E cost allocation method because it is part of a non-precedential settlement.[9] This argument, however, has little merit. The arbitrary one-third "status quo" cost allocation method is also the result of a settlement on the SoCalGas and SDG&E system.[10] Neither settlement is precedential. Furthermore, parties made a similar objection to SoCalGas and SDG&E adopting PG&E's low OFO structure in A.14-06-021. The Commission, however, appropriately recognized that better structures adopted through settlement for one utility may be appropriately applied at a later time to another utility under its jurisdiction.

On logical grounds, PG&E's cost allocation method is superior and should be adopted. SoCalGas and SDG&E continue to strongly advocate the adoption of the PG&E storage unit cost allocation method for the embedded cost of storage, as reflected in Table 4 of my Direct Testimony. Nevertheless, if the Commission chooses to retain the "status quo" one-third

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6 Revised Updated Direct Testimony of Ms. Fung in A.11-11-002 at 18.
7 Direct Testimony of Mr. Emmrich at 2.
8 Direct Testimony of Ms. Yap at 25, lines 5-9.
9 *Id.* at 25, lines 10-15.
10 D.14-06-007.

inventory, injection, and withdrawal cost-causation assumption, that approach should at least be modified to remedy its primary flaw—its use of unrealistically high annual firm capacities rather than seasonally-adjusted firm capacities. Table 2 below allocates one-third of the total costs to inventory, injection, and withdrawal, as under the status quo, but then allocates those costs over the seasonal injection and withdrawal capacities in Table 1 rather than the unrealistic annualized capacities of the "status quo" method used to generate Table 3 contained in my Supplemental Testimony.

Table 2
Adjusted Storage Cost Allocation

	2016		2017-2019
	($MM)		($MM)
	33/33/33; Seasonal Injection/WD Cost Alloc.		33/33/33; Seasonal Injection/WD Cost Alloc.
Core	$ 55.71		$ 60.31
Balancing	20.51		$ 28.13
Unbundled storage	$ 19.97		$ 22.15
Total	$ 96.19		110.58

IV. PROPOSED BALANCING CAPACITIES SHOULD BE ADOPTED

With the exception of Long Beach, no parties objected to the balancing capacities recommended in Table 3 of my Direct Testimony if SoCalGas and SDG&E's balancing proposals are adopted. Other than Long Beach, no parties objected to increasing the allocation of withdrawal from 340 MMcfd to 525 MMcfd. They recognized this would decrease the frequency of low OFOs. The parties recognized this 525 MMcfd allocation has to be on an annualized basis because the low OFO trigger is constant throughout the year—that is, a low OFO can be called in either summer or winter. No parties objected to increasing the allocation of injection from 200 MMcfd to 345 MMcfd in 2017, concurrent with the completion of the

Aliso Canyon Turbine Replacement Project.[11] Again, parties recognized this 345 MMcfd allocation has to be on an annualized basis because the high OFO trigger is constant throughout the year—that is, a high OFO can be called in either the summer or winter. Although many parties objected to moving to 5% monthly balancing, no party objected to the proposed 5 Bcf allocation to that function should 5% monthly balancing be adopted. In fact, when SCGC advocates 10% monthly balancing, it also proposes a 10 Bcf inventory allocation.[12]

Long Beach opposes the allocation of additional assets to the balancing function because (1) its transportation costs would increase by $170,000 per year, and (2) less unbundled storage might increase the prices for unbundled storage.[13]

Long Beach's opposition to the allocation of additional assets to the balancing function is misguided for a number of reasons. First, Long Beach should have no concern about unbundled storage prices since SoCalGas is willing to maintain core parity for wholesale customer storage prices.[14] Therefore, for Long Beach, it can choose fixed core storage rates rather than the unpredictable market price of unbundled storage.

Second, only 39% of the transportation rate increases noted by Long Beach result from the allocation of more assets to the balancing function. Thirty-seven percent of the increased cost for the balancing function is the result of the change in cost allocation method.[15] Another

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[11] IS objects to the high OFO proposal itself but does not object to the balancing allocation should that proposal be adopted. Direct Testimony of Dr. Alexander at 15, lines 15-18.

[12] Direct Testimony of Ms. Yap at18, lines 1-4.

[13] Direct Testimony of Mr. Fulmer at 6.

[14] See Southwest Gas DR 1. In addition, SoCalGas and SDG&E dispute Long Beach's assertion about the impact of its proposal on unbundled storage prices.

[15] Of the total $17.5 million increase in balancing costs in the Direct Testimony of Mr. Watson Table 4 ($27.8 million) vs. today's rates ($10.3 million), $6.5 million is the result of the change in cost method. *See* Supplemental Testimony of Mr. Watson Table 3 balancing costs of $21.3 million. 27.8 – 21.3 = 6.5. 6.5 ÷ 17.5 = 37%.

24% of the increase is the result of higher storage costs in 2017 relative to 2013 levels.[16] Most parties disagree with Long Beach's recommendation concerning balancing assets. For example, IS believes that decreasing the number of OFOs is more important than the direct cost impacts to noncore customers of higher allocations to the balancing function.[17] Other noncore customers such as SCGC and Edison do not object to the higher allocation of assets to the balancing function under SoCalGas' balancing proposals because they also recognize that increased allocations will decrease OFO frequency.

V. ORA AND EDISON OFF-SEASON CAPACITY ALLOCATIONS ARE IMPRACTICAL AND UNWISE

ORA does not object to the total firm capacities, the balancing allocations, or the on-season capacities for the core as shown in Table 1 of this Rebuttal Testimony. But ORA suggests that the core's on-season capacities be maintained throughout the year like the balancing capacities are.[18] The math behind this proposal simply does not work. SoCalGas and SDG&E cannot allocate 388 MMcfd of firm injection capacity to the core in the winter when that is the total amount of firm capacity available in the winter of 2016. Further, SoCalGas and SDG&E cannot allocate to the core 2,225 MMcfd of firm withdrawal capacity in the summer when the total firm summer withdrawal capacity is 1,812 MMcfd. SoCalGas and SDG&E have proposed to allocate all of the firm off-season injection capacity not dedicated to the balancing function to the core—190 MMcfd. That leaves zero firm off-season injection capacity for unbundled storage customers—a point about which Edison complains. SoCalGas and SDG&E have further proposed to allocate to the core 84% (the same percentage of the core's on-season rights) of the firm off-season withdrawal capacity not dedicated to the balancing function—1,081

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16 Today's rates are based on embedded costs of $89.6 million vs. the $110.6 million for 2017-2019. 110.6 ÷ 89.6 = 124% overall cost increase.

17 Direct Testimony of Dr. Alexander at 18, lines 10-18.

18 Direct Testimony of Mr. Stannik at 10, lines 1-5.

MMcfd. That leaves only 206 MMcfd of firm withdrawal capacity during the summer for unbundled storage—a point about which Edison complains.

In separate Confidential Rebuttal Testimony, I provide corrections to some of ORA's transaction analysis presented in ORA-3-CONF. The corrections show that the proposed 1,081 MMcfd of firm summer withdrawal capacity would not have significantly constrained core summer withdrawals over the last six years. The corrections also show that the proposed 190 MMcfd of firm winter injection rights (as opposed to the current 388 MMcfd of firm rights subject to significant pro-rationing) would not have significantly constrained core's winter injections.

Edison has the opposite concern; it believes that the SoCalGas and SDG&E proposal provides the core with too much off-season capacity. Edison proposes that 64% of off-season capacity not allocated to the balancing function be allocated to unbundled storage and only 36% to the core.[19] Edison's proposed allocation is flawed since it is based on relative throughput of end-use customers and ignores actual usage of unbundled storage. End-users comprised less than half of SoCalGas' unbundled storage purchases. In fact, financial institutions and producer/shippers comprise the largest share of the unbundled storage market. Therefore, using throughput as an allocator of off-season capacities is not justified. The core's unique balancing need for winter injection capacity needs to be considered.

Edison claims that SoCalGas has not justified allocating all the winter injection to the core. SoCalGas refers Edison to IS Data Request Number 1, Question 2, reproduced below:

> *Q. Please explain why "Whatever winter injection capacity is not allocated to the balancing function" should be allocated exclusively to the Utility Gas Procurement Group and Core Transportation Agents to provide them with more flexibility. Why does SoCalGas feel that unbundled storage customers should not have some of that flexibility?*

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[19] Direct Testimony of Mr. Grimm at 11, lines 8-18.

> A. During the winter months of November through March, Gas Acquisition on behalf of core procurement customers is required to hold interstate capacity equal to 100% of its forecast average annual customer load. In order to optimize its use of this transportation and balance its supplies with customer load during these months, Gas Acquisition injects delivered supplies into storage when its load falls below its deliveries….SoCalGas and SDG&E are not aware of any CPUC-mandated interstate capacity requirements for noncore customers.

Furthermore, Edison's proposal to allocate 826,000 dth/d of summer withdrawal capacity to the unbundled storage is unreasonably high. The maximum fifth cycle firm withdrawal nomination by unbundled storage customers in the summers of 2012, 2013 and 2014 was 128,000 dth/day. SoCalGas and SDG&E's proposed summer allocation of 206,000 dth/day is more than sufficient for the unbundled storage program.

VI. IS' OBJECTION TO NEW HIGH OFO PROCEDURES IS UNFOUNDED AND ADJUSTMENTS TO THOSE PROCEDURES ARE UNNECESSARY

Only one party, IS, objects to the new high OFO procedures that SoCalGas and SDG&E are proposing to implement in 2017. IS does not believe it is important to achieve symmetry with PG&E's OFO procedures or with SoCalGas' soon-to-be-implemented low OFO procedures.[20] Instead, IS thinks the highest priority should be to reduce the number of OFOs,[21] given that shippers have the potential to make more money as balancing rules of any sort become more lax. IS recognizes that the PG&E OFO, and now SoCalGas and SDG&E's low OFO, approach achieves the Commission's objective of customers paying for the capacity they use for balancing. IS simply does not consider this a high priority objective.

Recognizing the weakness of this position, IS suggests a "second best" alternative.[22] They propose no change in the high OFO trigger but charging for the as-available, interruptible capacity used to balance load each day. A "market price" would be established for these

[20] Direct Testimony of Dr. Alexander at 7.
[21] *Id. at* 14, lines 13-14.
[22] *Id.* at 14-15.

volumes, and the revenue from this service would be allocated to unbundled storage. IS' "second best" proposal is impractical. First, determining ex-post how much as-available, interruptible capacity was scheduled for balancing as opposed to other purposes would be problematic. Second, there is no daily liquid market for interruptible injection; therefore, choosing an ex-post market price to reference would also be problematic. The implementation problems with this "second best" alternative, however, disappear under SoCalGas and SDG&E's proposal. If a high OFO is called because customers are using more firm assets to balance than is allocated to the balancing function, customers can still try to stay within the tolerance levels by using/buying as-available injection capacity, and the revenues from interruptible injection purchases would go to the unbundled storage program.

IS overstates the impact of the new procedures when it asserts that "SoCalGas will have more [high] OFOs than it currently does."[23] SoCalGas and SDG&E's data response to IS' data request 01-016 for a back-cast is reproduced in Table 3 below, which indicates this is not true in every year.

Table 3: High OFO Back-Cast

Year	SoCalGas/SDG&E		
	# High OFOs under Existing High OFO Protocol	# High OFOs under Proposed High OFO Protocol	Difference
2011	42	47	5
2012	57	51	-6
2013	35	42	7
2014	54	42	-12
2015 to (May 31st)	*48*	*5*	-43

IS is confused about the level of flexibility under the SoCalGas and SDG&E proposal vis-a-vis that of PG&E customers. Dr. Alexander states "the 600 MMcf difference between the high and low inventory levels for the PG&E system significantly exceeds the 340 MMcfd that SoCalGas is proposing for a low OFO trigger and the 200 MMcfd that SoCalGas is proposing for

23 *Id*. at 9, lines 4-10.

a high OFO trigger."[24] The difference between the high and low inventory levels currently showing on PIPERANGER for PG&E is just 400 MMcf, not the 600 MMcf that was in place before the San Bruno explosion.[25] If PG&E is operating in the middle of the current range, then it can only provide half of that 400 MMcf of flexibility in pack or draft. This 200 MMcfd of flexibility is lower than the 525 MMcfd SoCalGas and SDG&E are proposing for the low OFO trigger and the 345 MMcfd that SoCalGas and SDG&E are proposing for the high OFO trigger in this proceeding.

SCGC does not object to the new high OFO procedures per se, but expresses the same concerns about forecasting accuracy that it has expressed concerning low OFO procedures. SCGC suggests "[T]the applicants should be required to submit their forecast and associated back-cast to the Commission for review through the advice letter process to demonstrate sufficient accuracy in order to proceed with the implementation of the modified high OFO methodology."[26] Given the direction provided by the Commission in D.15-06-004, SoCalGas and SDG&E assume that this is what would happen even absent SCGC's comments. Furthermore, there is time to refine the methodology since the new procedure would not be implemented until 2017.

SCGC is also concerned that "following the PG&E protocol to impose progressively tighter caps on the range of tolerances that are allowed in higher stages of OFOs does not make sense."[27] SCGC cites the 15% limitation on tolerances for a Stage 3 high OFO. Over the last three and a half years, however, PG&E has issued no Stage 3 high OFOs and only 9 Stage 2 high OFOs. A Stage 2 high OFO provides for up to a 20% tolerance; this is more flexibility than a

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24 *Id*. at 12, lines 13-16.
25 *See* www.piperanger.com, "System Inventory Status."
26 Direct Testimony of Ms. Yap at 9.
27 *Id.* at 10.

345 MMcfd of injection allocation would make possible. Therefore, there is no need to deviate from the PG&E Stage/tolerance template for high OFOs.

VII. OBJECTIONS TO 5% MONTHLY BALANCING ARE UNFOUNDED

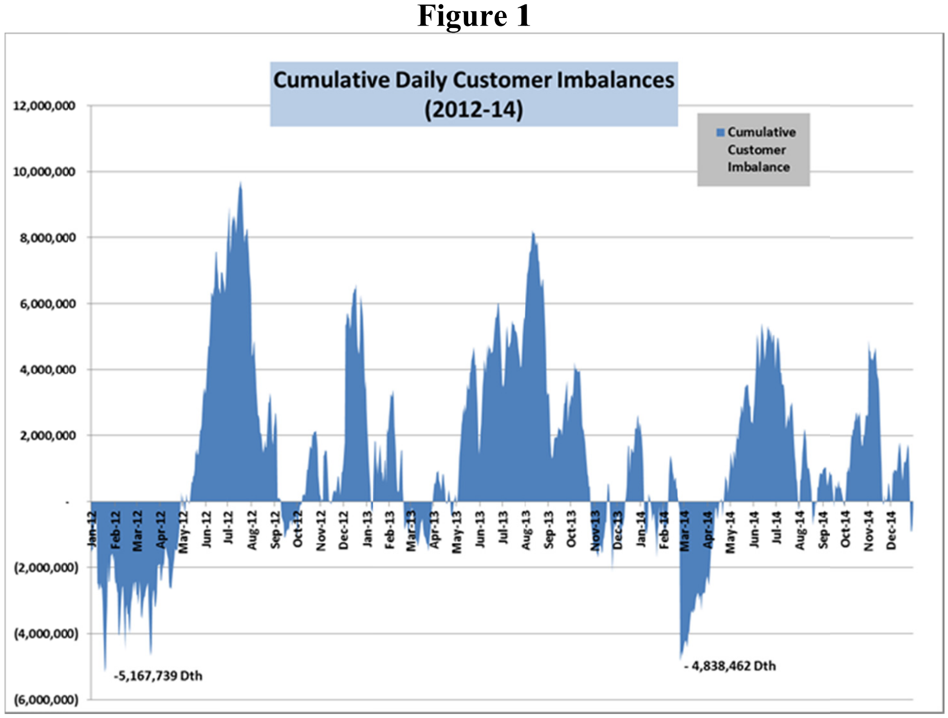
Although TURN and ORA support SoCalGas' proposal to move to 5% monthly balancing, the other interveners in this proceeding prefer the current 10% monthly balancing regime. SoCalGas and SDG&E note that PG&E has a 5% monthly tolerance. Increased monthly balancing discipline has the advantage of encouraging more daily balancing discipline by customers as well. The example provided by IS that is intended to show how "the need to balance on a monthly basis can put pressure on a customer to be out of daily balance at the end of the month"[28] actually supports SoCalGas and SDG&E's case. If the customer in IS's example were over-delivered by only 10% for the first half of the month, as opposed to his arbitrary 12% over-delivery assumption, then the need to under-deliver in the second half of the month disappears. SoCalGas and SDG&E want all customers to comply with the intent of their Rule 30 tariffs (Sheet 1) which state: "It is the intention of both the Utility and the customer that the daily deliveries of gas by the customer for transportation hereunder shall approximately equal the quantity of gas which the customer shall receive at the point(s) of delivery." Customers should not be incented to engage in the types of first half month over-delivery followed by second half month under-delivery schemes as outlined by Dr. Alexander. Five percent monthly balancing would reduce such perverse customer incentives.

Edison argues that large negative imbalances do not occur with the 10% rule.[29] "The impact of any individual customer imbalances cannot be considered in isolation. In fact, SoCalGas/SDG&E have hundreds of thousands of noncore customers and, at any point in time,

[28] Direct Testimony of Dr. Alexander at 24.
[29] Direct Testimony of Mr. Grimm at 6, line 23 through 7, line 10.

some customers are likely to have positive imbalances and some customers are likely to have negative imbalances." Contrary to Edison's assertion, economic incentives in the marketplace tend to incent all customers to over or under deliver in the same months. SCGC contends that no data was provided to demonstrate that significant net negative imbalances persist.[30] While the data was not provided in testimony, it is available on SoCalGas' public Electronic Bulletin Board, Envoy, and is provided in Figure 1 below. Over the last several years, SoCalGas and SDG&E have seen cumulative negative customer imbalances of -4.7 Mdth to -5.2 Mdths five times. The confiscation issue that concerns SoCalGas and SDG&E with -10% balancing is real and occurs in critical winter months; -5% monthly balancing would reduce such confiscation. Five percent monthly balancing would also reduce the encroachment by transportation customers on others' inventory rights that are on the positive side of the equation.

Figure 1



30 Direct Testimony of Ms. Yap at 16, lines 12-13.

Several opponents of SoCalGas and SDG&E's proposal, including SCGC, note "PG&E gives its customers two months, not just one month, to either trade or cash out the imbalance…Thus, in any given month, a customer on PG&E's system may have an accumulated balance as large as ten percent above or ten percent below its monthly burn because imbalances are actually cleared in the second month following the month in which the imbalance occurred."[31] The implication given that PG&E effectively provides as much monthly balancing flexibility as SoCalGas and SDG&E currently do with their 10% tolerance is incorrect. SoCalGas and SDG&E's system allows a party to be over-delivered or under-delivered by 10% each and every month of the year. PG&E's system allows a party to be over-delivered by 10 percent only for one month. After that the customer has to be in balance or be under-delivered the following month. Table 4 illustrates the difference in flexibility.

Table 4: Comparison of SoCalGas/PG&E Monthly Balancing Rules

Month	SoCalGas Monthly	SoCalGas Cumulative 1-month	PG&E Monthly	PG&E Cumulative 2-month
1	10%	10%	5%	5%
2	10%	10%	5%	10%
3	10%	10%	0	5%
4	10%	10%	5%	10%
5	10%	10%	0	5%
6	10%	10%	5%	10%
7	10%	10%	0	5%
8	10%	10%	5%	10%
9	10%	10%	0	5%
10	10%	10%	5%	10%
11	10%	10%	0	5%
12	10%	10%	5%	10%

[31] Direct Testimony of Ms. Yap at 15, lines 3-4, 24-26.

Although theoretically the PG&E approach allows an average 7.5% over-delivery over the year, compared to SoCalGas and SDG&E's current 10%, the practical flexibility is probably closer to 5% than it is to 7.5% given the need to be perfectly in balance in alternating months.

Due to metering and other technical limitations on SoCalGas' system, in the first years of imbalance trading SoCalGas had a two-month trading period, like PG&E still does. SoCalGas found, however, that large cumulative negative and positive imbalances occurred (much larger than +/-10 percent), which were deemed unacceptable.[32] SoCalGas recommended changing to a one-month trading period and incurring the necessary IT costs and system changes to enable this change. The Commission agreed that one-month trading was more consistent with the intent of the initial decision establishing monthly imbalance trading (D.90-09-089) and agreed with SoCalGas' proposal.[33] Suggestions to adopt 5% monthly balancing and reverse the advancement provided by D.90-09-089 by reverting to a two-month trading period should be rejected.[34]

VIII. PROPOSED 60/40 UNBUNDLED STORAGE INCENTIVE MECHANISM SHOULD BE ADOPTED

Several parties suggest maintaining the status quo shareholder incentive mechanism. They fail to recognize the impact of incentives on revenue generation. It has been SoCalGas' experience that the higher the shareholder incentive percentage in any given year, the higher the ratio of the ultimate sales prices negotiated by sales personnel relative to the minimum guidelines established by my staff. The guidelines themselves rose or fell with overall market conditions each year. That is, the ratio of sales price divided by staff guideline was highest when SoCalGas was in the 50/50 sharing band from the storage years 2007/8 to 2010/11 and lowest when in the 90/10 sharing band in storage years 2012/13 to date.

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[32] *See* Testimony of Peter Yu, March 1996 BCAP, pp. 34-35. Also attached is the "Load Balancing Study," Figure 3E, "Retail Non-Core Inventory."

[33] D.97-04-082, mimeo., at 30-32 and Finding of Fact 20.

[34] Direct Testimony of Ms. Yap at 17, lines 1-6. Direct Testimony of Laird Dyer at 7, lines 1-13.

Quantifying the exact impact of incentives is problematic. Nevertheless, assume that there is a small positive linear relationship between the shareholder percentage in the incentive mechanism and the percentage increase in revenues. That is, assume SoCalGas will generate twice as much incremental revenue with an 80/20 sharing mechanism as it would with a 90/10 sharing mechanism, and five times as much incremental revenue with a 50/50 sharing mechanism as with a 90/10 sharing mechanism. As long as that is the case, no matter how large or small the incremental revenue in question is, ratepayer benefits will always be maximized with a 50/50 sharing mechanism. Table 5 assumes that each 10% increase in shareholder sharing incents program personnel to generate an additional half of a percent increase ($130,000) in revenues. With 50/50 sharing, incremental 2.5% revenues ($650,000) are generated rather than the 0.5% incremental revenues generated under the 90/10 mechanism. Even more revenues are generated at the 60% or 70% shareholder level, but the ratepayer benefits begin to diminish beyond the 50% shareholder stage.

Table 5: $MM Benefits of Sharing Bands if 0.5% Δ Revenue for Each 10% Shareholder Increase in Share

Shareholder % of net	Costs	Revenues	Net Shareholder Gain	Net Ratepayer Gain
0	$ 26.00	$ 26.00		$ -
0.1	$ 26.00	$ 26.13	$ 0.013	$ 0.117
0.2	$ 26.00	$ 26.26	$ 0.052	$ 0.208
0.3	$ 26.00	$ 26.39	$ 0.117	$ 0.273
0.4	$ 26.00	$ 26.52	$ 0.208	$ 0.312
0.5	$ 26.00	$ 26.65	$ 0.325	$ 0.325
0.6	$ 26.00	$ 26.78	$ 0.468	$ 0.312
0.7	$ 26.00	$ 26.91	$ 0.637	$ 0.273
0.8	$ 26.00	$ 27.04	$ 0.832	$ 0.208
0.9	$ 26.00	$ 27.17	$ 1.053	$ 0.117
1	$ 26.00	$ 27.30	$ 1.300	$ -

Given the beneficial impact of higher sharing percentages for ratepayers, ORA's proposed incentive mechanism would be the best mechanism for ratepayers among the various alternatives suggested by the interveners. ORA proposes replacing the current sharing mechanism with a 75/25 (ratepayer/shareholder) split, while maintaining the $20 million cap.[35]

Of course, SoCalGas' 60/40 (ratepayer/shareholder) proposal would be even better for ratepayers than ORA's proposal. SoCalGas' proposal would provide more ratepayer benefit and would continue the effective shareholder and ratepayer split the program has realized over the last 15 years as shown in Table 6.

Table 6: Unbundled Storage Program Sharing History

		Unbundled Storage Revenues ($MM)	Unbundled Storage Allocated Cost ($MM)	Shareholder Pretax Earnings ($MM)	Ratepayer Benefit ($MM)	UBS Rev - UBS Allocated Cost ($MM)
SoCalGas Advice No. 2938-A filed on 9/15/2000	1999			N/A		
SoCalGas Advice No. 3033 filed on 6/25/2001	2000	19.2	20.6	(0.7)	(0.7)	(1.4)
SoCalGas Advice No. 3167 filed on 7/1/2002	2001	32.9	20.6	6.2	6.2	12.3
SoCalGas Advice No. 3277 filed on 7/10/2003	2002	42.0	20.6	10.7	10.7	21.4
SoCalGas Advice No. 3386 filed on 6/22/2004	2003	47.0	20.6	13.2	13.2	26.4
Not included in SoCalGas Advice No. 3496 filed on 5/2/2005	2004	48.8	20.6	14.1	14.1	28.2
SoCalGas Advice No. 3629 filed on 5/1/2006	2005	60.7	20.6	20.0	20.0	40.1
SoCalGas Advice No. 3740 filed on 5/1/2007	2006	72.2	20.6	25.8	25.8	51.6
SoCalGas Advice No. 3862 filed on 5/1/2008	2007	77.6	20.6	28.5	28.5	57.0
SoCalGas Advice No. 3933 filed on 12/5/2008	2008	75.4	31.5	12.2	31.7	43.9
	2009	82.4	24.2	19.4	38.9	58.2
Year-end NSBA Report	2010	73.8	25.2	14.6	34.1	48.6
Year-end NSBA Report	2011	50.2	25.8	3.8	20.5	24.4
Year-end NSBA Report	2012	46.7	27.1	2.7	17.0	19.6
Year-end NSBA Report	2013	34.1	28.4	0.6	5.1	5.6
Year-end NSBA Report	2014	26.0	26.0	-0.005	-0.048	-0.053
Cumulative 15-year History of Unbundled Storage Benefit				**$ 171.0**	**$ 265.0**	436.1
				39%	**61%**	
Annual Average for 15 years				$ 11.4	$ 17.7	29.1

[35] Direct Testimony of Mr. Stannik at 15, lines 7-8.

Table 6 is based on the actual advice letter filings on which sharing was based. It shows a 61% ratepayer, 39% shareholder split over the first 15 years of the unbundled storage program. Table 6 shows there was no "asymmetry" during the 2000-2007 period of the original 50/50 sharing mechanism as asserted in Ms. Yap's Table 5, which was fabricated for the Phase 1 2009 BCAP proceeding, but which was never formally recognized in that settled proceeding.[36]

SCGC proposes an 85/15 sharing mechanism that it claims provides the same shareholder benefits, in percentage terms, as the current Gas Cost Incentive Mechanism (GCIM) has produced over 13 years. There are three flaws in this proposal. First, there is no reason to have one program aimed at maximizing unbundled storage revenues mimic another program aimed at minimizing commodity costs for the core simply because both are SoCalGas incentive mechanisms. The size and structure of the storage market is very different than the markets the GCIM covers, including the GCIM encompassing transactions in a number of producing basins where there are many more counterparties to transact with as well as the overall dollar size of the transactions in the programs. Second, SCGC wrongly focuses on the percentage of the total gas costs savings that goes to shareholders under the GCIM mechanism. The focus SoCalGas will give to the unbundled storage program will have a direct relationship to the dollars involved in the program and the related potential rewards. Using GCIM-based percentages for a smaller program does not provide the same dollar incentive. There is no reason do so, but if the Commission were to try to mimic the GCIM mechanism, the unbundled storage program should be designed to provide a similar level of dollar (not percentage) benefit to shareholders. Given that gas commodity cost savings are more than twice as large as unbundled storage revenues (net of costs), more than a 30% shareholder split would be required to achieve this goal. Third, SCGC's proposed $5 million shareholder cap is inconsistent with the GCIM mechanism. The

[36] Direct Testimony of Ms. Yap at 20.

GCIM shareholder cap is 1.5% of the actual annual gas commodity costs. This has translated to an annual shareholder cap of $19 to $45 million each year, not $5 million.

Recognizing that SoCalGas' shareholders are not currently making enough under the 90/10 sharing band to justify the incremental efforts associated with the unbundled storage program, TURN proposes a minor "fix" to the current sharing mechanism. Under its "alternative" sharing mechanism, the first $500,000 of net unbundled storage program revenues are allocated to shareholders, with all subsequent revenues subject to the current method of 90/10 for net revenues above $500,000 and up to $15 million, 75/25 for the next $15 million, and 50/50 sharing for net revenues above $30 million.[37] TURN's proposal would increase the likelihood that there would be $500,000 of "net revenue" in the unbundled storage program, all of which would accrue to shareholders. But there would still be little incentive to generate more than that for the benefit of ratepayers because the proposal fails to address the basic fact that 90/10 sharing beyond that amount is insufficient. TURN suggests the first $500,000 to shareholders should be more than adequate to cover the cost of two unbundled storage program employees and back office staff, plus any additional resources devoted to increased "marketing" efforts. TURN's assessment of the O&M savings from a minimal effort program is low. Therefore, even under TURN's alternative mechanism, SoCalGas' shareholders might still be better off to realize O&M savings by returning to full balancing of unbundled storage revenues.

IX. IS' OBJECTION TO G-TBS TARIFF CHANGE IS MISGUIDED

Only IS objects to the reasonable tariff change SoCalGas suggests for inventory-only G-TBS contracts. Dr. Alexander states the effect would be to artificially and unreasonably

[37] Direct Testimony of Mr. Emmrich at 4.

constrain interruptible capacity.[38] This is not true. The total zero-priced "as-available" injection rights for TBS inventory packages would be set at 319 MMcfd and as-available withdrawal rights for TBS inventory packages would be equal to1,136 MMcfd—as opposed to the unrealistically high 50,000 MMcfd (maximum unbundled inventory or inventory rights) for each under today's rules.

Dr. Alexander ignores the potential to purchase unlimited quantities of additional interruptible injection and withdrawal capacity through the daily auction process, which is not affected by SoCalGas' proposed tariff change. The sale of such interruptible capacity would continue to be unlimited, and the scheduling of that capacity would only be limited through the scheduling process on the basis of physical capacity and price—consistent with Rule No. 30. Dr. Alexander states that he is not aware of problems in agreeing on the market value of inventory-only contracts—a problem that SoCalGas' proposal is intended to address. But Dr. Alexander was never a part of any storage price negotiations for an inventory-only contract.

X. CALIFORNIA PRODUCER METER AGGREGATION IS A PHASE 2 ISSUE

IS inappropriately interjects a Phase 2 TCAP issue, producer meter aggregation, into this Phase 1 proceeding.[39] The low OFO Decision specifically stated that this issue should be addressed in Phase 2, not Phase 1.[40] SoCalGas and SDG&E filed their Phase 2 TCAP Application on July 8, 2015, and as directed by D.15-06-004, included testimony regarding producer meter aggregation.[41] As provided in the Direct Testimony of Mr. Borkovich, the cost of implementing IS' proposal is estimated to be $4 million, which he proposes be allocated

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38 Direct Testimony of Dr. Alexander at 21, lines 13-14.
39 Direct Testimony of Dr. Alexander at 37-40.
40 D.15-06-004, mimeo., at 44 (Ordering Paragraph 14).
41 A.15-07-014.

specifically to the producers who benefit from it.[42] SoCalGas and SDG&E agree that IS' proposal would help California Producers comply with the new balancing rules proposed in my Direct Testimony, but believe it is more appropriately addressed in A.15-07-014.

XI. POSTING OF G-TBS STORAGE TRANSACTIONS IS UNNECESSARY

Parties who suggest maintaining the current storage posting requirement argue that it is necessary for what they claim is a vital monopoly storage service. They fail to provide any market analysis that supports this assertion. Furthermore, they fail to explain why a monopoly service for a vital product has not been able to generate revenues greater than costs—as has been the case over the last several years. There is nothing to be gained from this requirement, and it should be eliminated so that SoCalGas' storage is put on a similar footing with other storage providers in the competitive, interconnected Western U.S. storage market.

XII. CORE SHOULD BEAR SOME LOAD BALANCING INVENTORY COSTS

SCGC notes that "even though the Applicants propose that the core rely on the balancing inventory capacity to provide the monthly imbalance tolerance to the core, the applicants failed to allocate any of the cost of load balancing to the core."[43] SoCalGas and SDG&E agree, and this error will be corrected.[44] Contrary to SCGC's calculations, however, correcting this error increases the allocation of load balancing costs to the core by only $0.2 million, not $0.5 million.

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[42] Direct Testimony of Mr. Borkovich, A.15-07-014, at 8-9.

[43] Direct Testimony of Ms. Yap at 18-19.

[44] At page 19, line 3, Dr. Alexander of IS incorrectly states that "currently, balancing assets are dedicated to and paid for by non-core customers." Currently, core customers pay for their share of injection and withdrawal assets dedicated to both core and noncore customers for 10 percent balancing. Consistent with paragraph 9 of the 2009 Phase 1 BCAP Settlement, only inventory costs are not currently allocated to the core. In return, the core cannot exceed 83 Bcf in inventory.

XIII. SHELL'S FIRM RIGHTS PROPOSAL IS FLAWED

Shell spends much of its direct testimony complaining about SoCalGas' forecast that is used to trigger high OFOs under SoCalGas' current procedures. But all forecasts have errors. The proposed forecasting tool for the low OFOs is currently under review,[45] and SoCalGas believes that a forecasting tool for its proposed new high OFO procedures will have a similar review. If Shell is truly concerned about the unpredictability of OFOs created by inevitable forecast error, it could provide SoCalGas with a superior, more accurate forecast model developed by Shell. Alternatively, Shell could support regular daily balancing of +/- 10 percent or some similar daily balancing mechanism. Daily balancing mechanisms do not rely on forecasting tools at all, and would completely eliminate the inevitable uncertainty about which Shell complains at length.

Shell wrongly asserts that SoCalGas' storage assets are underutilized because of cuts to firm storage service.[46] Shell's assessment is incorrect because it ignores HUB activity and other transactions. A look at the "un-utilized firm capacity" page on ENVOY shows that there is less than 4 Bcf of unsold inventory and 25 MMcfd of unsold injection. If Shell does not want to purchase unbundled storage, SoCalGas is not having trouble finding other customers for that service.

Finally, Shell proposes that SoCalGas be prohibited from selling any capacity as firm that is not "commercially firm" and that SoCalGas' tariffs be amended to preclude the pro-rationing of firm injection and withdrawal rights. There are many flaws to this proposal. First, Shell makes no attempt to describe what quantities it thinks SoCalGas can offer on a firm basis. Second, Shell fails to recognize that SoCalGas' proposed downward adjustment of on-season

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45 *See* SoCalGas Advice Letter No. 4822.
46 Direct Testimony of Mr. Dyer at 7.

firm injection capacity and significant reductions of firm off-season capacities go a significant way towards increasing the firmness of its products. Third, Shell ignores the fact that firm withdrawal capacity is a function of gas in inventory. Therefore, SoCalGas cannot guarantee its 3,175 MMcfd of winter withdrawal rights are inviolate because it cannot force customers to maintain the minimum inventories necessary to make that feasible. Fourth, Shell ignores elapsed pro rata rules. SoCalGas cannot guarantee that injection nominations are firm if storage customers wait until cycle 3 to nominate those injections because the national elapsed pro rata rules would give priority to a portion of the interruptible nominations that had already flowed in earlier cycles. Fifth, Shell recommends the use of contentious and ill-defined "liquidated damages provisions" for any reduction in firm injection/withdrawal nominations, but it offers no concrete example of what it is recommending. The Commission should reject Shell's proposal.

This concludes my prepared rebuttal testimony.